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Optimization of Acid Treatments by Assessing Diversion Strategies in Carbonate and Sandstone Formations

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***Abstract*—**When acid is pumped into damaged reservoirs for damage removal/stimulation, distorted inflow of acid into the formation occurs caused by acid preferentially traveling into highly permeable regions over low permeable regions, or (in general) into the path of least resistance. This can lead to poor zonal coverage and hence warrants diversion to carry out an effective placement of acid. Diversion is desirably a reversible technique of temporarily reducing the permeability of high perm zones, thereby forcing the acid into lower perm zones.

The uniqueness of each reservoir can pose several challenges to engineers attempting to devise optimum and effective diversion strategies. Diversion techniques include mechanical placement and/or chemical diversion of treatment fluids, further sub-classified into ball sealers, bridge plugs, packers, particulate diverters, viscous gels, crosslinked gels, relative permeability modifiers (RPMs), foams, and/or the use of placement techniques, such as coiled tubing (CT) and the maximum pressure difference and injection rate (MAPDIR) methodology.

It is not always realized that the effectiveness of diverters greatly depends on reservoir properties, such as formation type, temperature, reservoir permeability, heterogeneity, and physical well characteristics (e.g., completion type, well deviation, length of treatment interval, multiple intervals, etc.). This paper reviews the mechanisms by which each variety of diverter functions and discusses the effect of various reservoir properties on the efficiency of diversion techniques. Guidelines are recommended to help enhance productivity from zones of interest by choosing the best methods of diversion while pumping an optimized amount of treatment fluid. The success of an overall acid treatment often depends on the effectiveness of the diverting agents.

***Keywords*—**Acid treatment, carbonate, diversion, sandstone.

I. Introduction

RESERVOIRS and wellbores are interconnected by pores in the formation. The flow of fluids through these pores is often restricted because of permeability damage in the near-wellbore (NWB) formation caused by drilling fluid invasion, cementing, completion operations, etc. Such operations tend to reduce the physical size of pore throats or block the pore spaces, causing impairment to the reservoir permeability. This impairment is often called formation damage.

Formation damage is quantified in terms of skin, a dimensionless factor expressing the reduction/improvement in formation permeability compared to its original permeability. Skin can be positive or negative. A positive skin value indicates a damaged formation. A zero value of skin indicates undamaged formation or original formation conditions. A damaged well can have a very high value of skin to an extent that the well will not adequately produce unless it is stimulated (skin factor reduced). For higher permeability formations, economic producing rates can often be achieved without reducing the skin to zero or a negative value. A negative value of skin implies that the well is stimulated. Causes of negative skin could be hydraulic fracturing, damage bypass, or removal through matrix stimulation. The skin factor of a stimulated well is, however, rarely lower than -5 through matrix stimulation. When formation permeability is very low, even a zero or negative skin factor may not result in economic producing rates.

NWB damage removal and skin reduction are often achieved by injecting acid or some other reacting fluid into the formation. This is an old production enhancement technique dating as far back as the nineteenth century [6]. Because of its cost effectiveness, it is still a highly preferred method of damage removal/stimulation adopted for sandstone/carbonate reservoirs. Acid treatment falls into three general categories [1].

1. Wellbore cleanout
2. Matrix acidizing
3. Fracture acidizing

A. Wellbore Cleanout / Pickling

The objective of acid washing/wellbore cleanout is simply to clean the tubular and wellbore. It is most often performed to clean out scale and other debris restricting flow in the well [1]. Wellbore cleanout is often referred in the field as pickling. This process is often used to clean treating tubulars prior to a formation acidizing treatment or even a proppant carrying hydraulic fracturing treatment to avoid carrying pipe contaminants into the formation.

B. Matrix Acidizing

During matrix acidizing, the acid treatment is injected at matrix pressure and staying below formation fracture pressure. Matrix acidizing has applications in both carbonate and sandstone formations. In sandstone formation, it is used to remove or dissolve acid removable damage in the formation pore network near the wellbore or to remove plugging in the perforations. In carbonate formations, matrix acidizing works

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best by forming conductive channels, called wormholes, through the formation rock [1].

Matrix treatments can be of three types.

