DEVELOPMENT OF RESERVOIR CHARACTERIZATION TECHNIQUES
AND PRODUCTION MODELS FOR EXPLOITING NATURALLY
FRACTURED RESERVOIRS

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Abstract

Development Of Reservoir Characterization Techniques And Production Models For Exploiting Naturally Fractured Reservoirs

For many years, geoscientists and engineers have undertaken research to characterize naturally fractured reservoirs. Geoscientists have focused on understanding the process of fracturing and the subsequent measurement and description of fracture characteristics. Engineers have concentrated on the fluid flow behavior in the fracture-porous media system and the development of models to predict the hydrocarbon production from these complex systems. This research attempts to integrate these two complementary views to develop a quantitative reservoir characterization methodology and flow performance model for naturally fractured reservoirs.

During the current reporting period, research has continued on characterizing and modeling the behavior of naturally fractured reservoir systems. This report proposes a model to relate the seismic response to production data to determine crack spacing and aperture, provides details of tests of proposed models to obtain fracture properties from conventional well logs with actual field data, and verification of the naturally fractured reservoir simulator developed in this project. The project is progressing in an orderly manner.

Executive Summary and Introduction

Many existing oil and gas reservoirs in the United States are naturally fractured. It is estimated that from 70-90% of the original oil and gas in place in such complex reservoir systems are still available for recovery, provided new technology can be implemented to exploit these reservoirs in an efficient and cost effective manner. Enhanced oil recovery processes and horizontal drilling are two fundamental technologies which could be used to increase the recoverable reserves in these reservoirs by as much as 50%. This research is directed toward developing a systematic reservoir characterization methodology which can be used by the petroleum industry to implement infill drilling programs and/or enhanced oil recovery projects in naturally fractured reservoir systems in an environmentally safe and cost effective manner. It is anticipated that the results of this research program will provide geoscientists and engineers with a systematic procedure for properly characterizing a fractured reservoir system and a reservoir/horizontal wellbore simulator model which can be used to select well locations and an effective EOR process to optimize the recovery of the oil and gas reserves from such complex reservoir systems.

The focus of the research is to integrate geoscience and engineering data to develop a consistent characterization of the naturally fractured reservoir. During the current reporting period effort has focused on relating the seismic response to production data to obtain reservoir properties, testing a proposed model for obtaining fracture properties from well logs, and enhancing and testing a naturally fractured reservoir simulator developed in this project. Overall, the project is proceeding in an order fashion.

An approach for relating the seismic response to the observed production and/or production tests has been developed. The foundation of the idea is based upon a simple model of the permeability. The crack porosity occurs in both the model for the permeability and the seismic response. In the elastic models used in this study, the seismic response is dependent upon the both the orientation and the crack porosity of the fractures in place. The permeability controlling the production depends upon crack porosity and the aperture as well as a correction factor related to the geometric aspects of the fractures. The correction factor adjusts for those phenomena not included in the simple permeability model. When and if the correction factor can be determined for a particular lithology and location, the simultaneous measurement of the seismic response (which yields the crack porosity and orientation) and the production (permeability) leads to a prediction of the crack spacing and aperture. The crack spacing and aperture are required for predicting the performance of fractured reservoirs. This means that at well positions, both the fracture apertures and spacing can be determined by combining seismic measurements and production tests.

In order to predict fracture aperture and spacing away from well control, a measure relating seismic attenuation to permeability is being developed. Preliminary work in this direction indicates the potential for mapping fracture aperture and spacing throughout the reservoir using the seismic response. The production well control in this circumstance offers confirmation and calibration of the data for the characterization of the reservoir. The key to calibrating the seismic (elastic and anelastic) is the production and/or production tests.

Conventional well logs may be used for fracture detection since they often exhibit abnormal values in response to fractured zones within a borehole. However, the response of conventional well logging tools is affected only indirectly by the presence of fractures. A genetic algorithm has been used to obtain fracture density and aspect ratio through the inversion of

fractured reservoir rock models using the model proposed by O'Connell and Budiansky (1977, 1984). In addition, a Fuzzy Inference System has been developed to analyze a suite of well logs to estimate the fracture index. During this period, efforts have focused on testing these proposed log analysis methods to obtain fracture properties. The models appear to provide information on the extent of fracturing but it is unclear how to quantify that information at this point in the project.

Work continues to progress on developing a naturally fractured reservoir simulator for use in a PC environment. During the current reporting period, work has focused on developing models to describe the transfer of fluids between the matrix and fracture system and implement them in the simulator. The effort has centered on testing the naturally fractured reservoir simulator to ensure the mathematical computations are correct. This is accomplished by comparing the simulator results to analytical solutions and commercially available simulator results.

Results and Discussion

For many years, geoscientists and engineers have undertaken research to characterize naturally fractured reservoirs. Geoscientists have focused on understanding the process of fracturing and the subsequent measurement and description of fracture characteristics. Engineers have concentrated on the fluid flow behavior in the fracture-porous media system and the development of models to predict the hydrocarbon production from these complex systems. This research attempts to integrate these two complementary views to develop a quantitative reservoir characterization methodology and flow performance model for naturally fractured reservoirs.

During the current reporting period, a method is proposed to relate the seismic response to production data to determine crack spacing and aperture, models to obtain fracture properties from conventional well logs are tested with actual field data, and the final developments of the naturally fractured reservoir simulator are tested. Details of the activities conducted during this period are discussed in the following sections.

