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STIMULATION OF THE TIGHT WESTERN GAS RESERVOIRS

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Hydraulic fracturing and high-explosive stimulation are the two principal methods that have been used to stimulate production of oil and gas reservoirs in the United States. Since the late 1940s, hydraulic fracturing has become the primary well-completion and cleanup method used in this country. The use of high explosives to increase production has declined, but still remains a viable method for reservoirs in which permeability is primarily fracture controlled. In these cases, the effective diameter of the explosive cavity has to be of the order of the primary fracture spacing. Nuclear explosives have also been tried in tight western reservoirs, but with varying results.

MASSIVE HYDRAULIC FRACTURE STIMULATION

Massive hydraulic fracturing (MHF), a variant of hydraulic fracturing, is proposed in a recent Federal Power Commission (FPC)^[1] report to be one of the most likely methods for stimulating tight gas reservoirs. In that report, MHF is projected to enhance western-reservoir production as much as or greater than nuclear explosives. MHF differs from hydraulic fracturing in that extremely large quantities of fluid and proppant are injected into the fractures created in the reservoir. In many cases, fluid and proppant are injected to create propped fracture lengths of 2500 feet or more. However, the empirical application of MHF in tight western gas formations has given variable, and in many cases, disappointing results. The best efforts of the CER-led industry/government consortium has not been commercially successful. To date, more than 20 MHF treatments have been performed in three tight western basins (Uinta, Piceance, and Green River) believed to contain major reserves. Only about 15% of these treatments

[1] Report of the Natural Gas Technology Task Force for the Technical Advisory Committee of the Natural Gas Survey by the Federal Power Commission (April 1973).

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have been successful, and commercial development of these reserves cannot be expected with this success ratio, especially since the cost of an MHF treatment, exclusive of the cost of the well, is more than \$250,000. On the other hand, the MHF success ratio is apparently much higher in the Wattenburg field northeast of Denver. There, Amoco is commercially stimulating more than 600 gas wells using this technique. Permeabilities in the Wattenburg field are similar to those in the other tight Western reservoirs, the major difference is that the Wattenburg field is characterized by a blanket sand while the other tight western reservoirs are highly interbedded with sand and shale.

A more successful general application of MHF requires a more detailed understanding of the hydraulic fracturing process involved — an understanding that can be gained largely through in-depth theoretical analysis. Such an analysis must include an appreciation of how the formation properties of these extremely low-permeability reservoirs interact with and affect the MHF process. While most MHF treatments are based on a simple theoretical analysis of the process, current theoretical techniques provide little understanding of the phenomena involved. Theoretical techniques need to be developed to study the entire hydraulic fracturing process.

Hydraulic fracturing was first reported to the industry in 1949 by Clark^[2] and has since been the object of analysis both to better understand the process and to create a logical basis for its design and application. Most current theoretical methods are based on the early work of Perkins and Kern,^[3] whose work has been further developed and expanded by others, particularly Howard and Fast.^[4] The resulting theory is based primarily on

[2] J. B. Clark, A hydraulic process for increasing the productivity of wells, Pet. Trans. AIME 186, 1, (1949).

[3] T. K. Perkins and L. R. Kern, Widths of Hydraulic Fractures, J. Pet. Tech., 13, 937 (1961).

[4] G. C. Howard and C. R. Fast, Hydraulic Fracturing, Monograph, Vol. 2, H. L. Doherty Series (Society of Petroleum Engineers of AIME, NY, 1970).

the assumption that the quantity of fluid pumped is equal the amount of fluid contained in the fracture and the piping (with some loss to the formation). The shape of the pressurized fracture is obtained from the analytic forms developed by Griffith, Sneddon, or England and Green. Pressure losses through the piping as well as the fracture are included so that pressure distribution through the fracture can be predicted. The equations predicting pressure drop through the fracture are highly simplified, in essence, representing fluid flow through a cylindrical channel. This theory provides some indication of the effects of fluid pressure and viscosity on the shape of the fracture aperture.

