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INTEGRATED REAL-TIME FRACTURE-DIAGNOSTICS INSTRUMENTATION SYSTEM

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ABSTRACT

The use of an integrated, real-time fracture-diagnostics instrumentation system for the control of the fracturing treatment during massive hydraulic fracturing is proposed. The proposed system consists of four subsystems: an internal-fracture-pressure measurement system, a fluid-flow measurement system, a borehole seismic system, and a surface-electric-potential measurement system. This use of borehole seismic and surface-electric-potential measurements, which are essentially away-from-the-wellbore measurements, in conjunction with the use of the more commonly used types of measurements, i.e., at-the-wellbore pressure and fluid-flow measurements, is a distinctive feature of the composite real-time diagnostics system. Currently, the real-time capabilities of the individual subsystems are being developed, and the problems associated with their integration into a complete, computer-linked instrumentation system are being addressed.

INTRODUCTION

Hydraulic fracturing has become an important technique in the stimulation of low-permeability hydrocarbon reservoirs. Historically, these low-permeability reservoirs were considered noncommercial, but with continuing advancements in hydraulic-fracturing technology, the reservoirs are becoming increasingly economic. At present, roughly 25 to 30% of total U.S. oil reserves are economically producible because of hydraulic fracturing. Treatments have become so widespread that approximately 35 to 40% of all wells drilled today are hydraulically fractured at some point (Veatch, 1983).

Optimization of a hydraulic-fracture treatment requires an approach that takes into account those properties of the formation that affect reservoir performance and those properties of the fracture--in particular, the fracture geometry--that will lead to increased production. In principle, the creation of an optimal fracture geometry will maximize the return (enhanced revenues minus treatment cost) of a hydraulic-fracturing treatment. Therefore, the creation of a satisfactory fracture geometry is particularly important in hydraulic fracturing, because the fracturing can constitute a large portion of the total well costs.

Accurate knowledge of formation properties is essential for selecting suitable values for the treatment parameters (Pai and Garbis, 1983). Unfortunately, the approach that is commonly used to select values for the treatment parameters is far from satisfactory. Except for pressure data collected during fracturing, this approach entails an almost total reliance on data generated from prefrac measurements in the laboratory and from prefrac observations and measurements in the field (including minifrac measurements).

The prefrac data, in the form of values for formation parameters such as porosity (ϕ), permeability (k), vertical distribution of minimum principal horizontal in situ stress (σ), material properties (e.g., Young's modulus (E) and Poisson's ratio (ν)), and probable fracture orientation, are used in conjunction

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with trial values for treatment parameters (e.g., viscosity (μ), leakoff rate (β), density (ρ), fluid volume (V), and injection rate (F) of the fracture fluid; size, crushing strength, and concentration of the proppant [sand]) as inputs to a fracture model from which estimates of fracture geometry (height (H), length (L), and width (W), in addition to probable orientation) can be made. Assuming that the physics incorporated in the fracture model is correct, then the use of this modeling procedure for optimizing the treatment design with respect to the desired fracture geometry is currently still limited to finding a satisfactory set of initial values for the treatment parameters (Veatch, 1983); the values for the formation parameters are fixed at the initial values obtained from prefrac measurements.

Initial values for the in situ viscosity and leakoff rate may be inaccurate, and these values may change during the fracturing process. Thus, the initial set of values for the treatment parameters may no longer be (and may never have been) optimal. Efforts to alter the treatment during fracturing, in such a way as to control or improve fracture geometry, must rely on judgments based on previous experience and on limited information (e.g., flow and, possibly, pressure and temperature data). In the absence of the means to measure the fracture geometry during fracturing, there is no way to update the values for the viscosity and leakoff rate (by comparing fracture-model output with observed fracture geometry), and lacking these values, the fracture model cannot provide reliable information that can serve as a guide in controlling or altering the treatment to achieve the desired fracture geometry.

CONTROL OF FRACTURE TREATMENT USING REAL-TIME DIAGNOSTICS

The use of a real-time fracture-diagnostics instrumentation system is essential for providing the information needed to control a fracture treatment and to determine whether or not the ongoing treatment is in fact appropriate. Figure 1 is a flow diagram that shows how a real-time instrumentation system might be used to optimize the fracture treatment and fracture geometry.

