# PREDICTING, PREVENTING AND REMEDYING HYDRAULIC FRACTURING SCREEN OUTS

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## ABSTRACT

Due to recent trends in hydraulic fracturing with very high proppant concentrations there has been a substantial increase in the frequency of screen outs. The present paper discusses methods of predicting screen outs both during the fracture treatment design stage as well as during the actual performance of the treatment. Different types of screen outs are presented with examples. Reservoir data is used in presenting screen out prevention methods. Procedures to handle screen outs along with several remedies are suggested and the merits of each method are discussed. Lab data on formation and sand pack damage due to mishandling screen outs are also shown.

## INTRODUCTION

Recent trends in Enhanced Proppant Concentration fracturing (EPC and UHSC) and Massive Hydraulic Fracturing (MHF) designs have been toward increasing surface proppant concentrations to as high as 16 to 18 pounds per gallon of fluid pumped. Designers have traditionally shown little or no regard for the ability of the fracture to accept such high concentrations. Inability of fractures to accept proppants in many instances, has lead to "screen outs" or "pressured outs". The term screen out is defined as a premature termination of a hydraulic fracturing operation due to excessive pressure buildup casued by blockage (solids) preventing slurry flow between the wellbore and the formation. Pressured out is usually referred to a situation where the treatment can be flushed down at low injection rate and maximum allowable pressure.

Screen outs can be classified into two (2) broad categories. The first type is wellbore screen out, and the second type is formation screen out. Although, both types are common, formation screen outs occur more frequently with use of the new crosslinked gel systems. Most wellbore screen outs are caused due to use of non crosslinked gel systems. These systems cause the precipitation of proppant in the wellbore. As the rat hole and the perforated interval is filled up with proppant, the surface wellhead pressure jumps up and the well is screened out. It should be noted, that during high injection rate fracturing, the wellbore screen out is indicated by step by step pressure buildup as each perforation is blocked off. Crosslinked fluids may also cause wellbore screen outs if proppant pumping is commenced before adequate frac width is developed.

Formation screen outs are caused by excessive frac fluid leak-off, resulting in either bridging of proppant within the fracture or the prop laden element concentrating to the point where the prop is almost dry and will no longer flow in the fracture. Figures 1 to 4 are graphical presentation of different types of screen outs.

Screen outs are caused by,poor quality of frac fluid, improper design, inadequate knowledge of fracturing pressures, communication behind pipe, equipment breakdown, perforation blockage and insufficient knowledge of rock properties.

PREVENTION OF SCREEN OUTS

Prevention of screen outs can best be accomplished by understanding the factors that cause screen outs.[1,2] Screen outs are caused by:

1. Excessive fluid leakoff - Most crosslinked systems have low fluid loss coefficients. However, if the formation to be fractured has high permeability and porosity in conjunction with fine hairline fractures it becomes necessary to increase polymer loading and to add fluid loss control agents to the frac fluid.

   The normal recommended dosage is 25 lb. to 50 lb. of fluid loss control additive per 1,000 gal. of frac fluids. To control leak off to hairline fractures and channels behind the pipe it is necessary to run 100 mesh sand or 100 mesh salt. Excessive amounts of fluid loss additives can be damaging to the formation and proppant permeability. Leak off can also be controlled by running sufficient pre-pad ahead of prop laden fluid and by running 3 to 5% of liquid hydrocarbon such as diesel in all the gel.

2. Low Injection Rates - If average injection rates are very low the prop settling rates and fluid leak off will be controling factors and will cause screen outs. Low injection rates also hinder adequate frac width development.

3. Smaller Frac Widths and Orientation - Frac width is a function of rock and frac fluid properties and fracturing injection rates.[1] Rock properties cannot be controlled, however, it is very important to have a fairly good knowledge of rock properties, such as Young's Modulus and rock parting pressure.[1] The rock parting pressure or the BHFP (Bottom Hole Fracturing Pressure) is used in determining if the fracture is vertical or horizontal. Studies have shown that frac gradients in excess of 1.0 psi/ft produced vertical fractures. Vertical fractures develop larger frac widths than horizontal. Horizontal fractures are usually not developed below approximately 3,000'.

Frac widths can be enchanced by using higher polymer loading of crosslinked gels and increasing injection rates.

4. Low Frac Fluid Viscosity - Low frac fluid viscosity causes excessive leak off leading to a screen out.

5. Equipment Failure - Equipment failure leading to shut down during pumping or prop laden fluid can cause a screen out.

6. Excessive Frac Height - If frac height developed during fracturing is much greater than estimated, smaller frac width will be developed and this may cause a screen out. Frac height should be estimated based on electric logs and temperature and radioactive surveys if available.

7. Excessive Bottom Hole Temperature - Most fracturing gels are unstable at high temperatures and are degraded. This causes excessive leak off and consequent screen out. The situation can be corrected by using gels stable at high temperatures and running a large coolant pad ahead of the proppant laden fluid.

8. Perforations Not Opened Up - It is very important that the perforations be "broken down" and "balled out" prior to the fracturing treatment.