1. Near-wellbore stimulation (NWS)
2. Intermediate matrix stimulation (IMS)
3. Extended matrix acidizing (EMA)

NWS is achieved through matrix treatments generally using acid volumes of 25 to 50 gal/ft of interval. If properly designed, these treatments typically improve the permeability within 2 to 3 ft of the wellbore and can result in skin factors ranging from a smaller positive skin on down to the range of 0 to -2.

IMS treatments use acid volumes of 50 to 150 gal/ft of interval. If properly designed with adequate diversion, these treatments typically improve the permeability within 3 to 6 ft of the wellbore and can result in skin factors ranging from -2 to -3.

EMA treatments are complicated and use larger volumes of acid than other treatments—often as much as 150 to 500 gal/ft of interval. These treatments can result in skin factors from -3 to -5, depending on the density of natural fractures, matrix porosity, acidizing fluids used, acid volumes, and the zonal coverage method.

C. Fracture Acidizing

During fracture acidizing, all or at least a significant portion of the acid treatment is intentionally pumped above formation pressure. For relatively heterogeneous carbonates, non-uniform etching of fracture faces can provide good flow channels after fracture pressure is removed [1]. However, due to the concern for excessive insoluble fines, this process is normally restricted to formation solubilities greater than 80% (some authors have recommend an 85% minimum solubility).

II. Multi-Zone Acid Stimulation

Often, stimulation through acidizing is required in separated discrete reservoir intervals or long productive intervals in vertical or deviated wells, or long lateral sections through a single zone.

Ideally, when acid is pumped into zones of variable permeability, it would distribute equally into all the zones. But, in reality, this does not happen; instead, when acid is pumped, distorted inflow of acid occurs into the formation for several reasons. One is that acid preferentially flows into high permeable regions over low permeable regions or, in general, into the path of least resistance.

Fig. 1 illustrates this phenomenon. This indicates two reservoir zones of 40 and 20 ft, respectively. The 40-ft interval has a permeability of 50 md, and the 20-ft interval has a permeability of 300 md and initial skin of 20 for both intervals. When acid is pumped into these zones, 75% (calculated based on relative matrix injectivity; permeability × interval height) of the acid flows into the 20-ft interval because it has a very high permeability compared to the 40-ft interval. Consequently, the damage in the 20-ft interval is removed at a higher rate and hence the skin is drastically reduced. Thus, at the end of the treatment, the 40-ft zone can have a skin of 15 and the 20-ft zone can have a skin of 0.

Such a distorted flow results into over-treating a high permeability zone and virtually not treating the low permeability zone, leading to poor zonal coverage. Because of poor zonal coverage, not all the zones stimulated with acid produce to its utmost potential, which limits the value of that stimulation treatment. This warrants the need for diversion to carry out a more effective placement of acid.

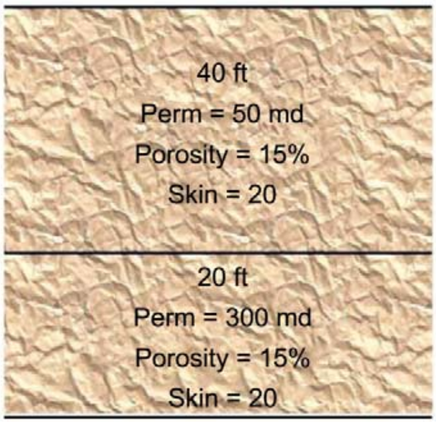

Fig. 1 (a) Before acid treatment

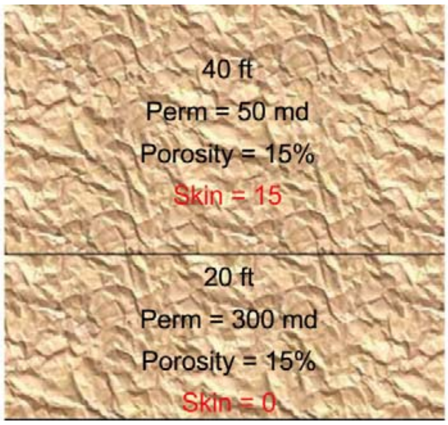

Fig. 1 (b) After acid treatment (without diverter)

Diversion is usually intended to be a reversible technique of temporarily reducing the permeability of high perm zones, thereby forcing the acid into lower perm zones. The temporary reduction in permeability is usually achieved by blocking the flow into the high perm zone so that the stimulation fluids flow into the low perm zones. This can be achieved using different diversion methods discussed later.

