Appendix B
Fracturing Technologies

Introduction

A characteristic of "unconventional resources" is that, while increased prices generally are an important condition for full commercialization, new technology developments are also required. In the long run, technology may have more impact than price on the amount of gas recovered. Studies of unconventional resources that OTA has reviewed have concluded that the amount of gas that could be produced with existing technology at prices considerably higher than today's is less than the amount of gas that could be produced with advanced technology at current prices for new gas. For example, the National Petroleum Council's tight gas study estimates that more gas can be produced for $3.00 per thousand cubic feet (MCF) with advanced technologies than can be produced for prices up to $9.00/MCF using base case technology. In response to this perception, a considerable amount of Government and industry research effort has gone into developing more advanced technologies for unconventional gas recovery,

In the past 5 years the state of technological development has advanced. With and sometimes without additional Government financing, producers have been willing to try innovative approaches. Nevertheless, a high failure rate still exists in probing certain types of unconventional gas formations. The following discussion describes successful new developments in fracturing technologies and delineates areas where work remains to be done. This appendix will serve to give the reader more insight into the validity of the assumptions used in the various estimates of recoverable resources and production potential.

New Technology Developments in Fracturing

The objective of fracturing a low-permeability reservoir is to increase the surface area of the formation that is in direct contact with the well bore. The pressure gradient between the lower permeability formation and the higher permeability fractures is the driving mechanism for the gas flow. Thus, the greater the area over which such a gradient can be established, the larger the volume of gas flowing at a given point in time.

Technologies for fracturing gas reservoirs are not new. Explosives have been used in Devonian shales since the late 1800s. Detonation of explosives shatters the rock immediately around the well bore, effectively increasing the well bore diameter. A large-scale variation on this theme was tried in the late 1960s in tight sandstone formations using nuclear explosives. The generally unsatisfactory results (possibly due to melting of the reservoir rock from the heat of explosion or permeability damage due to compaction of fine particles) and the lack of public enthusiasm for potentially radioactive gas put a quick end to this program.

