UNIT-III

Acid Fracturing, Acid Systems and Placement Techniques, Fracturing of Deviated and Horizontal Wells, Matrix Stimulations, Matrix Acidizing Design, Rate and Pressure Limits for Matrix Treatment, Fluid Volume Requirements.

ACID FRACTURING

Designing an acid-fracturing treatment is similar to designing a fracturing treatment with a propping agent. Williams, Gidley, and Schechter presents a thorough explanation of the fundamentals concerning acid fracturing. The main difference between acid fracturing and proppant fracturing is the way fracture conductivity is created. In proppant fracturing, a propping agent is used to prop open the fracture after the treatment is completed. In acid fracturing, acid is used to "etch" channels in the rock that comprise the walls of the fracture. Thus, the rock has to be partially soluble in acid so that channels can be etched in the fracture walls. As such, the application of acid fracturing is confined to carbonate reservoirs and should never be used to stimulate sandstone, shale, or coal-seam reservoirs. Long etched fractures are difficult to obtain because of high leakoff and rapid acid reaction with the formation.

(i)Acid-Fracturing Candidate Selection

In general, acid fracturing is best applied in shallow, low-temperature carbonate reservoirs. The best candidates are shallow, in which the reservoir temperature is less than 200°F and the maximum effective stress on the fracture will be less than 5,000 psi. Low temperature reduces the reaction rate between the acid and the formation, which allows the acid to penetrate deeper into the fracture before becoming spent. Because limestone reservoirs are ductile, a low effective stress on the fracture is required to maintain adequate fracture conductivity over the life of the well. In deep limestone reservoirs, in which problems exist with high bottom hole temperature and high effective stress on the fracture, water-based fluids with propping agents can be used successfully to stimulate the formation. In deep dolomite reservoirs that are less ductile than limestones, acid fracturing may work satisfactorily; however, proppant fracturing with water-based fluids may work also.

Acid-fracture fluids with propping agents are not recommended. When the acid reacts with the carbonate formation, fines are always released. If a propping agent is used with acid, the fines plug up the propping agent, resulting in very low fracture conductivity. When deciding to stimulate many carbonate reservoirs, the costs and benefits of an acid-fracture treatment should be compared with a treatment that uses water-based fluids carrying a propping agent. It should not be assumed that acid fracturing works best because the

Formation is a carbonate.

There could be a few applications in which acid fracturing could be the preferred treatment in a deep, high-temperature carbonate reservoir. For example, if a high-permeability carbonate reservoir is damaged as a result of drilling operations or non-Darcy flow effects, then a stimulation treatment can be applied to improve the productivity index. In such cases, injecting acid at fracturing rates can improve the permeability near the wellbore, which will reduce the pressure drop caused by skin and/or non- Darcy flow .

In other cases, especially in deep dolomites that contain an abundance of natural fractures, acid fracturing may work better than proppant fracturing. In such reservoirs, it is common that multiple fractures are opened when pumping begins. With multiple fractures, no single fracture ever gains enough width to accept large concentrations of propping agent. Near-wellbore screenouts often occur as the proppant concentration is increased to more than 2 to 3 ppg. In such cases, acid fracturing may work better than proppant fracturing.

Other considerations when selecting acid-fracturing candidates are cost and safety. In deep, hot reservoirs, the cost of an acid-fracturing treatment can exceed the costs of a proppant-fracture treatment. In hot reservoirs, expensive chemicals are required to inhibit the acid-reaction rate with the steel tubular goods and to retard the reaction rate with the formation. Acid must be handled with extreme care in the field. When pumping large volumes of high-strength acid, at high injection rates and at high pressures, safety should be the top concern of everyone in the field.

(ii)Acid Fluids Used in Fracturing

The most commonly used fluid in acid fracturing is 15% hydrochloric acid (HCl). To obtain more acid penetration and more etching, 28% HCl is sometimes used as the primary acid fluid. On occasion, formic acid (HCOOH) or acetic acid (CH_3COOH) is used because these acids are easier to inhibit under high-temperature conditions. However, acetic and formic acid cost more than HCl. Hydrofluoric acid (HF) should never be used during an acid fracturing treatment in a carbonate reservoir.

Typically, a gelled water or cross linked gel fluid is used as the pad fluid to fill the wellbore and break down the formation. The water-based pad is then pumped to create the desired fracture height, width, and length for the hydraulic fracture. Once the desired values of created fracture dimensions are achieved, the acid is pumped and fingers down the fracture to etch the walls of the fracture to create fracture conductivity. The acid is normally gelled, crosslinked, or emulsified to maintain fracture width and minimize fluid leakoff. Because the acid is reactive with the formation, fluid loss is a primary consideration in the fluid design. Large amounts of fluid-loss additives are generally added to the acid fluid to minimize fluid leakoff. Fluid-loss control is most important in high permeability and/or naturally fractured carbonate formations; thus, long etched fractures are difficult to obtain.

(iii)Acid-Fracture Design Considerations

In addition to Williams, Gidley, and Schechter.,two papers provide the technology commonly used today to design acid fracture treatments. There are several unique considerations to be understood when designing acid fracture treatments. Of primary concern is acid-penetration distance down the fracture. The pad fluid is used to create the desired fracture dimensions.

Then the acid is pumped down the fracture to etch the fracture walls, which creates fracture conductivity. When the acid contacts the walls of the fracture, the reaction between the acid and the carbonate is almost instantaneous, especially if the temperature of the acid is 200°F or greater.

As such, the treatment must be designed to create a wide fracture, with minimal leakoff, with viscous fluids. **Fig.1** illustrates why the design engineer should be striving to create a wide fracture. If a wide fracture is created with a viscous acid and minimal fluid loss, then a boundary layer of spent acid products will reduce the rate at which the live acid contacts the formation at the walls of the fracture. However, as the flow in the fracture becomes more turbulent and less laminar, the live acid will contact the walls of the fracture more easily, and the acid will not penetrate very far into the fracture before Becoming spent.

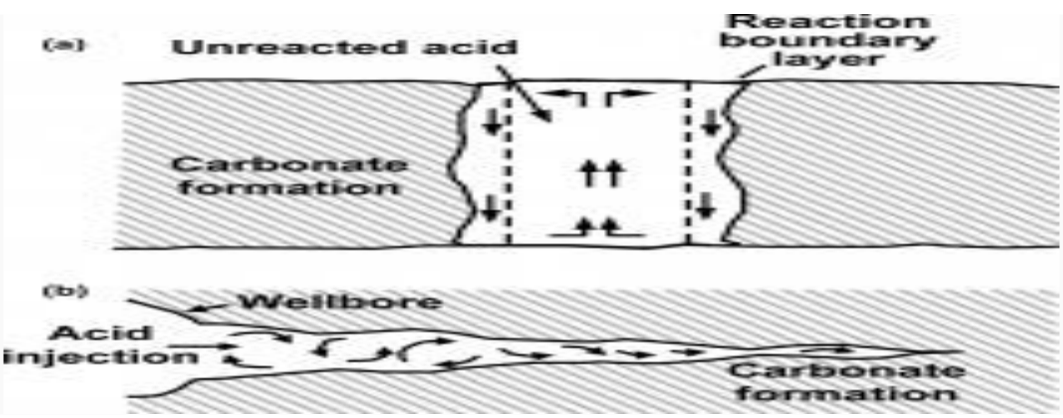

Fig. 1—Acid-flow behavior in the fracture

Factors such as fracture width, injection rate, acid viscosity, and reservoir temperature all affect acid penetration. **Figs.2 and 3** illustrate how fracture width and formation temperature affect acid penetration in the fracture, respectively. In **Fig.2**, as the fracture width increases, the distance that unspent acid will reach in the fracture also increases. The distance increases because, in a wide fracture, there is less turbulence. This results in less mixing as the live acid moves down the fracture; therefore, the viscous and leakoff properties of the fracture fluid should be controlled to maximize fracture width. **Fig.3** contains information concerning the effects of reservoir temperature, acid strength, and formation lithology.