Several analyses have also been performed to determine the effect of the pressure distribution in the fracture on the shape of the fracture aperture. From these analyses, one can predict created-fracture volume and the probable proppant size that can be safely carried into a given fracture with a specific fluid and at a given pump rate.

The current theories used in the design of hydraulic fracturing treatments for standard well cleanup and completion have shown sufficient success to warrant their continued application. The standard well cleanup treatment requires that the fractures be driven a few tens of wellbore diameters away from the wellbore in both directions to relieve the effects of damage due to drilling and to provide a larger production surface area. On the other hand, MHF is applied to create propped fractures several thousand feet in each direction from the wellbore. The large surface area created by these fractures is required to allow production from the extremely low-permeability reservoir rock. Under these conditions, the stimulation ratio is directly related to the amount of productive reservoir sand traversed by the fracture. Hence, an understanding of fracture geometry and how it is affected by the complex reservoir conditions is important.

Of the assumptions necessary to apply current theories, those related to created-fracture geometry require careful study and analysis. For example, the vertical extent of a fracture is assumed to be controlled by the stratigraphic arrangement of the reservoir. But the mechanics of

the fracture-controlling parameters are not addressed by current analyses. Hubbert and Willis^[5] have predicted that the orientation of a hydraulically created fracture will be perpendicular to the least principal stress. Thus, in tectonically relaxed areas, the fractures should be vertical because the horizontal stresses are smaller than the vertical stresses. Hubbert and Willis also indicate that injection pressures should be directly related to the least principal stress. That fractures will propagate perpendicular to the least principal stress has been experimentally verified by several investigators (e.g., Haimson and Fairhurst^[6] and Daneshy.^[7,8] However, we do not have sufficient information on all of the reservoirs to define the stress field. Several methods have been devised to locate the fracture intersection with the wellbore, but a single observation will not uniquely determine fracture orientation. Commercial development of a reservoir will require accurate knowledge of fracture azimuths in that reservoir. Hence, we must continue to research methods for measuring in situ stress fields. In addition, we need to develop theoretical models to study the effects of joints and other existing fractures on the hydraulically driven fractures. These models can also be used to determine if there are parameters that can be used to control fracture characteristics (e.g., orientation and possible branching) during the MHF operation.

We also need to address the question of fracture height in greater detail. This parameter is very important in current theoretical techniques in that fracture volume is directly related to the height and length of the fracture. Hence, if we assume a fracture height and know the quantity of fluid injected, the pressure of the fluid, and have an indication of the fluid loss, we can easily predict fracture length. Conversely, we can design MHF treatments for given fracture lengths. Although certain types

[5] M. K. Hubbert and D. G. Willis, Mechanics of Hydraulic Fracturing, Pet. Trans. 210, 153 (1957).

[6] B. Haimson and C. Fairhurst, Hydraulic Fracturing in Porous-Permeable Materials, J. Pet. Tech., 21, 811 (1969).

[7] A. A. Daneshy, J. Pet. Tech., 25, 1201 (1973).

[8] A. A. Daneshy, Soc. Pet. Engr. J., 13, 61 (1973).

of layering are thought to control the vertical extent of a fracture, this has yet to be proved directly. There are indirect methods, including reservoir analysis, which can and have been used to imply fracture area in productive regions of a reservoir. If the vertical extent of a fracture is controlled or significantly effected by layering, we need to determine those parameters that affect fracturing. Furthermore, we need to determine if current logging techniques can be interpreted in terms of these parameters or if other logging techniques have to be devised to make these measurements.

Related to the effects of layering on the created fractures is how the fractures behave in a highly interbedded region or a region containing lenses of productive reservoir rock interbedded in more barren material. Amoco's experiences at the Wattenburg field indicate some success where the reservoir is a linear-blanket formation. On the other hand, experiments in the highly interbedded regions of the three Western basins show a much lower success ratio. We need to understand how variations in the parameters of the continuum will affect fracturing and if the fractures tend to propagate through the less productive reservoir rock in preference to the more productive regions.