Hydraulic Fracturing Technologies

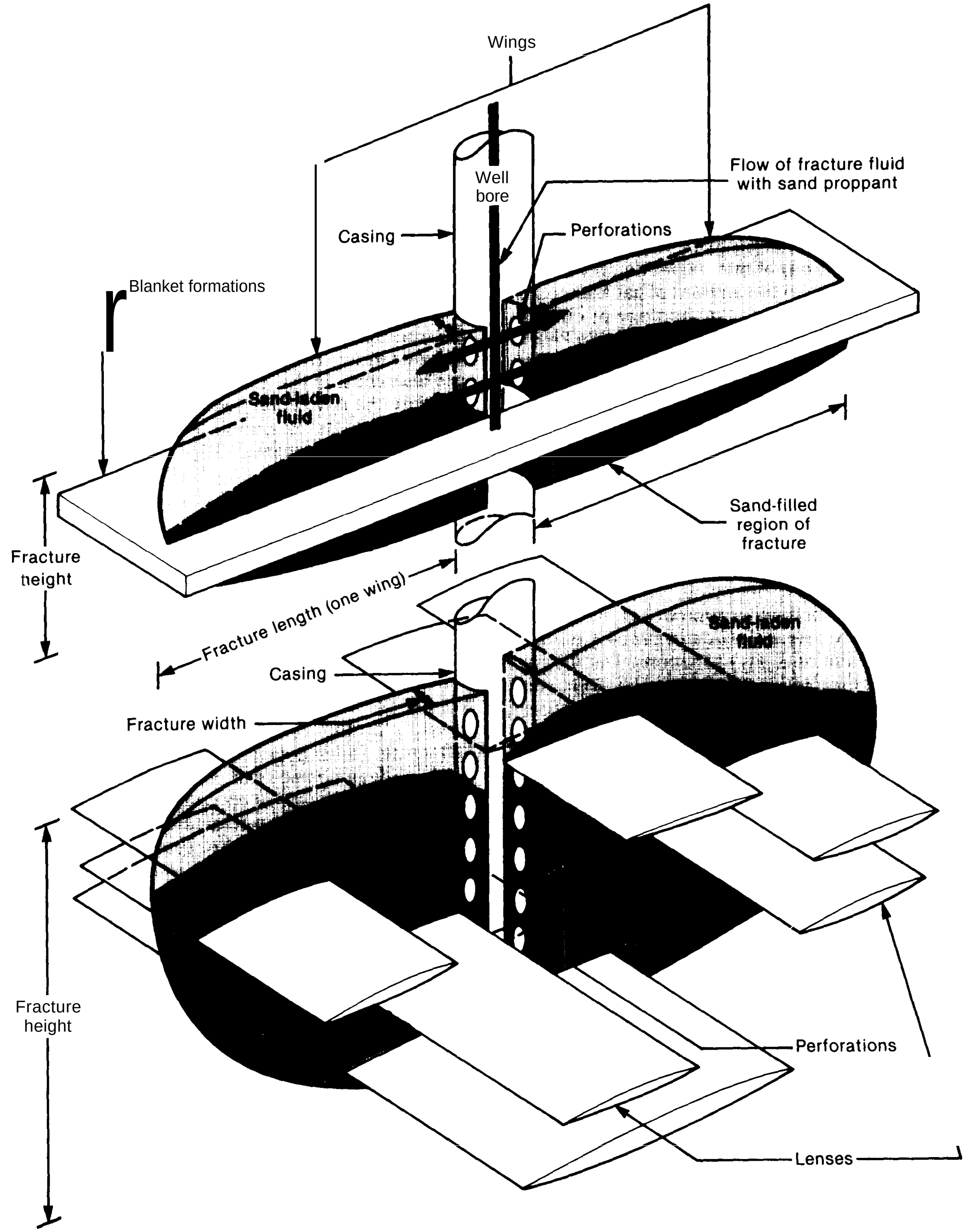
Hydraulic fracturing is the most commonly used fracturing technology today. The concept was first developed in the 1940s for use in conventional oil and gas reservoirs. In the early 1970s **producers began to increase the size of the fracture treatments to generate longer fractures, on the order of 1,000 ft in low-permeability sandstones.**[1] **This technique, known as massive hydraulic fracturing (MHF), is now a common means of well completion in the tight sand formations, although it is certainly not applicable** in all cases. Devonian shale and coal seam reservoirs use more conventional size hydraulic fracture treatments to create fractures ranging from 100 to 500 ft. Fractures in these types of reservoirs are designed to intersect natural fractures, which serve as the primary pathways for gas flow.

Hydraulic fractures are created by pumping large volumes of fluid down the well bore. The fluid exerts pressure on the rock formation, eventually creating a fracture. Fluids generally carry proppant materials, such as clean coarse sand, which are left in the fractures and hold them open when the fracturing fluid is removed. The induced fracture has a considerably higher permeability than the surrounding formation. Hydraulic fractures tend to be unidirectional, generally extending out as wings in opposite directions from the wellbore. By convention, their length is measured along one wing. Their direction and orientation (vertical, horizontal, or inclined) are controlled by the regional tectonic forces and the depth of the target formation. Most fractures at depths greater than 2,000 ft are oriented in the vertical plane. Figure B-1 schematically represents a hydraulic fracture.

Major research efforts in fracturing technology have focused both on increasing the fracture length and

[1] C.R. Fast, G. B.Holman, and R. j. Corlin, "The Application of Massive Hydraulic Fracturing to the Tight Muddy J Formatlon, Wattenberg Field, Colorado, " *Journal of Petroleum Technology,* January 1977, pp. 10-16

Figure B-1.—Conceptual Fractures Created by Massive Hydraulic Fracturing in Blanket and Lenticular Formations



solving some of the problems that reduce the effectiveness of the fracture in increasing rates of gas flow.