It is clear that the use of higher-strength acid increases the penetration distance in the fracture before the acid spending. Also, as temperature increases, the acid penetration distance decreases. As the temperature increases, the reaction rates between the acid and the formation increase substantially. In fact, the reaction rate doubles every time the temperature increases 18°F **Fig.3** also shows that dolomite is less reactive with HCl than limestone; therefore, acid fracturing may work slightly better in reservoirs that are more highly dolomitized.

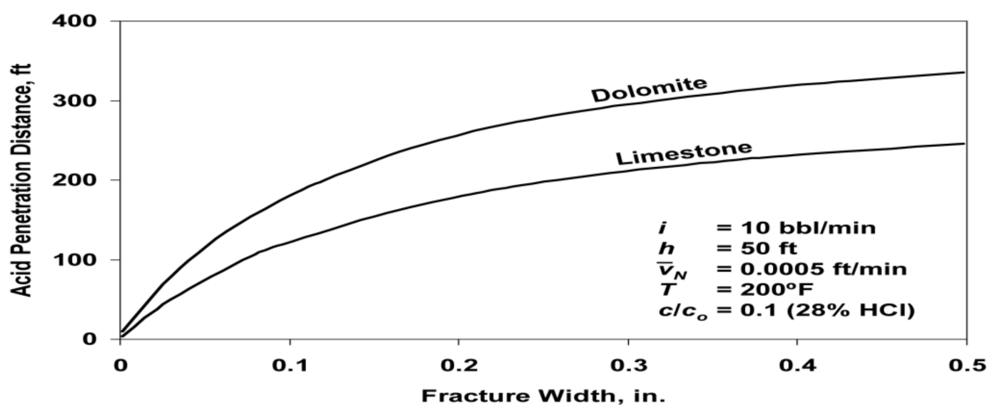

Fig.2 **Effect of fracture width on acid-penetration distance**

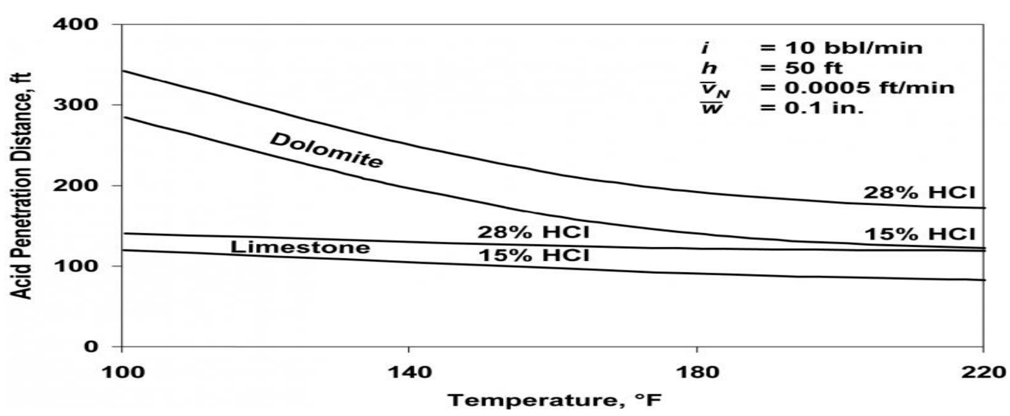

Fig.3. Effect of temperature, lithology, and acid concentration on acid-penetration distance

The problem with acid fracturing that prevents its successful application in many reservoirs involves sustaining fracture conductivity over time. When the acid etches the fracture walls, the resulting fracture conductivity can be several orders of magnitude more conductive than similar treatments that use water-based fluids and propping agents.

Fig.4 presents data concerning fracture conductivity as a function of effective stress on the fracture and rock embedment strength. The embedment strength is easily measured and can be correlated with the compressive strength of the rock. As the compressive strength increases, the rock embedment strength increases. The data in **Fig. 4** show that, when the embedment strength is less than 100,000 psi, large fracture conductivities, on the order of 10 to 50,000 md-ft, can be created during an acid-fracture treatment, as long as the effective stress on the fracture is 1,000 psi or less. However, once the effective stress on the fracture exceeds 5,000 psi, the fracture conductivity decreases substantially. As such, in deep limestone reservoirs in which the maximum effective stress on the fracture is much greater than 5,000 psi, an acid fracture will not stay open as the well is produced. In such cases, water-based fluids carrying propping agents should be considered as an alternative to acid fracturing.

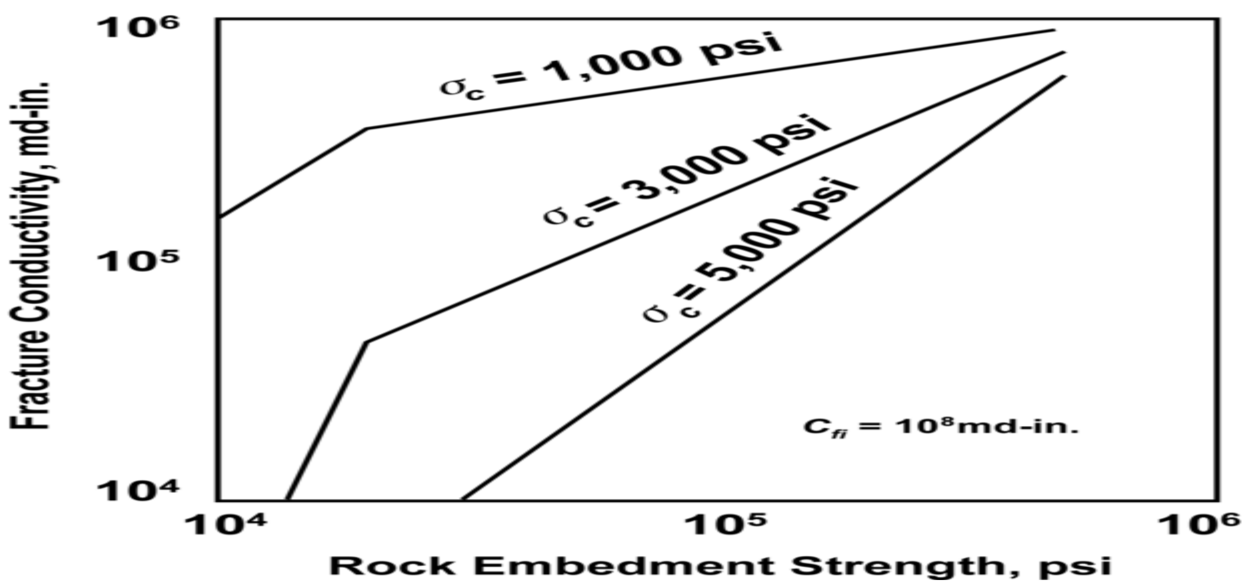

Fig.4. Fracture conductivity in a carbonate reservoir as a function of effective stress on the fracture and embedment strength

ACID SYSTEMS AND PLACEMENT TECHNIQUES

(i)Acid flow paths

In a typical treatment, most acid enters the formation through the least damaged perforation tunnels, as the schematic in **Fig. 5**shows.

