HYDRAULIC FRACTURING IN MATURE WATERFLOODS: DESIGN CONSIDERATIONS AND IMPLEMENTATION IN WEST TEXAS WATERFLOODS

Victoria B. Jackson, BJ Services Co., USA

ABSTRACT.

Fracture azimuth, directional permeability trends, overpressured water zones, poor cement quality, depleted production intervals... all major concerns when hydraulically fracturing in mature waterfloods. Mature waterfloods, such as those found in the Permian Basin of West Texas, present reservoir and production considerations not normally associated with primary recovery. After 30 or more years of waterflooding, pressure characteristics, fracture tendencies, and reservoir fluid properties can be altered. Fracture orientation, vertical and areal sweep efficiency, altered stress conditions, poor cement and casing quality, and large perforation intervals all affect hydraulic fracturing in mature waterfloods. This paper will address current hydraulic fracturing terminology, design considerations of all hydraulic fracture treatments, and discuss those issues unique to secondary recovery.

I. INTRODUCTION.

As early as 1947, hydraulic fracturing has been used to increase productivity or injectivity of oil and gas wells[1]. The first documented hydraulic fracturing treatment was performed in the Hugoton gas field in western Kansas. The two-stage treatment consisted of 1,000 gallons of napalm-thickened gasoline followed by 2,000 gallons of gasoline with 1% by volume amine for gel breaker. This first attempt at hydraulic fracturing was not successful in that no noticeable increase in productivity occurred after the treatment.

Much has changed since 1947 and hydraulic fracturing now accounts for a large portion of all stimulation work performed in the Permian Basin of West Texas. Field development in the past 50 years has altered industry's views on the economic viability and probability of success of hydraulic fracturing[2]. Originally considered a means of initial completion for primary producing wells, hydraulic fracturing is now being utilized to complete or recomplete wells in mature waterfloods. Mature waterfloods bring with them many considerations and opportunities not present in primary producing fields. The combination of hydraulic fracturing and waterflooding is of concern to many operators in the Permian Basin. Many papers have focused on those specific considerations. This paper will consolidate those ideas and incorporate hydraulic fracturing considerations, enabling an operator to better optimize hydraulic fracture treatments and waterflooding efficiency.

II. TERMINOLOGY.

Before addressing candidate selection and design considerations, a discussion of terms and expressions will aid the engineer in discussing fracturing design. These terms are not only unique to petroleum engineering, but unique to the area of hydraulic fracturing. Through more thorough definitions, one may better understand the mechanics and phenomena of fracturing. For discussion purposes, the following conditions will be imposed to aid in clarity of description: all hydraulically created fractures are assumed to be essentially vertical and occur perpendicular to the least principle horizontal stress[3,4] (Figure 1). Unless otherwise noted, this discussion will be focused on proppant-laden hydraulic fractures. Acid fracturing will be discussed briefly.

A. Near-Wellbore Effects.

Several near-wellbore phenomena need definition: including tortuosity and multiple competing fracture initiations. First, the introduction of different perforating schemes and completion designs can lead to a condition known as tortuosity[5]. Near-wellbore effects such as tortuosity can be defined[6] such that:

$$P_{nwb} = P_{meas} - P_{clos} - P_{perf} - P_{net}$$

Pressure increase due to tortuosity is the measured downhole treating pressure less the formation closure pressure, perforation friction[7], and the net pressure in the fracture. If one perforates a vertical well with 0° phasing and the perforations are not aligned in the direction of the minimum horizontal stress, the induced fracture is more likely to take a tortuous path to align in the direction of minimum stress (Figure 2)[8]. Another cause of near wellbore tortuosity can be severe skin damage creating areas of uneven stress near the wellbore (deviatoric stress), or hydraulic fracture contacting natural fractures adjacent to the wellbore[9]. Near wellbore tortuosity can be reduced by the introduction of a mini-frac or pre-frac injection of acid prior to the main fracture treatment to initiate the near wellbore fracture and increase the width of the restrictive channel[10,11]. It can also be reduced by completing wells with 90° or 120° phasing in the perforation interval.

Multiple fractures can result from different points of fracture initiation[12]. The occurrence of multiple fractures can also greatly increase near-wellbore friction and cause perturbations in the stress field in which the fractures will begin to compete with each other for fracture width[13,14]. This competition for fracture width can increase the risk of a screenout. In a significant number of cases (e.g., layered pay zones treated as one zone due to economic inviability of staged fracture treatments) multiple fracture initiations cannot be avoided, but the engineer should be aware of the increased risk of screenout.

