CONSIDERATIONS FOR DESIGNING WORKOVER OPERATIONS WITH CONTINUOUS COILED TUBING

Angus S. McReynolds
NOWSCO SERVICES

ABSTRACT

The use of continuous coiled tubing to perform various types of remedial treatments or workovers has been well documented.[1,2,3,4] Numerous successful treatments have been obtained with this device in oil, gas, injection and geothermal wells. However, the occurrence of and, more importantly, the causes of failures in operations involving coiled tubing have not been addressed by the industry. An examination of causes of failure should lead to a higher success ratio.

INTRODUCTION

Of the various types of workover operations currently available, the most cost effective in many instances is the use of continuous coiled tubing. Oftentimes, the coiled tubing may be applied in the same manner as the commonly employed small diameter wash pipes to form concentric strings within wellbores.[5,6] There are, however, important differences between jointed pipe and the continuous, reeled tubing which must be considered.

Instances of stuck or collapsed coiled tubing have resulted in costly fishing operations and lost revenues due to extended shut-in periods. The author proposes that many of these failures stem from a lack of consideration as to the unique characteristics of coiled tubing, the more important of which are that it is, relative to jointed pipe, a thin walled, highly flexible welded string of which a portion is exposed to the atmosphere during use. These features which impart versatility to the coil unit are the same which, if neglected, contribute to failures. It is felt that in these cases the fault is not due to an impracticality of the continuous coiled tubing unit as a workover device but rather to deficient or, in some cases, a complete lack of consideration as to the proper design of such treatments. Common applications of coiled tubing will be examined with attention to the areas of possible misuse.

Removing Fill from Wellbores

Frequently tubing units are utilized to remove solids from wellbores. The solid material may be propping agents left in the wellbore subsequent to screen-out of a hydraulic fracturing treatment or matrix material which feeds into the wellbore from unconsolidated formations. The units are particularly well suited to remove this fill from casing below a packer assembly. While in most cases these treatments are performed perfunctorily, there have been cases where the coiled tubing has become stuck and which resulted in the need to fish the tubing from the well.

It is apparent that this type of operation is frequently designed along arbitrary guidelines as to selection of wash fluid, circulation rate and tubing injection rate. In the majority of wells these considerations are nominal. They become critical when washing in larger diameter ($\geq$ 5½" O.D.) casing or in wells with mechanical peculiarities such as helically buckled production tubing, side pocket gas lift mandrels or an unusually high degree of deviation from the vertical. Certain guidelines may be followed which should reduce the occurrence of stuck tubing in this process.

Fluid Selection

Generally speaking, solid particles such as sand settle in fluids at some given rate. In the so-called perfect support fracturing fluids this rate is nil, but in fluids which are more Newtonian in nature and less viscous, the particles settle faster. The relevance of this fact to fill removal via coiled tubing is to select a fluid wherein the terminal settling velocity of particles such as frac sand is less than half rise rate of the fluid in the created annulus. Given that the rise rate of the fluid is a function of the circulating rate through the coiled tubing and considering the relatively small ID of the tubing, trade-offs occur which affect selection of the proper wash medium.

As the circulating rate through the coiled tubing is related to the injection pressure of the fluid, the excessive friction loss values of untreated waters or the more viscous fluids can give rise to pumping pressures which can exceed operating limitations for that portion of the tubing exposed to the atmosphere. The choice of fluid is therefore made to achieve adequate viscosity versus minimum friction loss which in turn equates to maximum circulation rate.

It is apparent that the most commonly employed fluids, fresh waters or brines, are the poorest performers. They allow high settling velocities and generate high friction losses which results in low circulation rates. Thick gels made with guar or derivitized gums offer good particle support but become difficult to pump at higher concentrations. It is suggested that fairly light gels made with 50-20 lb./1,000 gals. of guar provide adequate particle transport while allowing maximum circulation rate due to the dramatic drop in friction loss relative to water that these systems exhibit. Polyacrylamide friction reducers may be used to reduce the friction loss of fresh water or brine but do not impart the viscosity achieved with the gums. Nitrogen or foam may also be used as a circulating medium with which to remove debris. The use of these methods is particularly well suited to those wells whose conditions (e.g., water sensitive formations, lost circulation zones and inordinately low pressures) mandate low density and/or low water content systems. In respect to low pressure wells, these systems also have the advantage of allowing the well to be returned to production immediately after treatment as the extremely low density of these mediums eliminate swabbing.

Once the importance of proper fluid selection has been recognized, fill removal treatments in conventionally completed wells may be conservatively designed by adhering to the following recommended calculations.

A) Viscosity of fluid - As the shear rate of the fluid being circulated up the created annulus falls within very low ranges, its impact on the viscosity of the wash fluid may be ignored. However, in the interest of convenience, the viscosity may be calculated from the n' and K' values of the fluid published by service companies.

B) Terminal Settling Velocity (fall rate) - The velocity at which the particles in question fall through the wash fluid is viscosity dependent. The rate may be derived from tables supplied by service companies or calculated by Stokes' law:

$$\text{Terminal Velocity (m/sec)} = 5.58 \times 10^{-5} g \frac{Dp^2(\rho s - \rho_1)}{\mu} \qquad (1)$$

where:

g = acceleration due to gravity (9.8 m/sec^2)
Dp = particle diameter (mm)
ρs = density of particle (kg/m^3)
silicon = 2370 kg/m^3
ρ = density of fluid (kg/m^3)
water = 1,000 kg/m^3
μ = viscosity of fluid (Cp)

or, more simply for the case of sand in water,

$$\text{Terminal Velocity (m/min)} = 44.9\,\frac{Dp^2}{\mu}$$

where:

SAND MESH SIZE	DIAMETER (mm)
4 X 8	4.75 - 2.39
8 X 12	2.39 - 1.68
10 X 20	2.00 - 0.84
20 X 40	0.84 - 0.43

C) Fluid Rise Rate in Annulus - As mentioned, the circulating rate obtainable through the tubing is a function of friction loss. Rates of two to three times that of fresh water at pressure have been obtained using 15-20 lbs./1,000 gals. gelling agent. The rate through the 1" O.D. tubing will generally be 0.159-0.238m^3/min (1-1.5 BPM). The rise rate, once circulation has been established, will be:

$$\text{Rise Rate (m/min)} = \frac{P}{V} \tag{2}$$

where:

P = pump rate (m^3/min)
V = annular volume (m^3/m)

The values for annular volume may be obtained from engineering handbooks.

D) Coiled Tubing Injection Rate - Once circulation is initiated and fill is being washed from the well, the rate at which the tubing is run into the well should be set according to a predetermined lift concentration. Using the aforementioned gel concentrations, a conservative approach is to wash the sand from the well at a concentration not to exceed 119.8 kg/m^3 (1 lb/gal). The concentration is calculated using the bulk density of sand.

$$\text{Injection Rate (m/min)} = \frac{P(119.8)}{(1713)V} \tag{3}$$

where:

P = pump rate (m^3/min)
119.8 = maximum concentration (kg/m^3)
1713 = bulk density of sand (kg/m^3)
V = annular capacity (m^3/m)

This method of designing wash treatments is conservative and should apply to a broad spectrum of situations. The use of gelled water is economical and allows for a measure of wellhead pressure control. In cases where nitrogen gas is desired as a "wash" medium, the job design criteria can become much more complicated. As the specific gravity of nitrogen gas is .967 relative to air, a convenient alternative to tedious calculations can be had by applying the charts for 1.0 gas gravity developed by R. R. Angel in his work "Volume Requirements for Air & Gas Drilling." The charts are plotted to solve for circulation rates necessary to achieve a standard air velocity in the annulus of 914.4 m/min (3000 ft/min).

Mechanical Problems in Wellbores

Wells that are completed with mechanical complications such as landing nipples, gas lift mandrels, production tubing landed in compression and deviated wellbores should be addressed on an individual basis before coiled tubing is run into the well. A recurrent problem associated with workover failures utilizing the coiled tubing is both the casualness with which jobs are "designed" and the monitoring of the job while in progress. Attention to detail can minimize the associated risks of using the tubing.

The presence of landing nipples and/or side pocket gas lift mandrels is common in completions. While presenting little or no problem to convention workover methods, they can cause problems when they are not considered relative to their impact upon the use of coiled tubing. It must be recalled that relative to jointed pipe, the coiled tubing is extremely flexible and is injected into the well by means of a powerful hydraulically activated traction device. If an obstruction upon which the coiled tubing may hang is encountered, frequently the tubing will become wadded and possibly stuck before the operator is aware of the problem. A simple but often neglected means of avoiding this type of problem is the insistance of the use of adequate centralizers at the end of the coiled tubing. Basket type centralizers which allow flow through them are to be much preferred to bullet types which can cause problems associated with flow restriction.

Even when no possible obstructions are evident upon examination of well records, consumers of coiled tubing should insist upon adequate centralizers to preclude unforeseen difficulties. These problem areas would include the potentiality of split production tubing or casing and foreign objects. The likelihood of extracting coiled tubing from the vicinity of a fish which was not noted on well records would be greatly enhanced by the use of centralizing tools. The importance of thorough well records and their examination cannot be overly stressed as to their relevance to the use of coiled tubing. As an example, the debris remaining from a through-tubing perforating gun or wireline while having little or no relation to a well's normal performance, may be a major factor in the design of coiled tubing treatments. On occasion the coiled tubing may be injected past such a fish but will become caught upon extraction. The use of the tools should help to alert the operator of such an encounter. In any event, coiled tubing should always be injected slowly into a well while maintaining circulation rather than being injected as quickly as possible in the interest of economics. The downside potential of conservative use of coiled tubing is far less than potential failures resulting from indiscriminate use.

Oftentimes production tubing is landed in compression such that the tubing becomes helically buckled within the casing. The impact of buckling upon the use of coiled tubing is a function of the sizes of the production tubing and the casing. The larger the casing relative to the production tubing in conjunction with set down weight, the more pronounced the buckling effect. Hand calculations as well as computer modeling of the helical buckling effect as described by Lubinski et al. and Hammerlindl are readily available. Work is now in progress to modify the mentioned works specifically to the use of coiled tubing.

As may be inferred, the problem can be quite severe and well records must be examined with this effect in mind prior to injecting the coiled tubing into a well. It is quite possible to inject the coiled tubing into a buckled string and to exceed its tensile strength upon attempts to extract it. If in the event the tubing becomes lodged in such a situation, it would be much preferred to circulate to kill the well and release the pressure upon the packer, thereby negating the effect, prior to extracting the coiled tubing.

Economic or environmental considerations at times dictate the drilling of many wells from one surface location. This equates to wells which are highly deviated from the vertical. Single wells are often directionally drilled for geologic or surface topography reasons. The angle of deviation and the number of bends can become a factor in the design of coiled tubing workovers. In extreme situations, the friction drag associated with such bends may make it impossible to extract the coiled tubing from the wellbore once it has been introduced. Again, the characteristics of the coiled tubing which make for its convenience may become a liability if not considered.

An equation with which to judge such potentialities is available. This equation calculates the maximum pull required to extract the coiled tubing from a deviated wellbore. This required force drops dramatically once movement of the coiled tubing is initiated because of the resulting change from static to dynamic friction considerations;

X = lbs. force required to extract coiled tubing from well.

Note: Because of the mechanical forces being exerted on the tubing (e.g. weight, friction, etc.) are incremental, the problem must be solved from the bottom of the tubing upwards.

$$X = w\left\{H_1 + \left(\frac{\pi\alpha_1 R_1}{180}\right) + 1\cos\alpha_2 + \mu\, 1\sin\alpha_2 + \left(\frac{\pi\alpha_2 R_2}{180}\right) + H_2\right\} +$$

$$(F_6) + \frac{\mu\{w\, 1\cos\alpha_2 = w\,\mu\, 1\sin\alpha_2 + H_1 w + (F_6)\}\sin\alpha_2}{(\cos\beta_2 - \mu\sin\alpha_2)}$$

where:

$$\beta_1 = \tan^{-1}\frac{\{(1-\cos\alpha_1)\}}{\{\sin\alpha_1\}}$$

$$\beta_2 = \tan^{-1}\frac{\{(1-\cos\alpha_2)\}}{\{\sin\alpha_2\}}$$

w = wt of coiled tubing in air, psi/ft
H_1 = length of straight section below second bend, ft.
R_1 = radius of second bend, ft.