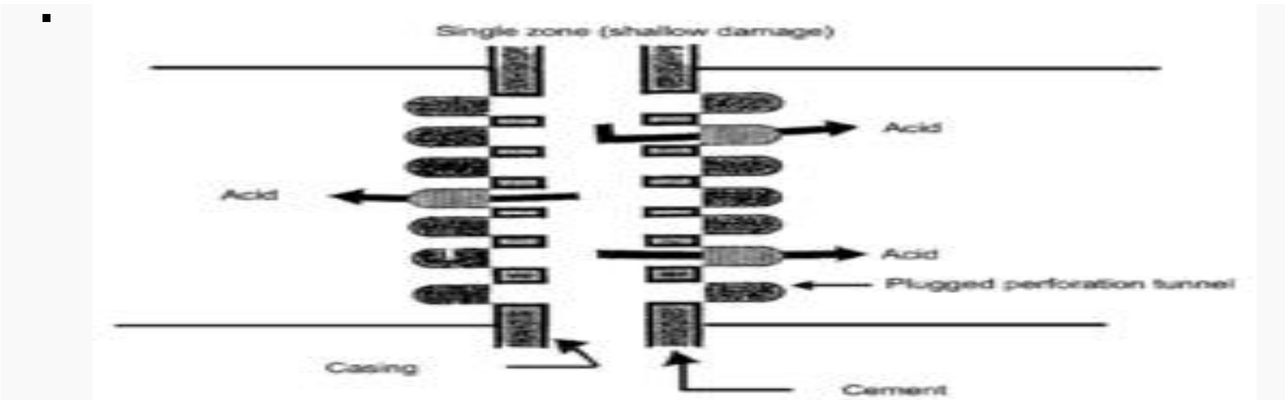

Fig. 5.Acid entry into formation through perforations

When this happens, it can be readily concluded that acidizing does not work well and is expensive. However, acidizing does work very well to remove damage when the type of damage is known, and known to be acid-removable, the treatment is properly designed and properly executed. Extreme damage may require more than what is discussed. Actions required may include a chemical soak and swabbing the soak back before acidizing or reperforating, and/or fracturing to bypass damage. Even moreso, long horizontal or deviated, open hole completions limit diversion and placement options. Different placement considerations than those discussed below, must be made.

Numerous methods help control acid placement. Selection is based on:

- Wellbore hardware
- Formation characteristics
- Field experience

Additional guidelines are provided in McLeod. The four main types of zone coverage techniques in matrix acidizing of cased and perforated completions are:

- Mechanical
- Particulate
- Viscosity
- Density segregation

These methods also can be combined in treatments.

(ii)Mechanical techniques

Opposed cup packer or perforation wash tool

This perforation wash tool allows selective injection of acid into closely spaced perforations in high-permeability formations. High rate and/or pressure should be avoided when using either this tool or closely spaced straddle packers. High pressures can cause the cups to leak or turn over or the tool to separate at the port (the weakest part). High pressure can also establish communication behind the pipe between the point of injection and nearby perforations without removing damage from the plugged perforation. This type of isolation is best used for removing damage from severely plugged perforations in high-permeability formations. A field example of this technique in a Gulf Coast sandstone is given by McLeod and Crawford.

Squeeze packer and retrievable bridge plug

A good method of isolating perforated intervals is to use a retrievable bridge plug and a squeeze packer. The bridge plug is set in blank sections of casing between perforated sections. The treatment usually begins with the lower set of perforations and finishes with the upper set. Straddle packers may be used in a similar way and have been used successfully in the Permian Basin to better clean damaged perforations.

Ball sealers

Ball sealers can be divided into two categories:

- Heavier (sinkers) than the fluid
- Lighter (floaters) than the fluid

Successful use requires a good cement job on the installed casing and round good quality perforation holes. Sinkers have been used the longest and usually require 200% excess ball sealers and a high pump rate (greater than 5 bbl/min). The high pump rate usually prohibits their use in sandstone matrix acidizing, but they may be used in fracture acidizing or perforation breakdown. Floaters, or neutral-density ball sealers, provide excellent mechanical isolation for matrix acidizing at injection rates of 1 bbl/min or higher. The density or specific gravity of these ball sealers is matched to the fluid being pumped so better ball action will take place. Surface flowback equipment must be modified to catch the floating ball sealers during flowback.

Ball sealers are limited in their use. They are not used in:

- Long intervals with high-perforation density

- Wells perforated with more than 4 shots/ft, low-rate treatments (1/4 to 1/2 bbl/min)
- Gravel-packed wells

Regardless of the type of treatment or ball used, treatment will be more effective when density of the ball is very close to the density of the fluid used in the treatment.

(iii)Particulates

Pre-gravel pack acid treatments

One effective way to divert acid in a treatment before gravel packing is to use slugs of hydroxyethylcellulose (HEC) gel and gravel-pack sand. Ammonium chloride brine mixed with HEC at a concentration of 90 lbm/1,000 gal can be mixed in 5-bbl batches with 100 lbm of correctly sized gravel-pack sand. The combination of viscosity and sand packing helps divert acid to other perforations. The unique feature of this method, as opposed to other "particulate diverters," is that the perforation tunnel is packed with gravel-pack sand instead of some other material that would prevent gravel-pack slurry from entering the perforations during later slurry placement.

Soluble particulate diverters

Selection of the optimal particulate diverter is based on the kind of fluid injected and/or produced. The diverter must be temporary and easily removed; otherwise, there will be a new kind of damage to be treated and removed. Oil-soluble resin (OSR) is one of today's more common diverting agents. OSR is slowly soluble in toluene, xylene, condensate, crude oil, and EGMBE (mutual solvent). OSR should be mixed on site with a blender and immediately pumped or added to the acid "on the fly" with a chemical injection pump. If OSR diverters are mixed off location or are allowed to stand for an hour or more, they will clump and may cause pump failure or plug perforations. OSR diverters should not be used with solvent-acid mixtures, which dissolve the resin enough to reduce its effectiveness. The chart in **Fig. 6** shows the application of high concentrations of OSR to achieve significant pressure increases by more effective diverter action. The annular pressure (static column of fluid between the well tubing and coil tubing) shows pressure increases when diverter concentration increases. [4] Please refer to Brannon[5] for a full explanation. Shown in **Fig. 7** are gamma ray logs before and after using radioactive tracers with OSR diverters in a California well. [1] Such tracers are excellent diagnostic tools to find where the acid is going. In this case, radioactive intensity shows that most of the acid bypassed the preferred interval and went behind the casing and entered a thief zone behind the pipe.