9. Improper Design - It is necessary to consider all the above mentioned factors in designing frac treatments. All pertinent data must be studied and evaluated prior to the job design. Computer studies should be conducted to determine the amount of pad needed and the frac width developed during pumping.

The key to successful hydraulic fracturing is a design based on sound engineering principles. Hydraulic fracturing should not be conducted until the rock properties are investigated. Depending on pay thickness, the perforating program should be designed to achieve optimum selectivity and control during fracturing. If possible, the perforating program should be designed to achieve Limited Entry treatment. Casing type gun should be used for perforating to achieve 0.42" diameter holes with maximum penetration. Prior to fracturing; the perforations should be broken down with 150 to 200 gallons acid per perf and "balled out" using at least 50% excess ball sealers to ensure that all the perforations have been opened. If EPC and MHF type treatments are to be conducted the acid breakdown volumes should be increased and the breakdown injection rates should be maintained at 6 to 8 BPM.

It is necessary to determine frac height (zone of fluid entry) based on electric logs or temperature surveys. To obtain a more accurate estimate of the fracture height it is essential to pump a gelled water dummy stage (5,000 gal. to 10,000 gal.) at essentially the same rate as the fracture treatment. A temperature survey conducted after the dummy stage has been pumped provides a fairly accurate estimate of the frac height.

Based on the pumping and the instantaneous shut down pressure of the acid treatment, the fracture orientation should be determined. Horizontal fractures should be treated with much larger pre pad and pad fluid prior to pumping prop laden fluid. Fluid leak off should be based on accurate reservoir data and conditions. Frac fluid selection should be determined based on leak off considerations under down hole conditions. Frac fluid volumes should be determined based on computer studies and the same studies should be used to determine maximum acceptable prop concentration (lb/ft.$^2$). Frac widths should be checked to see that proppant bridging will not occur.

Fracturing injection rate and pressure should be designed to be within the constraints established by the internal yield of the tubular goods. Infact, average treatment pressure should be 500 to 1000 psi below the internal yield to leave sufficient margin for sudden or unexpected increase in treatment pressure due to a screen out or a ball out.

PREDICTING SCREEN OUT

Screen out prediction can be accomplished both during the designing phase as well as during the actual performance of the treatment. The stimulation program design should include a method by which the design is checked to ensure that no screen out will occur during any part of the job. Screen out prediction becomes very important especially during performance of EPC or MHF programs. The latest industry studies show that proppant concentrations in the fracture system should exceed 1.5 lb/ft$^2$. To achieve these high concentrations it becomes necessary in many instances to schedule proppant as high as 15 lb. per gallon of slurry.

A. Screen Out Prediction Calculation:

Fracture volume should have the ability to physically contain the amount of proppant pumped, therefore, it is necessary to check that each sand concentration can be physically placed in the appropriate fracture segment. Consider a one square foot fracture segment with a dynamic frac width of 0.24 inches, then the fracture volume will be:

$$V = 1 \text{ ft.} \times 1 \text{ ft.} \times \frac{0.24 \text{ in.}}{12 \text{ in./ft.}}$$

$$= 0.02 \text{ ft}^3$$

If this segment was completely occupied by sand, then the sand concentration would be:

$$C = \text{Sand Concentration (lb/ft}^2\text{)}$$

$$C = \frac{V \times \text{(Bulk density of sand)}}{\text{Area ft.}^2} \qquad \text{——— } 1$$

$$= \frac{0.02 \text{ ft.}^3 \times 100 \text{ lb/ft.}^3}{1 \text{ ft.} \times 1 \text{ ft.}}$$

(Where bulk density of sand = 100 lb/ft$^3$)

$$= 2 \text{ lb/ft.}^2$$

It is apparent that a dynamic width greater than 0.24 inches will be required to achieve a sand concentration of 2 lb/ft.$^2$ since some allowance must be made for gel in the slurry. There is no fool proof method for determining the frac width required to accomodate the slurry without sand bridging. A widely used acceptance criteria is that the frac width should be equal to or greater than 1.5 times the physical width of sand (Table I), where the width W is given by:

$$\frac{W\ (\text{inches})}{12\ \text{in/ft.}} = \frac{\text{Concentration lb/ft.}^2}{100\ \text{lb/ft}^3} \times (1.5\ \text{factor}) \qquad \text{—— } 2$$

The 1.5 factor should be modified depending on regional experience. The factor normally varies from 1.5 to 2.5.

Table II presents the reservoir data used for the computer study. Table III shows a computer print out for a proposed sand schedule. For a leakoff coefficient of 0.002 ft/(min) $^{0.5}$ the prop concentration profile for the middle segment is very high. For this particular case the frac width required is:

$$W = \frac{(4.522) \times 1.5 \times 12}{100} \quad \text{(Where 4.522 = max. prop conc.)}$$

$$= 0.81\ \text{inches}$$

Predicted pumping width of 0.5 inches, therefore, would be insufficient and the design would be subject to a screen out. Applying the same criteria the maximum prop concentration would be:

$$\frac{0.5\ \text{inches}}{12\ \text{in/ft}} = \frac{\text{Concentration}}{100} (1.5)$$

$$\text{Concentration} = \frac{0.5 \times 100}{12 \times 1.5}\ \text{lb/ft}^2$$

$$= 2.78\ \text{lb/ft.}^2$$

Only the 20,000 gal. pumped at 1 ppg. and the 40,000 gal. pumped at 5 ppg. will be within our constraints. It is clear that too much sand is being pumped since the overall concentration is greater than the 2.78 lb/ft$^2$.