Another potential problem, especially where the fracturing fluid could damage the adjacent reservoir material, is to determine how soon we can start producing fracturing fluid. This question is directly related to how soon the fracture sides relax and hold the proppant material. Once the proppant is held by the walls of the fracture, flow back of the fracturing fluid can begin. Understanding the mechanisms that allow fluid pressure to decrease is paramount to this question. At least two mechanisms are thought to be involved: 1) the fluid leaks into the reservoir via porous flow, and 2) the fracture tends to extend slightly, allowing the pressure to degrade. Probably both of these mechanisms may be important; and a better understanding of the phenomena involved will help determine how quickly we can start flow back.

In summary, advanced theoretical and experimental techniques are needed to provide a more complete understanding of the hydraulic fracturing process and, thereby, a faster and more economic development of the western tight gas reservoirs. Theoretical models based on multidimensional continuum descriptions properly verified by both laboratory and field experiments should be used to analyze the basic physical phenomena involved in hydraulic fracturing. These models must be versatile enough to provide a comprehensive description of the mechanical characteristics of the reservoir material as well as to describe flow phenomena in the fractures and the surrounding porous reservoir rock. In addition, the models must address the effects of in situ stresses, layering, natural joints, and fractures in the host reservoir rock. Such model development will require that an experimental program be carried out in the laboratory concurrently with the theoretical effort.

To apply the theoretical models effectively, the mechanical properties of the host reservoir rock must be measured and characterized, including both laboratory measurements of core material and field measurements (logs). Ultimately, the laboratory measurements can be terminated relying entirely on the log information. This of course will initially require a comparison and correlation program between the laboratory and logging measurements.

Sonic logging tools, primarily those that can measure the mechanical properties of host reservoir material without having the measurements obscured or altered by the presence of fluid, can provide mechanical characteristics of the in situ rock. These measurements may also be used to interpret the natural fracture spacing in the reservoir. Sonic logging, however, is restricted to those areas where the hole will "stand" without casing to allow sonic measurements to be taken.

HIGH-EXPLOSIVE FRACTURE STIMULATION

McKee, Hanson, and Terhune^[9] have developed a theory that predicts how permeability is enhanced in both cylindrical and spherical geometries. This theory shows strong correlation with the existing three events where permeability was measured as a function of radius from the center of the shot. Two of these events were nuclear shots, one American (Hard Hat) and the other French (Hoggar). The third event was a chemical-explosive shot fired in a coal seam near Kemmerer, Wyoming.^[10] The McKee-Hanson-Terhune theory also allows permeability enhancement to be determined from multiple-array shots.

For single shots in ideal elastic geologic materials, permeability will decay around a cylindrical geometry proportional to r^{-4} and around a spherical geometry proportional to r^{-5} . This simply means that, at three cavity radii, permeability will have decayed to 1.5% of the maximum enhancement in the cylindrical case and to less than 1% of the maximum enhancement in the spherical case. When real material properties are included, the relationship has the form

$$k = k_c \left[\frac{r_d^{-3f-3}}{(r_d^{-f-m} + n_o/n_o)^2} \right] + k_o,$$

where k_c and n_c represent permeability and fracture density at the edge of the pulverized region near the cavity wall; f is the geometric attenuation factor; m is the dissipation due to real material effects; k_o is the original permeability; n_o is the initial fracture density in the reservoir; and r_d is the scaled radius. In this case, the degree to which permeability enhancement can be significant depends on the materials and initial fracture density as well as the geometric attenuation. In reference [9], we see that materials that show the greatest dissipation of the explosive-generated dynamic wave

[9] C. R. McKee, M. E. Hanson and R. W. Terhune, Permeability from Single and Multiple Charges, Rept. UCRL 78207, Lawrence Livermore Laboratory, Livermore, CA (1976).