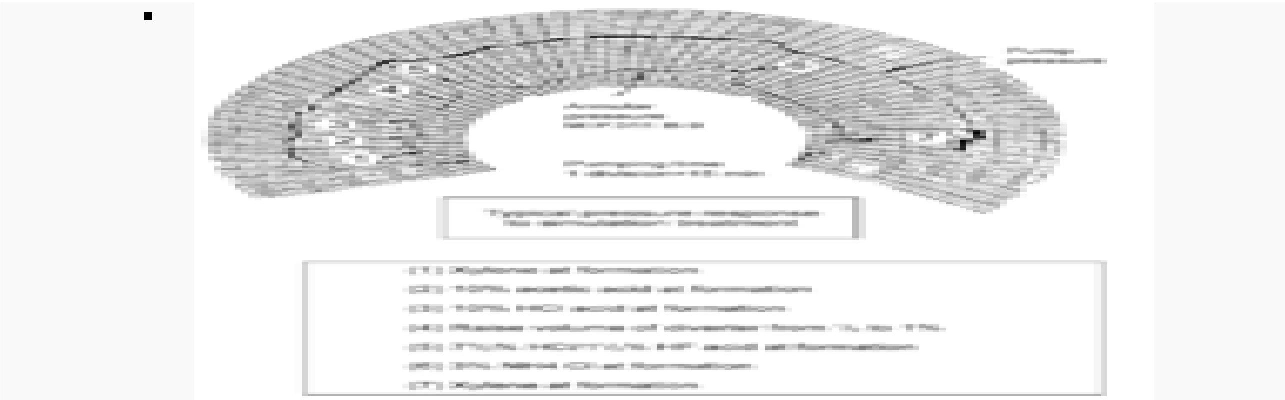

Fig. 6—Pressure response to acidizing using OSR diverter.

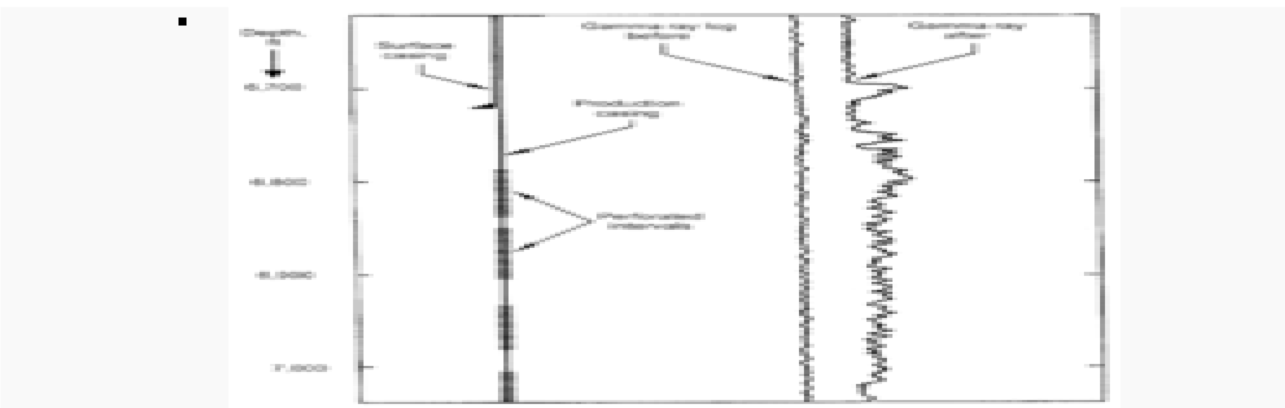

Fig. 7—OSR diverter evaluation radioactive tracer.

Benzoic acid flakes or powder are soluble in toluene, xylene, alcohol, and some condensate fluids. They dissolve very slowly in water/gas. Benzoic acid is often used because it is soluble in the fluids normally encountered in oil/water wells; however, if not well dispersed or mixed, it will plug perforations. Benzoic acid plugs do not dissolve fast because not enough fluid can flow by it to dissolve the plug. One well took 6 months to return to normal productivity after being treated with caked benzoic acid powder delivered to the location.

(iv)Viscous acid

Thickening the acid through use of soluble polymers, nitrogen and foaming agents, or dispersing oil (either as loose two-phase mixtures or with emulsifiers) is useful in high-permeability formations with deep damage. Design is difficult; therefore, experience and on-site flexibility are important for success. Excellent results have been obtained with staged foam slugs between acid stages in high-permeability Gulf Coast gas wells to remove near-wellbore damage. This technique is so promising because the diverter (gas and fluid) disappears when the foam breaks with little chance of damage as with slowly dissolving particulates. See Gdanski and Behanna for useful guidelines.

Fadele *et al.*show that diverters often need not be used in gas wells because of the natural viscous diversion. Water and acid are 100 times more viscous than gas, and this provides a natural diversion for acid entering a gas formation. This may be one reason acidizing works better in gas wells than in oil wells. Other recent papers offer further improvements with viscous acids and diverters.

Other significant factors are the rathole below the lowest perforation and the space just above the top perforation and below the packer. Rathole fluid should be heavier than the acid, and fluid above the top perforation should be lighter than the acid. If not, acid can end up in the rathole rather than the formation. Acid left in the borehole can cause casing leaks below the treated interval. Spotting acid over the perforations before injecting is very important in low to moderate permeability (10 to 50 md), and density segregation must be planned to achieve the best contact of acid with damaged perforations in these formations. Concentric tubing helps to achieve accurate placement of the acid in the wellbore to take advantage of density segregation.

Concentric tubing

Concentric tubing is preferred for matrix acid treatments, because it:

- Allows the rathole to be circulated clean
- Permits better placement for acid contact with all perforations
- Bypasses production or injection tubing debris
- Can be acid cleaned on surface before running into the hole
- Limits pump rate to 0.5 to 1 bbl/min because of fluid friction pressure in small tubing (1 to 1.5 in.)

(v)Advances in acid diversion

The design and implementation of diverting systems has been advanced by recent design techniques but still relies on guidelines and field experience. Hill and Rossen[11] have provided a better means to compare diverting methods and design diverting treatments. Gdanski and Behenna[6] have provided some appropriate guidelines for foamed acids or foamed-diverter stages.