Note: If length of arc is given, radius is equal to:

$$R = \frac{\text{length of arc, feet}}{\left(\frac{\alpha}{180}\right)(\pi)}$$

α_1 = angle of second bend, degrees.
l = length of straight section between bends, ft.
α_2 = angle of upper bend, degrees.
R_2 = radius of upper bend, ft. (see note for R_1 above).
H_2 = length of vertical section from surface to first bend, ft.
μ = static coefficient of friction.

$$F_6 = \frac{\{\mu(H_1 w) \sin \alpha_1 \}}{\{(\cos \beta_1 - \mu \sin \alpha_1)\}}$$

Note: When both coiled tubing and annulus are filled with a similar fluid, w must be adjusted to correct for bouyancy effects;

$$y = \frac{12 \frac{\{\pi(O.D.^2 - I.D.^2)\}}{4}}{1728} \text{ X density of fluid, lbs/ft}^3$$

Subtract y from w, use new term as w.
When coiled tubing is full of gas and annulus is filled with fluid;

$$y = \frac{12\left(\frac{\pi\ O.D.^2}{4}\right)}{1728} \text{ X density of fluid, lbs/ft}^3$$

Mechanical Problems with Coiled Tubing

On occasion coiled tubing will become egg-shaped or oval because of careless handling or misuse. This ovality has a profound affect upon the collapse resistance of the tubing. As can be seen in Table I, the maximum allowable external pressure or resistance to collapse of various sizes of coiled tubing decreases dramatically with the increase in deviation from perfect roundness. These values are calculated according to the Theory of Thin Shells developed by Dr. R. G. Sturm. As is evidenced, severely out-of-round tubing should be rejected by both the consumer and operator of coiled tubing units. Consideration should be given to avoiding excessive negative pressure differentials when designing workovers. To this end, pains should be taken to measure fluid weights and pressures precisely. Care should be exercised to ensure that acceptable tubing is not ovaled by improper adjustment of the injector mechanism.

The coiled tubing which is reeled onto the unit is composed of relatively short lengths which are welded together. Both consumers and operators should ascertain the quality of such welds, especially those between lengths of thin walled and heavy walled sections. In deeper wells, caution should be exercised to reduce the number of welds which would be within the wellbore in the upper segments of the coiled tubing.

The coiled tubing is composed of a high strength, low alloy steel which is subject to hydrogen embrittlement. Complete records should be kept by operators of coiled tubing as to amount of contact with H_2S and degree of severity. Operators should weigh these records carefully prior to subjecting coiled tubing with an inordinate exposure history to H_2S to prolonged, stressful use in sour environments. By no means should strings of tubing with the characteristic "onion skin" appearance of hydrogen sulfide cracking be deemed suitable for use by the operator. These sections should be removed from the string and discarded.

CONCLUSION

While not to be construed as an indictment against the utility of the coiled tubing unit as a workover device, the aspects of job design presented in this paper are offered with the intention of reducing misuse and possible treatment failure. The realities of those treatments which result in stuck, lost or collapsed tubing indicate to the author that too often the units are applied with a certain casualness as to details of treatment design. When applied correctly, the units are extremely functional, utilitarian tools with which to economically perform a variety of tasks. The point is to understand that those attributes of the device which contribute to its usefulness are also those which, if ignored, can result in costly mistakes.

REFERENCES

1. Taylor, D. B. and Plummer, R. A.: "Gas Well Stimulation Using Coiled Tubing and Acid with Mutual Solvent", Society of Petroleum Engineers Paper 4115, presented at SPE 47th Annual Fall Meeting, San Antonio, 1972.

2. Weeks, Steve G.: "Coil Tubing, Nitrogen Cut Workover Costs", World Oil (Feb. 1, 1970).

3. Russell, Stephen C.: "Workover and Stimulation of Water Injection Wells Using Continuous Coiled Tubing", presented at the Southwestern Petroleum Short Course, Lubbock, Texas, 1980.

4. McReynolds, Angus S. and Maxson, H. L.: "The Utilization of Endless Coiled Tubing and Nitrogen Gas in Geothermal Well System Maintenance", Geothermal Resources Council Annual Meeting, Salt Lake City, 1980.

5. Fincher, Norton E.: "Concentric Workover Operations in Deep Sour Wells", J. Petroleum Tech. (Oct. 1980), pp. 1674-1678.

6. Weeks, Steve G.: "Small-Diameter Concentric Tubing Extends Economic Life of High Water/Sour Gas Edwards Producers", J. Petroleum Tech. (Sept. 1982), pp. 1947-1950.

ACKNOWLEDGEMENTS

The author wishes to thank NOWSCO WELL SERVICE LTD. and Mehrzad Afifi of Bowen Tools, Division of Big Three Industries for their assistance with this paper.

TABLE 1
OUT-OF-ROUNDNESS EFFECTS ON ALLOWABLE EXTERNAL PRESSURE

Deviation From Perfect Roundness Inches	Allowable External Pressure: 1" O.D. X .065" Wall Thickness		Allowable External Pressure: 1.25" O.D. X .084" Wall Thickness	
	For Yield PSI	For Collapse PSI	For Yield PSI	For Collapse PSI
0.000	11700	15698	12096	16229
0.001	7980	10706	8889	11926
0.002	6054	8123	7026	9427
0.003	4878	6544	5809	7794
0.004	4084	5479	4951	6643
0.005	3512	4713	4314	5788
0.006	3081	4134	3822	5128
0.007	2744	3682	3431	4604
0.008	2473	3319	3113	4176
0.009	2252	3021	2848	3821
0.010	2066	2772	2625	3522
0.015	1464	1964	1887	2531
0.020	1133	1520	1472	1976
0.025	925	1240	1207	1620
0.030	781	1047	1023	1373

NOTE:

1. Design yield strength = 60,000 PSI.

2. Collapse pressure based on design strength = 80,500 PSI

MHF - FROM CONCEPT TO EXECUTION

VITHAL J. PAI, SAM J. GARBIS AND G. HOWARD HALL

THE WESTERN COMPANY OF NORTH AMERICA

ABSTRACT

In recent years Massive Hydraulic Fracturing (MHF) has become an important technique for the stimulation of low permeability zones. Since the financial considerations for MHF treatments are significant, the treatments should be well planned and cost effective to eliminate unnecessary expenditures. This paper will discuss: 1) MHF design parameters and considerations, 2) the type of equipment required, 3) pre-job planning and logistics and 4) the use of temperature and RA surveys, such that the ultimate goal of a cost effective MHF treatment is achieved.

INTRODUCTION

To develop and produce hydrocarbons from tight formation gas (TFG) reservoirs special stimulation techniques such as Massive Hydraulic Fracturing (MHF) are required. The extremely high cost of MHF combined with the need to create deeply penetrating, highly conductive fractures under very high overburden stresses, demands a high level of technology. Several major operators, such as Amoco Production Company[1] and Mobil, have special in-house programs between various departments to address the broad array of complex design requirements. The design parameters studied were fracture height and orientation, rock properties and fracture pressure behavior. Studies such as these have helped improve fracture fluid efficiencies and reduce indiscriminate vertical fracture growth.

Current estimates of potential increases in gas reserves from TFG sources are 190 to 570 Tcf in the U.S.[1] TFG production rates of 4 to 8 TCF/year can be expected by 1990 if MHF techniques are prudently applied. These treatments, which can range from 100,000 to 1 million gal. of fluid and up to 3 million pounds of proppant contribute substantially to the overall drilling and completion costs. It has been shown that MHF costs may vary from 10 to 50% of total drilling and completion costs.[1] It is imperative therefore, that MHF design and preparation be directed towards optimizing TFG development economics.

For MHF treatments to be "successful" accurate knowledge of all rock and design properties is an absolute must. Thus, the design of MHF treatments is far more critical than the design of conventional frac treatments.[2,3] The results of MHF treatments have been disappointing in some instances.[4,5] Initially these negative results were attributed to certain design errors, however, it appears now that this response is inherent in the nature of some formations.[4]

Recent decline in gas prices and demand has forced all energy companies to devote attention to reducing cost and eliminating waste during TFG completions. Success of MHF operations depends on the ability to predict and prepare for the several problems that could be encountered while pumping. Contingency plans are necessary to minimize operational problems during the long pumping hours. Down time should be avoided to prevent loss of design integrity. With the growth in technology, there has been a drastic increase in available options and complexity of products and equipment, which has made careful analysis and detailed planning vital.

The main body of this paper is divided into five (5) parts:

A. Design considerations
B. Rock properties and frac height selection
C. Frac fluid selection and frac design
D. Logistical and operational considerations
E. Equipment requirement

The major purpose of this paper is to provide the completion engineer with a checklist in designing, preparing and performing an MHF treatment. We have also tried to identify problem areas and suggested methods of either avoiding them or minimizing their effects. Although not all the problems encountered can be discussed here, we have attempted to be as exhaustive as possible. Some topics are dealt with in greater detail than others because of their relative importance in the overall process.

Definitions of Terms:

The term MHF has been loosely defined as a large volume (fluid volume and proppant weight) treatment being conducted in a LOW permeability zone (TFG) usually associated with gas producing sands. Various authors have defined MHF based upon fluid volume, proppant quantity, length of propped conductive fracture and propped fracture height. The commonly accepted definition for MHF was: a frac process that created propped fracture wings on either side of the wellbore in excess of one thousand (1,000) feet. This definition does not include the effect of fracture height, the quantities of frac fluid and proppant, the long pumping times and equipment requirements. The authors definition tries to encompass all these factors, and is based on the fracture area created. We have attempted to define MHF as a fracturing process that creates fracture areas in excess of 200,000 square feet. This definition is independent of fracture inclination, i.e. horizontal or vertical.

The tight or low permeability formation (TFG) is defined as a formation with permeability less than 0.1 md which is the same definition used by Federal Energy Reserve Commission to designate Tight Gas Sands. MHF treatments have made commercial wells in formations with permeabilities ranging from 0.1 to 0.001 md.

Geographical Areas of MHF Applications:

MHF has been successfully applied in many of the low permeability sands of the Rocky Mountain area. Specifically, MHF, has and is being employed in the San Juan Basin (Dakota) of Northwest New Mexico, Wattenberg field (Muddy J) in the Denver Basin of Colorado, Wamsutter field (Mesa Verde) in Green River Basin in Southern Wyoming, Moxa Arch (Frontier) in Southwestern Wyoming, Cotton Valley Sand and Lime in East Texas, Cotton Valley formation in Louisiana and Arkansas, Canyon Sand formation of West Texas, Austin Chalk formation of South and Central Texas, and Morrow and Atoka formation of Southeast New Mexico.

MHF DESIGN CONSIDERATIONS

The object of hydraulic fracturing is to bypass formation damage caused by leakoff of drilling and completion fluids, and most importantly to create a deeply penetrating highly conductive fracture extending the wellbore radius.

The factors considered in MHF design are: zone selection, determining number of perforations, injection rate, fluid requirements, fracture geometry, and proppant type and size.

Zone Selection:

Zone selection for completions employing MHF technology involves factors such as: water saturation, proximity to water bearing zones, porosity, barrier height and competency between zones. Since permeabilities in TFG zones are usually below 0.1 md, they are not considered in zone selection. In fact, low permeabilities make MHF necessary in order to make these wells commercially viable. Most zones selected have been based on pre-stimulation flow tests and evaluation of offset well information such as open hole logs.