[10] T. Butkovich, Correlations between Measurements and Calculations of High Explosive-Induced Fracture in a Coal Outcrop, Int. J. Rock Mech. Min. Sci. 13, 45 (1976).

also display the greatest permeability enhancement from the shot. Also, our ability to enhance permeability with explosives is primarily controlled by our ability to distribute porosity with the explosive shot.

Even though explosives do not, in general, display outstanding characteristics for stimulating gas reservoirs, they have a definite application in certain instances. For example, in a reservoir where permeability is primarily fracture-controlled, explosives can be used to link the permeable fractured regions to the wellbore.

PROPPANT TRANSPORT

A fluid (either water or a water-condensate emulsion) is normally used to pressurize and propagate a fracture as well as to carry the material (proppant) that will hold the fracture open (proppant) after the pressure is released. This will result in the fracture having a much higher permeability than the surrounding host rock. It is normally conjectured, and partially borne out by experiment, that the proppant-carrying capabilities of a fluid are primarily related to its velocity and viscosity. The product of this viscosity and velocity is a force, normally called a drag force. This hypothesis assumes that relative motion between the fluid and the proppant is required to create a drag force on the proppant material.

Most of hydraulic-fracturing fluids are thickened in some manner to increase their viscosities and thereby enhance their proppant-carrying capacities. Moreover, injection procedures have been developed that are thought to place the proppant material in pillars, in stable banks, or spread evenly throughout the fracture. However, there has been little experimental evidence in the literature on the success or failure of any of these techniques. In addition, theoretical methods have not been developed to predict how the proppant material is distributed within the fracture. A basis for such theoretical models probably could be developed using methods originally designed to analyze sediment transport in rivers and streams.

Finally, an interesting set of experiments are now being carried out at the Nevada Test Site in which hydraulic fractures are being created in a mesa and then physically mined out. These experiments could be used to examine proppant-deposition characteristics of the various injection techniques. In addition, the proppant-transport capabilities of various fracturing fluids can be investigated.

TASKS

I. MODEL DEVELOPMENT AND APPLICATION

Develop two- and, if required, three-dimensional theoretical models to analyze the hydraulic fracturing process in mechanically complex geometries of the tight Western reservoirs. These models should include the capabilities to analyze pore-pressure effects and the effects of layering and interbedding, joints, bedding planes, and other discontinuities in the reservoir. Implied in developing these theoretical models is the need to correlate model development with laboratory experiments (see Task 2) and field data wherever possible.

Apply these analytical models to problems aimed at better understanding the hydraulic fracturing process in a real reservoir. These problems should include, but by no means be limited to, the following:

A. Problems related to reservoir properties that can influence the fracture geometry.

- 1) If shale layers contain the vertical extent of a fracture in the reservoir, what mechanical properties impede fracture growth in the shale? Can variations in these properties be detected by well-logging techniques?
- 2) What are the effects of layering compared to an isotropic formation. What percent in variation of the parameters across an interface is important in the fracturing process?
- 3) What are the effects of sandstone lenses interbedded with shale? How do fracture-propagation characteristics change when the horizontal extent of the reservoir is changing?
- 4) What are the effects of already existing joints and fractures on the hydraulic fracturing process?
- 5) What is the maximum depth at which hydraulic fracturing can be used for stimulation?
- 6) What controls the azimuth of the created fractures when the two minimum principal stresses are approximately equal?

B. Problems related to fracturing-fluid properties and porous-flow effects.

- 1) Since changes in pore pressure can alter effective breakage stress, how do changes in pore pressure from the porous flow affect the hydraulic fracturing process?
- 2) Can the thermal effects from pumping a cold fluid into a warm reservoir have a significant effect on the fracturing process?
- 3) Do fracturing-fluid parameters (e.g., viscosity, velocity, pressure) affect the fracturing process?
- 4) Can fracture characteristics (e.g., length, branching, etc.) be enhanced or otherwise influenced by varying fluid parameters during the stimulation operation?