Task I. Characterize Fractured Reservoir Systems

The flow properties of a porous rock influence the seismic response because of pore pressure communication (Xu, 1998). Pore pressure influences the elastic properties by resisting the external stresses. The time scale for pressure communication contributes to the frequency dependence of the elastic properties. Pore pressure and pore geometry influence the degree of fluid movement during the passage of a wave. It is this fluid movement that contributes to the attenuation of the wave.

In this portion of the project poroelastic models accounting for the pore fluid (single phase) movement via a permeability tensor were used to predict the intrinsic attenuation of a fractured medium. The model requires the permeability tensor, the length scales for the fluid movement (Squirt-flow tensor) and the stiffness matrix (drained).

The objective of using the poroelastic models was to utilize the seismic response to predict important flow properties for reservoirs. Here the emphasis is upon the attenuation and its relation to the permeability of the formation. This study has illustrated how knowledge of the attenuation within a fractured reservoir can be utilized to predict fracture aperture and spacing throughout the reservoir.

The report begins with a brief review of how to calibrate the elastic component of the seismic response. This calibration phase is not always necessary, but doing so yields an estimation of the specific crack compliance using known values of the crack porosity. Next, a description is given of how to combine the seismic (elastic component) and well tests to obtain fracture aperture and spacing at a well position. The report ends by showing how combining the total seismic response (elastic and attenuation) can be used to obtain fracture aperture and spacing throughout the field.

Calibration Of The Elastic Component Of The Seismic Response. One simple model for the elastic compliance of a rock fractured by a single set of fractures with normal components, n_i , can be written in the form (Schoenberg and Sayers, 1995)

$$S_{ijkl}^c = \frac{Z}{4} (n_j n_k \delta_{il} + n_j n_k \delta_{il} + n_j n_k \delta_{il} + n_j n_k \delta_{il}) \dots\dots\dots 1$$

where the Z factor is referred to as the specific compliance of the cracks. A number of popular models describe the specific compliance as a function of the crack density (e.g., Hudson, 1980, 1981). Brown et al. (2001) have suggested that specific crack compliance can be proportional to the crack porosity. Using K as the constant of proportionality, the specific compliance can be written in the form

$$Z = K \phi_c \dots\dots\dots 2$$

Schoenberg and Sayers (1995) prescribe a number of useful formulae to calibrate the specific compliance in terms of a factor δ that controls the P-wave and S-wave anisotropy. For example, if δ is known along with the shear modulus of the matrix (μ), the constant K in the prescription of the specific compliance can be determined using

$$Z = K \phi_c = \frac{\delta}{\mu (1-\delta)} \dots\dots\dots 3$$

One way to calibrate this expression, i.e., estimate Z, is to measure the shear wave splitting for a fractured rock with known crack porosity. In the example used for this report, a 10% shear wave splitting is assumed for crack porosity of 5%.

$$Shear_Wave_Splitting_Fraction = 1 - \sqrt{1-\delta} \dots\dots\dots 4$$

This leads to an estimate of Z following Brown et al. (2001).

Fracture Aperture and Spacing. Engineers need more information about the fractures than a simple statement about fracture permeability. They also need input on the fracture aperture and spacing in order to help predict reservoir performance. In addition, they require some estimate of the coupling between the matrix and the fractures in terms of the flow. One approach to estimating the aperture and spacing using production data or testing is described in this section (Brown et al., 2001).

Fig. 1. Schematic of Combining Seismic and Production Data to Obtain Fracture Properties.

A simple model for the permeability of a fractured system is to assume Eq. 2 applies to the flow through the cracks (see for example, Oda (1985)). A is the aperture of the cracks and ϕ_C is the crack porosity. The n_i are the components of the normal to the crack set.

$$k_{ij} = \frac{A^2 \phi_C}{12} (\delta_{ij} - n_i n_j) \dots \dots \dots 5$$

This idealistic equation can be applied to a realistic fracture system following the type of approximations used by Oda (1985) or Brown and Bruhn (1998).

$$k_{ij} = \lambda(\phi_C) A^2 \phi_C (\delta_{ij} - n_i n_j) \dots \dots \dots 6$$

where λ is a correction factor accounting for the roughness of the fractures, their connectivity and other aspects not taken into account by the ideal equation. It is assumed for the moment to be some function of the crack porosity (Brown and Bruhn, 1998). Now we are in a position to estimate the apertures of the fractures by combining the seismic response along with production or well test data.

Fig. 2. Schematic for Determining the Fracture Spacing.

Once the aperture (A) is found from well testing and seismic (elastic) the fracture spacing (L) can be found from the formula for the crack porosity of a series of parallel fractures.

$$\phi_C = \frac{A}{L + A} \dots\dots\dots 7$$

Thus by combining a seismic estimate of crack porosity and production data or well testing estimates of permeability yields an estimate of the crack apertures and spacing at a well site can be obtained. Unfortunately, finding the aperture and spacing at the well site is not sufficient for describing the long term performance of a fractured reservoir. Estimates of the aperture and spacing are required throughout the reservoir.

Fig. 3. Depiction of Matrix to Fracture Fluid Transfer.

Replacing Well Tests With Measurements of Seismic Attenuation. In order to predict the permeability, aperture and spacing throughout a fractured reservoir, a seismic method of measuring the permeability is required. This can be accomplished by establishing a model for relating the permeability to the seismic attenuation.

One model for relating seismic attenuation is the Biot/Squirt model. The model does not account for all aspects of the problem but does offer an applied approach to the problem that can be useful for actual applications. Like the other simple models discussed in this report, calibration is required. However, the Biot/Squirt model involves length scales of fluid movement that are not typically accounted for in a strict Biot treatment of a poroelastic medium (e.g., Schmitt, 1989).