Primary zone selection is based on porosity. Most operators have selected porosity zones in excess of 6 to 7% shale corrected porosity. If zone extent becomes too large the lower cutoff could be raised up to 8 to 10% porosity. In general, compensated neutron density log with shale corrections is the most common method of evaluation.[2]

Formation water saturation is also used by some operators as a method of zone selection. Water saturation numbers are virtually meaningless when the effects of fracturing out of zone at some distance from the wellbore are considered, which in many instances is undetectable on post fracture surveys. It is suggested that a water saturation cutoff of 70% is an adequate protection from triggering excessive water production.

Proximity to water oil or water gas contact i.e. proximity to water bearing zones should be of prime concern. If a water-bearing zone is suspected, the perforations should be placed at least 100' above the water zone, especially if a competent shale barrier is not present.

Competency and height of barrier (shale) zones may be evaluated with help from SP logs, while Poisson's ratio and Young's modulus may be calculated from acoustic, density and gamma ray data. Shale barriers, however competent, do not usually provide adequate protection from fracturing out of zone if the barrier height does not exceed 50'. This fact is further compounded by channeling behind casing due to poor cement jobs and high fracture injection rates. There is strong correlation between height and injection rates and it is a safe practice to reduce injection rates if the barrier competency is felt to be inadequate.[2] Usually fractures tend to move upward due to increased overburden stresses with depth. However, in many instances the fractures have shown a preponderance of downward growth. It could be said with reasonable confidence that frac height is related to barrier comptence, height and hardness, as well as the nature of the cement bond.

Perforating Schedule:

Perforating schedule should be based on either Limited Entry Technique or Modified Limited Entry Technique using ball sealers. The success of MHF treatment is highly dependent upon an engineered design of the perforating program. Most MHF gross zones are 200' or more. Adequate fluid distribution can be achieved by shooting 25 or less 0.42" dia. shots with large deep penetrating casing guns. Fluid entry should be 1.25 to 2 BPM per perforation to achieve limited entry. Perforating programs should be based on zone height and average injection rate, given the pressure limitations of the tubular goods.

Injection Rate Selection:

Injection rate selection should be based on:

1. Zone or estimated frac height (number and size of perforations)
2. Size and grade of flow conduit
3. Pressure limitations
4. Proppant concentrations and fluid properties

Zone or estimated fracture height is normally related to the number "n" and size of perforations by design. The larger the number of perforations the greater the injection rate to achieve limited entry or uniform fluid distribution. The injection rate required to effectively treat perforations is given by:

$$Q = 1.64\ nd^2\ (\Delta Pp/D)^{0.5} \qquad (1)$$

In most design work a pressure drop of 200 psi is adequate to obtain uniform fluid distribution.

Injection rate affects fracture height and fluid distribution and is very critical to the overall success of the treatment. Where interval yield of the tubing of the casing limits injection rate, the treatment should be staged using ball sealers. Figure 1 presents injection rate as a function of surface pressure. The HHP (horsepower) costs can go up significantly at higher rates making economic considerations important as shown in Table 1.

Some operators recommend starting at high injection rates and low sand concentrations and tapering the injection rate and increasing the sand concentration.[8,11] The high initial injection rate allows for the majority of the ultimate fracture height to be created while the pad and low prop concentration slurries are being pumped. This establishes leakoff control over the entire frac height while the pad is being pumped, thus reducing chances of screenout.

Reducing injection rate during later treatment stages reduces the chances of fracture height growth and also prevents equipment overload during high sand concentration pumping.

Fluid Mechanics:

The mechanics of fracturing consists of transmission of energy from surface frac pumps to the formation via a fracturing gel. The bottom hole fracturing pressure (BHFP) is defined in equation 2 and 3 below.

$$BHFP = ISIP + HH \tag{2}$$

$$BHFP = FG \times depth\ (ft) = STP + HH - \Delta Pp - \Delta Pf \tag{3}$$

Friction pressure drop through the pipe can be calculated using charts provided by service companies for different fluid types and pipe sizes. Presence of proppants increases friction drop due to abrasion, and a correction factor should be used to determine the average friction drop. Prop concentrations also increase HH and cause a drop in STP.

Crosslinked fluids increase friction drop through tubing, thus increasing cost due to higher STP. Employment of delayed crosslinkers, which prevent crosslinking of fluid until it reaches bottom of tubing lowers STP, thus saving several thousands of dollars in horsepower costs and making the entire operation safer and more efficient by not overloading the equipment.

Pressure drop across perforation can be calculated using equation 1. The same equation can be used to compute the number of perforations accepting fluid at any time.

Fracture Geometry:

Fracture geometry entails fracture length, width and height. The commonly used fracture design computer programs assume a constant fracture height. The gross fracture height determines the fracture volume and the net fracture height determines the height over which fluid loss will occur. Most TFG zones will have gross heights ranging from 100'to 1,000' and net heights ranging from 30 to 300'. The fracture length selected is based on economics and a productivity increase ratio as presented in Figure 2. Fracture lengths normally vary from 1,000' to 2,500'. Frac width developed by the computer using Perkin's and Kern equation is shown in Figure 7. The frac geometry details are shown under "Frac Design", which is based on a computer study.

The rock properties that control MHF design are Young's modulus, permeability, porosity, frac height and Poisson's ratio. Poisson's ratio has minimal effect and may be ignored for design purposes. Young's modulus has a considerable effect on frac width and is assumed constant throughout the fracture. Young's modulus in TFG may vary from 3.5 to 9.5 x 10^6 psi.

Mini Frac:

The mini frac technique is an alternate method for gathering data on a particular formation without extensive laboratory studies. A mini frac treatment may be run on the subject well 2-5 days prior to the MHF treatment, to obtain pertinent data that may be used to re-check the MHF design.[7] The data obtained from the pumping of 10,000 - 40,000 gal. of the proposed treating fluid combined with post fracturing pressure decline data and temperature surveys may yield in-situ combined C values for the frac fluid, fracture closure pressure, net fluid loss interval, Young's modulus, fracture heights and fracture lengths.[7,15] The mini frac also serves as a mechanical test on the frac line, wellhead protector, tubing, packer and all other equipment being used. It also gives an idea of average treating pressures.

The mini frac treatment is conducted in conjunction with routine perforation breakdown operations. First, a closure test is run while breaking down perforations with the usual non damaging breakdown fluids (KCl water, acid, etc.). The procedure includes step-rate tests, i.e. repeated pump-in flow-back operations with small fluid volumes (1,000 - 10,000 gal.), and shut-in pressure decline tests. Next, the mini-frac test is conducted using moderate volumes (10,000 - 40,000 gal.) of the fluid that will be used in the major portion of the MHF treatment. The fluid must be proppant free to allow for unrestricted fracture closure. The pumping friction pressure and bottom hole frac pressure is recorded while pumping. Pressure decline data is monitored following shut-in, as well as post frac temperature surveys.[7] At first glance, the many calculations involved in the data analysis may seem overly cumbersome; however, most of the major service companies have computerized location data aquisition and computation capabilities that greatly reduce the work and time involved in data analysis.

Fracturing pressure during treatments is measured as bottom hole fracturing pressure minus closure stress. Perkins and Kern's width theory stated that net fracturing pressure is proportional to a function of the frac length:

$$P_n \sim (E)^{3/4} \left(\frac{L}{H}\right)^{1/4} (Q\mu)^{1/4} \quad (4)$$

Assuming E, Q, μ and H are constant then:

$$P_n \sim L^{1/4} \quad (5)$$

For non-Newtonian fluids:

$$P_n \sim L^{1/2n' + 2} \quad (6)$$

Recall, most fracturing gels have an n' between 0.4 and 0.6, therefore:

$$P_n \sim L^{1/3} \quad (7)$$

If a plot of the log of net fracture pressure is made versus the log of time, a variety of information concerning fracture propagation may be determined. Figure 3 represents four modes of pressure behavior observed in field studies.[15]

Mode 1: Confined frac height unrestricted fracture extension (slope 1/4 - 1/3).

Mode 2: Uncontrolled leakoff signaling hairline fracture opening. The pressure is constant since L is not increasing, or stable height growth versus length extension is observed.

Mode 3: A unit slope indicates some type of flow restriction which may lead to slurry dehydration, proppant bridgeing and width increases. (Screen-out potential is high).

Mode 4: Uncontrolled height growth.

The point labeled Pc in Figure 3 is the critical pressure i.e. the pressure above fracturing pressure required to open hairline fractures which results in excessive fluid leakoff. When Pc is defined for a formation in a particular field the value may be used in frac design to limit surface treating pressures and maintain a mode 1 type slope.

Frac Height Determination:

The one parameter that is critical in fracturing design is fracture height. Adequate knowledge of frac height may greatly improve the job design, results, and overall costs. The literature contains many good discussions on frac height determination.[2,7,12,14] Post fracturing temperature decay profiles combined with post-fracturing radioactive surveys, with tagged fluids and proppants, are currently the most widely applied techniques for measuring frac heights. The most common procedure consists of a base static temperature log run just prior to fracturing, followed by static temperature and gamma ray logs conducted during the shut-in period. Shut-in surveys should begin as soon as possible after fracturing and continue for 2-4 hours. The temperature survey should begin at a point above the zone of interest that is at least 100% of the zone size. For example, if the zone to be fraced is from 10,000 to 10,100' the temperature survey should begin at 9,900' or 100' above the perforations. Logging speeds should be in the 20 ft/min. range. Usually large temperature anomalies are observed opposite the zone fractured. Figure 4 shows a typical temperature survey, the perforated zone is from 12,360' to 12,465'. The survey began at 12,200' or 165' above the zone and terminates at 12,465' T.D. The dashed line represents the temperature gradient for the well. The bar graph denotes the total frac height while the black section shows the zone that accepted the majority of the treatment.

FLUID SELECTION:

One important consideration in any type of fracturing design is the fracturing fluid selection. The following three fluids have been used in MHF treatments as reported in the literature.

1. Crosslinked HPG (30-60 lbs. systems)[1,4,9]
2. Polyemulsion[2]
3. Foam[6]

Points to consider when choosing a fracturing fluid are:[1,4]

1. Viscosity - The fluid should exhibit sufficient viscosity to transport the proppant under down hole conditions.

2. Fluid Loss Additives - Frac fluids should include additional particulate fluid loss agents or a 3-5% diesel phase.

3. Friction - The fluid should exhibit low tubular friction pressures.

4. Fluid Compatability - The fracturing fluid should be compatible with the formation fluids.

5. Non-Damaging - The fracturing fluid should not significantly reduce the natural permeability by inducing formation damage.

6. Ease of Recovery - Fracturing fluid should be recovered in a short (30 day) period of time.

7. Cost - The fluid of choice should be reasonably priced.

8. Safety - The fluid should not pose a safety hazzard on location.

Crosslinked hydroxypropyl guar systems were the fluids used in 80% of the MHF treatments with which the authors have been associated. The properties of these fluids have been well defined by the industry and may be tailored to produce the desired characteristics. The subsequent discussion will exemplify the thought processes involved in choosing a HPG based fluid system.

Crosslinked HPG gelled in 2% potassium chloride water with appropriate additives can fit all eight aforementioned criteria. The viscosity of HPG fluids can be controlled by adjusting the gel loading i.e. 30,40,50 and 60 lb. per 1000 gallons. Temperature versus fluid penetration curves as shown in Figure 5 and field data obtained from offset wells and mini fracs are useful in determining the viscosity required. Recall, fracture height growth is dependent on viscosity.[7,15] A compromise viscosity may be desirable to provide for proppant transport without creating excessive frac heights.

The addition of particulate fluid loss material or a second phase (3-5% diesel) to the fluid system will be dictated by the formation to be treated. In general, some type of fluid loss control is desirable. As the job progresses the sand laden fluid may dehydrate without adequate fluid loss controls, thus increasing sand concentration and increasing screen-out possibilities.[16]

The friction properties of crosslinked HPG systems are given in Figure 1 for various tubing sizes. Low tubular friction pressures are desirable to maintain lower surface treating pressure, and lower hydraulic horsepower costs (See Table 1).