Maximizing the effective length of a fracture is not simply a function of increasing the volumes of fluid pumped into the well bore. One must make sure that the proppant is transported to the end of the fracture, and effectively holds the fracture open once the fracturing fluid is removed. Other problems that must be overcome include minimizing damage to the formation caused by the fracture fluids and containing the fracture within the "pay interval," the layer where gas is present. If the fracture intersects a permeable zone that allows the fracturing fluid to "leak off" at a high rate, further penetration of the fracture may become impossible because the fluid loss prevents further pressure from being built up.

Each of the objectives of fracture research will be discussed in turn:

Maximizing High Conductivity Fracture Length.– Accomplishing this objective involves choosing appropriate fracture fluids and proppants. The proppants should be strong enough not to crush as the fracture closes, and of sufficient diameter to overcome any tendency to become embedded in the formation. Also, they must be light enough to be carried by the fracturing fluid to the design fracture length without settling.

Conventional practice is to use clean rounded sand as the proppant material. It is the least expensive proppant and, at shallow and intermediate depths, has sufficient strength to hold the fracture open without crushing. At greater depths where closure pressures are higher and proppant crushing prevalent, a stronger material is needed.[2] Producers most commonly use sintered bauxite under these conditions. However, bauxite has two drawbacks–high cost and high density. Because of the latter, it is difficult to transport the bauxite particles to the end of the fracture. Service companies are rapidly developing alternate intermediate and high strength proppant materials. A number of these materials, including ceramic beads and resin-coated sands, have lower densities than bauxite and appear to have sufficient strength for most fracture applications. More work needs to be done to develop materials with densities lower than sand and adequate strength to maintain high fracture conductivities.

The need for a fracture fluid with a high capacity to carry proppants in suspension has led to the development of very sophisticated fluids. These include water- and hydrocarbon-based polymer liquids and gas-charged emulsions and foams.

The water-based fluids use organic polymers for friction reduction, fluid loss control, and viscosity enhancement. The polymers are long chains of organic molecules which bond loosely with the water, forming gels. The resultant fluid is thicker than water and has a higher surface tension. It flows with less turbulence, can suspend greater volumes of proppants and does not leak off into the formation as rapidly as pure water.

Probably the most significant technical development in fracturing fluids is the process of **cross-linking.** Cross-linking is a chemical reaction which bonds polymer chains together, effectively increasing the viscosity of the fluids as much as an order of magnitude. The reaction is timed so that cross-linking occurs just as the fluid arrives at the fracture entrance. The increased pressures required to pump the thicker fluid will widen the fracture and the enhanced viscosity can carry the proppant greater distances. At the end of the treatment the fracture fluid warms up to the higher reservoir temperatures and the cross-linked polymers break down. Now significantly lower in viscosity, the fluid can leak off into the formation or flow back out of the wellbore, leaving the proppant in place.

Hydrocarbon-based fracture fluids behave similarly to water-based fluids and can also be cross-linked. They are used in instances where water-based fluids are likely to cause significant formation damage—as in the presence of water-sensitive clays. However, in gas-bearing reservoirs the introduction of a third phase (oil, in addition to gas and water) may further impede the flow of gas in the formation.

Minimizing Formation Damage.—In addition to fluids designed to improve proppant transport, more exotic fracture fluids have been designed to address the problem of formation damage. Fracture fluids have been a major factor in causing formation damage. Fluid leak-off into the formation can block pores, especially if the gels are not completely broken down. introduced fluids can also cause clays to swell, or dislodge fine particles to block pores.

All three types of unconventional gas reservoirs are susceptible to formation damage. Devonian shales may be the most affected because they have naturally low water content and high clay content. Devonian shales have, as a consequence, served as a testing ground for a number of the new fracturing fluids.

Many of the fluids developed to minimize formation damage use a gas phase to reduce the amount of water required. Foamed fluids are gas-in-water emulsions, where the surface tension of the bubbles holds the proppant in suspension. Such fluids cannot

[2] R. A. Cutler, D. O Enniss, A. H Jones, and H. B. Carroll, "Compa risen of the Fracture Conductivity of Commercially Available and Experimental Proppants at Intermediate and High Closure Stresses," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11634, 1983.

transport large volumes of proppant long distance—they are generally used for shorter fractures. Nitrogen (N,) is the most common gas used in foamed fluids, although CO_2 can also be used. Producers are experimenting with increasing the percentage of gas from 75 to 90 percent of the total fluid volume.