The Biot/Squirt formulation is obtained by extending the equations of Biot (1956, 1962) following ideas described by Dvorkin and Nur (1993) to account for local flow. Kazi-Azoual et al. (1988) and Parra and Xu (1994) have extended these ideas to anisotropic models. The computations for the Biot/Squirt plots presented in this report were made by J. Parra and P. Xu and presented by Brown et al. (2001).

The equations set up for this model lead to a set of coupled differential equations and an uncoupled partial differential equation (Parra, 1997, 2000). Plane wave solutions are sought that lead to estimates of the phase velocity and attenuation. These solutions can be used in full waveform modeling studies (Parra, 2000). The resultant model gives a prediction of the velocity and attenuation of the waves.

The basic idea of these equations is to account for additional fluid motion not taken into account in the original Biot equations. The input parameters for the model are the permeability tensor, the length scales for the fluid movement (Squirt-flow tensor), and the stiffness matrix (drained).

Two example computations are given in the figures. Notice that the largest attenuation takes place when the waves are traveling perpendicular to the fractures. Also note that the larger scale local flow moves the attenuation peak into the surface seismic frequency range.

Fig. 4. Comparison of Attenuation.

The Biot/Squirt model is based upon the assumption that the effective permeability controlling local flow is the same as the permeability controlling the reservoir performance. We recognize the potential limitations of this assumption. In addition, the model does not account for the effects of “local heterogeneity” and does not include the effects of different types of elastic scattering from such a heterogeneity. Finally, the model does not account for the kind of sensitivity to saturation reported for shear waves (e.g., Xu, 1998, Brown et al., 2001) at high frequencies.

In spite of these limitations, the model gives a practical approach to the difficult problem of predicting the P-wave attenuation associated with fractured reservoirs. Previous work by Parra (1997) and Parra et al.(2000) using well control and core data have illustrated the

applicability of the model with VSP and crosswell data. The flexibility of the model originates from the assignment of the local flow length scales (the squirt-flow tensor) to match the observed attenuation. This model gives a direct estimate of the intrinsic attenuation without the contamination of elastic scattering effects.

The assignment of local flow length scales can be done by combining well control and seismic attenuation measurements of permeability at the well. Once the squirt-flow lengths have been assigned for a particular lithology/field, the squirt-flow tensor can be assumed to remain constant throughout the field. This does not mean that the fracture orientation is constant. In this way the permeability can be mapped via seismic attenuation measurements away from the well control. The problem remains of determining a practical approach to estimating the attenuation associated with fractured reservoirs.

Summary. The specific compliance of a fracture set is controlled by the crack compliance and can be calibrated when the crack porosity is known via other means. Once this calibration has been accomplished, the elastic portion of the seismic model can be used to estimate the crack porosity. By combining seismic determinations of the crack porosity at well positions with production data or tests at the wells, the fracture apertures and spacing can be determined. Finally in order to predict fracture aperture and spacing away from the well control, additional information is required. One approach is to use seismic attenuation as a measure of the permeability throughout the field. Our models are necessarily oversimplified at this point, but they offer a practical foundation for actual implementation. More detailed models are required that better define the physical relationship between the small scale reservoir properties and the larger scale seismic and production response.

Task II. Develop Interwell Descriptors of Fractured Reservoir Systems.

In previous progress reports, a self-consistent physical model based on the theory of O'Connell and Budiansky (1984) was reported as well as a model based on the Fuzzy Logic computer science technique. Both models use conventional well logs to obtain parameters that try to characterize fracture parameters that can be related to flow properties for use in numerical simulators. The O'Connell and Budiansky model uses a genetic algorithm to obtain the crack density (ε) and aspect ratio (α). Mavko, et al. (1998) have shown that once ε and α are known, crack porosity can be computed using:

$$\phi_c = \frac{4}{3} \pi \varepsilon \alpha \dots\dots\dots 8$$

A complete description of the O'Connell and Budiansky algorithm can be found in the January 2001 Semiannual Technical Progress Report and in paper SPE 67280 (Martinez, *et al*, 2001). The Fuzzy Inference System obtains a fracture intensity index and is described in the July 2001 Semiannual Technical Progress Report.

Both models were run using a synthetic example and a field case where the level of fracturing was unknown. Geologic characterizations of cores from the Frontier formation in Wyoming, the Mesa Verde formation in Colorado and the Austin Chalk formation in Texas were obtained from John Lorenz at Sandia National Labs. After contacting the current operator of the wells, the only logs available were for a well in the Austin Chalk formation. For this reporting

period, the majority of this task was spent processing these logs and comparing the geologic characterization of the core with the fracture density and aspect ratio of the O'Connell and Budiansky model and the fracture index from the fuzzy logic model.

Boreholes that are suitable for case study are rare. In order to apply the Fuzzy Inference Algorithms, several conventional well logs that are useful for fracture detection must be available, and in order to apply O'Connell and Budiansky inverse algorithm, the suite of logs available must be complete enough to allow for the calculation of the lithology and saturations. Data quality must be carefully examined since reliable log information cannot be obtained under adverse borehole conditions. Additionally, some calibration of the log results to actual data is recommended. In order to do so, the borehole must either be continuously cored, or contain a detailed imaging log that can be used for comparison.

Well Description

The Mills-McGee well #1 is located in Milam County, TX in the Giddings field (Figures 5 and 6). The Giddings (Austin Chalk-3) Field produces from the Cretaceous Austin Chalk formation (Railroad Commission of Texas, 1997). In the area of the well, the formation produces from fine-grained limestone and chalk. Productivity and fluid flow directions are predominantly controlled by the presence of fractures.