During treatment, continual comparison of the fracture geometry predicted by the fracture model with the fracture geometry sensed by the instrumentation system makes it possible to provide updated values for the in situ viscosity and leakoff rate. Provided that the fracture model is correct and convergence is obtained in this model-convergence loop (yielding an altered but physically reasonable and self-consistent set of values for these parameters), then there exists sufficient information with which to use the model to test the effect on fracture geometry of modifying the fracturing treatment. Using the desired fracture geometry as a goal, iterations within the treatment-parameter loop are potentially useful for providing the information needed to guide and control the course of the treatment. As indicated in Figure 1, it is of course possible that the iterative procedures will not lead to eventual agreement between observed and calculated fracture geometries. In this event, there is no model-derived rationale by which the ongoing treatment can be controlled or improved, and the empirical fracture geometry must be used in determining the course of the treatment.

REAL-TIME FRACTURE-DIAGNOSTICS INSTRUMENTATION SYSTEM

Overview

An integrated, real-time instrumentation system consisting of a number of diagnostic subsystems is proposed. A conceptual framework for the system is shown in Figure 2.

To provide this real-time instrumentation system, four diagnostic subsystems have been or are currently being developed. These subsystems, which are to be linked together by a microcomputer network, consist of (1) an internal-fracture-pressure measurement system, (2) a fluid-flow measurement system, (3) a borehole seismic system (BSS), and (4) a surface-electric-potential (SEP) measurement system.

Use of a combination of diagnostic subsystems is required to ensure that all pertinent fracture parameters, which define the fracture geometry, are measured. These subsystems are complementary, and in addition, they provide a certain amount of redundancy in the measurements, through the use of which it is possible to make consistency checks.

The composite instrumentation system will provide not only the at-the-wellbore measurement capabilities afforded by the use of the pressure and fluid-flow diagnostic systems but also the away-from-the-wellbore measurement capabilities made possible by the use of the BSS and the SEP system. In addition, the composite system, in conjunction with the fracture model and the computer-driven diagnostic methodology, will provide the capability to subject the data acquired from all four measurement subsystems to real-time analysis and interpretation. It is these attributes of the proposed system that make it unique.

Diagnostic Subsystems

The vertical distribution of minimum horizontal in situ stress has the greatest influence on fracture height (Warpinski et al, 1982; Thiercelin and Lemanczyk, 1983). Layers with low minimum in situ stress are fractured even with low fracture pressures, while those layers with high minimum in situ stress require high fracture pressures. As a fracture grows in height, pressures and temperatures within each fractured layer readjust in response to the introduction of fracturing fluid, thereby changing the pressure profiles of the fracture interval with time. These changes can be monitored at the wellbore. If sufficient contrasts with respect to horizontal in situ stresses exist, then real-time pressure measurements, coupled with prefac determinations of these stresses, can be used to determine the fracture height (H). Pressure and in situ stress measurements for each layer can be used as inputs to a generalized version of the Simonson model (Simonson et al, 1978), from which an estimate of fracture height can be obtained.

For a vertical fracture with length greater than height, an estimate of fracture width (W) can be made using estimated fracture height, the real-time pressure measurements, and the prefrac measurements of Poisson's ratio and Young's modulus. Width is then calculated using the width equation of Perkins and Kern (Perkins and Kern, 1961). Alternatively, Sneddon's equation (Sneddon, 1946) can be used to calculate width, if the fracture geometry is penny-shaped.

Calculations of both fracture width and fracture height require that fracture pressure be known. Initially, the measured wellbore pressures are used. Pressure at any given point in a fracture, though, depends on fracture height and width and on distance from the wellbore. To calculate far-field fracture parameters, it is necessary to adjust the wellbore pressures for the large pressure drop due to fluid flow along the length of the fracture (Warpinski, 1983). This adjustment requires that fracture length be known.

Fluid-flow measurements provide fracture volume (V), from which fracture length (L) is calculated. Additional parameters required in the calculation include fracture height, width, and the leakoff rate (β), which is determined during the prefrac well tests. Because fracture height and width are needed to calculate length and because fracture length is required to determine the fracture pressure (i.e., the fracture pressure away from the wellbore) used in the height and width calculation, the calculated length is incorporated into the height and width calculations iteratively, until convergence is achieved giving both near- and far-field values for the fracture height, width, and length.

The real-time measurement of pressure and fluid flow is, of course, standard practice in a fracture treatment; however, the use of pressure and fluid-flow measurements in a real-time analytical context is not. Furthermore, using current modeling methods, these at-the-wellbore measurements cannot be used to determine fracture orientation (θ) or the ratio (α) of the lengths of the fracture wings (L_{maj} and L_{min}). To determine these parameters, BSS (Seavey, 1982) and SEP (Bartel, 1978) measurements are made in the near and far fields, respectively. The BSS and SEP measurements are essentially away-from-the-wellbore measurements, and their incorporation within a real-time instrumentation system is what distinguishes the proposed diagnostic system from that used in standard practice.