Hill and Rossen compared the techniques of:

- Injection rate diversion, coined MAPDIR[12] (maximum pressure differential and injection rates)
- Particulate diverting agents
- Viscosified fluids
- Foamed acid

(a)MAPDIR(maximum pressure differential and injection rates)

introduced by Paccaloni in 1992,results in effective treatment of lower-permeability layers but at the expense of much larger volumes of acid. It may also be limited in use by pump and tubing capacities. Wells can clean up faster because no particulates are used. Also, treatment time is less to achieve the same reduction in skin factor as other techniques. The particulate diverting is most efficient in terms of volumes of acid and, thereby, is generally more economic if treating time is not a large economic factor. Oil soluble resins are not completely oil soluble, and sometimes plugging by these resins may not be temporary. Better quality assurance/quality control (QA/QC) is required for successful implementation. Quality assurance is the pretreatment planning to ensure that proper materials and procedures are used. Quality control is on-site supervision and testing to ensure that quality treatment is performed. Foam diversion is nondamaging in that surfactants are soluble and removable in produced water and nitrogen is recovered. Foams are most difficult to design and are not completely understood in terms of their behavior in different formations; however, guidelines for designing and implementing foam treatments are provided by Gdanski and Behenna. [6] Foams tend to be more stable in high-permeability layers and, therefore, reduce the acid losses in these layers. They also tend to be more stable in water zones and less stable in oil layers, providing some selectivity in treating wells with high water cuts or nearby bottom water. Viscosified fluids are similar to foam but provide a more consistent fluid hydrostatic pressure when well pressure limitations are present. The viscous behavior of these fluids in different formations is not well defined. These systems may be combined with MAPDIR when rate is limited by equipment.

FRACTURING OF DEVIATED AND HORIZONTAL WELLS

Horizontal wells are special cases, which have been covered by Frick and Economides. They emphasize how damage control and removal is just as important in horizontal wells as in vertical completions. Moderate damage can reduce horizontal well productivity to that below the productivity of an undamaged vertical well. The authors provide a stimulation technique employing coiled tubing. They also provide a design strategy for calculating volumes of acid required and the rate of coiled-tubing withdrawal during acid placement. A method of optimization for completion and stimulation of horizontal wells is also presented. Other papers have further advanced the planning, design, diversion, execution, and evaluation of acidizing horizontal wells employing similar methods to those used in vertical wells.

Fracturing of highly deviated and horizontal wells poses new challenges, results in certain advantages and creates new possibilities. Although there are some examples of large-volume hydraulic fracturing operations (i,e., Overbey et al., 1988), success in the fracturing of horizontal and high angle wells has not always been met. In the past, fracturing of deviated wells has been unsuccessful or not aggressively pursued for a number of reasons, including the following. Concern as to what methods would be economically effective for isolating individual stages and whether or not simultaneous injection into multiple fractures is an effective stimulation procedure. The later will be discussed further. Failure of some hydraulic fracturing stimulations associated within attention to the unique stress conditions around boreholes. Some of these treatments have been performed under the false premise that fracture initiation and propagation would not differ from that for a vertical well. The direction of fracture initiation may not be the same as the ultimate direction of propagation (preferentially perpendicular to the minimum principal stress, unless overridden by in-situ discontinuities). Hence, induced hydraulic fractures may not be planar, they will initiate in a direction governed by a dynamic interaction between the stress conditions prevailing at the wellbore wall and the rate-viscosity characteristics of the treatment, later propagating in a direction perpendicular to the minimum in-situ stress component. These aspects and the associated economic considerations should be addressed in planning the fracturing of high-angle and horizontal Well.

Fracturing from horizontal and highly deviated wells can often result in complex, non-planar fracture geometry. A two-dimensional model was developed to analyze the effects of non-planar fracture propagation for different in situ boundary conditions and hydraulic fracturing parameters. Numerical simulations show that curving fracture geometry reduces created fracture length compared to a planar fracture and causes a fracture width restriction at the wellbore. Reduction in fracture length can reduce expected well stimulation effects and jeopardize well economics. Near-wellbore width restrictions increase fracture treating pressure and may cause wellbore screen-out during the proppant stages of a fracturing treatment. The negative impact of non-planar geometry can be mitigated with short perforated intervals, high viscosity fracturing fluids, proper wellbore alignment and pre-pad proppant slugs for near-wellbore erosion.

Hydraulic fracturing in deviated and horizontal wells offers new challenges compared to operations in vertical wells. The fracture geometry can be more complicated due to the fact that the wellbore is not necessarily aligned favorably with the in-situ stress state. Non-planar propagation of the fracture can result in excess treating pressure, potential bridging and screen-out of the proppant near the wellbore, and high closure stresses on the proppant. Experimental work has shown that for non-planar fracture geometries, fracture widths near the injection point are diminished and treating pressures are abnormally high.

The numerical model developed for this work is intended to quantify the effects of non-planar fracture geometry on treating pressure, fracture width, fracture length, and potential sand transport. It can be used as a predictive tool to analyze the effects of in-situ stress magnitudes, wellbore orientation, perforation interval length, pump rate and fluid viscosity on fracture treatment behavior for highly deviated and horizontal wells.

MATRIX STIMULATIONS

It goes without saying that the oil and gas industry faces unprecedented challenges today. Low oil prices are driving continued improvements in efficiency and a search for technologies to deliver barrels at the lowest possible cost. Health, safety, and environmental (HSE) impacts of chemicals used in drilling, completion, and production operations are under increased scrutiny from regulatory and community stakeholders. At the same time, more and more complex and technically challenging reservoirs must be developed to replace reserves.

Matrix stimulation is being used to maintain production from existing wells and reservoirs and maximize production from new wells at an attractive cost per incremental barrel. Close cooperation between suppliers, service companies, and operators is required to deliver systems-level life-cycle solutions that leverage the HSE benefit to improve effectiveness and operational efficiency.

Over nearly a century of application and study, acidizing technologies have been matured for relatively pure carbonates, clean sandstones (less than 10% carbonate), and temperatures below approximately 100°C. Today, the industry is developing reservoirs that have more-complex mineralogy, greater permeability contrast, and higher temperatures. New chemistries are being deployed to control the aggressiveness of stimulation fluids at high temperatures and to minimize the effect of unwanted damaging precipitation reactions. Sandstone matrix acidizing traditionally requires the use of a carefully designed sequence of stages to manage the complex reactions between hydrofluoric acid and siliceous minerals. New formulations that can be applied at higher temperatures and sometimes with a single stage have been developed and deployed in the field. In addition to increasing the potential application range and effectiveness, these formulations reduce the chemical footprint of sandstone stimulation. Laboratory data indicate that they are very effective but must be tailored carefully to the target reservoir. Continued experiments, theoretical modeling, and field testing are needed to understand and achieve the full benefits of deploying these new technologies.

In low-permeability carbonate reservoirs, acid stimulation is a low-cost alternative to propped hydraulic fracturing. New chemical and mechanical diversion technologies are being deployed to enable creation of distributed etched-fracture and wormhole networks along long interval and multilateral wells in low-permeability and heterogeneous reservoirs. These technologies are being taken up across the globe and are delivering optimized treatment designs and execution on a large scale.

Finally, there is an ongoing effort to use state-of-the-art simulation technologies (e.g., computational fluid dynamics) to model complex coupled reaction and flow processes and improve the understanding of stimulation processes and interpretation of more-detailed data now available (e.g., from distributed-temperature sensing).

Matrix stimulation remains a critical technology for delivering barrels at minimum cost. It is finding application in unconventional- as well as conventional-reservoir development. Chemical formulations and theoretical models continue to develop, sometimes incrementally and sometimes in step changes, to broaden the scope of application, improve effectiveness, reduce cost, and reduce HSE impact.