Laboratory tests should be performed to determine the frac fluid's compatibility with the formation fluids and rock prior to stimulation. Results of these lab studies will dictate volumes and type of surfactants, de-emulsifiers, scale inhibitors, and clay control agents required.

Frac fluid recovery is essential to a successful MHF treatment. The addition of gel breakers and low surface tension agents may greatly facilitate clean-up. The addition of an energizer such as, N_2 or CO_2 gas to the tail end of the treatment may increase the possibility of an early hydrocarbon show.

Dramatic cost reductions may be realized by tapering the polymer concentration of the fluid system. As the gel weight is reduced, job costs are reduced in three categories: 1) polymer costs are reduced, 2) horsepower costs are reduced as a result of lower friction pressure, and 3) less polymer is pumped down hole and wells may clean-up faster.[4]

The most meticulously planned job may go awry if no attention is payed to on-location quality control. Quality control should begin with the proposed water source to ensure that the crosslinked gel may be prepared with that water source. Frac tanks should be cleaned before filling and the water rechecked after placement in the tanks. If the frac water sits idly for several days, bactericides may be required. As each tank is gelled, fluid viscosities and crosslink times should be measured and recorded (see Table 2). Samples should be collected while pumping to ensure gel crosslinking during fracturing.

Proppant Selection:

Hydraulic fracturing is designed to provide deep penetrating flow channels with flow capacity large enough to provide optimum production rates. The flow capacity contrast ratio should be on the order of 10^3 to 10^6. The flow capacity of a fracture is defined as:

$$\text{Flow Capacity} = k_f . W \qquad (8)$$

The flow capacity or the fracture conductivity is a function of type, size, strength, quality, density of the proppant, and the overburden pressure of the formation.

Sand (20-40 mesh) is the most commonly used proppant. Figure 6 presents frac conductivity as a function of overburden pressure or the closure stress. 20-40 sand, depending on the source and the supplier, exhibits a wide variation in quality. The generally accepted practice is to avoid use of 20-40 mesh sand when closure stresses are estimated to exceed 6,000 psi. At closure stresses in excess of 6,000 psi the sand conductivity drops considerably due to crushing. At high closure pressure the use of an intermediate proppant such as Westprop I or sintered bauxite should be considered. For example, typical closure pressures for the Morrow formation in S. E. New Mexico range from 5,800 psi to 7,500 psi. Sand would be adequate at the lower pressure range, but the use of intermediate proppant or bauxite would be suggested at the higher pressure range.

Proppant selection should be based on producing closure pressure with the criteria that the permeability contrast should exceed 30.L (L = propped frac length).

Assuming a well with a depth of 11,500' and a frac gradient of 0.92 psi/ft., the BHFP will be:

$$BHFP = 11{,}500 \times 0.92 = 10{,}580 \text{ psi} \quad (9)$$

$$\text{Flowing BHP} = 3{,}800 \text{ psi (given data)}$$

$$\text{Closure Pressure} = BHFP - FBHP = 6{,}730 \text{ psi} \quad (10)$$

The fracture conductivity should be equal or greater than 30 L i.e. 30 x 1,000′ md ft. (L = 1000′).

$$\text{Therefore } \frac{W.kf}{k} > 30{,}000 \quad (11)$$

Usually, propped width should be 0.15 to 0.2 inches and assuming a (formation) permeability of 0.1 md.

$$kf > \frac{30{,}000 \times .1 \text{ md}}{0.15 \times 12} \quad (12)$$

This suggests that k_f should exceed 1667 md. Intermediate proppant has a permeability of approximately 2500 md at 6700 psi (overburden) which satisfies our criteria (see Figure 6). If sand were used it would have a permeability of 525 md. and would not meet our criteria.

The general trend in hydraulic fracturing is to obtain proppant concentration in excess of 1 to 1.25 lb/ft^2. Also use of 100 mesh and 40-60 mesh sand in the first 25% of the treatment helps in hairline fracture leakoff control and fracture initiation.

The high cost of pumping bauxite and intermediate proppant (intermediate proppant cost is approximately half of bauxite) has led to design modification where the higher strength intermediate proppant is pumped only in the last 10 to 30% of the treatment. This technique reduces the job cost substantially and affords an excellent proppant permeability in the immediate vicinity of the wellbore where the drawdown is maximum.

With the introduction of intermediate proppant the overall cost of treatments has been reduced by 15 to 20%. Since the placement of proppant within the fracture is the ultimate goal of fracturing we recommend that the higher strength proppant be run in the last 10 to 40% of the treatment where closure stress demands their use. In the final analysis, an MHF treatment producing 1,000' to 2,500' propped length is worthless if the proppant pack is crushed and does not have adequate permeability.

TREATMENT DESIGN:

A wide variety of parameters must be considered when designing an MHF treatment such as, well mechanical considerations, reservoir properties, stimulation fluid properties and desired productivity increase. Well mechanical considerations include: internal yield of casing or tubing, and wellhead and packer pressure specification. Accurately measured reservoir properties are desirable to avoid costly design error. Table 3 lists the required reservoir and frac fluid design data required. If specific data is not available for the subject well, then data from off-set wells may be substituted.

Computer simulators should be used to aid in MHF design. The computer can generate down hole pumping temperature profiles and simulate frac geometrys (See Figures 5 and 7). The data presented on Table 3 was applied in an example MHF design.

Initially a pre-pad of 100,000 gals. of non-crosslinked HPG with 20 lbs. fluid loss additive and other necessary chemicals is pumped to: (1) cool the formation to slow viscosity loss in the fracturing fluid, and (2) to establish a filter cake on the fracture to minimize the fracturing fluid from leaking off and possibly causing a screenout.[16] Also during the pre-pad rates should be maximized to create the total frac height with the less costly pre-pad fluid.

The proppant laden fluid employed was a crosslinked, low residue modified guar gum. The gel loading was determined with the assistance of Figure 5, and was tapered from 50-30 lb/1000 gal. (See Figure 8). For computer modeling purposes, an average of the rheological properties was calculated and used as input data.

The gel breaker may be scheduled with help from Figure 5. Lower concentrations of breaker will be required early in the treatment. As the job progresses the breaker must be increased to allow for shorter residence times and lower temperatures.

Total proppant pumped was 580,000 lb. of 20-40 mesh sand. Sand concentration averaged 2 lb/ft^2 which should give excellent permeability contrast k_f/k. Figure 2 graphically represents the calculated productivity increase versus frac length. The optimum penetration ranged from 50 - 70% of the drainage radius. Note, propped penetration given on Figure 7 was 1055' or 56% of the drainage radius.

Finally, nitrogen or carbon dioxide gas may be added to the last 25 - 40% of the treatment to energize the fluid and reduce clean-up time.

Selection of an injection rate is important because enough rate must be obtained to place the sand in the formation and to treat the entire zone and at the same time to remain within the limits of the tubular goods. For this particular study a rate of 20 BPM was chosen.

LOGISTICAL PLANNING

To successfully achieve the goal of a cost effective MHF treatment, careful logistical planning is required. Logistical planning often receives the least attention and may be a major cause of treatment failure. The four categories of logistical planning are listed below:

1. Wellsite design
2. Equipment requirement

3. Frac fluid quality control
4. Mechanical considerations

Wellsite Design:

MHF wellsite design and layout should be made prior to building the location. The size of the location should be based on average treatment size and equipment required for other treatments in the area. It is more economical to build the location as per design before drilling operations commence then trying to modify the location just prior to stimulation. Several articles have been presented on location preparation and size.[6,7,8] Location size ideally should be 200' to 350' square and is dictated by equipment and tank requirements, proppant quantity, auxilliary equipment needs such as tracer survey equipment, N_2 or CO_2 equipment, and fuel storage.

Items left on location from the drilling operation and early delivery of production equipment such as tank batteries, separators, pump jacks, flare pits, etc. make equipment placement and material handling awkward and hazardous. The location should therefore, be unobstructed by equipment and lines that tend to limit the job size and lead to improper equipment placement. Locations should be sufficiently large to allow at least 100 feet between pumping equipment and the wellhead. From a safety standpoint, the wellhead should be accessible from the main entry road without having to cross any high pressure pump lines.

Many authors suggest the location be sloped so as to incline the frac fluid holding tanks to minimize waste of gel which is left at the bottom of the tank.[6,8] However, in our job designs we assume useful tank capacity to be 95% of the actual, thus eliminating the need to slope the tank pads. It is also a good practice to have 2 to 5 (5% over job design) extra tanks of gel to compensate for calibration errors, human errors, tank and manifold leakage, etc. Sloping tank pads is expensive and time consuming and can be avoided. Careful planning may eliminate fluid accounting problems that may compromise the treatment design.

The planning phase of the MHF should include a scaled drawing of the location with pits, high pressure gas lines, roads and other fixtures clearly marked. Different possible equipment layouts should be tried with the help of scale models of equipment, tanks and proppant storage, with the most efficient layout selected. Figure 9 is a schematic representation of a typical MHF equipment layout. Location size and equipment lay out should be based on the following factors:

1. Leave sufficient space behind tanks to allow for filling during the fracturing operations.

2. For safety leave at least 50' to 100' between any manually operated equipment and wellhead. A clear unobstructed path should be available between the service road and the wellhead.

3. Equipment should be spaced so as to facilitate refueling and any repairing operations.

4. Equipment, especially blenders, should be spaced such that they can be easily replaced with minimum downtime in case of failure.

5. Frac tanks should be spaced such that none of the blenders are further than 6 to 8 tanks from the farthest tank. This rule should be adhered to especially when the base gel is very viscous and suction can pose a problem.

6. Frac tanks should be arranged in two rows. The front row is the "working tanks" which are connected to the blender and the pumps pumping to the wellhead. The rear row usually will contain water ready to be gelled or gel waiting to be transferred to the working tanks. This method prevents waste of expensive gel in case the job has to be prematurely terminated.

7. Quality control van should be placed near the frac tanks to inspect the water and gel quality and also inspect water level at regular intervals.

8. Engineering van should be ready and available whenever equipment failure occurs.

9. All objects capable of hindering equipment placement and smooth flow of mobile equipment traffic should be removed from location. Also avoid premature installation and construction of production equipment.

10. Accurate weather forecasting can be of tremendous help especially in areas where location is not competent enough for heavy equipment travel when water logged.

11. Water hauling, CO_2 or N_2 and RA and temp. survey (wireline) equipment should be included in the layout.

12. Diesel for fluid loss additive should be placed at least 100' to 200' from the wellhead.

<u>Standby Equipment:</u>

Depending on injection rate and surface treating pressure equipment cost will vary from 10 to 25% of the total MHF cost. The integrity of the treatment design and the success of the job can be seriously jeopardized by absence of adequate standby equipment. The cost of refracturing is much higher than the cost of standby equipment which normally will be less than 10% of the entire treatment cost. Standby equipment should include 100% excess HHP and 200% excess blenders. Equipment failure goes up with treating pressure and pumping time and proppant concentration.

$$\text{Pumping time} = P_T = \frac{V + 0.002\,\dot{S} + F}{60\,Q}\ \text{Hrs.} \qquad (13)$$

Pumping time is an important variable, since it is a factor in planning manpower needs to operate the equipment. Equipment operators should be relieved at least every eight hours, and hot meals should be provided 3 times a day especially in remote areas.

Gel Quality Control:

All fracturing tanks should be numbered. The chemist and the treatment supervisor should have a layout with tanks clearly numbered on it. They should be aware of the tank number that is being pumped out of at anytime. A fluid quality checklist should be prepared on each tank at 3 places (top, middle and bottom). The data should include fluid temperature, pH, base gel viscosity, iron content, (bacteria count not necessary), sulfates and presence of reducing agents. Each tank should be pilot tested for crosslinker required, time of crosslinking and texture of crosslinked gel. This is time consuming and needs a crew of 2 or 3 technicians working from at least 48 hours before the job begins, depending on the size of the treatment.