High quality geological and geophysical data was acquired for the Mills-McGee #1 well. This well was drilled by The Union Pacific Resources and is now operated by Anadarko Petroleum Corporation. The well had a comprehensive suite of state-of-the-art logs and 220 ft of core was obtained. The well log data was provided to this study in digital format. Well logs used in this study are listed in Table 1. Only those logs that are known to be affected by the presence of fractures were chosen for this analysis. The original well log data is displayed in Figures 7–9. Special core analysis characterizing the natural fractures for the well was provided by Lorenz (1997).

Fig. 5. Top Producing Oil and Gas Fields in Texas

Fig. 6. Giddings (Austin Chalk - 3) Field Map

Table 1: Well Logs available for the Mills McGee Well #1

Well logs	Fracture detection significance
Caliper	Registers borehole enlargement that may be caused by the presence of fractures.
Spontaneous Potential	It may indicate the presence of fractures, but, it is not consider a reliable fracture detection tool. (Schlumberger Ltd., 1989)
Gamma Ray	Without the spectral gamma ray data, the gamma ray log by itself is not conclusive in fracture detection.
Bulk Density	Open fractures filled with drilling fluid may cause a reduction in bulk density (Fertl, et al, 1980).
Density correction	It is considered one of the best fracture detection tools among the conventional well logs (Serra, 1986)
Photoelectric factor	Has been recognized as a useful fracture detection tool (Schlumberger Ltd, 1989)
Sonic transit time	Fractures are know to cause cycle skipping (Bassiouni, 1994)
Shallow/Deep Induction combination	The resistivity of the deep induction tool will exceed the one for the shallow induction tool
Spherically Focused Log	Often exhibits erratic values in the presence of fractures, but is sensitive to poor borehole conditions. (Schlumberger, 1987)

Fig. 7. (a) Caliper, (b) SP, (c) Gamma Ray and (d) Δt logs.

Fig. 8. (a) Neutron and Density Porosities, (b) Bulk Density, (c) Δ Bulk Density and (d) Resistivity Logs.

(a)

(b)

Fig. 9. (a) Induction and (b) PEF logs.

Description of Fractures in the Mills McGee #1 Core. Lorenz (1997) describes two categories of fractures that were recognized in the Mills McGee #1 well: 1) “Hairline fractures, which are healed, fully mineralized fractures 0.1 mm or less in width; 2) Semi-open fractures which are somewhat wider than hairline fractures. These two fracture types occur in the same zones and are not naturally exclusive. They are inferred to be components of a single fracture population since they have similar characteristics. Unfortunately mechanically induced fractures were identified from the cores but excluded from the analysis.

The caliper log displayed in Figure 7(a) shows that although this is a well in a fractured formation, the borehole does not present any enlargement in the zone between 5860 and 6040ft. The good borehole condition makes the well log measurements very reliable. The conventional SP log is presented in Figure 7(b). It is possible to observe several zones with an erratic SP behavior presumably due to the presence of fractures. The behavior of the gamma ray log as shown in Figure 7(c) is not a conclusive fracture indicator. The peaks that this log displays in the interval between 5870ft and 6010ft might be due to thin shale beds or to the presence of fractures. Figure 7(d) shows the sonic log, in this case cycle skipping is not clearly observed, and the compressional travel time values are those corresponding to chalk/shale lithology.

Neutron porosity and density porosity are presented in Figure 8(a). In this case the density porosity value does not report high changes. On the other hand, the neutron porosity is not as smooth as the density porosity, possibly due to the presence of fractures. Figures 8(b) and 8(c) present the density and density correction logs. The density log reports an almost constant value of bulk density in the interval between 5870 and 6070ft., however, the density correction log reports high correction values in the interval between 5850 and 5940ft. Since the caliper in this interval reports a gauge hole, the abnormalities in the density correction values may be due to the presence of fractures in this interval.

Figure 8(d) presents the resistivity logs; AT10, AT60, and AT90. AT10 is the shallow resistivity log while AT90 is the deep resistivity log. It is possible to observe some separation between the shallow and deep resistivity logs, especially between 5860 and 5920ft., however in general, in the interval analyzed, there is no significant separation between the two resistivity measurements.

Induction logs are shown in Figure 9(a). In fractured formations these logs indicate the presence of fractures if the SFL (spherically focused log) reads less than the ILD (deep induction log); according to this criteria, it is possible to distinguish several fractured zones in this interval. The photoelectrical index log is shown in Figure 9(b). This log reports a fairly constant value in the range between 4.5 and 5.5, which is in agreement with the lithology expected in this well.

No individual log shows fracturing directly, but through the use of the FIS, it is possible to infer the presence of fractures in the well analyzed. The processed logs used in the Fuzzy Inference System are shown in Figures 10–12, along with the locations of open and semi-open fractures reported in the core analysis.

The FIS was applied under six different scenarios (set of rules). Figures 13–14 report the results obtained for the different cases. The rules for each one of the cases are presented in Table 2. Each set of rules is defined arbitrarily based on the discussion about the effects of fractures on the different logs presented in the July 2001 Semiannual Technical Progress Report for this project.

(a) (b) (c) (d)

Fig. 10. Processed Logs (a) Caliper, (b) Gamma Ray, (c) SP and (d) Sonic Travel Time.

Fig. 11. Processed Logs (a) PEF, (b) $\square$ Bulk Density, (c) Bulk Density, (d) Neutron Porosity – Density Porosity.

Fig. 12. Processed Logs (a) SFL, (b) Medium to Deep Ratio, (c) Shallow Induction and (d) Shallow Induction log to Deep Induction log ratio.