$$\text{Concentration} = \frac{540{,}000}{2 \times 80 \times 1191}\ \text{lb/ft}^2$$

$$= 2.83\ \text{lb/ft}^2.$$

In this case the best design option is to lower the overall sand concentration to approximately 2.5 lb/ft$^2$ or less and improve fluid loss coefficients by going with a gel system that has a leakoff coefficient of 0.0015 ft/(min)$^{.5}$

$$\text{Sand required} = 2 \times (80\ \text{ft}) \times (1191\ \text{ft}) \times 2.5\ \text{lb/ft}^2$$

$$= 476{,}400\ \text{lbs.}$$

The program should be rerun with the new values until no segment concentration is above 2.7 $lb/ft^2$. Table IV presents the new stimulation design with none of the segments having more than 2.7 $lb/ft^2$. The maximum concentration for the available width for the new example is:

$$C = \frac{.527 \times 100}{12 \times 1.5}$$

$$= 2.93 \ lb/ft^2$$

The overall concentration in Table IV is:

$$C_o = \frac{465{,}000}{388 \times 2 \times 80}$$

$$= 2.09 \ lb/ft^2$$

None of the segment in Table IV even approaches a concentration of 2.93 $lb/ft^2$, therefore, the probability of a screen out is remote.

## PREDICTING SCREEN OUTS DURING TREATMENT

The key to successful completion of hydraulic fracturing operation is very careful monitoring of surface treatment pressure[1] and fluid injection rate. Figure 5 is a typical hydraulic fracturing treatment curve. The hydraulic fracturing treatment curve is a plot of surface treatment pressure versus time for a constant injection rate. The fracturing curve presented in Fig. 5 is for a two stage treatment with each pressure alteration marked from A through H. Point A is the formation breakdown pressure. The breakdown pressure is defined as the pressure at which the pay zone starts accepting injected fluid. Zone B denotes the treatment pressure during pumping of the spearhead acid. When the gelled pad is pumped (Zone C) the surface pressure will drop due to friction reduction property of the gel. The surface pressure will continue to drop till the entire pipe is filled with gel at which point (Zone D) the surface pressure will stabilize. The surface pressure will start decreasing (Zone E) as proppant carrying gel is pumped due to increase in the hydrostatic head. With each increament in proppant concentration there will be surface pressure drop. However, it should be noted that the surface pressure drop due to increase in proppant is less than the increase in friction pressure caused by presence of proppant in the gel. The surface pressure increase at point F is due to the use of a diverting agent such as ball sealers or benzoic acid flakes. The diverting agent is used to separate the two stages. All subsequent pressure changes are identical to Stage 1. The average treatment pressure will be higher during Stage 2 than Stage 1.

All pressure variations during a frac treatment should be accountable and should be as expected. Pressure changes during a fracturing operation are due to one or more of the following reasons:

1. Change of fluid pumped - This usually occurs during change from acid to gel or while changing tanks during the treatment.

2. Change of injection rate - Increase or decrease in injection rate causes increase or decrease in surface treating pressure.

3. Change in proppant concentration - Increase in proppant concentration should cause a drop in surface treating pressure due to increased hydrostatic head. Increased proppant concentration also causes increase in friction pressure. However, the effect of increase in hydrostatic head is more pronounced than the increase in friction due to higher sand concentration.

4. Use of diverting agents - Use of a diverting agent causes increase in surface treating pressure due to partial blockage of the zone.

5. Perforation blockage or screen out - Perforation blockage causes increase in surface pressure due to greater pressure drop across the fewer perfs left open.

SURFACE TREATING PRESSURE CALCULATIONS

Pressure changes during fracturing operations should be accountable to one or more of the reasons mentioned earlier. These changes should be within $\pm 10\%$ of the values obtained from calculations. The fundamental equation used in all surface treatment pressure calculations is:

$$STP = ISIP_c + \Delta P_{pipe} + \Delta P_{perf} \qquad \text{—— } 3$$

Where STP = Surface treatment pressure (psig)
$ISIP_c$ = Instantaneous surface treatment pressure corrected for fluid (psig)
$\Delta P_{pipe}$ = Friction pressure loss in the pipe (psig)
$\Delta P_{perf}$ = Friction pressure loss through perforations (psig)

ISIP is obtained from an offset well treatment or from a prior treatment. Prior to a large expensive frac treatment it is necessary to pump a dummy stage of $\pm 10{,}000$ gal. and obtain a shut in pressure. The shut in pressure should be corrected for fluid pumped and the sand concentration employed.

Friction loss in pipe $\Delta P_{perf}$, can be obtained from charts provided by service companies for different gel systems. The number obtained from these charts should be corrected for sand concentration pumped using Fig. 6 and Fig. 7.