Pure N_2 has also been used as a fracturing fluid. It is not an efficient fracturing fluid as it requires very high injection pressures. However, nitrogen fracturing has proved very effective in increasing gas flow because it does not adversely affect the formation. Nitrogen gas cannot carry proppants, therefore it is only effective at shallow depths where the fractures are less likely to close. Whether wells fractured with nitrogen will maintain higher production levels over the long term is still unknown.

Some wells have been fractured using liquid $C0_2$, which has the ability to transport proppants. As the liquid $C0_2$ warms, it reverts to the gas phase and easily flows back out of the hole with minimal damage to the formation. Liquid CO_2 fracturing is a relatively expensive process and somewhat more dangerous to use than foamed fluids, In addition, the casing and pumping materials must be capable of withstanding very low temperatures.

The tradeoffs of minimizing formation damage, transporting proppants, and containing costs all enter into the decision of which fracture fluid is used. Generally, an important element in the decision should be laboratory compatibility tests between formation cores and the proposed fracturing fluids, which can identify potential damage problems.

Containing the Fracture within the Pay Interval.–As a fracture propagates outward from the wellbore it may also grow vertically up or down, Vertical growth occurs at the expense of lateral growth, thus reduces the effective length of the fracture for the same volume of fluid pumped. Those portions of the fracture which extend above and below the gas-producing interval are essentially wasted; also, they may extend into water-bearing strata which will adversely affect gas flow.

It has been recognized in the last few years that the main factor controlling containment of a fracture is the difference in the stress characteristics of the rocks making up the producing and nonproducing zones. The stress on the rocks, or "in-situ stress," is a function of the mechanical properties of the rock and the regional stresses acting on the rock. Thus, the same type of rock at different locations or depths or in different tectonic environments may have different in-situ stress characteristics. A sand-shale interface in the Cotton Valley Sands may effectively contain a fracture within the sand zone. A fracture in the Piceance Basin may break through a similar sand-shale interface. Similarly, different rocks will have large differences in their mechanical resistance to fracturing and thus require substantially different applied pressures for fracturing.

No commercially available technologies exist today that successfully deal with fracture containment. Some recent research efforts have focused on developing innovative techniques to control the growth of fractures out of the pay zone. GRI is testing three approaches:[3]

- **Fracture initiation placement–the well casing is perforated above or below the pay zone allowing the fracture to grow vertically into the producing interval. A field test of this technique was performed in July 1983.4 Preliminary results** indicate increased flow but further cleanup is necessary before final results can be assessed.
- **Controlled process zone–the fluid viscosities and pumping rates are controlled to get preferential initial leak-off in the pay zone. This should result in** more penetrating rather than taller fractures. This technique is still being tested in the laboratory.
- **Lightweight additives–impermeable floating** proppants are used to seal off upper, non-producing portions of the fracture. Appropriate proppant materials are currently being tested.

Predicting and Monitoring Fracture Behavior.– Another important research objective in improving fracturing technology is to develop techniques to predict and monitor fractures. To know in advance how a fracture is likely to perform or to be able to tell in the field whether a fracture is conforming to design parameters increases the chances that stimulation will be successful. Furthermore, as fields become more developed, it is important to know the direction and length of a fracture, and thus the drainage area of a well in order to minimize interference from subsequent wells. Fracture diagnostics probably is one area where the most innovation has occurred in the last few years.

Predicting fracture behavior.–State-of-the-art prediction of fracture behavior comes mostly from formulation of sophisticated mathematical models and comparison of the model results with results of laboratory experiments. There has been little field verification because of the cost and technical difficulty involved in obtaining a detailed picture of the physical results of fracturing.