A. Diversion Methods

There are two basic types of diversion methods.

1. Mechanical diversion
2. Chemical diversion

Mechanical diversion, as the name suggests, is when you mechanically block the high perm zone and thereby force the stimulation to fluid pass into the low perm zone. Chemical diverter will be designed to do the same, but through chemical means, and with less assurance as with a mechanical diversion. The choice of the type of diverter method depends on its applicability, accessibility, and the associated costs. The applicability of a diverter greatly depends on the reservoir properties and the well characteristics.

III. Mechanical Diversion

The surest way to uniformly treat an interval is with a mechanical isolation device, such as when a temporary set plug or packer can be used to isolate a lower zone, or an upper zone where the packer is on the outside of a treatment string. To isolate a small zone from both zones above and below, a straddle packer might be used. However, these methods are associated with moderate to very high costs and therefore are less preferred in general.

A. Ball Sealers

Perforation ball sealers are likely the most widely used mechanical diversion method in perforated wells. Perf Ball sealers were introduced within the oil and gas industry in 1956 and have been proven to be much more economic than conventional packers [2]. Ball sealers are small spheres intended for sealing the perforation entry. The balls are usually added to the treating fluid and carried to the perforation [3], as shown in Fig. 2. To divert the ball sealer to the perforation, the inertial force of the ball must overcome the drag forces created by the fluid velocity through the perforation.

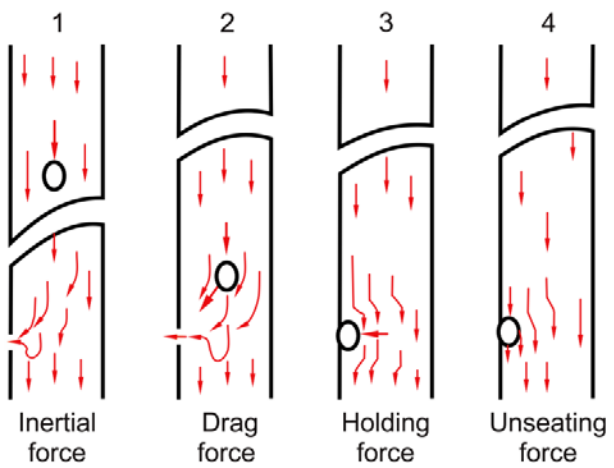

Fig. 2 Basic forces governing ball sealer efficiency [10]

The efficiency of a ball sealer depends on its seating efficiency, which in turn depends on the following [3].

- Density contrast between the ball and the fluid
- Flow rate through the perforation
- Flow rate past the perforation
- Fluid viscosity
- Differential pressure to hold a ball once seated

There are three basic types of ball sealers based on their density as compared to the carrier fluid being used for a specific treatment.

- Sinkers (non-buoyant balls)
- Floaters (buoyant balls)
- Neutral buoyant

Ball sealers generally work efficiently in vertical wells. Ball sealer efficiency in horizontal and deviated wells depends largely on the angle of well deviation, ball density, flow rate, perforation orientation, and permeability contrast. In a lateral wellbore, floating ball sealers will more easily seat on the upper side of the perforations and sinking ball sealers seat easier on the lower side of the perforations. The neutrally buoyant ball sealers have a significant (though lower) tendency to seat on the horizontally oriented perforations. Neutrally buoyant ball sealers favor 0 or 180° phased perforations.

With sinkers, excess number of balls range from 50 to 100% above the number of perforations to be “balled-out.” Literature indicates that buoyant balls are 100% efficient at all flow rates greater than 0.4 gal/min per perforation. Therefore, the number of buoyant balls used in diverting a treatment generally should not exceed 110% of the number of perforations being treated [3].