Fig. 13. Fuzzy Inference System Cases 1 – 4 (See Table 2 for Rules).

Fig. 14. Fuzzy Inference System Cases 5 and 6 (See Table 2 for Rules).

Table 2: Set of Rules used in the different cases for the FIS.

<p>CASE 1 IF SFL is high and AT10/AT90 is high THEN FI is high IF DRHO is high and PEF is high THEN FI is high</p> <p>CASE 2 IF DT is high and DRHO is high and CAL is high THEN FI is high IF GR is high and SP is high and SFL is high THEN FI is high IF DRHO is high and CAL is medium THEN FI is high</p> <p>CASE 3 IF DT is high and SFL is high THEN FI is high IF PEF is high and DRHO is high THEN FI is high IF AT10/AT90 is high and ILD/ILM is high THEN FI is high</p> <p>CASE 4 IF GR is high and PE THEN FI is high IF DT is high and SFL high THEN FI is high IF NPOR - DPHI is high and DRHO is high THEN FI is high</p> <p>CASE 5 IF CAL is high and GR is high and SP is high THEN FI is high IF DT is high and GR is high THEN FI is high IF DT is high and SP is high THEN FI is high</p> <p>CASE 6 IF CAL is high and GR is high and SP is high THEN FI is high IF DT is high and GR is high THEN FI is high IF DT is high and SP is high THEN FI is high IF SFL is high and GR is high and SP is high THEN FI is high IF SFL is high and AT10/AT90 is high THEN FI is high</p>
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Figures 15(a – c) present the results obtained using O’Connell and Budiansky inverse model. Figure 16(d) combines the results obtained for Case 6 of the FIS (the scales have been reduced from 0-1 to 0-0.01), and the fracture porosity. The fractures reported by the core description are displayed in the figures as dots. Only open and semi-open fractures are shown. Hairline fractures are not displayed because they are very numerous, most of them are sealed, and they are not analyzed in the core description.

Discussion. From the caliper log, it is possible to say that the borehole does not present any major enlargement due to fractures; this fact makes the suit of logs more reliable for the analysis.

For the six cases analyzed using FIS, there is good correlation between the fracture detection algorithm and the core analysis, specifically in the interval between 5910 and 5930 ft.

All the cases presented in Figures 13–14, are able to recognize that interval as one with high fracture presence.

The correlation between the core analysis and the log analysis for the set of fractures between 5965 and 5990 ft is not as clear. The only case that is detecting this fractured zone is Case 3, however this case has a high noise level, which makes this combination of rules poorly suited for a FIS for fracture detection.

Case 5 does not seem to be the most appropriate set of rules for the fracture detection algorithm. This indicates then, that caliper, gamma ray and spontaneous potential logs are not conclusive tools for fracture detection.

The fractured interval reported by the core analysis between 5965 and 5975 ft is not recognized by any of the cases analyzed. This may indicate erroneous core description or, more likely, a depth shift in the core analysis.

The high fracture frequency observed in zones where core analysis does not report fractures might indicate the presence of mechanically induced fractures that are excluded from the core description. However, the FIS algorithm may be responding to hairline fractures that are not accounted for in the core description provided.

Case 6 seems to be the most appropriate in this specific example. Case 6, besides having the same rules as Case 5, has two additional rules involving the resistivity and the SPF log. It is then possible to conclude that induction and resistivity logs play a very important role in detecting fractures for this case.

The fracture porosity reported in Figure 15(c), clearly identifies several of the high fracture frequency zones reported by the core analysis, specifically the following intervals: 5920–5925 ft and 6000–6007 ft. However, there are zones where it is difficult to correlate the fracture porosity obtained with the O’Connell and Budiansky model and the one reported by the core analysis. The main reason that can explain this difficulty is the presence of more than 700 hairline fractures that are not classified as open or semi-open fractures in the interval analyzed and may be affecting the fracture porosity results obtained. The whole interval reports a relatively high crack density and fracture porosity that may be reflecting the presence of a high number of hairline or mechanically induced fractures.

From Figure 15(d), it is possible to observe a fairly good correlation between the results obtained with the FIS and the inversion of O’Connell and Budiansky model in most of the intervals where the FIS reports a high fracture intensity index. This may lead us to the conclusion that the FIS system proposed might be used as fracture porosity indicator.

Discrepancies between core description of fractures and indicators of fractures using well logs are expected, due to a number of factors such as:

- Fracture indicators are based on well log data that reflect bulk rock properties up to several feet away from the borehole while the core analysis is only reflecting the characteristics of the borehole itself.
- In highly fractured zones it is difficult to obtain reliable core samples.
- Shifts between recorded core depths and well log depths (due to unfilled space in the core barrel, core expansion, stretch in the wireline logging cable, operator error, etc.).

Fig. 15. O'Connell and Budiansky model results (a) Fracture Density, (b) Aspect Ratio, (c) Fracture Porosity and (d) Fracture Porosity with Fracture Index from FIS Case 6.

Remaining Work

Both models appear to be providing some information on the extent of fracturing, but it is unclear at this point how to quantify exactly what that information is. The next phase of the work will be to continue to find ways to use the two models to quantify both the accuracy and the uncertainty involved with using conventional well logs to estimate fracture properties. In addition, there is a need to be able to relate the information from these models and more sophisticated (Formation MicroScanner and Borehole Televiewer) log information to data collected at the surface- or crosswell-seismic scale. Also, work needs to be performed that relates this same information to flow properties for use in numerical simulation.

Task III. Develop Wellbore Models for Fractured Reservoir Systems.