The fluid preparation phase should commence with the cleaning of tanks. Tanks should be cleaned with water and steamed since most modern crosslinked systems are sensitive to fluid pH and chemical contaminants such as iron, sulfates and reducing agents. These ions can prevent crosslinking or seriously impede the gel hydration process.

During summer months bacterial contamination is very serious problem and it should be overcome with the additon of bactericide when the tanks are being filled. Bacteria tends to give the gel black coloration and a H_2S ordor. Bacterial contamination is insignificant when ambient temperatures are below 60° F.

When ambient temperature is below 40° F most crosslinking mechanisms slow down and crosslinking time may increase from 20 seconds to 3 - 5 minutes, depending on the gel system, the crosslinker used and ambient temperature. In order to accelerate the crosslinking process it may be necessary to heat all the treatment fluid to 60° F or higher.

The gel system base water source and the additive should be checked for compatibility prior to hauling water on location.

Unexpected delays on location due to mechanical failures, perforating problems, screen-outs and tubing and packer leaks can postpone a job indefinitely. Gel deterioration can render the fluid unusable during this delay causing a loss of several thousands of dollars.

Mechanical Considerations:

The specialized equipment needed to perform MHF can be listed as follows:

A. Wellhead isolation device
B. Sand conveyor system (sand master)
C. Intensifers
D. Trailer mounted manifold system

These pieces of equipment will be dealt with in detail under the heading "Equipment Requirement".

MHF jobs typically require high injection rates and high sand concentrations pumped at high pressures. These conditions make it necessary to pump these jobs via tubing below a packer especially in old wells where the condition of casing is not known. In order to achieve high injection rates at lower pressures it become necessary to run 2-7/8" or 3-1/2" (where possible) tubing. Larger size tubing can lead to substantial savings in horsepower costs as seen from Table 1.

To reduce excessive differential pressure on the packer, the annulus should be loaded and pressured up to 2000 psi or more throughout the treatment. The maximum surface treatment pressure should not exceed the internal yield of the tubing.

Larger amounts of sand pumped for long hours can cause serious erosion problems in the treatment line, tubing, and in and around the wellhead area. Erosion occurs mostly at places having sudden diameter changes, or sudden changes in flow direction such as elbows, tees, chicksans and threaded connections where nippled edges restrict the fluid flow. Erosion problems become more severe with increase in proppant concentration and fluid velocity.

The authors recommend the use of a wellhead isolation tool even if the expected surface treating pressure is below the working presure of the tree or the wellhead. The wellhead isolation tool isolates the expensive wellhead equipment from high treatment pressures and erosion effects of the proppant slurry. Due to a sudden change in diameter between the I.D. of the tubing and the I.D. of the wellhead isolation tool at the seal there is an induced turbulence effect enhancing the erosive effect of the slurry. If the erosion becomes too pronounced, the tubing could rupture exposing the high pressure to the casing and the wellhead equipment. It is, therefore, recommended that the top one or two joints of tubing should be higher weight and grade to combat the effects of turbulence induced erosion.

The treating line diameter is usually much larger than the diameter of the wellhead isolation device, thus requiring the use of a change-over swedge. Valve and threaded connections also pose erosion problems. Erosion at the diameter changes and the threaded connections can be reduced by the use of tapered machine integral swedge. The gentle taper can substantially reduce the turbulence. Threaded connections should be eliminated in all valves and swedges and replaced by integral swedges and valves.

When the treatment is performed using the "triple entry" technique i.e. pumping via tubing and tubing casing annulus, the sand-laden fluid enters the wellbore three ways as marked in Figure 10. The entry into the annulus of high concentration sand slurry at high velocity produces tremendous erosion action on the tubing and may eventually cut it. High strength and weight (greater wall thickness) blast joints should be used in this critical area (top joint) to withstand the erosion caused by impact with high velocity proppant particles.

To avoid leaks, all threaded connections and frac lines should be inspected prior to treatment. The tubing string used should be new and high API grade such as N-80, L-80, P-105 or C-75.

All treating lines should be secured with chains and anchors. Also the treating line should have two or more bleed off valves to relieve any excess pressure if the treatment has to be stopped. The pressure should be purged a safe distance away from the manned equipment and preferably in or towards a pit.

OPERATIONAL PLANNING:

Operational planning includes the following factors:

1. Frac fluid transport
2. Multiple bank systems
3. Fluid injection rate and proppant rate control
4. Premature termination
5. Pressure variations

Frac Fluid Transport:

MHF treatments require a large number of tanks for fluid storage. With the large number of tanks the pumping blender will be positioned a long distance from many of the frac tanks. The small pump on the blender is not designed to drain high viscosity gel from the remote tanks at the required injection rates. This problem can be overcome by placing another blender at the remote end and transferring the fluid to the pumping blender. All the tanks should be manifolded together with valves capable of isolating each tank.

Multiple Bank System:

While pumping high sand concentration jobs it is possible to exceed rated proppant transporting capacity of the blenders. Most blenders in use today can pump 10,000 lb. of proppant per minute which is adequate for most jobs. However, during a high rate and high sand concentration job such as 10 ppg. sand at 60 BPM, the blender is required to pump 25,200 lb/min. To achieve this rate the job is divided into 3 banks with 3 blenders, each blender having to pump a maximum 8,400 lb/min. which will be well within its capacity (see Figure 11). In this configuration each blender will be pumping at a rate of 20 BPM and the 3 blenders will be pumping in parallel. A simple multiple bank frac layout is presented in Figure 11.

Standby blender should be rigged up in line and should be close to a sand source so that minimum changeover time is required and the job may continue as per schedule in case of blender failure.

Fluid Injection Rate & Proppant Rate Control:

Since MHF treatments consist of large fluid and proppant volumes pumped over long time intervals (6 to 24 hours), it is of paramount importance to monitor the fluid and proppant rates. Even small variations in rates become significant when rates go unscrutinized over extended periods of time. This fact is further complicated by high proppant concentration and use of gas such as CO_2 and N_2.

Fluid rate monitoring is usually accomplished by turbine type flow meters and recorded on "Frac Monitors" with accuracy of 5 to 6%

provided calibration is done carefully. The flow meters measure slurry volumes instead of fluid volumes, and are sensitive to changes in viscosity, proppant concentration, and entrapped air in the gels. The authors recommend that two other methods be simultaniously employed for rate verification. Pump strokes count is a fairly reliable source if the displacement capacity and pump efficiency is accurately known. Most service companies have published pump efficiencies and displacement capacities for each pump type. The other method of monitoring fluid rate is by measuring the fluid pumped from the tank in a given length of time (5 minutes). All tanks and manifolds should be checked for leaks. A person should be assigned to measure tanks and make sure the proper valves are opened and closed so that the fluid flow to the blenders and pumps is smooth and contiinous so the pumps do not "catch air". All the above mentioned methods should be used in conjunction with each other. The tank strapping method, however, should be regarded as the most reliable.

Sand or proppant injection rate should be monitored using RA densiometers, by measuring sand containers (bins, silos and sand master), and by checking "sand-screws" or augers RPM. Again all the methods should be used in conjunction to prevent large errors. The radioactive densiometers should be used only if great accuracy is desired. Slight errors in calibration of these units may lead to significant error and the recording instruments need to be dampened to stabilize the output of proppant rates. The sand auger RPM method is accurate if displacement volume is known and the wear and tear on the augers is minimized. Each blender should be calibrated for different types and mesh size of proppant with respect to RPM and fluid injection rate.

Premature Termination:

Premature terminations may result due to any one or more of the following reasons:

1. Equipment failure
2. Screen-out
3. Tubular goods failure
4. Leak in the lines or wellhead
5. Weather
6. Erroneous design

If the treatment has to be shut down the well should be "flushed" whenever possible and the proppant pumped into the formation instead of settling in the wellbore. If the problem is minor and can be corrected in a short time, the pumping should continue as per original schedule.

Pressure Variations:

Pressure variations occur due to changes in gel quality, screen out and variations in proppant concentrations.[9] Several corrective actions can be taken. These are listed in reference 16.

EQUIPMENT REQUIREMENTS:

With continuing improvements in equipment it is possible to successfully fracture deep tight zones at high treating pressures using high proppant concentration. The key to successful operation depends on use of superior equipment operating in the middle or upper middle range of its rated capacity. Most operators, with good reason, insist on the use of the following equipment:

High Rate Blenders: 100 to 125 BPM blenders with metered additive systems for sand, solids and liquid chemical additives. Blenders should be able to pump sand in excess of 10,000 lb. per minute. Where possible, blenders should possess eductor mixing unit for mixing solid powdered chemicals. Blenders should be calibrated for different density proppants being used.

Complexor Injector: This injector is composed of tanks, a pump, and an accurate flow-metering system to inject liquid complexor material on crosslinked fluid treatments. The pump on this unit must be able to pump form a fraction of a GPM to 10 GPM at approximately 100 psi line pressure. This unit should be trailer mounted for ease of mobility around the location. Cleanliness and accuracy of this unit is imperative.

Master Sand Conveyor: This trailer mounted unit is designed to collect sand from several sand storage units and transfers them to the blenders at rates up to 10,000 lb/min. This unit usually has adjustable trailer length and a self-contained power source.

Light Plant: Sufficient light should be available at key places in the layout, especially when the job may be going on into the night. (See Figure 9).

Sand Master: This unit is a self-contained, jobsite and sand-storage unit, filled either pneumatically or mechanically with proppant.

The sand master should be capable of discharging proppant into mixing or blending equipment at rates up to 10,000 lb. per minute. These units have a capacity of 2,000 to 4,000 cubic ft.

Trailer Mounted Manifold System: This piece of equipment is a time saver because it simplifies and streamlines the pump truck hookup. The trailer has both a suction and discharge side. On a recent job where ten pump trucks were rigged with the trailor manifold, approximately 40 man hours of labor were saved. (See Figure 12).

Densiometer: A densiometer measures and records sand concentrations with quick and accurate response. An RA detector and source measures sand concentrations on the high pressure side of pumps to maximum 15,000 psi.

Wellhead Protector: This unit (Figure 13 & 14) is a wellhead isolation tool designed to fit 2-3/8", 2-7/8", 3-1/2" or 4-1/2" tubing. Knowledge of the exact I.D. of tubing is essential for a perfect seal. The purpose of this tool is to allow wells to be treated at pressures above the pressure rating of the tree. It is a good practice to use a wellhead protector regardless of the pressure, to isolate the tree from long term abrasive effects of the proppant laden fluids and the corrosive effects of acids as previously discussed. The protection to an expensive piece of equipment such as a tree more than compensates the rental charges on this unit. (See Appendix A)

Intensifiers System: New intensifier technology takes fracturing capabilities beyond the limitations of conventional pumping systems. Standard pumps are not designed to handle the high pressures, greater proppant concentrations, and longer pumping duration encountered in a typical MHF treatment.

The intensifier system consists of power units and the intensifier itself. The power units provide hydraulic fluid to power the intensifier pump. The intensifier transfers pressure applied on a large diameter piston to one on a small diameter. This causes the smaller piston to intensify the pressure applied to the frac fluid being pumped. During the treatment, the hydraulic or the power unit pushes the larger pistons of the intensifier forward and the smaller piston forces frac fluid down hole at a much higher pressure. (See Figure 15).

The design of the intensifier reduces the wear and tear associated with crankshaft drive pumps. The longer stroke of the intensifier (68") reduces pumping cycles by 90% or more. This results in considerably reduced wear on valves and packing element and extended fluid-end component life. Furthermore, these units are less susceptible to damage from acid and high strength proppants. The intensifier therefore, can provide a more reliable service for a much longer duration under more severe conditions.

The intensifier delivers from 1,000 to 5,000 HHP at treating pressures up to 20,000 psi. In some units the precision sequencing of triplex pistons for smooth action is accomplished by using microprocessor technology. This new technology reduces pressure surges by setting rates and pressures, thus extending pump lives beyond 12 hours.