B. Perforating Schemes.

Two types of perforating schemes, clustered and limited entry, have been developed specifically for hydraulic fracture optimization. Clustered perforations, or point source perforating[15], is a perforating scheme developed to enhance the efficiency and decrease the risk of a screenout. (i.e. condition in which the well will not accept additional fracture fluid without an inordinate increase in surface treating pressure (STP)[16]). The idea of clustered perforations is to perforate a select zone (±20 ft) and allow the fracture to grow vertically to connect additional zones of interest. While not necessarily ideal for production purposes, clustered perforations is a completion design suited for a well which will be hydraulically fractured and has very little variation within the pay zone.

Whereas clustered perforating is designed to reduce height growth, limited entry perforating utilizes scattered perforations and friction pressure drop across the perforated interval to interconnect different zones. Limited entry perforating is a design method in which a limited number of perforations are shot per zone of interest. Limited entry technique relies on perforation friction to allow fluid into multiple zones of differing in-situ stress states[17].

C. Far-Field Fracture Environment.

The far-field fracture environment refers to that section of the fracture not considered near-wellbore, and is an area generally considered unaffected by changes in stress due to drilling and completing the well. The far-field fracture contains the majority of length and is the area in which the highest leakoff occurs. Several cases of multiple far-field fractures coexisting have been presented in the literature, also resulting in length reduction.

Far-field stress is the stress state of the reservoir unaffected by the pressure drawdown of the producing well. Theoretically, if all far-field stresses are equal, hydraulic fracturing would not occur in a preferential direction[18]. The true closure pressure will be equal to this far-field stress state; the observed closure pressure may differ due to near-wellbore effects.

Natural fractures, in some cases, follow a preferential azimuth trend[19]. This natural fracture azimuth can be an indication of the direction in which hydraulically created fractures will develop. The preferential fracturing trend can be measured through the use of tiltmeters, oriented cores, and fracture imaging logs[20].

D. Fluid Leakoff.

Leakoff can be described as the rate of fluid loss to the formation during a fracturing treatment. In non-naturally fractured reservoirs, fluid leakoff is controlled by the reservoir matrix and the fracturing fluid parameters[21,22,23]. The rate of fluid leakoff greatly influences the fracture geometry. The fracturing fluid leakoff coefficient, C_L or C_C, is a measurement of three different sets of parameters[24,25]. The terms generally used are:

C_I or C_v: Effluent Viscosity and Relative Permeability
C_{II} or C_c: Reservoir-fluid viscosity/compressibility effects
C_{III} or C_w: Wall Building Effects

Wall Building Effects refers to a fluid's ability to build a filter cake on the face of the fracture to stop additional leakoff. Leakoff characteristics are dependent on both rock and fluid properties. Permeability and wall building control leakoff.

E. Pipeline Fracturing.

Pipeline fracturing is a technique which was developed to isolate the zone of interest and control undo height growth into zones not of interest. Pipeline fracturing has been promoted extensively in the San Andres and Delaware zones of West Texas and Southeast New Mexico to control height growth into water-bearing zones. The technique utilizes a crosslinked pad to initiate the fracture followed by a linear fracture fluid which is proposed to place proppant more definitively and selectively within the more viscous pad fluid by means of viscous fingering[26].

F. Immediate Flowback Techniques.
After a well is fracture treated, the well can either be shut-in or immediately flowed back. Immediate flowback is sometimes referred to as "forced closure." Immediate flowback can reduce the time required for the fracture to close upon the proppant. Providing the gelled fracture fluid has had sufficient time to break, immediate flowback can be an effective means of improving fracture cleanup and reducing proppant settling effects.

G. Convection vs Settling.
Two different phenomena can occur during and after a well has been fracture treated. The first is proppant settling which is the result of the proppant falling out of the gelled fluid after shutting in the well. The proppant can settle to the lowest zone of the fracture resulting in a closing of the area in which no proppant exists. Convection can also occur during treatment or after a well has been shut in. Convection is simply a process which redistributes proppant within the fracture. The proppant concentration can migrate away from the net pay intervals[27], to areas opposite less desirable zones. Proppant is not placed during pumping with piston-like displacement (vertical series). Instead, the proppant is placed in horizontal series within the wellbore (Figure 3)[28]. In areas where downward projecting fractures are prevalent, convection can seriously hinder well performance. The hydraulic fracture can be designed to reduce proppant convection by pumping higher density pad volumes followed by lighter proppant-laden stages[29]. Convection can also be avoided by reducing pad volumes, increasing proppant volumes, pumping fracture designs which pack the fracture, and by employing immediate flowback procedures[30]. Convection and settling can both affect the proppant placement within the fracture and the long time productivity of the well.