Friction loss through perforations, $\Delta P_{perf}$, can be computed using the following equation.

$$\Delta P_{perf} = \frac{0.372 \times Q^2 \times \rho}{(d)^4 \times n^2} \qquad \text{—— } 4$$

Where

$Q$ = Injection rate, bbl/min. (BPM)
$\rho$ = Fluid density, lb/gal.
$d$ = Diameter of perforations, inches
$n$ = Number of perforations

Equation 4 can be used to determine the number of perfs open or taking fluid, by rearranging the terms as follows:

$$n = \frac{0.609\ Q}{d^2} \left(\rho/\Delta P_{perf}\right)^{0.5} \qquad \text{—— } 5$$

If surface treatment pressure is greater than 10% of the computed number a formation screen out or wellbore perforation blockage could be predicted. When a screen out is predicted the following action should be immediately initiated.

1. Reduce proppant concentration.
2. Start reducing the injection rate in steps.
3. Pump for approximately 5 minutes and observe the surface pressure. If pressure drops, re-establish rate. If pressure increases go to Step 1 or abort if pressure is too high.
4. If the well is treating at calculated rate and pressure go back to the original design proppant schedule.

## REMEDYING A SCREEN OUT

When a screen out occurs or is in the process of occuring, the engineer must take the following action:

1. Immediately shut down all pumps and abort the original frac design. Do not try to displace or flush the proppant laden fluid at a slow rate. Trying to displace the proppant laden fluid will damage the proppant pack conductivity around the wellbore. The permeability damage is caused by the gelling agent dehydrating through the proppant pack which acts as a filter. This damage increases with the amount of fluid pumped as evidenced from Fig. 8.

2. Flow back well for 15 to 30 minutes.

3. Pump approximately 50 bbl. of pad fluid and try to establish rate.

4. If step 3 is successful frac with remaining gel with reduced proppant concentration and increased fluid loss additive.

5. If step 3 is unsuccessful

    a. Circulate proppant out of wellbore. If proppant is hardened,drill out and reperforate.

    b. Reacidize to open perforations.

    c. Refrac with a conservative proppant schedule.

## CONCLUSIONS

1. Screen outs should be avoided as they lead to production downtime, sand flowback for several days and incomplete stimulation of the pay zone.

2. It is possible to predict screen outs by investigating reservoir and frac fluid properties. Screen out can then be avoided by changing stimulation hydraulics design and fluid properties.

3. It is possible to predict screen out during the treatment by studying the treatment chart. Early detection of a screen out can be used to take corrective actions such as, decreasing proppant concentration and increasing injection rate.

4. If a well does screen out, the treatment should be immediately terminated and no attempt should be made to flush the prop laden fluid, attempt to flush after a screen out can lead to severe sand pack damage.

5. After a screen out the sand should be circulated out of the wellbore (or drilled out) and the well restimulated if the well was not sufficiently stimulated prior to screen out.

## REFERENCES


1. Nolte, Kenneth G. and Smith, Michael B.: "Interpretation of Fracturing Pressures", SPE Paper No. 8297, Fall meeting of SPE-AIME, Las Vegas, Nevada, Stptember 23-26, 1979.

2. Osboren, N. W., McLeod, H. O., Jr. and Schroeder, H. D.: "The Analysis and Control of Hydraulic Fracturing Problems." SPE/DOE Paper No. 9869, 1981 SPE/DOE Low Permeability Symposium, Denver, Colorado, May 27 - 29, 1981.


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## TABLE I

| SAND MESH SIZE | MAX. DIA. (IN.) | AVG. DIA. (IN.) |
|---|---|---|
| 6 - 8 | .1320 | .1171 |
| 8 - 12 | .0937 | .0779 |
| 10 - 20 | .0787 | .0559 |
| 12 - 20 | .0661 | .0496 |
| 20 - 40 | .0331 | .0248 |
| 40 - 60 | .0165 | .0132 |

## TABLE II

### RESERVOIR DATA

| | |
|---|---|
| BHP | 1500 psi |
| Frac Gradient | 0.7 psi/ft |
| Depth | 6000 ft. |
| BHFP | 4200 psi |
| Young's Modulus | $6 \times 10^6$ psi |
| Permeability To Reservoir Fluid | 1.00 md |
| Permeability To Frac Fluid | 0.6 md |
| Reservoir Fluid Viscosity | 0.02 cp |
| Reservoir Fluid Compressibility | $5 \times 10^{-4}$ $psi^{-1}$ |
| Rerervoir Porosity | 10% |
| Frac Height | 80 ft. |

### FRAC FLUID PROPERTIES

| | |
|---|---|
| N' | 0.61 |
| K' | 0.078 $lb\text{-}sec^{n-}/ft^2$ |
| Combined "C" | 0.0015 $ft/min^{1/2}$ |
| Fluid Spurt Loss | 0.0 cc |
| | |
| Injection Rate | 15 BPM |

## TABLE III

### PROPPANT PROFILE STUDY, PERFECT SUPPORT FLUIDS

Fluid Studied - Crosslinked HPG Gel
Total Volume - 224489 gal
Fluid Penetration - 1263 ft.