A treatment designed to treat the near-wellbore reservoir formation rather than other areas of the production conduit, such as the casing across the production interval, production tubulars or the perforations. Matrix stimulation treatments include acid, solvent and chemical treatments to improve the permeability of the near-wellbore formation, enhancing the productivity of a well. Matrix stimulation is a process of injecting a fluid into the formation, either an acid or solvent at pressures below the fracturing pressure, to improve the production or injection flow capacity of a well.

The goal of a matrix treatment is different in sandstones than in carbonates. In sandstones, matrix treatments restore or improve the natural formation permeability around the wellbore by removing formation damage, by dissolving material plugging the pores or by enlarging the pore spaces. In carbonates, matrix stimulation creates new, highly conductive channels (wormholes) that bypass damage. Because of these differences, the selection criteria for the treating fluid are also distinct.

For sandstone treatments, knowledge of the extent, type of damage, location, origin, reservoir mineralogy (petrographic study) and compatibility of the treating fluid with the formation are especially important. In carbonate treatments, reservoir temperature, pumping rate and fluid type become more significant because these parameters directly affect the reactivity of the treating fluid with the reservoir rock.

A sandstone matrix stimulation treatment is generally composed of a hydrochloric acid [HCl] preflush, a main treating fluid (HCl-HF mixtures) and an overflush (weak acid solution or brine). The treating fluid is maintained under pressure inside the reservoir for a period of time, after which the well is swabbed and returned to production. In carbonate reservoirs, HCl is the most common fluid used. Organic acids such as formic and acetic acid are used in either sandstone or carbonate acidizing, mainly in retarded-acid systems or in high-temperature applications. Matrix stimulation is also called matrix treatment or matrix acidizing.

MATRIX ACIDIZING DESIGN

Once you determine that a well is a good candidate for matrix acidizing and have selected appropriate acids, you are ready to design the treatment. Essentially, the design process is a systematic approach to estimating and calculating injection pressure and rate, volumes, and concentrations. Live HF acid usually penetrates only about 6 to 12 in. into the sandstone before spending. If acid can easily reach nearby plugging solids, small volumes of 25 to 50 gal/ft of HF-type acid can dissolve this damage; however, with more severe damage, more time and volume are needed to reach the plugging solids. Effective acid diversion reduces acid volumes needed.

Design Steps

- Estimate safe injection pressures: determine present fracturing gradient, determine present bottom hole fracturing pressure, and determine allowable safe injection pressure at both the wellbore (at least 200 psi below fracturing pressure) and at the surface (tubing and wellhead pressure limitations).
- Estimate safe injection rate into the damage-free formation.
- Estimate safe injection rate into damaged formation.
- Select stages required for fluid compatibility.
- Calculate volume of each stage required: crude oil displacement, formation brine displacement, acetic acid stage, hydrochloric acid stage, hydrofluoric acid (HF and HCl acid) stage, and overflush stage.
- Select acid concentrations according to formation mineralogy

Matrix acidizing refers to one of two stimulation processes in which acid is injected into the well penetrating the rock pores at pressures below fracture pressure. Acidizing is used to either stimulate a well to improve flow or to remove damage. During matrix acidizing the acids dissolve the sediments and mud solids within the pores that are inhibiting the permeability of the rock. This process enlarges the natural pores of the reservoir which stimulates the flow of hydrocarbons. Effective acidizing is guided by practical limits in volumes and types of acid and procedures so as to achieve an optimum removal of the formation damage around the wellbore.

(i)Acidizing Treatments

Acidizing is used to either stimulate a well to greater than ideal matrix reservoir flow or to remove damage. These are two distinct and different purposes, the field applications and results of which are often merged or confused. Basically, there are two types of acid treatments that are related to injection rates and pressures. Injection rates resulting in pressures below fracture pressure are termed "matrix acidizing," while those above fracture pressure are termed "**fracture acidizing**."

Fig. 8 shows the increase in pressure linearly with rate until parting pressure is attained, at which time rate can continue to increase with little change in pressure above parting pressure. Matrix acidizing is used primarily for damage removal, while fracture acidizing is used to enlarge the effective wellbore by creating an acid-etched fracture deep into the wellbore for relatively low-permeability formations to improve well productivity several-fold.

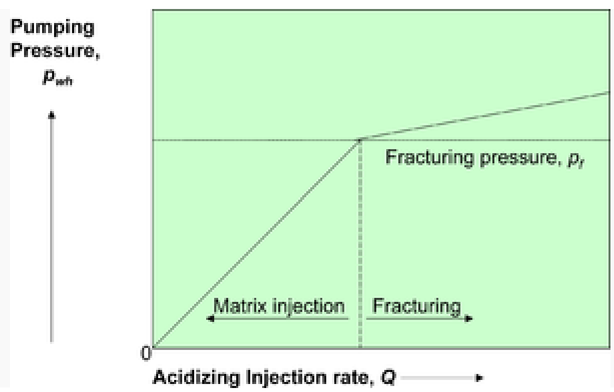

Fig. 8—Matrix acidizing injection rates below fracturing pressure.

(ii)Acidizing to remove damage

A matrix treatment restores permeability by removing damage around the wellbore, thus improving productivity in both sandstone and carbonate wells. Although the acid systems used in sandstone and carbonate differ, the same practices apply to both. In the absence of damage, the large volume of acid that is required to improve the formation permeability in the vicinity of the wellbore may not justify the small incremental increase in production, especially in sandstone. In carbonate rock, hydrochloric acid enlarges the wellbore or tends to bypass damage by forming wormholes. The permeability increase is much larger in carbonate than in sandstone. The effect of damage on well productivity and flow is illustrated in **Figs. 9 and 10**.

Severe damage (k_D/k less than 0.2) is usually close to the wellbore, within 12 in., as in **Fig. 9**. More moderate damage (k_D/k greater than 0.2) may occur much deeper (3 ft from the wellbore or more), as described in **Fig. 10**. Oilwell flow behavior is greatly affected by the geometry of radial flow into the wellbore; 25% of the pressure drop takes place within 3 ft of the wellbore if no damage is present, as shown in **Fig. 11**. Because of the small flow area, any damage to the formation at that point may account for most of the total pressure drop (drawdown) during production and, thereby, dominate well performance.