H. Tip Dilatancy.
As hydraulic fractures propagate laterally through the reservoir, the process environment surrounding the tip of the fracture can experience an increase in net pressure known as tip dilatancy. One explanation of this increased pressure has been the identification that the tip region is also the region of maximum fluid leakoff[31]. High fluid leakoff is resisted by the plastic deformation of the rock at the fracture tip. This rock dilatancy can constrain the opening of the fracture and cause an increase in net pressure[32,33]. Tip dilatancy is often assumed to be 1.0, or negligible to the overall behavior of the fracture.

I. Fracture Toughness.
Fracture toughness is the ability for a material to resist crack growth[34]. Fracture propagation can occur when the stress intensity factor, K_I (a function of loading parameters and fracture geometry), reaches a critical value, K_{IC}[35]. This value must be obtained experimentally. Absolute value of fracture toughness has little to no bearing on fracture modeling.

III. CANDIDATE SELECTION

Within the past five years, new theories have been developed as to the effectiveness and economic viability of hydraulic fracturing in wells of moderate to high permeability, gas (1-10 md) or oil (10-100 md)[36]. The focus of this paper, however, is in the more classical sense of hydraulic fracturing candidates - low-moderate permeability (0.1-10 md), high skin, limited connectivity to the surrounding wellbore, and other means of limited production potential.

Waterflooding has been an economically viable secondary recovery mechanism used as early as 1865. The first waterflood was undertaken accidentally. An observed increase in production occurred when water was accidentally injected into the producing interval in the Pithole City area of Pennsylvania[37].

As fields mature and the prospect of finding a giant field with billions of barrels of recoverable oil diminishes, operators must rely on less conventional waterflooding candidates to maintain their production and reserve base. Lower permeability reservoirs and reservoirs with known natural fracture and permeability trends are being converted to waterflood operations. Hydraulic fracturing of both producers and injectors within a waterflood pattern can alter sweep efficiency; time to fill-up and water breakthrough; and overall economic viability resulting from a decreased time to flood response.

Waterflooding comprises the majority of all secondary recovery methods in the domestic United States and accounts for significant production throughout the world. Of all the waterflooded fields, very few utilize hydraulic fracturing as a means of increasing either productivity or injectivity. Hydraulic fracturing, if planned and executed properly, can extend the life of the reservoir and produce reserves that might otherwise be unobtainable.

In the early 1950's, with the development of hydraulic fracturing and the implementation of waterflooding in the Permian Basin, it was recognized that the use of hydraulic fracturing could increase injectivity of wells[38]. Of the three fields discussed in Ref. 38 (i.e. Kermit (Queen/Yates), Cherrykirk (Penn Sand), and Pecos Valley (Yates)), two successfully utilized hydraulic fracturing to increase productivity and injectivity (Kermit and Cherrykirk Fields). Fracturing producing wells in the Pecos Valley Field was not deemed successful due to timing considerations. It was felt the wells should have been fractured after fill-up to optimize the fracture treatment and the waterflood efficiency. If the proper treatment (hydraulic fracturing or otherwise) had been done in the Pecos Valley Field, the wells would have shown incremental production response, regardless of the timing of the fracture treatment.

So what makes wells in a waterflooded area candidates for hydraulic fracturing? The most obvious response is near wellbore damage from drilling or injection operations. This near wellbore damage can be removed (or fractured through) to increase the damaged zone permeability back to or better than initial reservoir conditions[39].

This increase in permeability, which is translated to a fracture half-length by the equation,

$$x_f = \frac{5.615 q_i \sqrt{t}}{2\pi h C_L}$$

increases the effective wellbore radius which, in turn, increases the fracture conductivity. C_L (or CC) is described as the total leakoff coefficient in oilfield units of ft/min$^{1/2}$ and describes the leakoff characteristics of the formation.

High Conductivity Reservoirs: $$r'_w = \frac{x_f}{2}$$

Low Conductivity Reservoirs: $$r'_w = \frac{k_f w}{4k}$$

Argawal et al.[40] and Cinco-Ley and Samaniego[41] introduced dimensionless fracture conductivity:

$$F_{cd} = \frac{k_f w}{k x_f}$$

to describe the relationship between fracture width (w), fracture permeability (k_f), reservoir permeability (k), and fracture half-length (x_f).

Some reservoirs are not initially considered candidates for waterflooding due to low permeability, or highly varying permeability which can create thief zones and zones of early water breakthrough. However, they can become waterflooding candidates with the correct stimulation application. Applying the correct technology and exclusively fracturing the low permeability zones, can lead to a more balanced waterflood with better injection conformance.

Within any reservoir, there are wells which do not perform as well as their offsets. Correct and more vigorous completion methods can help these underachieving wells. Fracturing a select number of wells can balance flood patterns and increase drainage in areas of low production or poor injectivity. The fracturing techniques and specific considerations unique to waterflooding operations will be addressed in Section V.