CONCLUSIONS

1. The key to performing a successful MHF treatment is planning. Careful attention to each and every detail will minimize job problems and reduce overall job costs.

2. Planning should begin before the well is drilled i.e. building location large enough to accommodate the equipment required.

3. Data on the formation characteristics from lab studies, offset wells, and mini frac treatments must be assimilated to assist in fracturing design, with careful attention devoted to frac height determination.

4. The search for the proper frac fluid and proppant should be guided by the criteria outlined with careful attention paid to additives required, temperature and pressure limitations, fluid breaker schedule, and on-sight quality control.

5. Finially, job safety should be integrated into the planning stages so the end result is a safe, successful MHF treatment.

NOMENCLATURE

BHFP - Bottom hole frac pressure (psi)
BHP - Bottom hole pressure (psi)
C - Leakoff coefficient ($cc/t^{1/2}$)
d - Diameter of perforations (inches)
D - Density of sand laden fluid (lb/gal)
e - Young's modulus (psi)
F - Flush volume (bbl)
FBHP - Flowing bottom hole pressure (psi)
FG - Frac gradient (psi/ft)
HH - Fluid hydrostatic head (psi)
ISIP - Instantaneous shut-in pressure (psi)
J - The productivity index after fracturing
Jo - The productivity index before fracturing
k - Permeability of the formation (md)
k′ - Frac fluid viscosity index ($lb\ sec^n/ft^2$)
kf - Permeability of the proppant in the fracture (md)
L - Frac length (ft)
μ - Viscosity (cps)
n - Number of perforations
n′ - Fluid deviation from Newtonian behavior
Pc - Pressure required to open hairline fractures (psi)
Pn - Net fracturing pressure (psi)
ΔPf - Friction pressure through tubing and surface lines (psi)
ΔPp - Pressure drop across perforations (psi)
S - Sand weight (lb)
STP - Surface treating pressure (psi)
t - Time (min)
V - Treatment volume (bbl)

REFERENCES

1. White, J. L. and Daniel, E. F.: "Key Factors in MHF Design," J. Pet. Tech. (Aug. 1981) 1501-1512.

2. Fast, C. R., Holman, G. B. and Colvin, R. J.: "A Study of the Application of MHF to the Tight Muddy "J" Formation Wattenburg Field, Adams and Weld Counties, Colorado," SPE paper No. 5624, Fall meeting of SPE of AIME, Dallas, Texas, Sept. 28 - Oct. 1, 1975.

3. Strubhar, M. K., Fitch, J. L. and Medlin, W. L.: "Demonstration of MHF in Piceance Basin, Colorado, "SPE paper No. 9336, Fall Technical Conference and Exhibition of the SPE of AIME, Dallas, Texas, Sept. 21-24, 1980.

4. Schlottman, B. W., Miller, W. K. and Lueders, R. K.: "MHF Design for the East Texas Cotton Valley Sands," SPE paper No. 10133, Fall Technical Conference and Exhibition of the SPE of AIME, San Antonio, Texas, Oct. 5-7, 1981.

5. Parker, C. D.: "Logistic and Operational Considerations for Massive Hydraulic Fracturing." J. Pet. Tech, (July 1981) 1189-119.

6. Wendorff, C. L. and Ainley, B. R.: "Massive Hydraulic Fracturing of High-Temperature Wells with Stable Frac Foams," SPE paper 10257, Fall Technical Conference and Exhibition of the SPE of AIME, San

Antonio, Texas, Oct. 5-7, 1980.

7. Veatch, R. W., Jr., Crowell, R. F.: "Joint Research-Operations Programs Accelerate MHF Technology," SPE paper 9337, Fall Technical Conference and Exhibition of the SPE of AIME, Dallas, Texas, Sept. 21-24, 1980.

8. Gidley, J. L., Mutti, D. H., Nierode, D. E., Kehn, D. M. and Muecke, T. W.: "Stimulation of Low-Permeability Gas Formations by MHF - A Study of Well Performance," J. Pet. Tech. (April 1979) 525-531.

9. Kozik, H. G. and Holditch S. A.: "A Case History for Massive Hydraulic Fracturing the Cotton Valley Lime Matrix, Fallon and Personville, Fields," J. Pet. Tech (Feb. 1981) 229-243.

10. Holcomb, W.: "How To Choose A Hydraulic Frac Treatment: MHF Versus Conventional," Petroleum Engineer International (Aug. 1982) 108-116.

11. Matthews, B. A., Miller, W. K., II and Schlottman, Bernard W. "Record MHF Treatment Pumped in East Texas Cotton Valley Sands," Oil and Gas Journal (Oct. 4, 1982) 94-98.

12. Malone, W. T., Stahl, E. J., Jr. and Coulter, G. R.: "MHF from Planning to Performance, "Proceeding of the MHF Symposium Feb. 28 - March 1, 1977, University of Oklahoma.

13. Hannah, R. R., Matson, B. G. and Crawford, A.: "Status Report on MHF in the Fort Worth Basin," Proceedings of the MHF Symposium, Feb. 28 - March 1, 1977, University of Oklahoma.

14. Dobkins, T. A.: "Methods to Better Determine Hydraulic Fracture Heights", SPE paper 8403, Fall Technical Conference of the SPE of AIME, Las Vegas, Nevada, Sept. 23-26, 1979.

15. Nolte, K. G., and Smith M. B.: "Interpretation of Fracturing Pressure Decline", SPE 8341, presented at SPE 54th Annual Tech Conference, Las Vegas, Sept, 23-26, 1979.

16. Pai, V. J.: "Predicting, Preventing and Remedying Hydraulic Fracturing Screen-Outs", presented at the Texas Tech Short Course, April 21-22, 1982.

ACKNOWLEDGEMENTS

The authors wish to thank The Western Company of North America for their help in publishing and presenting this paper. We gratefully acknowledge their assistance in allowing us access to the computer programs and the results of many years of painstaking research. Thanks are also due to many of the technical and operations personnel of The Western Company whose stimulating discussions and "coffee sessions" helped clear many doubts that lingered in our minds.

Thanks also go to Linda Farnum and Mary Ann Cathey for their unending patience and invaluable assistance in preparing this paper.

APPENDIX A

The wellhead protector should have sufficiently large opening for pumping at high rates with high sand concentrations. The unit should be totally hydraulic and capable of being installed or removed at high pressure such as 15,000 psi.

Most units in use have 15,000 psi working pressure limitation although they are tested above 20,000 psi. The operator should provide the service company with the exact size and weight of the top joint of tubing in the well, the type and size of flange on top of the tree and the distance from the top flange to the gate in the lowest master valve to determine the mandrel size.

From a safety standpoint only a flanged bottom protector should be used if maximum pressure will exceed 7,500 psi. For tall Christmas trees mandrel extensions (6", 12", 24" and 36") are available.