Perm. To Stimulation Fluid - .600 md
Perm. To Reservoir Fluid - 1,000 md
Leak-Off Fluid Viscosity - 1.00 cp
Reservoir Fluid Viscosity - .02 cp
Reservoir Fluid Comp. - 5.00E-04 1/psi
Stim. Fluid C-III - 0.00260 ft/sqrt (min)
Fracture Height - 80 ft
Combined C - 0.00200 ft/sqrt (min)
Frac. Pressure - 4200 psi
Reservoir Pressure - 1500 psi
N Prime - .610
K Prime - 0.07800 lb-sec/ft$^2$
Youngs Modulus - 6.00E+06 psi
Width - .500 in
Injection Rate - 15.0 BPM

| Fluid Volume (gal) | Surface Proppant Conc (lb/gal) | Location In Fracture (ft) | Fracture Proppant Conc (lb/ft$^2$) | Cumulative Proppant (lb) |
|---|---|---|---|---|
| 40000 | .00 | 1191 to 1263 | .000 | 0 |
| 20000 | 1.00 | 1144 to 1191 | 2.654 | 20000 |
| 20000 | 2.00 | 1085 to 1144 | 4.288 | 60000 |
| 40000 | 3.00 | 930 to 1085 | 4.522 | 180000 |
| 40000 | 4.00 | 630 to 920 | 3.456 | 340000 |
| 40000 | 5.00 | 0 to 630 | 1.982 | 540000 |

Total Frac Fluid Volume - 200000 gal.

## TABLE IV

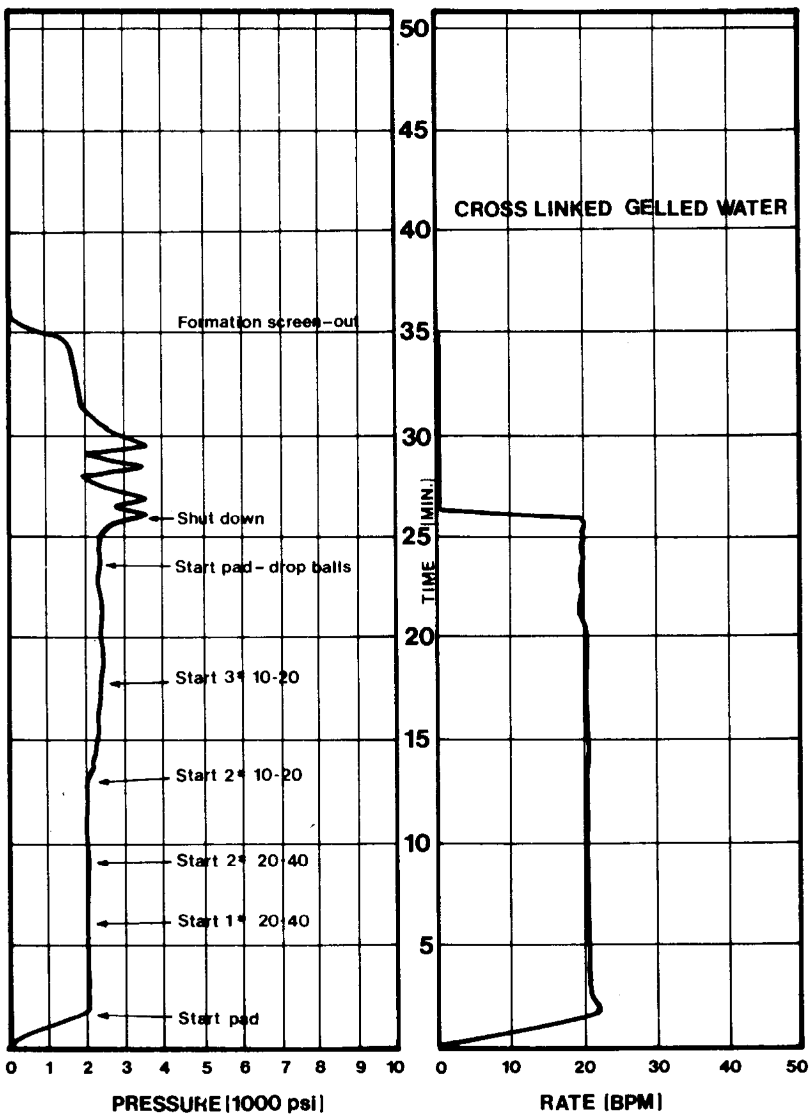
### PROPPANT PROFILE STUDY, PERFECT SUPPORT FLUIDS

Fluid Studied - Crosslinked HPG Gel
Total Volume - 221088 Gal
Fluid Penetration - 1496 ft.