IV. DESIGN CONSIDERATIONS

Some aspects of hydraulic fracturing are common regardless of whether the field is in primary, secondary, or even tertiary production life. Several issues stand out as major concerns for operators: net height growth, optimal fluid and proppant type, and economic advantages to hydraulic fracturing.

A. Net Height Growth.
Many theories exist as to the ability to contain height growth while fracturing. The best method for height growth containment is natural stress barriers above and below the zone of interest. However, strong barriers are rarely present when hydraulic fracturing. Height growth in waterflood situations especially is critical for two reasons: to avoid fracturing into known water zones and to allow the fracture to grow in length and not consume the volume with excessive height growth. Non-propped fracturing such as acid fracturing[42] can control height growth in areas of major concern.

When fracturing near the oil-water contact, or in a reservoir with oil and water zones in close proximity, height growth can be a major determinant in the success of a fracture treatment. Fracture height growth into a water zone can quickly make a well uneconomic; excessive height growth will also result in reduced fracture length.

Other than through rock mechanical processes[43] (e.g. in-situ stress, Young's Modulus, Poisson's Ratio, etc.) there are several methods to try to contain a fracture in the zone of interest. The first, simply, is sacrifice length to avoid height growth. Design a much smaller fracture treatment than would normally be implemented to avoid height growth. If the fracture treatment is volumetrically small, there will not be an excessive amount of fluid present to allow the fracture to grow.

The second method to contain height growth is to decrease injection rate. The decrease in injection rate hinders the fracture height growth due to the corresponding decrease in net pressure. The pressure realized by the fracture needs to be enough to continue fracture length extension but not greater than the net pressure which would result in excessive height growth. This range of pressures can be estimated through the incorporation of sonic derived rock mechanical properties logs and 3D simulation[44].

B. Optimal Fluid and Proppant Type.

Many different types, under many different names, of fracturing fluids exist in the petroleum industry. However, they can be classified into three simple categories: water, oil, or acid-based fluids. In order to determine which fluid is most appropriate for any specific condition, the reservoir fluids and rock properties must be considered[45]. If a known fluid or technique (proppant fracturing vs acid fracturing) has been successful in a specific area, that is usually a good place to start. However, do not be complacent about fluid selection. Even though the field on the other side of the lease line is being treated with a certain fluid or technique, it does not necessarily mean that those are the optimal choices.

All previously described fluid types have been utilized in West Texas. The most common fracture fluid is a water-based system with different additives to achieve desired design dimensions. Oil-based fluids are also used in the area. Acid-based systems are usually used without proppant in acid fracturing.

Different characteristics of fluids are necessary for different aspects of hydraulic fracturing. In a reservoir where leakoff to the formation is expected to be high, the fracturing fluid leakoff properties can be critical to acheiving the desired geometry development and proppant placement. A fluid with adequate viscosity must be chosen for fracture width development and proppant transport. Crosslinked fracturing fluids are often used to enhance viscosity, reduce leakoff, and enhance proppant transport capabilities. Other concerns in fluid selection are friction properties, temperature stability, shear stability, relative permeability damage to the reservoir, fracture conductivity requirements, post-treatment break and cleanup effects, and cost[46].

Proppant selection is based largely on closure stress on the proppant and of the resulting conductivity of the fracture. Loosely defined, closure stress on proppant is the fracture extension pressure minus the bottomhole flowing pressure in the fracture. Proppant companies and independent laboratories perform laboratory tests on proppants to determine the conductivity versus closure pressure on the proppant. A proppant selection can be made based upon expected closure stress and appropriate data from laboratory testing.

Proppant is referred to by mesh size[47] (e.g. 20/40, 16/30, 12/20); the larger number is an indication of smaller proppant diameter. A 100 mesh sand would indicate a mesh screen which would contain 100 holes/unit area of the screen. The larger the proppant, the greater the conductivity at low closure stress values. However, as closure stress increases, the larger proppant can be more susceptible to failure. An evaluation must be done to determine the largest mesh which can sustain the greatest closure stress while maintaining sufficient fracture permeability and reducing formation fines migration[48].

Proppant can be resin-coated and pumped in the latter stages of the job to help eliminate proppant flowback when the well is brought on line. A curable resin coat is "activated" to form a bond between sand particles, reducing flowback risk. In high closure stress environments, the resin coat can be curable or precured to reduce point loading by eliminating eccentricities in the sphericity of the proppant. Bauxite and ceramic beads have also been used in place of sand in high closure pressure environments.