Seismic signals generated during treatment are thought to be caused by shear fractures induced by high pore-fluid pressure or possibly by tensile failure at the hydraulic fracture's expanding edge. Potentially, the extent (L and H), orientation (Θ), and asymmetry (α) of the fracture can be inferred from these signals.

One vertical and two horizontal geophones monitor the seismic activity downhole. The responses of the geophones are functions of the angle of incidence of the seismic signal's compressive component. From these responses the azimuth and inclination of the seismic source can be determined. The direction from which the signal approaches, however, is ambiguous by 180° (i.e., θ or θ + 180°); this ambiguity can be overcome by fielding two or more borehole seismic packages in different wells.

The SEP technique measures variations in the electrical contrasts of the earth, in this case resistivity contrasts that result from the flow of conductive fracturing fluids into the earth. By measuring potential gradients during fracturing, fracture azimuth (θ) and asymmetry (α) can be inferred.

In the SEP technique, pulses of current are injected into the treatment well/fracture combination, and a remote well casing 1 to 2 miles away acts as the return electrode. The induced potential distribution is measured at the earth's surface, on the circumferences of concentric circles located around the fracture well. As a fracture grows, the conductive fracture fluid filling it alters the induced surface electrical potentials around the fracture well. The potential gradients associated with pairs of probes (one probe at each radius) are measured as the fracture develops.

A composite instrumentation system that includes BSS and SEP capabilities has been discussed for a multiwell stimulation experiment (Hart et al, 1983). The fielding of the composite system and the operational procedures associated with its use are described. This description provides an example of how the proposed real-time instrumentation system might be deployed in the field.

SUMMARY AND STATUS

A fracture-diagnostics system with real-time capability offers an opportunity to control the treatment during fracturing. In the real-time system, fracture parameters are predicted prefrac just as they are in current treatments. However, once fracturing has commenced, the real-time instrumentation, consisting of an integrated system of fracture-diagnostic subsystems, measures the fracture parameters in real time. Measured and predicted parameters are compared and necessary revisions to the treatment are made to ensure that the fracturing process is leading to the desired fracture geometry.

Current efforts to develop a real-time instrumentation system are focused on (1) developing the real-time capabilities of each of the separate diagnostic subsystems, (2) solving the problems associated with the integration of these subsystems into a complete real-time system, and (3) testing the system in the field. The fracture-diagnostics system will be tested in a series of stimulations to be conducted in the Multi-Well Experiment (MWX). The combined use of three closely spaced wells, comprehensive core and logging programs, and extensive in situ stress measurements and geophysical surveys will make the MWX (Northrop and Sattler, 1982) an ideal field laboratory for testing the real-time fracture-diagnostics system.