This work is complete. The models have been implemented in the reservoir simulator and have been tested. Refinement is on going as the simulator is tested and enhanced pending testing when the reservoir simulator is fully developed. Details have been provided in earlier semi-annual reports.

Task IV. Reservoir Simulator Development/Refinement and Studies.

This task has focused on developing a naturally fractured reservoir simulator for use in analyzing the performance of naturally fractured reservoirs. The effort has included the implementation of Evans' (1982) model for naturally fractured reservoirs into an existing homogeneous reservoir simulator. Because of its simplicity and the accessibility of its source code, BOAST-VHS available from the US Department of Energy (Chang) was selected and modified. The final version of the modified BOAST-VHS has been called BOAST-NFR. The name BOAST-NFR was selected to identify this new modification of BOAST in order to provide a direct relation of the BOAST source code to the naturally fractured reservoir application.

Modification Process

The original BOAST-VHS code was translated from FORTRAN to Visual Basic (VB) and implemented in macros in an Excel-VB environment. Several runs were performed to verify the results from the converted simulator code with the original simulator. This translation was undertaken to assist in providing a PC-based simulator that can be easily implemented without a major investment in computer hardware or software. The ability to use a simple spreadsheet application for data input and output will allow the user the ability to use the graphics capability of the spreadsheet software for visualizing the results, eliminating the need for a sophisticated graphics package.

After verifying the translated code, the simulator was modified to handle the fracture system. To accomplish this, the BOAST formulation was compared with Evan's formulation for a naturally fractured reservoir. It was found that the formulations were similar and equation discretization followed a similar process, except terms that contain the non-diagonal part of the fracture permeability tensor. The partial differential equations were solved using finite difference approximations in the same way BOAST equations were discretized. The modified version also uses an IMPES solution of the resulting set of linear equations. The simultaneous solution of pressure equations for the fracture and the matrix is handled using LSOR.

The modified simulator, BOAST-NFR, has the following capabilities.

1. Numerical simulation of oil and gas recovery by fluid expansion, displacement, gravity drainage, and imbibition mechanisms.
2. Rectangular grid-blocks with variable dimensions.
3. Zero transmissibility option (inactive grid blocks and faults).
4. Simulation of tilted reservoirs by specifying the elevations to top of grid-blocks.
5. Porosity and permeability distributions for matrix and fracture systems. For fracture permeability, simulator requires a full tensor.
6. Inter-porosity flow rate calculation for single and multiphase fluids using constant shape factors.
7. Different relative permeability and capillary pressure tables for matrix and fracture systems. One table for each system is needed.
8. Pore matrix and fracture compressibility as function of pressure.
9. Oil-water-gas PVT tables for reservoir fluids.
10. Bubble point pressure tracking scheme.
11. Pressure and saturation initialization for both porous media.
12. Automatic time-step control.
13. Option for automatic control of LSOR acceleration parameter.
14. Material balance check on solution stability.
15. Vertical, horizontal and slant wells with specification of rate or pressure constraints on well performance. Horizontal wells can be produced with different wellbore conductivity by using either infinite conductivity or uniform flux.
16. No restrictions regarding the number of iterations, gridblocks, and wells.
17. Additional or re-completion wells during the period represented by the simulation.

Simulator Performance Tests. After completion of the simulator, extensive testing has been undertaken to verify the new simulator. Initial testing compared the numerical results obtained from BOAST-VHS and its modified version, BOAST-NFR, to ensure that the new simulator could duplicate the homogeneous reservoir case.

Simulator performance was first compared using a single-phase fluid in a reservoir drilled by a vertical or a horizontal well. Then, two-phase flow in the reservoir was allowed by injecting either water or gas through an additional well. Finally, the effect of fractures was tested in single- and two-phase fluid flow problems. In these tests, the effect of mass transfer between matrix and fracture media on fluid flow was not explored.

Single-phase Flow, Vertical Producer. Both simulators (VHS and NFR) were run twice simulating a vertical producer in a homogeneous reservoir. During the first run, the well was depleted at a constant flow rate while the second run was done at a constant bottomhole pressure. The description of the wells is shown in Table 3. For comparison purposes, the changes in average pressure and oil flow rates versus time were plotted in Figs. 16 and 17. BOAST-NFR gives yielded similar results to BOAST-VHS. There were some differences in the amount of iterations and time required for simulation; however, those differences are attributed to the programming languages in which the simulators were created.

Table 3. Vertical Well Description

Run	Well Type	Fluid Type	Location			Constant Parameters			
			X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
1 st	Producer	Oil	5	2	1	1000	---	---	---
2 nd	Producer	Oil	5	2	1	---	---	---	800

Fig. 16. Average reservoir pressure vs. time at constant oil flow rate, $Q_o=1000$ STB/D.

Fig. 17. Average reservoir pressure and oil flow rate vs. time at constant bottomhole pressure, $p_{wf}=800$ psia.

Single-phase Fluid, Horizontal Producer. As with the vertical producer, two runs were used to simulate a horizontal oil producer at constant oil flow rate and bottomhole pressure. The description of the wells for the two runs is shown in Table 4. Again, average reservoir pressures and oil flow rates versus time were plotted in Figs. 18 and 19. As seen in the figures, both simulators provided similar results.

Table 4. Horizontal Well Description

Run	Well Type	Fluid Type	Location of Intercepted Blocks			Constant Parameters			
			X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
1 st	Producer	Oil	3	2	1	200	---	---	---
			4	2	1				
			5	2	1				
			6	2	1				
			7	2	1				
2 nd	Producer	Oil	3	2	1	---	---	---	800
			4	2	1				
			5	2	1				
			6	2	1				
			7	2	1

Fig. 18. Average reservoir pressure vs. time at constant oil flow rate, $Q_o=200$ STB/D.