Fluid selection, proppant selection, proppant density, and cost are combined to create an optimal treatment schedule to develop the desired characteristics of the fracture - conductivity, half-length, height, etc.[49] Treatment schedules can be a trial-and-error procedure or can incorporate a systematic model (such as described in Ref. 49) to optimize the fracture design.

C. Economic Advantages.

Each hydraulic fracture treatment should be evaluated to determine the optimal fracture length to realize the most net present value from the well. Hydraulic fracturing can both speed the time to ultimate recovery and can allow one to recover reserves[50] which would have been unobtainable without hydraulic fracturing. An ideal fracture length exists at the point where the economic benefit received from increasing the length (e.g. more fluid, proppant, horsepower) is not greater than the additional cost[51,52]. A Net Present Value (NPV) vs fracture half length (x_f) plot (Figure 4) will show a maximum NPV, indicating the optimal fracture length.

An increase in injectivity can also be an economic benefit of hydraulic fracturing in a waterflood. The increased injectivity can reduce surface requirements for the injection facilities by reducing downhole injection requirements. This increased injectivity can become more significant as the field matures and more of the water is "recycled". The additional water being produced can become greater than the injection facilities and the present number of wells can handle. Without an increase in injection capabilities, disposal would be required for the additional produced water.

Hydraulic fracturing in mature waterfloods should be another consideration to increase the economic soundness of a waterflood. Economics can be evaluated either on a field-wide basis, for specific areas of the field, or for individual flood patterns. Hydraulic fracturing should be considered when evaluating old floods, infill drilling old floods, or even developing new fields. Production and injection enhancements can be the result of a carefully executed stimulation proposal.

V. DESIGN CONSIDERATIONS: SECONDARY vs PRIMARY RECOVERY

Waterflooding, at least water injection for pressure maintenance, has been around for more than 100 years. Hydraulic fracturing has been used for close to 50 years. However, hydraulic fracturing is not as common in fields already being waterflooded. As a hypothetical example, Operator A began water injection in the XYZ field in 1957. In 1997 Operator B purchases the XYZ field and realizes the upside potential of both infill drilling and the hydraulically fracturing of both infill wells and current producers. After careful consideration, Operator B also decides to fracture stimulate one or two under-performing injectors. How do design considerations differ from the considerations when the XYZ field was still in primary production?

A. Fracture Orientation.

The XYZ field was previously determined to have a fracture orientation[53,54] of northeast/southwest. This fracture trend influences both the waterflood pattern alignment and the desired orientation of fractures. In this example with existing regional fractures northeast/southwest, a line drive pattern would have a lower areal sweep efficiency than would a five-spot or staggered line-drive (Figure 5). Fracturing mechanics dictates that the fractures will follow the trend of the regional fractures unless an alteration has recurred in the stress orientation due to subsidence or overpressure[55]. Staggering the injectors between two rows of producers would lead to maximum drainage.

The knowledge of fracture orientation, either naturally occurring as discussed above, or hydraulically created, can lead to better flood patterns. The preferential fracture trends influence the pattern efficiency and ultimate recovery[56]. The optimal fracture orientation would align the producer between two injectors, not between injector and producer (Figures 6 and 7). If the fracture is aligned between injector and producer, early breakthrough will most likely occur, and the waterflood may rapidly become uneconomic.

B. Areal and Vertical Sweep Efficiency.

Areal sweep efficiency is enhanced by hydraulic fracturing. The fractures allow for increased sweep from the injector to the producer. As long as the well remains in pseudo-steady state production, the production well is in linear flow as opposed to radial flow for a non-fractured producer in a non-closed system (constant pressure boundary)[57]. Linear and radial flow occur as described by the equations below:

$$q = \frac{-kk_r h}{B\mu}\left\{\frac{\partial P}{\partial x} + \rho g \sin\alpha\right\} \qquad \text{Linear Flow}$$

$$q = \frac{-kk_r h}{B\mu}\left\{\frac{(P_e - P_{wf})}{\ln(r_e / r_w)} + \rho g \sin\alpha\right\} \qquad \text{Radial Flow}$$

Sweep efficiency is affected by the increase in effective wellbore radius. As the effective wellbore radius increases, the injectivity increases[58]. This increase in injectivity increase pattern efficiency and overall recovery. As this is a complex flow scenario, linear to radial flow patterns, a definitive equation can not describe the increase in injectivity after hydraulically fracturing an injection well.

Vertical sweep efficiency can be altered greatly by the induction of fractures in the porous medium. Vertical fractures connect the zones of varying permeability and allow for flow between layers not previously connected. Fracturing, however, can have a detrimental effect on vertical sweep efficiency by creating highly permeable pathways which bypass zones of lesser permeability[59]. Another concern for fracturing injection wells is the problems which can arise through injection conformance. The hydraulic fracture can make it more difficult to control injection into a specific interval. Overall, the introduction of vertical fractures will positively influence the drainage patterns of a waterflood, positively enhancing areal and vertical sweep efficiency.