[3] "GRI's Unconventional Natural Gas Subprogram, " Status Report, December 1982.
[4] "New Fracturing Technique Undergoing Tests, " *Oil and Gas Journal,* Aug. 8, 1983.

Current practice in the field is to use relatively simple analytical models against which to compare fracture behavior, proppant placement, fracture length, and well performance. Two commonly used models are the Perkins and Kern model and the Gertsma and De Klerk model. The first is considered by some practitioners to be the more reliable model for fractures extending laterally without significant increase in height, with the second more reliable for short fractures with length to height ratios less than one.[5,6]

More sophisticated models are being developed to deal with more complex situations such as fracture propagation response to changing stress fields, or intersection of an induced fracture with a natural fracture. Such models have been used occasionally to design actual field stimulations where preliminary investigation indicates a simplified model would give inadequate or misleading results. Use of complex models for field design is limited at present due to high costs, time required to run the simulations, and probably most importantly, inadequate input data. At present these models are mostly used as controls for design of experiments and for comparison with experimental results. The extent to which experimental results reproduce the simulated results both confirms the validity of the simulation and identifies the controlling parameters.

Laboratory experiments are conducted to observe fracturing behavior under controlled conditions. In these experiments, scale models are used to simulate field conditions. For example, a block of reservoir material can be placed in an experimental apparatus which can reproduce confining pressures and temperature conditions of the actual reservoir. Fluid is pumped into a hole drilled into the block, inducing a fracture. Sensors monitor strain buildup and release. Finally the fractured block can be sectioned to observe the fracture configuration. Experimental conditions allow certain variables to be held constant while others are varied to determine the effect each has on the fracture, One set of experiments was run to observe induced fracture behavior in the presence of an existing fracture system.[7] Results indicated that an induced fracture would cross an existing fracture only at high angles of approach (i e., close to perpendicular) or if the stress field created a strongly preferred fracture orientation. Otherwise the preexisting fractures would open, diverting fracture fluid and stopping the induced fracture from propagating.

[5]Johnston & Associates, Inc., "The Status and Future of Production Technologies for Gas Recovery From Devonian Shales, OTA contractor report No, 333-6810

[6]J. W. Crafton, "Fracturing Technologies for Gas Recovery From Tight Sands, " OTA contractor report, 1983

The major problem with laboratory experiments is determining whether the laboratory conditions are truly representative of the reservoir environment. it rarely is clear whether the small-scale laboratory fracture would behave in the same fashion if it were increased to field scale. Consequently, the next step in predicting fracture behavior is the field test. Field tests are extremely expensive, and therefore few have been conducted. Perhaps the most useful are "mineback" experiments which excavate and expose an induced fracture, allowing comparison of actual behavior with predicted behavior and physical measurement of the rock, fracture, and fracturing materials.

Successful field-scale experiments of massive hydraulic fractures have been conducted at the Nevada Test Site in volcanic rocks.[8] These rocks are not particularly characteristic of tight sandstone reservoirs but the experiments still provided useful and frequently applicable information. One significant result indicates that fracture tortuosity (irregularities of the fracture path) significantly increases the pressure gradient in the fracture, leading to wider than predicted fractures.[9] Other studies demonstrated the mechanics of fluid leak-off and sand distribution.

Because of their expense, mineback experiments are no longer being conducted by the Department of Energy (DOE) or GRI.[10] Instead, field testing for understanding fracture behavior is focusing on experimental well tests. These tests rely on sophisticated in-well measurements to **infer fracture behavior** in contrast to the direct observations possible with minebacks.

The largest scale well test at present is the DOE Multiwell Experiment (MWX). This test consists of three wells drilled in close proximity to each other in a tight sands field in the Piceance Basin in Colorado. The multiple wells serve many functions. They allow collection and correlation of geologic data and provide testing sites for new logging tools. Perhaps most importantly, they provide sites to monitor behavior of fractures induced in one of the wells. A fracture has been completed in the blanket sand reservoir in this field and results have indicated the importance of an existing natural fracture system on fracture behavior and well performance. Subsequent stimulation treatments are planned to address specific problems of fracturing in lenticular formations.