Perm. To Stimulation Fluid - .600 md
Perm. To Reservoir Fluid - 1.000 md
Leak-Off Fluid Viscosity - 1.00 cp
Reservoir Fluid Viscosity - .02 cp
Reservoir Fluid Comp. - 5.00E-04 1/psi
Stim. Fluid C-III - 0.00260 ft/sqrt (min)
Fracture Height - 80 ft.
Combined C - 0.00150 ft/sqrt (min)
Frac. Pressure - 4200 psi
Reservoir Pressure - 1500 psi
N Prime - .610
K Prine - 0.078000 lb-sec/ft$^2$
Youngs Modulus - 6.00E+06 psi
Width - .527 in
Injection Rate -15.0 BPM

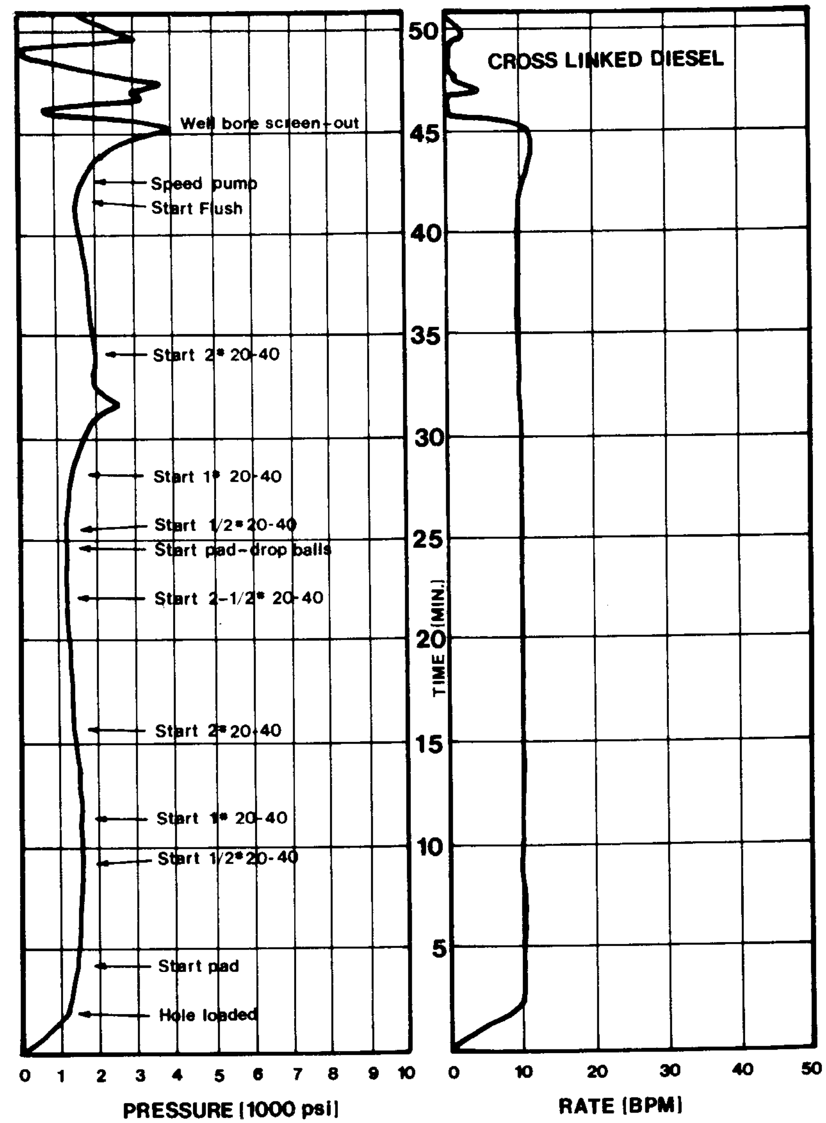
| Fluid Volume (gal) | Surface Proppant Conc (lb/gal) | Location In Fracture (ft) | Fracture Proppant Conc (lb/ft$^2$) | Cumulative Proppant (lb) |
|---|---|---|---|---|
| 40000 | .00 | 1388 to 1496 | .00 | 0 |
| 35000 | 1.00 | 1259 to 1388 | 1.702 | 35000 |
| 35000 | 2.00 | 1081 to 1259 | 2.458 | 105000 |
| 30000 | 3.00 | 863 to 1081 | 2.581 | 195000 |
| 30000 | 4.00 | 538 to 863 | 2.303 | 315000 |
| 30000 | 5.00 | 0 to 538 | 1.743 | 465000 |

Total Frac Fluid Volume - 200000 gal.