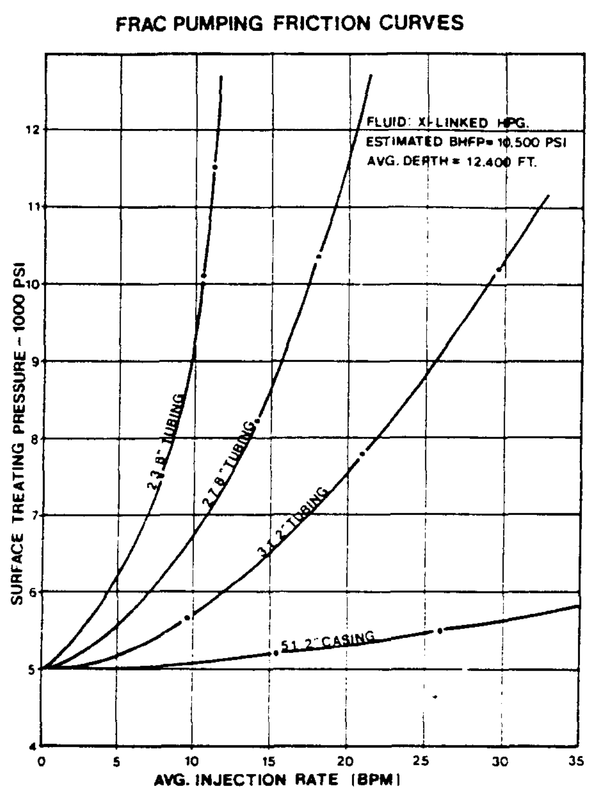

FIGURE 1

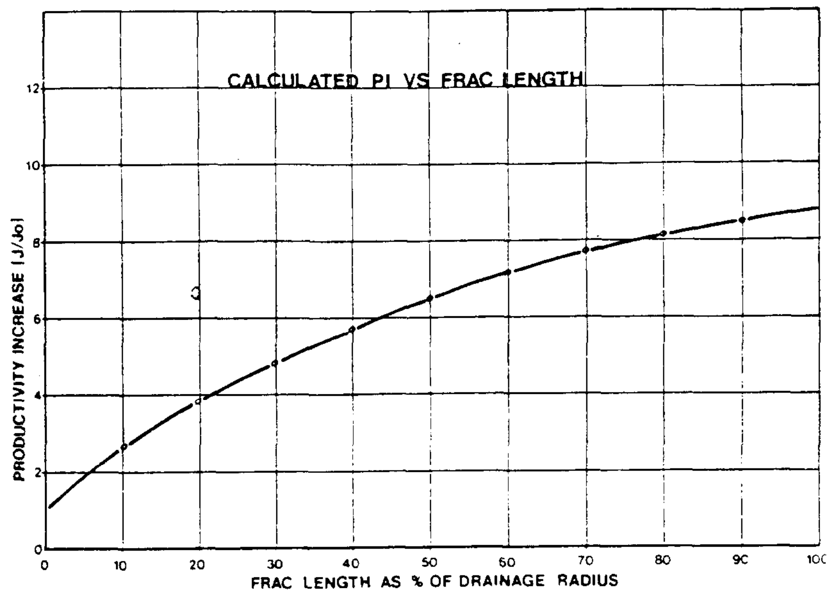

FIGURE 2

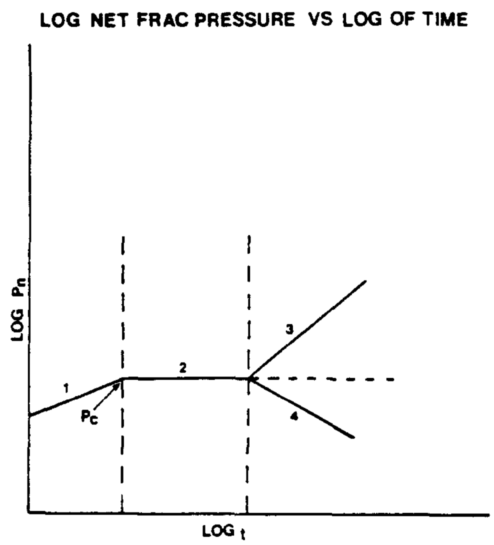

FIGURE 3

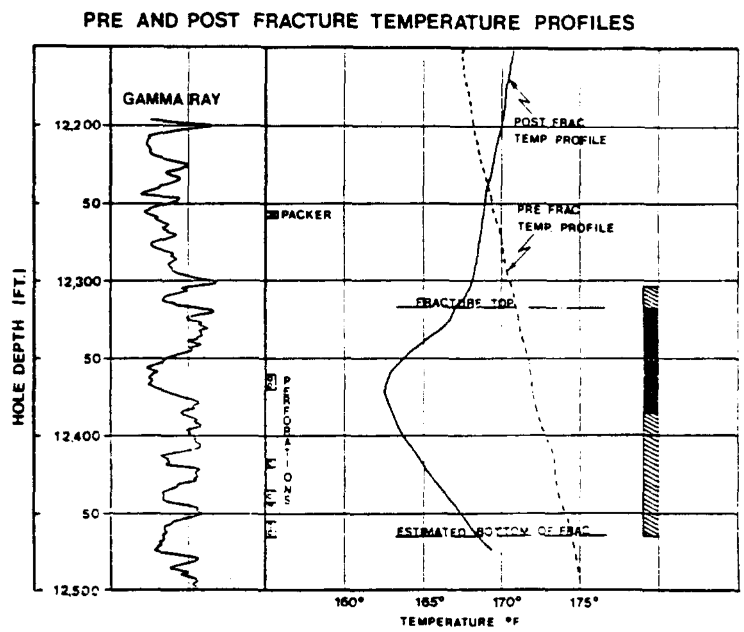

FIGURE 4

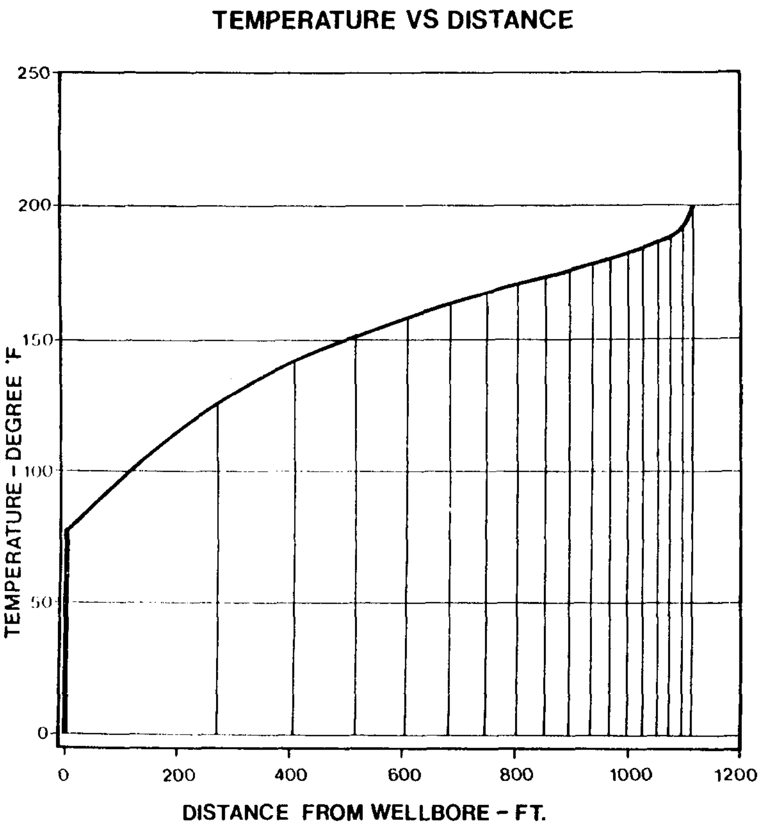

FIGURE 5

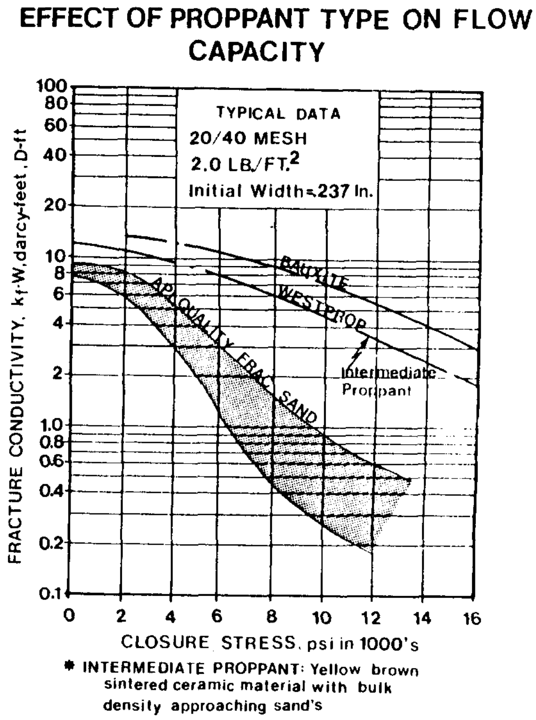

FIGURE 6

FIGURE 7

WESTERN PETROLEUM SERVICES
PROPPANT PROFILE STUDY
PERFECT SUPPORT FLUIDS

FLUID STUDIED - X-LINKED 2%KCL WATER
TOTAL VOLUME - 386304 GAL
FLUID PENETRATION - 1127 FT

PERM. TO STIMULATION FLUID - 0.12 MD
PERM. TO RESERVOIR FLUID - 0.2 MD
LEAK-OFF FLUID VISCOSITY - 1 CP
RESERVOIR FLUID VISCOSITY - 0.02 CP
RESERVOIR FLUID COMP. - 1.3E-04 1/PSI
STIM. FLUID C-III - 3.30E-03 FT/SQRT(MIN)
FRACTURE HEIGHT - 150 FT
COMBINED C - 1.86E-03 FT/SQRT(MIN)

FRAC. PRESSURE - 10500 PSI
RES. PRESSURE - 6000 PSI
N PRIME - 0.63
K PRIME - 0.055
YOUNGS MODULUS - 7.0E+06 PSI
WIDTH - 0.481 IN
INJECTION RATE - 20 BPM

WESTERN PETROLEUM SERVICES
PROPPANT PROFILE STUDY
PERFECT SUPPORT FLUIDS

FLUID VOLUME (GAL)	SURFACE PROPPANT CONC (LB/GAL)	LOCATION IN FRACTURE (FT)			FRACTURE PROPPANT CONC (LB/FT**2)	CUMULATIVE PROPPANT (LB)
80000	0.00	1055	TO	1127	0.000	0
80000	0.50	948	TO	1055	1.247	40000
80000	1.00	773	TO	948	1.530	120000
40000	2.00	633	TO	773	1.901	200000
20000	3.00	537	TO	633	2.085	260000
20000	4.00	413	TO	537	2.145	340000
40000	6.00	0	TO	413	1.937	580000

TOTAL FRAC FLUID VOLUME - 360000 GAL
TAILING GALLONS CONTAINING BAUXITE - 0 GAL

FIGURE 8
SUGGESTED PROCEDURE

1. Rig up safety wellhead protector.
2. Rig up to frac via tubing (3-1/2").
3. Apply and hold 2500 psi on annulus.
4. Frac in a single stage as follows:
    a. Pump 100,000 gal. gelled 2% KCl water pre-pad; all the rate allowed.
    b. Pump 80,000 gal. 50 lb. X-linked 2% KCl water at 20 BPM.
    c. Pump 80,000 gal. 50 lb. X-linked 2% KCl water with 0.5 ppg. 20-40 sand.
    d. Pump 80,000 gal. 40 lb. X-linked 2% KCl water with 1 ppg. 20-40 sand.
    e. Pump 40,000 gal. 30 lb. X-linked 2% KCl water with 2 ppg. 20-40 sand.
    f. Pump 20,000 gal. 30 lb. X-linked 2% KCl water with 3 ppg. 20-40 sand.
    g. Pump 20,000 gal. 30 lb. X-linked 2% KCl water with 4 ppg. 20-40 sand.
    h. Pump 40,000 gal. 30 lb. X-linked 2% KCl water with 6 ppg. 20-40 sand.
5. Flush to perforations with gelled 2% KCl water.
6. Shut-in ±8 hours; open to recover load.