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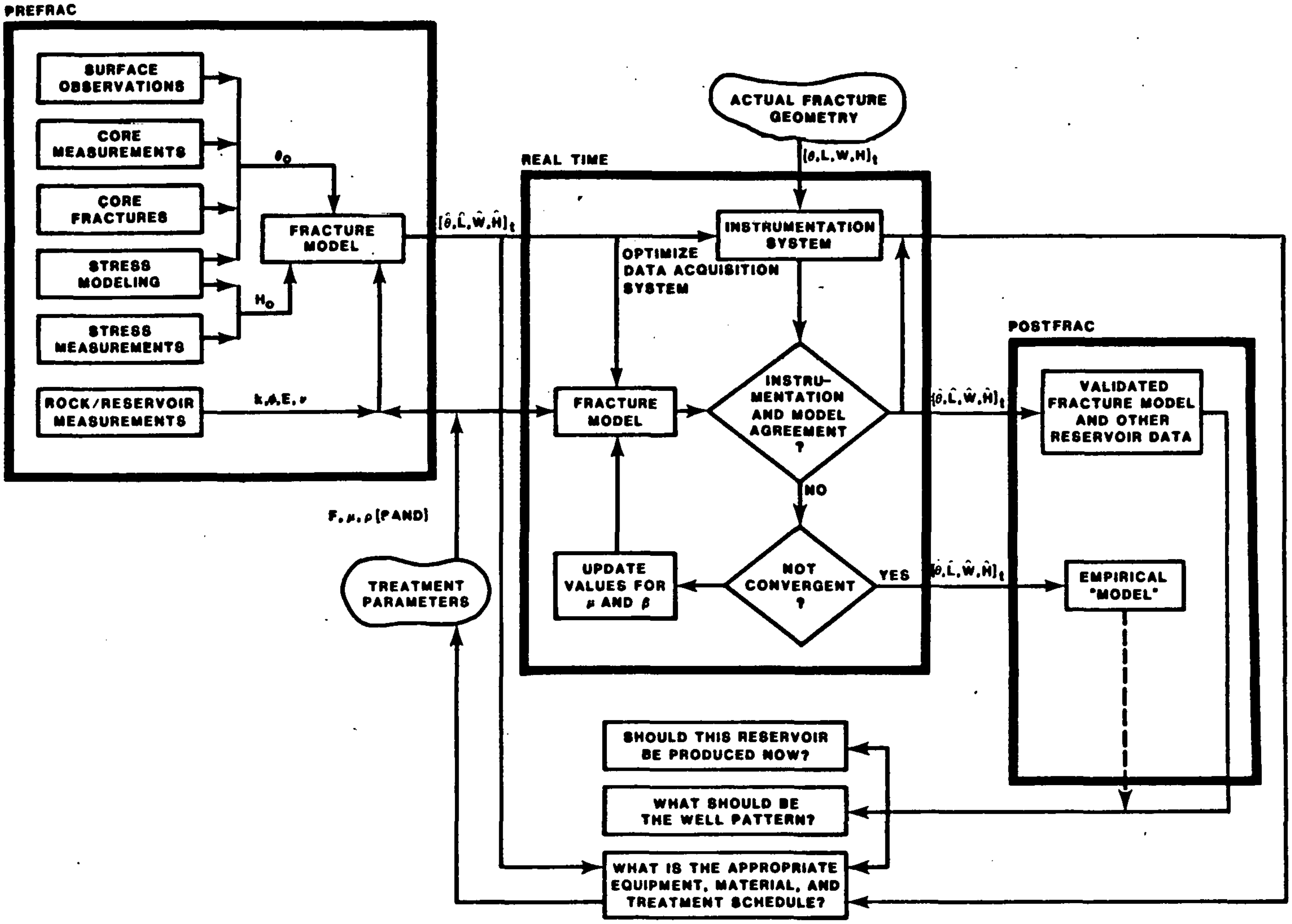

Figure 1. Flow Diagram Showing the Use of a Real-Time Instrumentation System in the Control of the Fracturing Treatment and Fracture Geometry

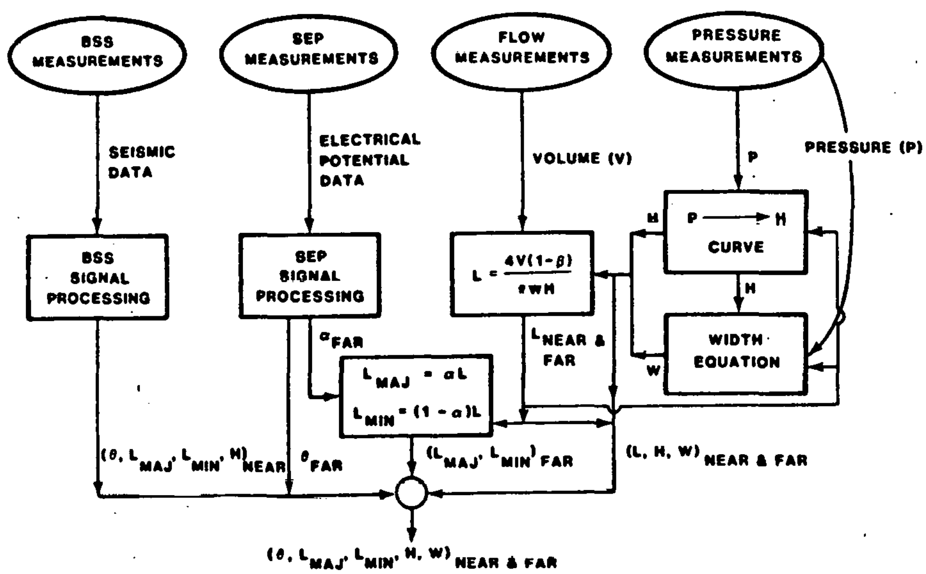

Figure 2. Real-Time Fracture-Diagnostics Instrumentation System