[7]T. L. Blanton, "An Experimental Study of Interaction Between Hydraulically Induced and Pre-Existing Fractures " *SPE/DOE Unconventional Gas Recovery Symposium*, SPE/DOE 10847, 1982, pp 559-562.

[8]N. R. Warpinski, L. D, Tyler, W. C. Vollendorf, and D. A. Northrup, " Direct Observation of a Sand Propped Hydraulic Fracture, Sandia National Laboratory Report SAND81 -0225, May 1981.

[9]N. R Warpinski, "Measurement of Width and Pressure in a Propagating Hydraulic Fracture, " *SPE/DOE Symposium on Low Permeability Gas Reservoirs*, SPE/DOE 11648, 1983.

[10]Charles Komar, Morgantown Energy Research Center, personal communication, 1984.

Similar but smaller scale well tests are being conducted in Devonian shales to determine effectiveness of different types of stimulation in improving reservoir production.

Monitoring fracture behavior. –Most of the technologies under development to monitor fractures in the field are adaptations of existing geophysical and well logging techniques. They include magnetic, electrical, and seismic instrumentation as well as temperature, pressure, and radioactivity measurements (see box B-1). Some techniques such as temperature and radiation logs are only useful in the immediate vicinity of the borehole. They indicate fracture height under certain conditions but not depth of penetration.[11] Tiltmeters and microseismic measurements which record minute deflections and seismic disturbances caused by the propagating fracture may be able to measure fracture direction and total length, but cannot discern propped (effective) length. Superconducting magnetometers may have potential for determining propped length from magnetic material introduced with the proppant.[12]

Most of these technologies are still in the experimental stages. Their depth limitations, sensitivity, and overall accuracy have not yet been fully evaluated. Using a number of these technologies together would probably be the most effective way to collect data on a fracture[13] but for practical application would be too costly.

There are other constraints to widespread use of fracture diagnostic techniques. For example, adverse terrain and difficulty in obtaining surface access rights cause problems for methods which require widely spread surface arrays of detection equipment.[14,15] The extremely sensitive nature of the instruments and the necessity of measuring signals that are only marginally discernible above background noise requires very careful setup and monitoring that may not be achieved under ordinary operating conditions.

The technique most commonly used today to evaluate whether a fracture satisfies design criteria is pressure transient testing. This type of test generally is run after the fracture treatment is completed, although it can be useful as a pre-fracturing test as well. Essentially, a post-fracturing test matches the actual performance of a well for a given period of time against the simulated performance of a fracture of given propped configuration. This gives a **minimum estimate of the propped length.** The technique gives valuable empirical data on the flow rate and pressure decrease with respect to time for the well. However, it is generally considered as not providing sufficient information to allow producers to discern whether lower-than-predicted flows are due to fracturing out of the pay interval, inadequate fracture conductivity, or formation damage.[16]

Improved fracture diagnostic techniques may reduce some of the undefined variables (e.g., actual propped fracture length). This would allow the reasons for success or failure of a particular fracture treatment in a given formation to be better understood, resulting in improved fracture design.

High Energy Gas Fracturing or Tailored Pulse Loading

This technique is dramatically different from hydraulic fracturing techniques, and is derived from earlier explosive fracturing. A propellant charge is used that can pressurize the wellbore at a slower rate than the conventional explosives, changing the characteristics of the fractures created.[17] The loading rate—i.e., the rate at which the energy stored in the gas is released—can be controlled to create different types of fractures. For example, at intermediate loading rates, fractures form radially around the well bore. At slow rates, fractures form in an analogous manner to hydraulic fractures, directionally controlled by the regional stress field. This technique may have significant potential for commercial use, especially because it causes little formation damage. Commercial application in the Devonian shales may occur in the near future. Application in tight formations is more problematic, however.[18]

---

[11] C. M. Hart, D. Engi, and H. E. Morris, "A Comprehensive Fracture Diagnostics Instrumentation Fielding Program," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE 11810, 1983, pp. 461-485.