C. Altered Stress Condition.

Whereas the overburden pressure does not change appreciably with time, the advent of waterflooding greatly affects the pore pressure of the reservoir. As the pore pressure is returned to levels gretaer than or equal to that of the virgin reservoir pressure, the pressure differential between the overburden and the pore pressure is less than would be expected. This change in differential pressure can affect hydraulic fracturing processes.

Hydraulic fractures occur perpendicular to the least principle stress. The increased pore pressure from waterflooding can alter the direction of least principle stress[60]. If a specific zone accepts too much water, it can become overpressured and locally alter the stress characteristics. This increase in pore pressure reduces the effective stress, defined as:

$$\sigma_{eff} = \sigma_c - P_p$$ [61]

This reduction in effective stress alters fracture tendencies. The change in an isolated zone (overpressuring) within a producing formation can reduce the effectiveness of the fracture treatment by artificially creating a barrier to fracture growth or by restricting the zones to be treated. If the area of altered stress is not sufficient to contain height growth, the overpressured zone must be avoided when fracturing. The presence of zones of overpressure can be an indication of uneven injection distribution. Where an overpressured zone exists, there may be zones of underpressure. The depleted zone can cause a fracture to grow preferentially in that direction due to a decrease in effective closure stress[62]. Excessive height growth through this water charged zone can provide a conduit for water flow and increase the risk of early breakthrough.

D. Cement and Casing Quality.

Poor cement quality, the result of either a poor primary completion or deteriorated cement due to repeated acidizing, can ruin a potential candidate for hydraulic fracturing. The drilling of infill wells through highly pressured and potentially over-injected zones can also lead to poor cement quality. Potentially, the overpressured zone could require a fluid density gradient greater than the reservoir pressures in the producing formation, or the water may continue to flow during the cementing operation. This inflow could dilute the cement or create a weak bond between the formation, cement, and casing. A channel could result in the cement column hindering the ability to contain a stimulation treatment.

Poor cement quality and corroded casing are both common in mature fields of the Permian Basin. Again, poor cement quality can be the result of a poor primary cementing job, or as a result of cement deterioration due to repeated matrix acidizing or secondary or tertiary recovery methods[63]. Acid deteriorates the cement sheath leaving an operator with little to no means of stimulation containment. Highly corroded casing due to highly corrosive injection water, can leave the wellbore in a near-openhole condition. If fracture stimulation over a large interval with encroachment into a water zone is not a problem, corroded casing may not be a huge concern. However, if fracture containment within the producing interval is the prime objective, corroded casing and poor cement quality can be detrimental to a successful fracture treatment.

If it is suspected that casing and or cement integrity is poor, logs or mechanical calipers can be run to determine the severity of the problem. Cement evaluation logs, bond logs, ultrasonic imaging logs, casing inspection logs, corrosion detection logs, and calipers can be run to ascertain the quality of the cement and casing. If the cement is in exceptionally poor condition, and fracture containment is a key issue, cement squeezing or placing a liner prior to the hydraulic fracture treatment, can be beneficial.

E. Large Perforation Intervals.
Operator B realizes poor cement quality and altered areas of stress already exist in the XYZ field. However, infill drilling is still an option, as is recompletion of current wells. The XYZ Field was drilled on 40-acre spacing and perforated selectively over the 700 ft of net pay. Now, 40 years later, Operator B wishes to fracture a select number of producers to increase reserves. Due to poor cement, corroded casing, and necessity of avoiding fracturing initiation into known thief channels, Operator B will have to stimulate through tubing. This scenario will limit the available rate due to friction pressure, and will require multiple bridge plug and packer settings. The limited rate could reduce the possibility of excessive height growth, and could be a hindrance in effectively placing proppant. Instead of completing the well in a manner conducive to hydraulic fracturing, the perforating scheme and economics will govern the completion methodology and dictate the extent of stimulation possible.

VI. CONCLUSIONS

Neither hydraulic fracturing nor waterflooding are new technologies to the oil industry; however, the implementation of the two technologies together requires special attention to details not normally associated with primary recovery hydraulic fracturing. Hydraulic fracturing can assist the engineer in proper pattern alignment and can help determine the optimal flood pattern. Waterflooding and hydraulic fracturing can be combined to optimize a field's potential and make previously uneconomic projects viable for production.