Most ball sealers work best in the temperature range of 100 to 200°F, but more costly higher temperature versions are available. The exact temperature up to which the ball sealers work is based on the material of its construction. At higher temperatures, the balls may become more deformable or degrade with time and extrude into the perforation into the formation, thereby blocking the path of reservoir fluid into the wellbore.

The principle by which ball sealers function requires the formation to have high permeability contrast. When contrast is high, the treatment fluid velocity through some perforations (connected with high permeability layers) overcomes the drag force on the balls and consequently balls seat on those perforations and divert fluids efficiently to the next set of perforations.

Sinkers can have limited effectiveness for long intervals or high-shot-density completions, as they require a minimum injection rate per perforation to prevent settling in the rat hole after bypassing all perforations. Sinkers are used in both sandstone and carbonate formations. However, Sinkers are not generally the best choice for sandstone acidizing [4].The high pump rate required to place the sinkers is usually prohibited in sandstone matrix acidizing to avoid formation breakdown.

Ball sealers are suitable with bullheading treatments. As a good practice, the treatment tubular’s inside diameter (ID) must be greater than three ball diameters if the ball is dropped in clusters. Thus, the tubing diameter becomes a constraint in CT operations.

B. Limited Entry Completions

In recent years, limited entry completions have been adopted as a common choice for the diversion technique for treating long horizontal intervals. The limited entry is achieved by proportioning the number of perforations according to the thickness of the pay zones and by pumping at pre-calculated limited entry rates; each zone will be given the desired amount of treatment fluid for effective zonal coverage. When perforation opening sizes have significantly variations, this type of application becomes more challenging.

IV. Chemical Diversion

A. Degradable Particulates

Degradable particulates, as the name suggests, are chemical particulates that, when sent downhole along with the stimulation fluid, will enter higher permeability regions and create a very low permeability cake on the formation face or a low permeability plug just inside the perforations in the pipe, in the NWB region. The added pressure drop caused by this cake increases flow resistance in the areas where diverting agents have been deposited, causing diversion of flow to other parts of the interval where little or no diverting agent has been placed.

Degradable particulate diverting materials are divided into three size groups—very coarse, coarse, and fine [5]. Depending on the pore throat dimension of the formation to be treated, the appropriate particulate diverter is chosen. To be effective, degradable particulates must have a particulate-size distribution designed to deliver the appropriate flow resistance once placed across the zone of interest. Fig. 3 illustrates a more recently introduced diverter which is a combination of different size groups.

Particulate diverters work best in perforated casing. In open hole completions, a large quantity of diverter is often required, as surface area is higher, to block the high perm. This can pose difficulties during cleanup, causing additional damage. They have limited application treating gravel packs where flow behind the screen can redistribute acid in an undesired manner.

Fig. 3 Example of newer mixed-size particulate diverter

Some particulate diverters, when used in horizontal wells, can cause well cleanup issues. They are therefore best used in vertical wells. In horizontal wells, the diverter must be carefully selected to avoid clean up issues. At higher temperatures, the particulates can either degrade or cause a delaying effect on cake buildup. Particulates work best in regions with medium permeability contrast. At low permeability contrast, cake buildup occurs more equally in all the zones and may not be effective. Particulates might not work effectively in zones of high permeability and high pore throat because the particle size might not be large enough to block the pore throat.

Although many particulate materials have been described as degradable, their removal is actually accomplished by their solubility with a subsequent fluid, either produced or injected.

The particulate selection often depends on the completion type. For open hole, the surface area and pore throat size are the deciding factors during the selection of particulates. In perforated completions, the perforation size and the particulate loading affect the amount of particulate to be pumped for diversion. When large cavities have been dissolved behind a large number of the perforation holes it could require unexpectedly large volumes of diverter material to achieve diversion.

B. Foams

In the 1980s, foam diversion became popular in both field application and academia [5]. Foam diversion is still routinely used in both sandstone and carbonate formations. The ease of pumping foamed diversion treatments, along with excellent cleanup characteristics, has substantially decreased the use of particulate diverting agents [5].

Foams exist as a two-phase system of gas and liquid. Liquid is generally the wetting phase, and thus resides as a series of lamella bridging across pore throats and as thin films on rock surface [7]. Gas is a discontinuous phase, residing in the larger void spaces in porous medium [7]. The addition of surfactant allows the foam to maintain a stable two-phase configuration in which the lamella can break and reform during dynamic events [7].