[12] M. D. Wood, C. W. Parkin, R. Yotam, M. E. Hanson, M. B. Smith, R. L. Abbot, D. Cox, and P. C)' Shea, "Fracture Proppant Mapping by Use of Surface Superconducting Magnetometers," *SPE/DOE Symposium on Low Permeability Gas Reservoirs,* SPE/DOE 11612, 1983,

[13] D. A, Northrup, A, R. Sattler, and J. K. Westhusing, "Multiwell Experiment: A Field Laboratory for Tight Gas Sands," *SPED(3E Symposium on Low Permeability* Gas *Reservoirs,* SPE/DOE 11646, 1983.

[14] Hart, Engi, and Morris, Op. cit.

[15] Johnston & Associates, Inc., OP. cit.

[16] This is a matte, of some dispute, because some specialists claim to be able to distinguish among the possible causes of disappointing flows,

[17] Crafton, op. cit.

[18] S. A, Holditch, personal commu nication, 1984.

Box B-1. --Well Logs

Well logs are measurements of rock formation characteristics taken by devices, called sondes, that are lowered into the wellbore on an electric wireline and transmit back information toa surface recording device. There are a great variety of these devices. The most common are:

1. Eletrical logs measure the electrical characteristics of the rock surrounding the wellbore before the well is cased. Electrical logs measure either resistivity or spontaneous potential.
   - Resistivity logs pass an electric current through the rock formation and measure its ability to conduct electricity. These logs help to determine the type of fluid contained in formations and the relative saturation of oil and water. There are a variety of resistivity logs, including:
     - –Induction logs, which measure formation resistivity in wells drilled with freshwater drilling fluids or with nonconductive fluids such as air or oil.
     - –Laterolog, which can identify thinner formations than ordinary resistivity logs. These are used with saltwater drilling fluids.
     - –Microlog, which is used to identify the porous and permeable zones by measuring the resistivity of the thin layer around the wellbore that is invaded by drilling fluids.
   - The spontaneous potential log measures the electrical potential created by the differences in salinities between the formation water and drilling fluids. This log helps to differentiate between rock types (e.g., sand and shale) and to define formation water salinity.
2. Radioactive logs measure either the naturally occurring radioactivity in the rock formation or the response of the formation to bombardment by neutrons or gamma rays. These include:
   - Gamma-ray logs record the naturally occurring gamma rays in the rock formation surrounding the well bore. They differentiate between shales and other formations, or measure the amount of shale in the formation.
   - Neutron logs bombard the formation with neutrons and measure the induced gamma rays: They delineate porous formations, and indicate the amount of fluid (and, in some cases, fluid type). They are useful in locating gas zones and determining rock types.
   - Formation density logs measure the scattering of gamma rays bombarding the formation from a source on the logging tool. They are used to determine porosity, and help in determining rock types in conjunction with sonic or neutron logs.
   - Gamma spectrometry logs measure both the scattered neutrons and the gamma-ray spectrum from neutron bombardment. They help in measuring 'hydrocarbon saturation, porosity, formation water salinity, and rock types.
3. Acoustic velocity, or sonic logs, measure the velocity of an acoustic (sound) wave along the wall of the borehole. They are used to measure porosity, to distinguish between salts and anhydrites, to detect shales with abnormal pressures, to determine rock types, and to identify fractures.
4. Nuclear magnetism logs measure the effects of applying a large magnetic field to the rock formation. They are used to measure permeability, porosity, producibility, and water saturation.
5. Temperature logs are used to identify zones where drilling mud is being lost into the formation or, in air-drilled wells, the locations of gas entry into the wellbore.

SOURCES: F. A. Giuliano (cd.), *Introduction to Oil and Gas* Technology, 2d ad., Intercomp Resource Development and Engineering, Inc., Houston, TX, 1981; British Petroleum Co. Ltd., Our *Industry Petroleum*, 1977; and Schlumberger Well Services, *Openhole Services Catalog*, 1983.