NOMENCLATURE

α:	dip angle of reservoir, °
μ:	viscosity, cps
ρ_w:	density, lb/ft^3
σ_{eff}:	effective stress, psi
σ_{ob}:	overburden stress, psi
B:	formation volume factor, RB/STB
C_L:	leakoff coefficient, ft/min$^{1/2}$
F_{CD}:	dimensionless fracture conductivity
g:	gravity, ft/sec^2
h:	net pay thickness, ft
k:	absolute permeability, md
k_f:	fracture permeability, md
k_r:	relative permeability, md
K_I:	stress intensity factor
K_{IC}:	critical value of stress intensity factor
P_{clos}:	closure pressure, psi
P_e:	pressure at external reservoir boundary, psi
P_{meas}:	downhole measured pressure during treatment, psi
P_{net}:	net treating pressure, psi
P_{nwb}:	pressure due to near-wellbore effects, psi
P_{perf}:	pressure due to perforation friction, psi
P_p:	pore pressure, psi

P_{wf}:	bottomhole flowing pressure, psi
q:	flowrate, BPD
r_e:	external radius of investigation, ft
r_w:	wellbore radius, ft
r_w':	effective wellbore radius, ft
STP:	surface treating pressure, psi
x_f:	fracture half length, ft

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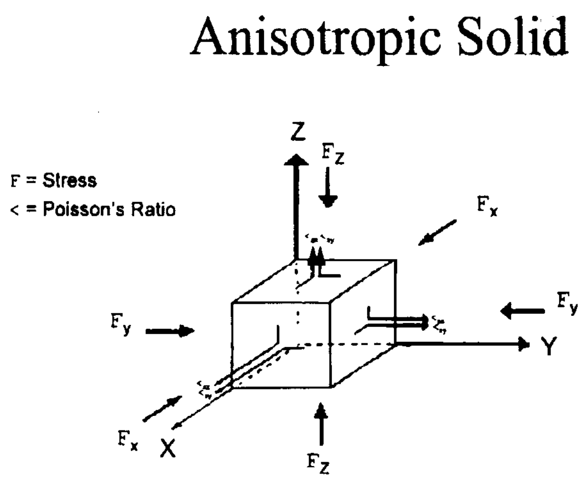

Figure 1- from SPE paper 29598. General three-dimensional stress field and definition of anisotropic parameters used in text derivations.

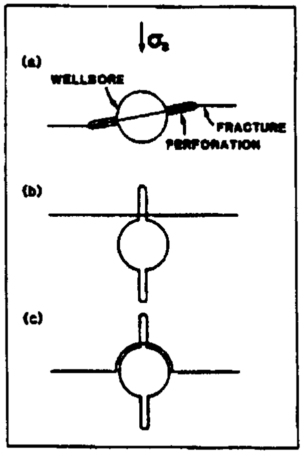

Figure 2 - from SPE paper 20656. Models of crack initiation: a.) fracture follows tunnel and reorients; b.) fracture cross-cuts tunnel; c.) fracture grows around wellbore.

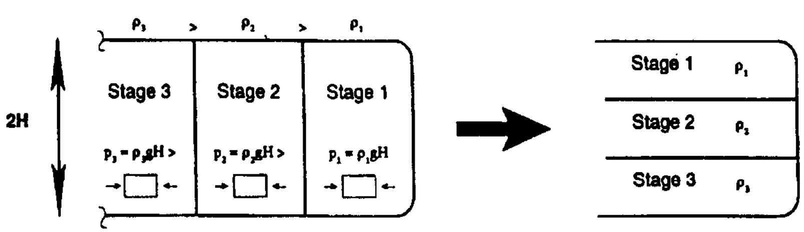

Figure 3a - from SPE 24825. Piston/plug displacement in conventional 2-D models.

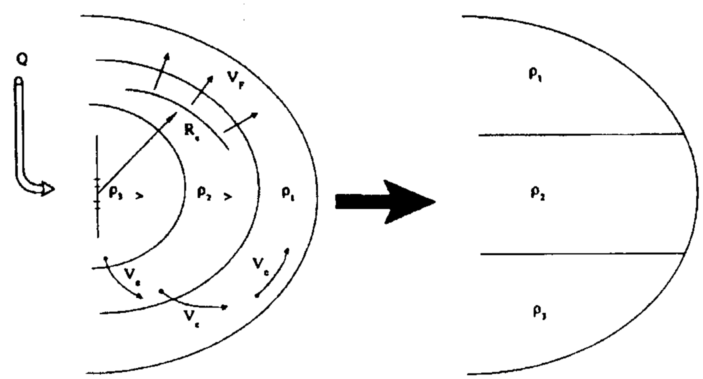

Figure 3b - from SPE paper 24825. Representation of fracture and associated convection.