Fig 19. Average reservoir pressure and oil flow rate vs. time at constant bottomhole pressure, $p_{wf}=800$ psia.

Two-phase Flow, Vertical Producer and Injector. Four cases were run to test the BOAST-NFR simulator performance with two-phase flow with vertical wells. For all four cases, the same reservoir model used in the single-phase flow, vertical producer case was modified to include both a vertical producer and a vertical injector.

The first two cases were for constant rate oil production with constant rate injection. In one case, water was the injection fluid and gas was the injection fluid in the second case. Table 5 provides the details for the wells. Figs. 20 and 21 present the results for both the naturally

fractured reservoir simulator and Boast-VHS. Once again, the proposed simulator provided similar results.

Table 5. Description of Vertical Wells

Run	Well Type	Fluid Type	Location			Constant Parameters			
			X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
1 st	Producer	Oil	10	2	1	1000	---	---	---
	Injector	water	1	2	1	---	1000	---	---
2 nd	Producer	Oil	10	2	1	1000	---	---	---
	Injector	gas	1	2	1	---	---	500	---

Fig. 20. Average reservoir pressure vs. time for a vertical oil producer at constant oil flow rate, $Q_o=1000$ STB/D, and a vertical water injector at constant flow rate, $Q_w=1000$ STB/D.

Fig. 21. Average reservoir pressure vs. time for a vertical oil producer at constant flow rate, $Q_o=1000$ STB/D, and a vertical gas injector at constant flow rate, $Q_g=500$ MCF/D.

The additional two runs were for the case of constant bottomhole pressure production and injection. Table 6 gives a description of the two wells simulated. The results are given in Figs. 22 and 23. The figures show similar results and indicate BOAST-NFR is performing well and is capable of reproducing the results of BOAST-VHS.

Table 6. Well Description

Run	Well Type	Fluid Type	Location			Constant Parameters			
			X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
1 st	Producer	Oil	10	2	1	---	---	---	500
	Injector	water	1	2	1	---	---	---	1100
2 nd	Producer	Oil	10	2	1	---	---	---	500
	Injector	gas	1	2	1	---	---	---	1100

Fig. 22. Average reservoir pressure and oil flow rate vs. time for a vertical oil producer at bottomhole pressure, $p_{wf}=500$ psia, and a vertical water injector at constant bottomhole pressure, $p_{wf}=1100$ psia.

Fig. 23. Average reservoir pressure and oil flow rate vs. time for a vertical oil producer at bottomhole pressure, $p_{wf}=500$ psia, and a vertical gas injector at constant bottomhole pressure, $p_{wf}=1100$ psia.

Two-phase Flow, Horizontal Producer and Horizontal Injector: Two cases were designed to check the capability of BOAST-NFR at handling horizontal wells. In order for BOAST-NFR to be able to reproduce the results of BOAST-VHS, it was necessary to eliminate the capillary pressures.

The first case considered constant rate injection and production. The characteristics of the wells used in this case are shown in Table 7, and the results of the simulation are shown in Figs. 24 and 25. The first run was done injecting water at a constant flow rate of 1000 STB/D, and producing oil at the same flow rate of 1000 STB/D. The second run was done injecting gas at a constant rate of 500 MCF/D and producing oil at a rate of 1000 STB/D. Both simulations yielded similar results.

Table 7. Horizontal Wells Description For First Run

Well Type	Fluid Type	Location of Intercepted Blocks			Constant Parameters			
		X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
Producer	Oil	3	2	1	1000	---	---	---
		4	2	1				
		5	2	1				
		6	2	1				
		7	2	1				
Injector	Water	3	2	1	---	1000	---	---
		4	2	1				
		5	2	1				
		6	2	1				
		7	2	1

Fig. 24. Average reservoir pressure vs. time for a horizontal oil producer at constant flow rate, $Q_o=1000$ STB/D, and a horizontal water injector at constant flow rate, $Q_w=1000$ STB/D.

Fig. 25. Average reservoir pressure and gas oil ratio vs. time for a horizontal oil producer at constant flow rate, $Q_o=1000$ STB/D, and a horizontal gas injector at constant flow rate, $Q_g=500$ MCF/D.

Two cases were also examined for the constant bottomhole pressure case. The well descriptions for the first run are given in Table 6. The first run was done injecting water at a constant bottomhole pressure of 1100 psia, and producing oil at a bottomhole pressure of 900 psia. The same bottomhole pressures were used in the second run with the difference being that gas was injected instead of water. The results of the simulation are given in Figs. 26 and 27.

Table 8. Horizontal Well Description For First Run

Well Type	Fluid Type	Location of Intercepted Blocks			Constant Parameters			
		X	Y	Z	Q_{oil} (STB/D)	Q_{water} (STB/D)	Q_{gas} (MCF/D)	P_{wf} (psia)
Producer	Oil	3	2	1	---	---	---	900
		4	2	1				
		5	2	1				
		6	2	1				
		7	2	1				
Injector	Water	3	2	1	---	---	---	1100
		4	2	1				
		5	2	1				
		6	2	1				
		7	2	1

Fig. 26. Average reservoir pressure vs. time for a horizontal oil producer at constant bottomhole pressure, $p_{wf}=500$ psia, and a horizontal water injector at constant bottomhole pressure, $p_{wf}=1100$ psia.

Fig. 27. Average reservoir pressure and gas oil ratio vs. time for a horizontal oil producer at constant bottomhole pressure, $p_{wf}=900$ psia and a horizontal gas injector at constant bottomhole pressure, $p_{wf}=1100$ psia.