The process that causes the flow reduction when foam enters a rock formation is different than the process used with a particulate-diverting agent or a viscous gel. Because foam contains a large amount of gas, it causes an increase in gas saturation and a decrease in liquid saturation near the wellbore as it enters the rock. This saturation reduces the liquid relative permeability of the formation in the zones where foam has entered. This reduction in relative permeability can increase the resistance to liquid flow 100 to 1,000 times over the resistance originally exhibited by the formation before foam entry [7].

As foam is injected and enters the highest permeability or least damaged zones of the interval, subsequent acid stages will be at least partially diverted to zones where little or no foam has entered. The gas used for foam diversion is typically N2, while the liquid phase can be either an acid or a non-reactive salt solution, such as ammonium chloride. Sometimes, carbon dioxide is also used for foam diversion in place of nitrogen. Surfactant blends are used as foaming agents.

Foam diversion has shown to be the more effective diversion method for acidizing in slotted liner and gravel pack completions. It has proven effective in both vertical and deviated wells. Foam diversion works best in the range of 150 to 250°F. Higher temperature could have a detrimental effect on the foam quality. Sandstone formations with permeability above 150 md are the suitable candidates for foam diversion. At lower permeability, there is risk of fracturing the formations. However, in carbonates, foam diversion can be used in permeability as low as 1 md. Low perm zones will require small stages of foam for diversion and higher permeability requires continuous diversion. Foam diversion works best in the range of 50 to 500 ft of treatment interval with a bullheaded treatment method. In much longer treatment intervals, pumping foam becomes difficult due to high friction pressure. Coiled tubing (CT) is the preferred placement method in longer intervals. The wormholes produced in the presence of foam are thin and uniform in diameter and display very little branching. Foam diversion is more preferred in gas reservoirs than in oil and water reservoirs because cleaning is easier in gas wells.

Displacing the high-density fluid with low-density gas in CT is difficult. However, CT is a common medium for injection of foamed acid or foam diversion. The small diameter coil allows for maintenance of foam quality and stability during injection, thereby increasing the chances of efficient diversion, which otherwise is difficult. Thus both bullheading and CT can be preferred.

Foam diversion has some drawbacks, including high pump friction pressure, more required equipment on location, and possibly greater overall job costs [5].

C. RPMs

RPMs were first introduced to reduce water cut in producing wells. The basic function of a RPM is to reduce the treated interval’s effective permeability to water while keeping permeability to oil or gas near constant [8]. Theoretically, with water wet formations, simultaneous water flow path and oil flow path in the same capillary or flow channel is different. Water flows along the periphery of the capillary/channel and oil flows through the core of the capillary/channel. Thus, water layers lie against the rock surface. The RPM functions by adsorption onto rock surfaces and effectively reduces water flow with little or no damage to hydrocarbon flow.

RPMs can also be used as diverters in acid treatments [13]. The RPM system complements virtually any acid treatment to help ensure targeted hydrocarbon-producing zones are selectively acidized relative to water-producing zones. The system is placed in alternating stages with the acid throughout the entire treatment. The treatments are extremely easy to mix and pump and often require no post job shut-in time. It is a solids-free diverter (as opposed to the plugging mechanism of typical particulate diverters). The system can be used for sandstone and carbonate formations. Thus, RPM works simultaneously as diverter during the treatment (i.e., injection) and as conformance agent during production.

RPMs work equally well in all types of completions. They are used effectively in both vertical and deviated or horizontal wells. Most polymers used as RPMs work best in the range of 50 to 200°F. The best candidates for RPM polymers are formations with permeability less than 500 md. RPMs can be used both in sandstone and carbonate formations. Thus, being a conformance agent, it is never used in wells that are intentionally water producers. Both bullheading and CT are preferred for placing the polymer, depending on the specific well condition.

D. Viscous Diverter

High viscosity gels create a permeability barrier and subsequent fluid stages are diverted to other sections of the zone. Viscous diverters are of three types.