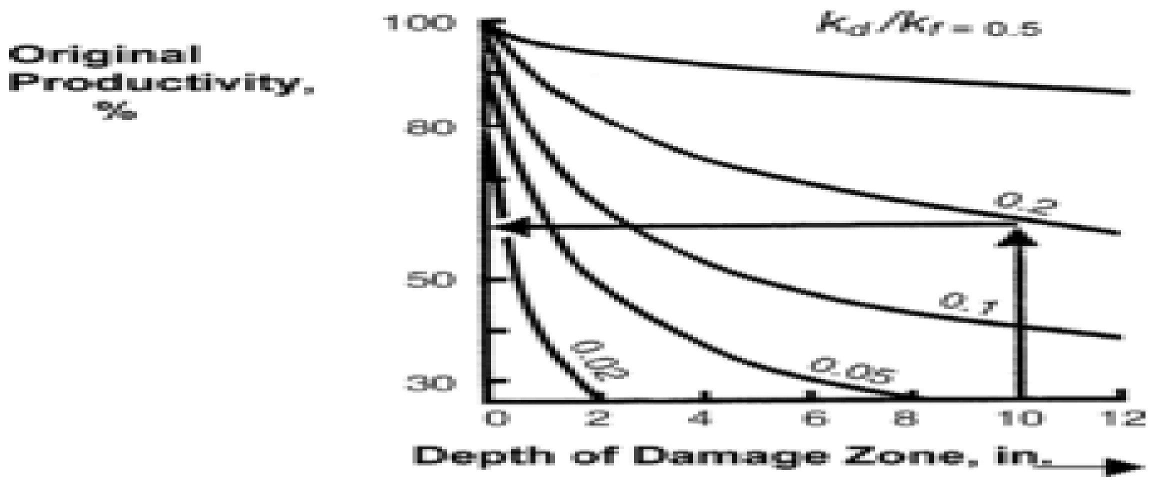

Fig.8. Effect of damage on well productivity-shallow damage

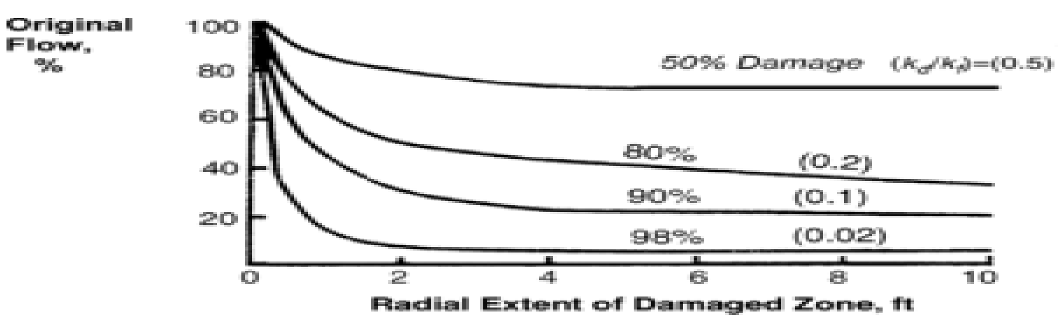

Fig.9. Effect of damage zone on flow-deep damage

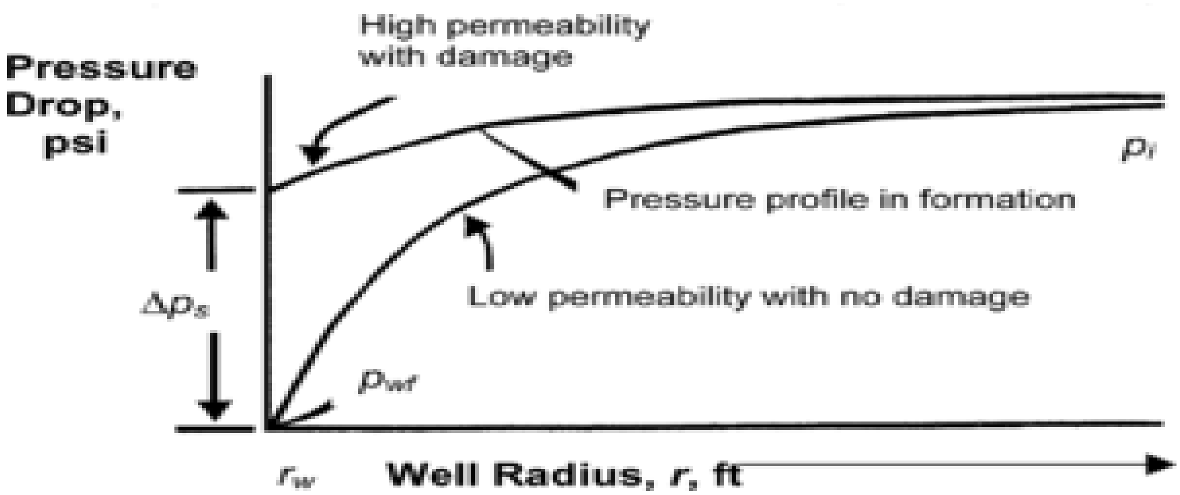

Fig.10.Pressure distribution around a well

(iii)Acidizing to enhance productivity

Matrix acidizing is applied primarily to remove damage caused by drilling, completion, and workover fluids and solids precipitated from produced water or oil (i.e., scale or paraffin). Removal of severe plugging in carbonate or sandstone can result in very large increases in well productivity. On the other hand, if there is no damage, a matrix treatment seldom increases natural production more than 50%, depending on the size of the treatment and the penetration depth of live acid, as demonstrated in **Fig. 11**

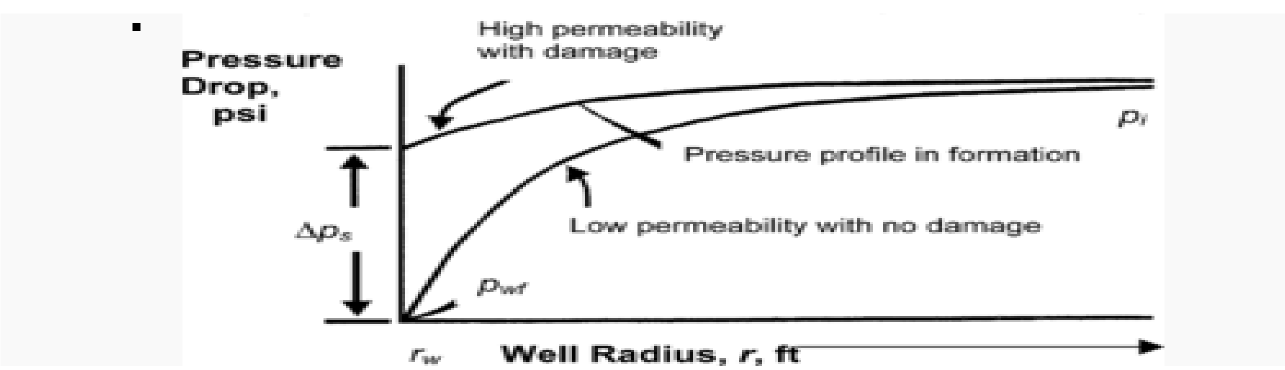

Fig. 11—Effects of acidizing an undamaged well.

(iv)Wormholes

Wormholes are small, continuous channels formed by acid preferentially enlarging pores in carbonate, usually around 2 to 5 mm in diameter. In radial flow, wormholes form a dendritic pattern, like the roots of a tree.

Gdanski[3] developed a practical model for wormholing during matrix acidizing in carbonates, which shows that practical limits for effective penetration of hydrochloric (HCl) acid varies from about 1 to 5 ft. Penetration is limited by injection rate and volume. The maximum rate allowed is a function of the carbonate permeability. Radial penetration is so limited in low-permeability carbonate that it is a better candidate for fracture acidizing.