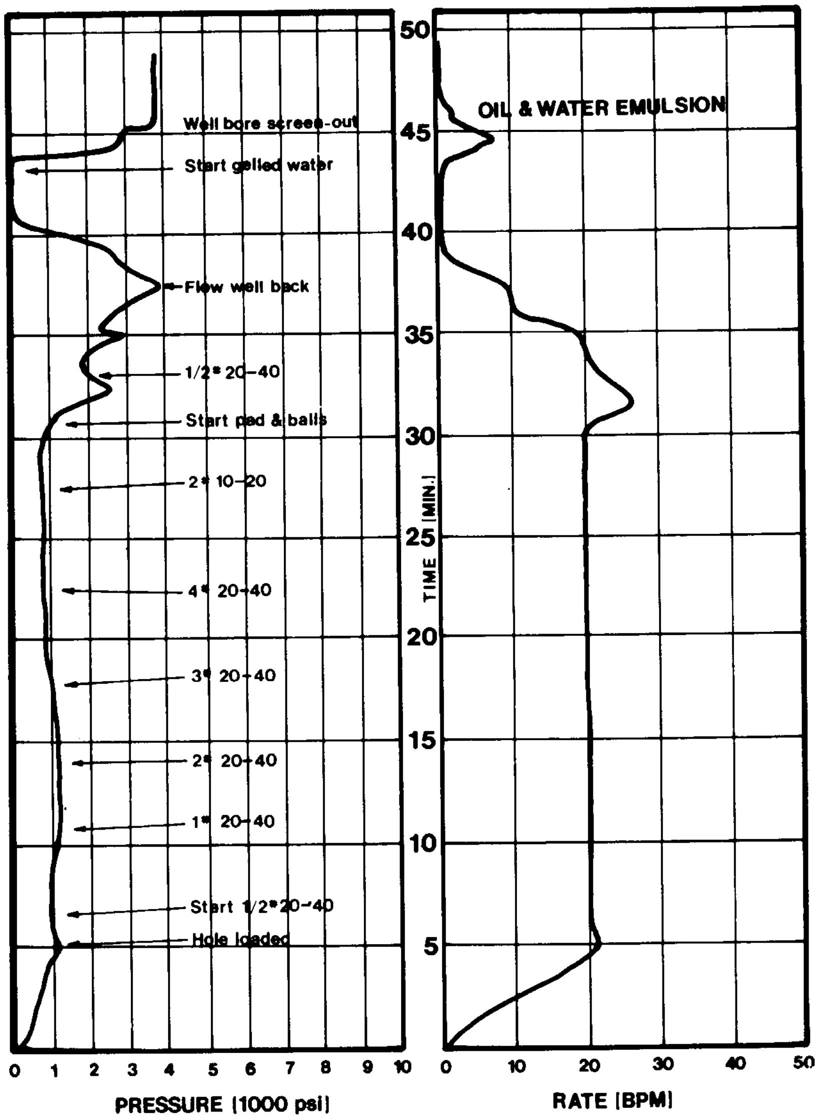

FRACTURING CHART

Figure 1



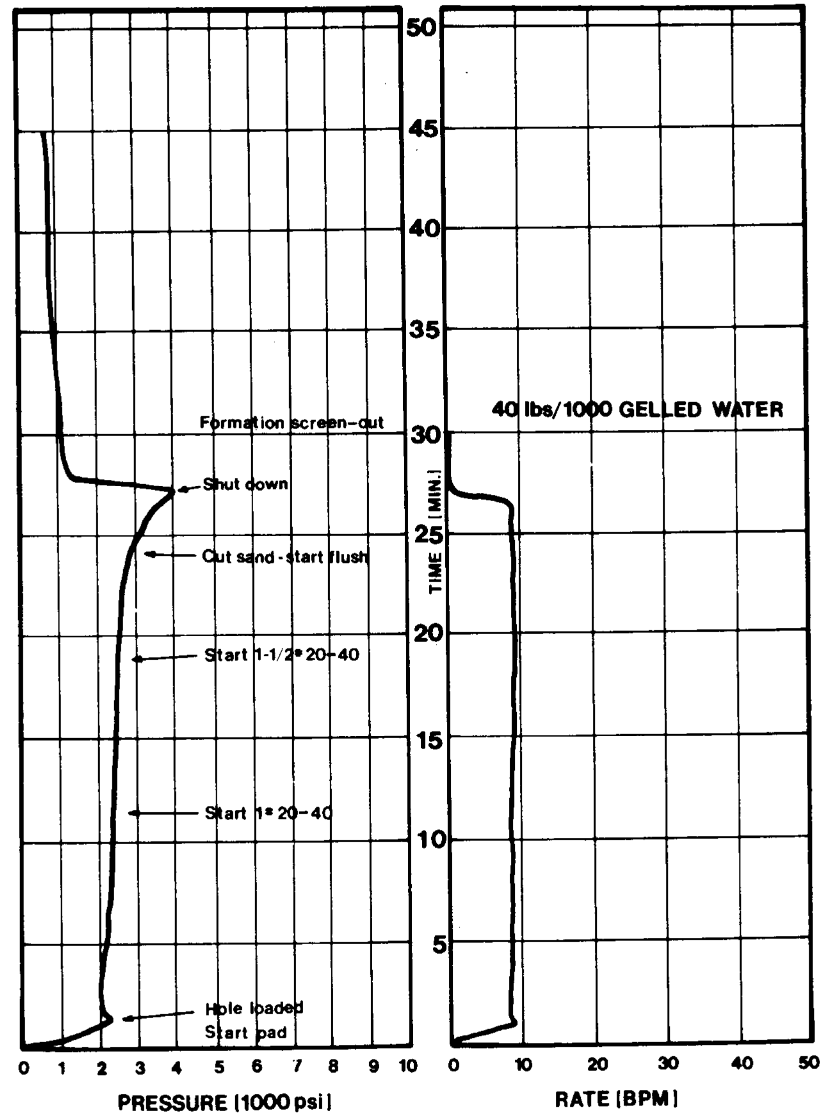

FRACTURING CHART

Figure 2



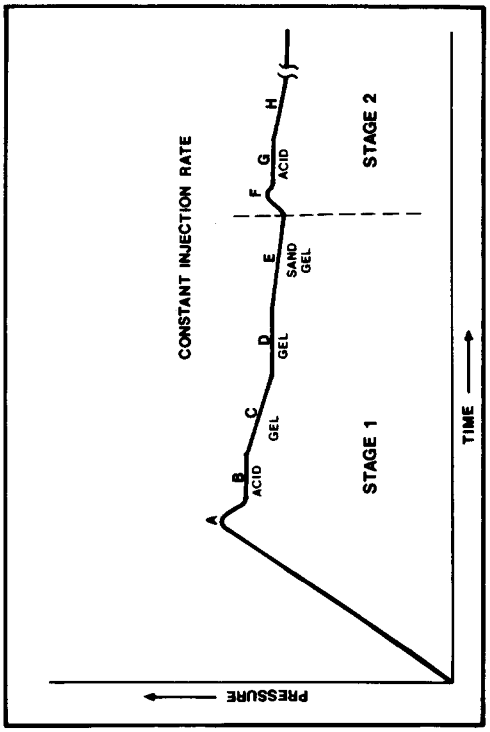

FRACTURING CHART

Figure 3



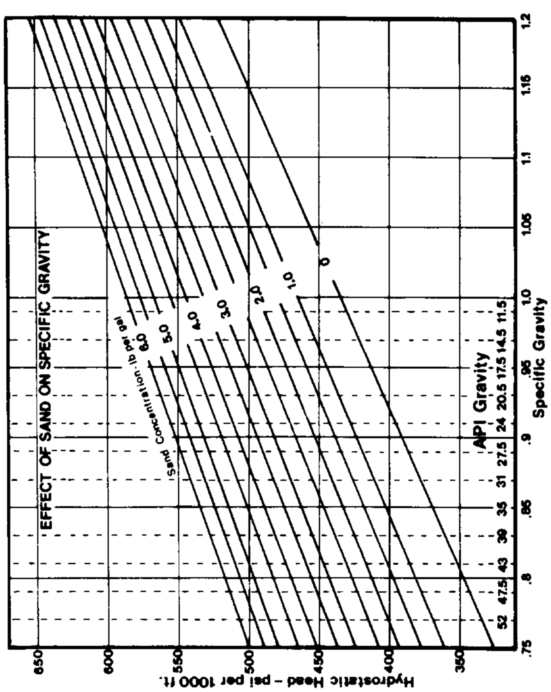