C. Problems related to the control of the hydraulic fracturing process.

- 1) Can fracture orientation be influenced by the stimulation borehole or by neighboring boreholes?
- 2) Are there pumping techniques that can dynamically enhance certain fracture characteristics? Can varying the rate or pressure of the fracturing fluid exert some control on fracture geometry? It has been implied that certain intermittent pumping procedures can enhance the bifurcation of a fracture.
- 3) Are the dynamic effects of the fracturing process important to fracture orientation and shape? Are the dynamics of the fracturing process important to the development of the theoretical basics and an understanding of the fracturing process?

D. Other problems.

- 1) When the sides of the fractures relax on the proppant, at least two mechanisms are thought to contribute to the escape of the fluid trapped in the fracture. These are: fluid leak-off into the reservoir and/or further fracture extension. The time required for these processes to occur is important because, as soon as the proppant is held by the fracture, flow back and cleanup can begin.

- 2) Compare massive hydraulic fracturing (MHF) with other stimulation methods (e.g., explosive fracturing) for various reservoir characteristics.

II. LABORATORY EXPERIMENTAL MODELING

Experimentally model the hydraulic fracturing process on small laboratory specimens. Test the fracturing process under various stress conditions to study the mode of fracturing and the effects of the intermediate principal stress on the mode and orientation of the fracturing. Examine the effects of layering on the fracturing process. The data generated in this effort will be required to correlate and verify the theoretical models.

III. MECHANICAL-PROPERTIES MEASUREMENTS

Measure core material to determine the mechanical and physical properties and the breakage characteristics where these data do not exist. Compare these measurements with data retrieved by logging, especially the mechanical properties obtained by wet- and dry-hole sonic logging methods. These data are a major importance to the theoretical models discussed in Section I.

IV. RESERVOIR ANALYSIS

Where data are available, analyze the flow and pressure buildup characteristics from MHF stimulations to assess the effects of the stimulation. In addition, interpret fracture length from these analyses.

V. PROPPANT TRANSPORT AND DEPOSITION

Field experiments dealing with proppant transport and deposition are already being performed at the Nevada Test Site. First, fractures are created hydraulically. They are then mined out to determine proppant distribution in the fracture. Further experiments should follow the NTS experiments. These experiments should be applied to lead the development of the theoretical models of the process.

SCHEDULE

	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>
Model development and application	xxxx + Begin application of two-dimensional models	xxxx	xxxx	xxxx	xxxx
Laboratory modeling	xx	xxxx	xxxx	xx	
Mechanical-properties measurements	xxxx	xxxx	xxxx		
Logging correlation with lab data	x	xxxx	xxxx	xxxx	
Reservoir analysis	xxxx	xxxx	xxxx	xxxx	
Proppant transport		xxxx	xxxx	xxxx	

x = quarter year.

PRIORITIES

1. The geological and geophysical evaluation, identification, and characterization program should proceed concurrently with both the theoretical-model development program underway at LLL and the development of field-measurement techniques now being carried out by Sandia. These programs should receive top priority because of the long lead times required to realize useful results.
2. Field experiments and programs should proceed with special emphasis on obtaining as much useful knowledge about the reservoirs, the stimulation technique, and the effects of the stimulation as possible. These programs should also be supported where the geological and geophysical data retrieval can significantly supplement existing knowledge.

- 12
3. Measuring the mechanical properties of the reservoir rock is necessary to obtain input parameters for analyzing the fracturing characteristics of the reservoir. Comparison of these properties with log-derived properties can allow the termination of the laboratory measurements program relying on interpretation being made entirely from the logs.
 4. A small continuing reservoir-analysis effort is desirable for evaluating field treatments and determining fracture extent. However, a long lead time is not required for this effort, as it is in the fracture studies and field-measurements programs.
 5. Current knowledge on proppant transport needs to be examined and an evaluation made of how critical this problem is to the overall program before we can determine a realistic priority for this problem area.

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