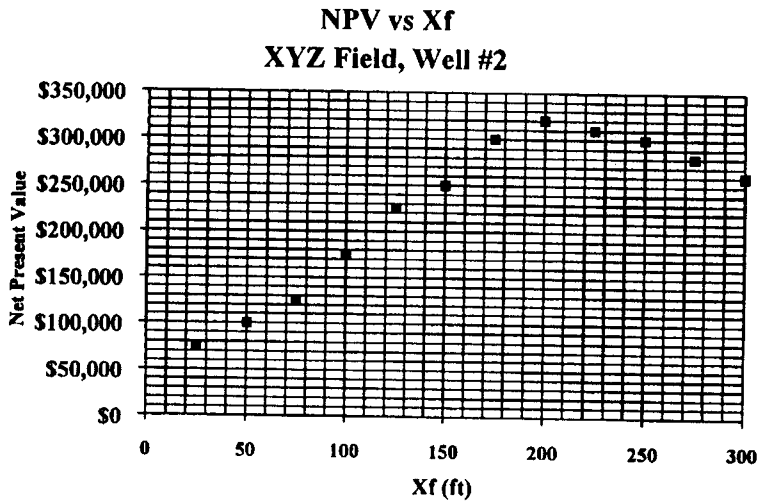

Figure 4

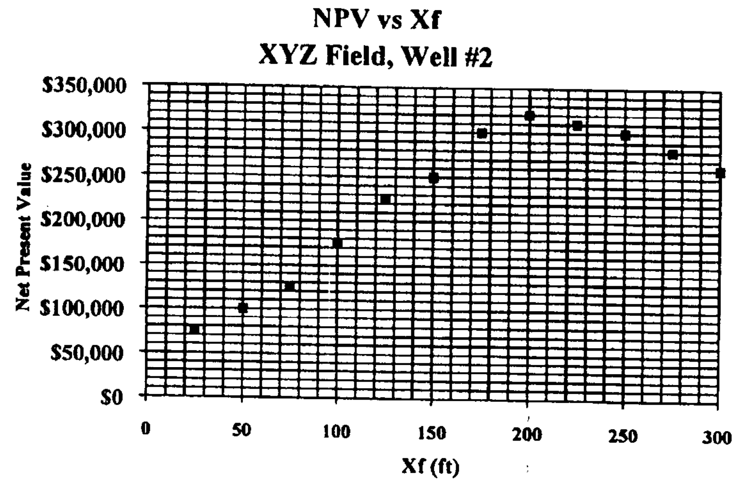

Figure 5 - 5-spot (Staggered Line Drive) Pattern.

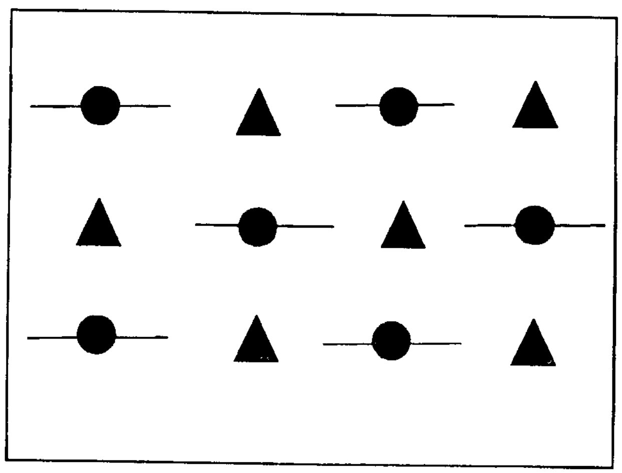

Figure 6 - 5-spot (Staggered Line Drive) Pattern.
w/E-W Fracture Trend.

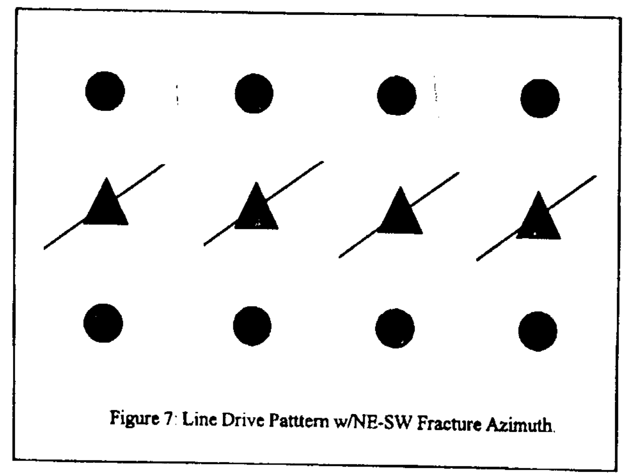

Figure 7: Line Drive Patttern w/NE-SW Fracture Azimuth.

Figure 7- Line Drive Pattern w/NE-SW Fracture Azimuth