FRACTURING CHART

Figure 4



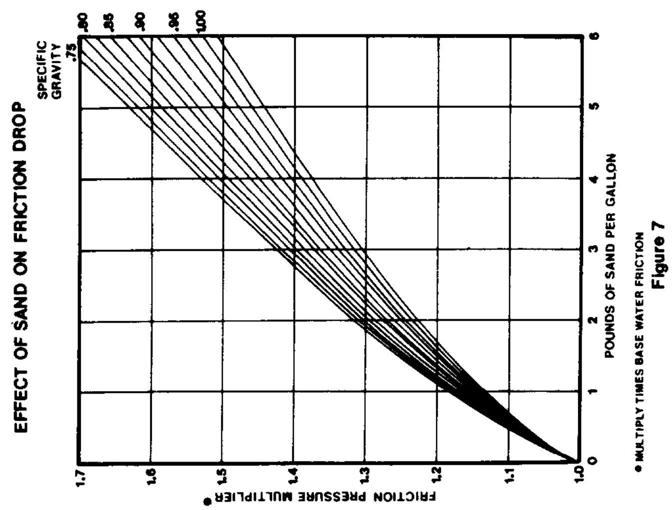
HYDRAULIC FRACTURING CURVE

Figure 5



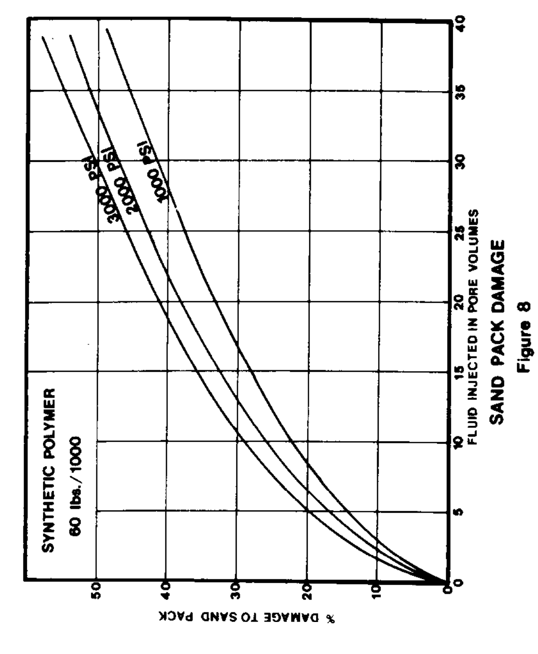
EFFECT OF SAND ON SPECIFIC GRAVITY

Figure 6



EFFECT OF SAND ON FRICTION DROP

Figure 7



SAND PACK DAMAGE

Figure 8