(v) Improper or poorly executed acid treatments

When there is no damage present, improper or poorly executed acid treatments can reduce the natural formation permeability and reduce well productivity, as in new wells with low reservoir permeability. Gidley[4] presented the results of an extensive statistical review of one company's acidizing success in sandstone reservoirs in the U.S. He found that only 54% of 507 wells increased in production following hydrofluoric (HF) acid stimulation. More recently, Nitters *et al.* stated that past programs resulted in only 25% success.

(vi)Evaluation and quality control

Where better evaluation and quality control have been implemented, the percentage of successful treatments has improved to 75 to 90%. Such a program was developed by Brannon *et al.*, [6] who successfully acidized 35 of 37 wells (95% success) for an average production increase of 343 BOPD. Other areas and formations still suffer from poor acidizing responses, which implies that opportunities for technology development still exist.

RATE AND PRESSURE LIMITS FOR MATRIX TREATMENT

(i) Injection-Rate Control and Monitoring

The main acid job should be circulated in place with HCl acid placed across the formation before the packer is set or before the bypass valve is closed. All perforations should be covered by acid before injection starts. Injection should start at a predetermined injection rate and the pressure observed to determine the condition of the wellbore. If the pressure rises close to the pressure limit, the rate should be cut in half until the pressure stabilizes at a level below the formation fracturing pressure. When the HF acid stage reaches the formation, a pressure drop is normally observed. The rate should not be changed as long as a positive pressure is observed at the wellhead. If the well goes on vacuum, the rate should be instantly raised until a positive pressure is observed at the wellhead. Hold the new rate steady as the acid is injected. Nevertheless, the constant injection rate of HF acid into the wellbore should not exceed an optimum ½ bbl/min unless the perforated interval is greater than 25 ft. If the formation is very thick, the rate can be 0.02 bbl/min per foot of net pay. Other authors have different opinions on allowable injection rates, as discussed later

(ii) **Pressure Behavior During Acid Injection**

Two pressure responses are often observed during acid treatment. **Fig. 12** shows one response. [7] In this well, when acid hit the formation, pressure dropped immediately. As the pressure dropped, the rate was increased; then the pressure began to rise. The rate was reduced, and then the well was shut in while another batch of acid was mixed on site. Injection was restarted at a rate of 2 bbl/min, then cut back to 1.5 bbl/min and stabilized at 2 bbl/min for the final injection of over flush. Rate should be held constant for a period of time at least until the pressure stabilizes. Haphazard changes in rate make it impossible to determine on site what the quantitative response of the well is to the acid treatment, unless newer computer models and monitoring equipment are available, as discussed later. A better-controlled acid treatment is shown in **Fig.13** Here, the rate is stabilized at 0.55 bbl/min. When the HF acid stage entered the formation, the pressure slowly declined but stayed above 0 psi. This rate was continued as long as the pressure was observed and is the type of response that one should observe when a well is treated to remove wellbore damage.

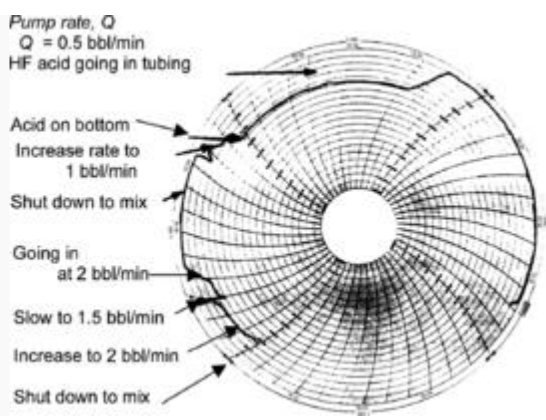

Fig. 12—Acid treatment with poor rate control

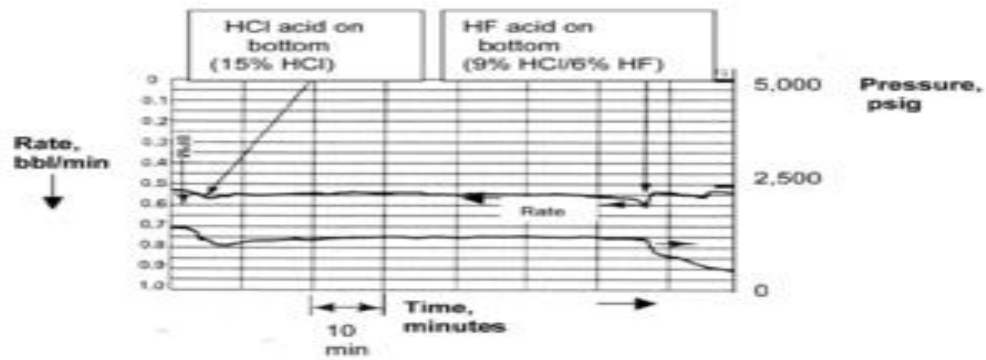

Fig. 13—Acid treatment with good rate control.

When the over flush reaches the formation, the rate may be increased as fast as allowed, as long as the pressure stays below the fracturing pressure. The faster over flush rate will push the spent acid deeper into the formation and over displace the spent acid reaction products more efficiently away from the wellbore. This safely finishes the treatment and allows the spent acid to be produced back sooner. The well should be flowed immediately, unloaded with nitrogen, swabbed back, or put on artificial lift.

FLUID VOLUME REQUIREMENTS

(i)Initial Pad Volume

The purpose of initial pad volume is to
• Provide effective fracture extension by controlling leakoff.
• Cool down the formation to slow down the reaction rate.
• Create a wide and long fracture that will provide a conduit for the acid to flow into the reservoir.
• Saturate natural fractures and vugs to minimize acid leakoff.

The pad volume is calculated to create the length required to optimize stimulation for a particular formation, as well as vertical coverage of all pay zones of interest. If the pad volume is not too small, the created fracture may not be long enough to generate the optimal production. On the other hand, excess pad volume will not increase etched fracture area, as acid may already be spent before it reaches all created fracture. In some cases, increased pad volume may damage the formation.
After performing several treatments with over forty thousand gallons of initial pad volume, the recommendation brought by Saudi Aramco engineers was to pump about 15,000 gallons of pad. This change in volume reduces the cost of acid fracturing while it does not compromise with the effectiveness of the

treatments.26 When acid is used without a pad fluid, the fracture will generally be short and narrow since the fluid loss for acid is high.

(ii)Acid strength and volume

The early development of the acid fracturing program consisted of pumping a viscous pad which is a combination of polymer and VES followed by 28% HCl. This type of design was an attempt to create fingering of the acid in the pad stages. Acid volumes of 28% HCl typically ranged from 1,500 - 2,000 gals/ft of treatment interval. A closed fracture acidizing stage with 28% HCl was pumped at the end of the treatment at a very low rate to increase the near wellbore etching and conductivity.

Rahim et al.3 noticed that even though the treatments were pumped in excess of 50 bpm, the loss of net pressure resulted in creating shorter fracture lengths. Therefore, today's treatments are designed with 3-4 stages of alternating pad and acid with acid volumes of 800 - 1,200 gals/ft. This re-design has significantly improved the success of sustaining positive net pressure during the treatment. Along with the multiple stages of pad and gelled acid, emulsified acid was also introduced in an attempt to obtain deeper penetration of the stimulation fluids.