EQUIPMENT LAYOUT FOR MHF TREATMENTS

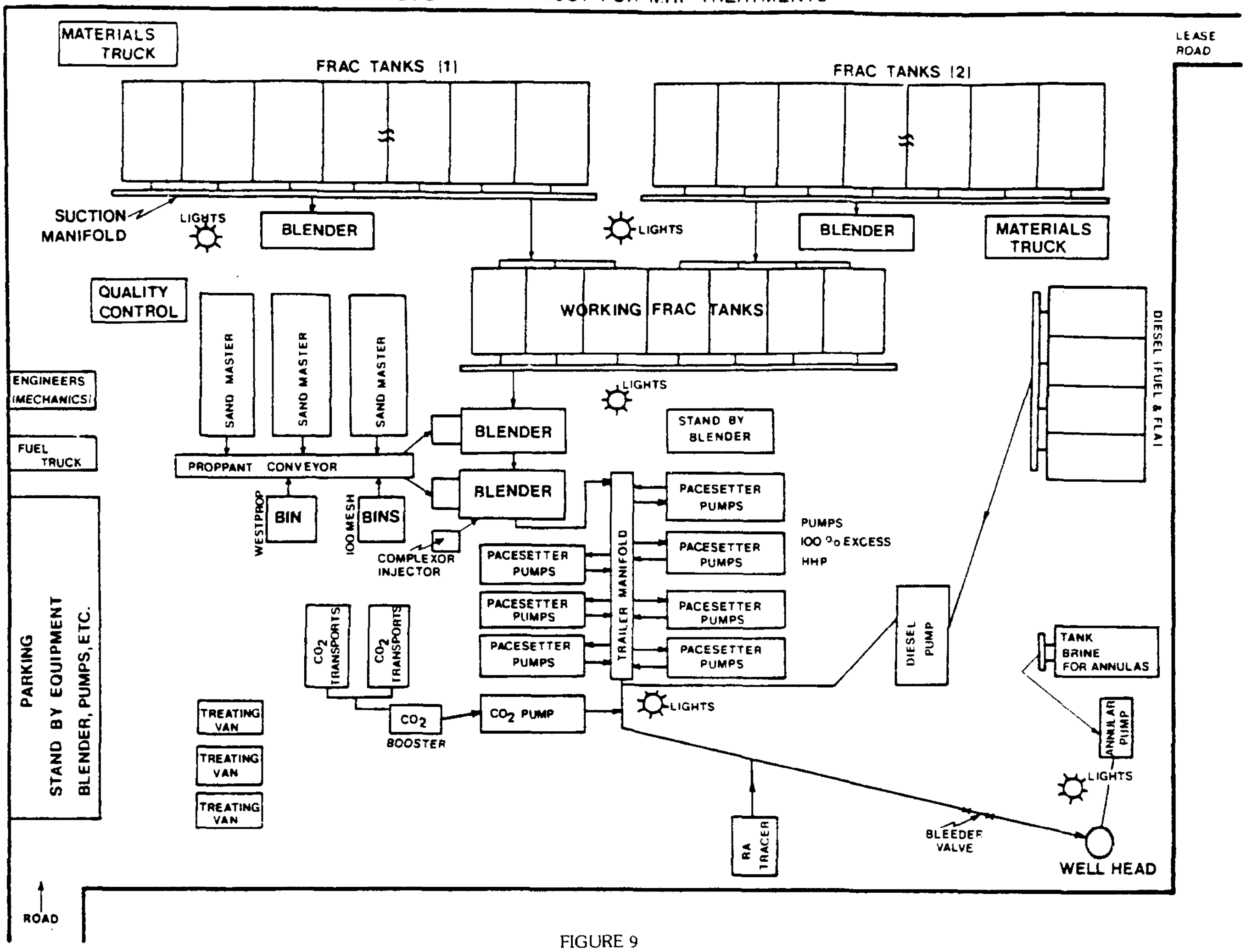

FIGURE 9

MULTIPLE BANK FRAC LAYOUT

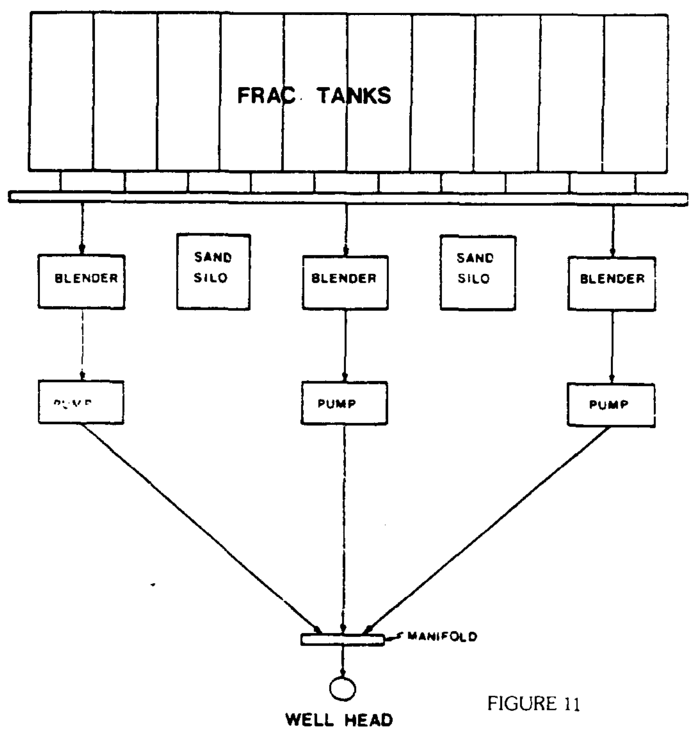

FIGURE 11

TRIPLE ENTRY FRAC WITH A BLAST JOINT

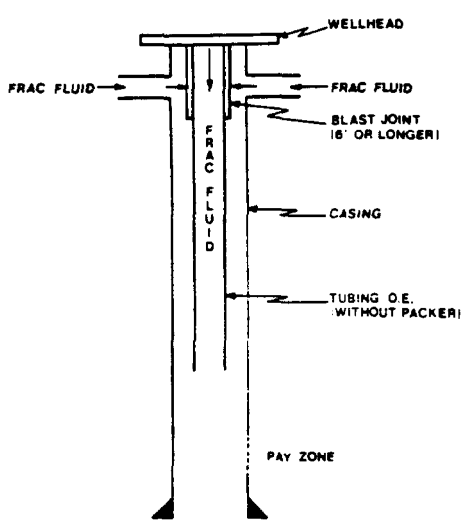

FIGURE 10

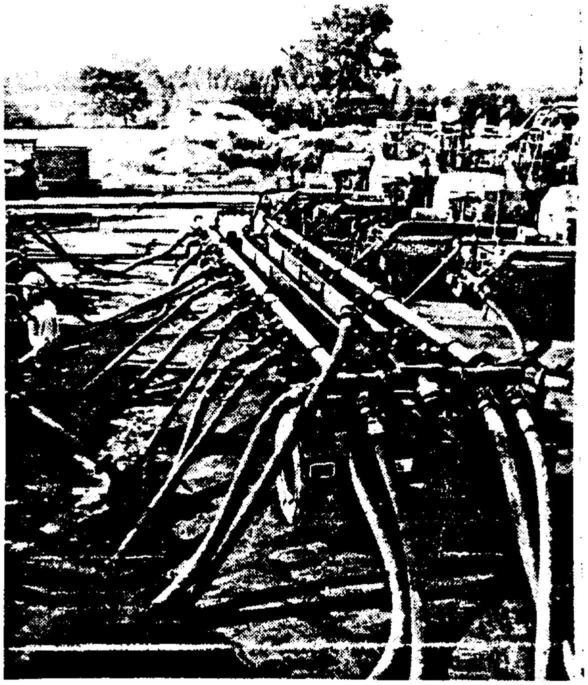

FIGURE 12 THE MANIFOLD TRAILER SAVES EQUIPMENT OPERATORS MANY TIME-CONSUMING HOURS ON RIGGING UP FOR MHF WORK.

WELLHEAD PROTECTOR FLANGED TO WELLHEAD

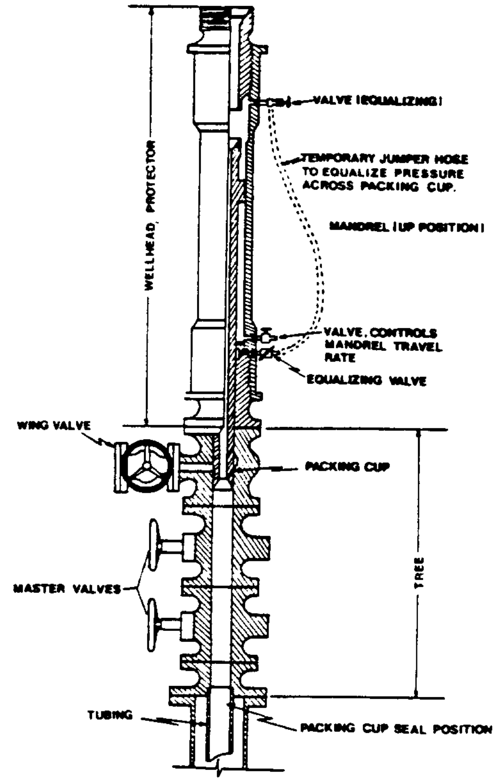

FIGURE 13

COMPONENTS OF A WELLHEAD PROTECTOR

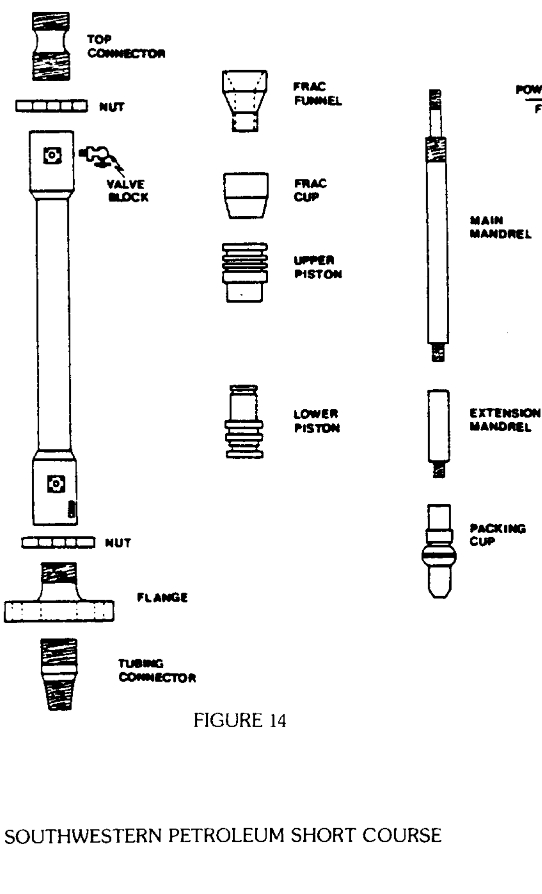

FIGURE 14

INTENSIFIER WORKING

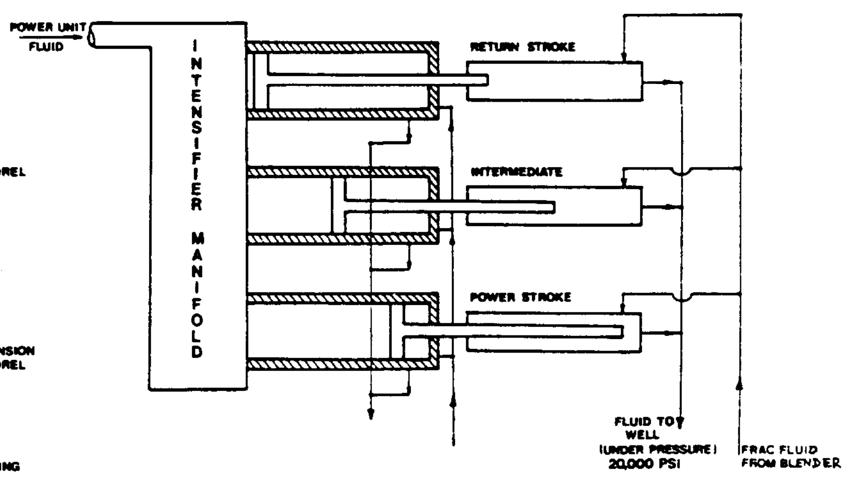

FIGURE 15

TABLE 1
HHP COST ANALYSIS FOR DIFFERENT TUBING AND CASING SIZES

BASIS: BHFP = 10,500 psi (Fg = 0.85 psi/ft)

DEPTH = 12,400'

ASSUME $\Delta P_{perf} = 0$

A.I.R.	STP (psi)				HHP				COST $			
BPM	2-3/8"	2-7/8"	3-1/2"	5-1/2"	2-3/8"	2-7/8"	3-1/2"	5-1/2"	2-3/8"	2-7/8"	3-1/2"	5-1/2"
10	9,500	6,700	5,700	5,100	2,328	1,642	1,397	1,250	15,132	6,814	4,959	4,063
12	13,000	7,300	5,900	5,150	3,824	2,147	1,735	1,515	52,006	8,910	6,159	4,924
15	-	8,600	6,500	5,200	-	3,162	2,390	1,912	-	20,553	8,485	6,214
20	-	11,900	7,500	5,300	-	5,833	3,676	2,598	-	67,954	15,255	8,444
25	-	-	8,850	5,500	-	-	5,423	3,370	-	-	35,250	10,952
30	-	-	10,400	5,600	-	-	7,647	4,118	-	-	60,029	14,619

TABLE 2
FIELD QUALITY CONTROL CHECK LIST

FIELD OR LEASE: ______________________

WELL NAME ______________________

SERVICE COMPANY NAME ______________________

TREATER'S NAME ______________________

DATE ______________________

I. WATER QUALITY

A. WATER SAMPLE TEST DATE ______________________

1. CHECK AND RECORD

a. VISUAL CHECK OF WATER (COLOR, ODOR, FINES, ETC.)

____

b. TEMPERATURE ______________________

c. SPECIFIC GRAVITY ______________________

d INITIAL pH ______________________

e. IRON CONTENT Fe^{+2}/FE^{+3} ______________________ ppm

f. BACTERIA COUNT (AEROBIC OR ANEROBIC)

______________________ colonies/ml

g. SULPHATES ______________________ ppm

II. FRACTURE FLUID QUALITY

A. CROSS-LINKED GEL

1. PERCENT OF ANTICIPATED CROSS-LINKER USED

$100 \times \left(\frac{\text{amount used}}{\text{anticipated amount used}}\right)$

____

2. APPEARANCE AND TEXTURE OF CROSS-LINK GEL

____

3. VISCOSITY OF GEL

a. BEGINNING OF JOB ______________________

b. MIDDLE OF JOB ______________________

c. END OF JOB ______________________

FIELD QUALITY CONTROL CHECK LIST

FLUID DESPCRIPTION:

TANK #	pH			TEMP.			VISCOSITY			X-LINKER TIME		
	Top	Middle	Bottom	Top	Middle	Bottom	Top	Middle	Bottom	Top	Middle	Bottom
1												
2												
3												
4												
5												
6												
7												
8												
9												
10												
11												
12												
13												
14												
15												
16												
17												
18												
19												
20												

TABLE 3
RESERVOIR & FRAC FLUID PROPERTIES

AVERAGE BOTTOM HOLE TEMP.	180° F
NET FRAC HEIGHT	70'
GROSS FRAC HEIGHT	150'
AVERAGE FORMATION PERMEABILITY	0.2 md
AVERAGE FORMATION POROSITY	10%
AVERAGE BOTTOM HOLE PRESSURE	6000 psi
AVERAGE BOTTON HOLE FRAC PRESSURE	10,500 psi
ROCK YOUNG'S MODULUS	7×10^6
RESERVOIR FLUID VISCOSITY	0.02 cps
AVERAGE FRAC GRADIENT	0.85 psi/ft.
DRAINAGE RADIUS	1867'
FORMATION PERMEABILITY TO FRAC FLUID	0.12 md
FRAC FLUID LEAK-OFF VISCOSITY	1 cps
SPURT LOSS	0
SPECIFIC GRAVITY	1.02
AVERAGE FRAC FLUID LEAK-OFF COEFFICIENT (C_{III})	3.3×10^{-3} cc/sec$^{1/2}$
AVERAGE n´	0.63
AVERAGE k´	0.055 lb sec$^{n'}$/ft^2
FRAC FLUID TYPE	30, 40 & 50 lb. X-linked HPG