1. Crosslinked acid systems
2. Gelled acids
3. Gel slugs

Crosslinked acid systems have been introduced within the industry to offer effective uniform treatment over long horizontal well intervals to treat damaged and low permeability zones [9]. Crosslinked acid systems have initial surface viscosity of approximately 20 centipoise (at 511 sec-1 shear rate), allowing for ease of pumping. As the acid system enters the zones offering the least resistance to flow, the acid crosslinks in the formation as it spends to a pH of 2 to 4. A buffer is added to help maintain this pH range for as long as possible. However, as the pH of the system increases above 4, the crosslinked gelled acid will break to a viscosity of approximately 5 centipoise (at 511 sec-1 shear rate), allowing for ease of flow back. An internal breaker can also be included. The resistance to flow provided by the crosslinked gel causes the diversion acid to force its flow into the lower permeability section(s) of the interval. The degree of diversion can be controlled by adjusting the HCl concentrations in crosslinked acid systems.

The viscoelastic surfactant (VES) molecules form rod-like micelles in the presence of salt at specific pH conditions, which results in significant viscosity increase. Therefore, when added to acid systems, VES helps increase the viscosity of the solution based on the acid-carbonate rock reaction [9]. These systems often include an internal breaker. In the absence of an internal breaker, mutual solvents or hydrocarbon flush are used to break the VES after diversion.

Gelled acids are when gelling agents are added to HCl, organic acids, and blends of these acids to produce viscosified acid. They can serve as tubular friction reducers for acidic fluids when added in low quantities. Gel slugs, or pills, are the stages of high viscosity fluids. Because this system does not require any crosslinking agent, temperature consideration is important, as increased temperature both reduces the viscosity and usually aid breaking of the gel within the system. Although we do not want the gel polymers to break down too quickly, after acid reaction is complete if the gel does not break then the residue from the gel may reside in the formation for a long period.

Gelled acid and crosslinked acid systems are preferred in openhole completions, slotted liners, and perforated casings. Unlike ball sealers and many of the historic degradable particulates, viscous diverters work well in both horizontal and deviated wells. Gelled acids work well in temperatures up to 250°F, beyond which they begin to degrade at faster rates. Compared to gelled acids, crosslinked gels can work at a higher temperature range. However, forcing the gels into low permeability zones requires high pressure that makes crosslinked gels more preferred in high permeability zones. Gel damage to the formation seems to be of greater concern in gas wells, and hence are not generally the preferred choice for acidizing of gas formations. The viscous diverters can be placed both by CT and by staged application when bullheading treatments.

One of the desired applications of gelled and crosslinked acid is controlling the leakoff, particularly in openhole completions. These systems are preferred when rate restrictions are applied because of surface limitations, and for NWB stimulation of long intervals.

V. The MAPDIR Technique

The MAPDIR technique refers to the maximum pressure differential and injection rate method for matrix acidizing. This was first introduced by Paccaloni and Tambi in 1993 and is sometimes referred to as Paccaloni's method. This technique uses injection rate as the key parameter to obtain sustained, planned, bottomhole differential pressure during the treatment [12]. MAPDIR calls for pumping acid stages at as high of rates as possible, but below fracture pressure. It is claimed that, by maintaining maximum allowable injection pressure, the need for diversion is greatly reduced [11].

It is postulated that if MAPDIR is applied under proper conditions, diverting agents might not be necessary [11]. When the interval to be treated is short and there is a low injectivity contrast within the zone, the MAPDIR technique has often proven more effective than treatment at a constant limited rate with diversion methods. However, in long intervals and/or high permeability variations, MAPDIR is recommended only in combination with the use of a diversion method.

VI. Conclusion

The study of diversion methodology has progressively improved the economic success of acid treatments. Over the years, a number of guidelines have been developed with respect to the application of modern diversion techniques. These theories have provided the following conclusions for selection of the best diversion method:

- Reservoir properties, well characteristics, and the purpose of the treatment must be thoroughly assessed.
- Sometimes, combinations of diverters work better than using a single diverter.
- Injection method also plays a critical role in effective placement.
- The cost and availability sometimes alter the diversion method selected.
- Optimization tools help quantify the diversion effect to defined objectives.
- The proposed guidelines might not apply in complicated well or formation scenarios.

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