Single- and Two-phase Flow in the Fracture System. BOAST-NFR was also tested for cases in which only fractures are part of the system. No mass transfer between matrix and fracture is present since no matrix system is used. The purpose was to model the fracture system and validate the implementation of fracture permeability tensors in the finite difference scheme. Two types of test were designed to study a reservoir with single phase and two-phase fluids.

Single-phase Flow: Earlougher (1977) presents data from an interference test analysis published first by Ramey (1975) for an anisotropic reservoir. Earlougher also presented an analytical solution for finding the permeability tensor and the direction of the fractures. The test starts by shutting in 3 of the 4 wells and injecting water through the fourth well at a constant rate. Locations of the wells are shown in Fig. 28. Fluid levels in the shut in well were observed and pressure changes tabulated. Even though a second phase is injected in the reservoir, Earlougher treats the reservoir as having only water flowing in the fracture system and therefore, only uses fluid properties of the water phase.

To check the reliability of BOAST-NFR in interpreting the anisotropy model through fracture permeability tensors, two problems were designed and the results compared with the solution given by Earlougher. One was to match the pressure build-up and the other was to matching dimensionless pressures with the analytical solution.

The first problem was to take the permeability tensor computed by Earlougher and use it as an input parameter in BOAST-NFR. After running the simulator, the pressure changes computed at the shut in wells were compared with the data published by Ramey. Figs. 29-31 show the pressure drops obtained using the simulator as well as the published pressure data. Those plots show that the simulator is able to reproduce the pressure data with a single-phase fluid. Therefore, BOAST-NFR appears to be handling fractures accurately.

$$\Delta X = \Delta Y = 115 \text{ ft}$$

$$\Delta Z = 25 \text{ ft}$$

Fig. 28. Grid system used to numerically model the single-phase problem presented by Ramey (1975).

Fig. 29. Pressure build-up in Well 1.

Fig. 30. Pressure build-up in Well 2.

Fig. 31. Pressure build-up in Well 3.

The second problem was to use pressure drops obtained using the simulator for an extended period of time and compute dimensionless pressures (P_D) using the following equations:

$$P_D \left(\left[\frac{t_D}{r_D^2} \right]_{dir} \right) = \frac{(P_i - P) h \sqrt{k_{max} k_{min}}}{141.2 q B \mu} \dots\dots\dots 9$$

$$\left(\frac{t_D}{r_D^2} \right)_{dir} = \frac{0.0002637 t}{\phi \mu c_t} \left[\frac{k_{max} k_{min}}{(k_x y^2 + k_y x^2 - 2 k_{xy} xy)} \right] \dots\dots\dots 10$$

The dimensionless pressures were then compared with the analytical solution, Eq. 11.

$$P_D = -\frac{1}{2} Ei \left(-\frac{r_D^2}{4 t_D} \right) \dots\dots\dots 11$$

The results are plotted in Fig. 32. The deviation that occurs from the analytical solution (which assumes an infinite reservoir system) at dimensional times greater than 5 is due to

boundary effects. The boundary effects are explained as follows: Once the pressure wave reaches the outer boundary, no fluid entry occurs at the reservoir boundary. This phenomenon is translated into a pressure drop at the boundary that is felt almost instantly at the well. The consequent reduction in the bottomhole pressure is captured through Eq. 9 in the dimensionless pressure causing the deviations observed in Fig. 32.

Fig. 32. Comparison of dimensionless pressures.

Two-Phase Flow: This test consisted of a single layer saturated with oil at residual water saturation. Seventeen wells were located in the system, sixteen producers and one injector. Fractures were assumed to be parallel and uniformly distributed throughout the reservoir. The reason for designing this problem was to look for the effect of fractures oriented at different directions in water production.

For this problem, fractures at three different directions were added to the 17-well system. The fractures were vertical fractures oriented at 30° , 45° and 60° . It was verified that there is symmetry in computing water breakthrough and rate production in cases with fracture orientation of 30° and 60° . Therefore only plots corresponding to the cases of 30° and 45° are presented. As a way of graphically showing the effect of fractures, plots of water production in each well versus time were prepared in Figs. 33 and 34. These plots also indicate well locations to compare water production in wells completed under similar reservoir conditions (mirror wells).

In Fig. 33, it is observed that the highest water production is obtained in Wells 2 and 10 located along the fracture trend and the injector. Even though water production was not expected in other wells because no matrix was used, some water is produced in wells close to the set of injector-producer wells aligned with the fracture trend. These wells (3 through 12) are also aligned with the fracture orientation but not with the water injection well. The reason for this

water production is due to the implementation of permeability tensor in a finite difference scheme, which follows the approach given by Nakornthap (1982). In this approach, flow along the fracture occurs at the grid-block boundary due to the pressure gradients in neighboring grid-blocks. Since the fracture orientation is not perpendicular to the grid-block boundary, some fluid is deviated and produced along fractures parallel to the fractures that directly connect injector and producers (Wells 2 and 10). This effect is better seen by comparing the production from Wells 1 and 9 and 4 and 12 in Fig. 34.

Fig. 33. Water production with fractures oriented at 30°.

Fig. 34. Water production with fractures oriented at 45°.

Future work. BOAST-NFR has been verified as a single porosity reservoir simulator with either only matrix or only fracture systems. Simulator performance testing is underway. Two types of tests are being designed. For single-phase flow, analytic solutions for dual porosity systems with constant shape factors proposed by Lim and Aziz are going to be used. To test two-phase flow performance, the Sixth SPE Comparative Solution Project (SPE paper 18741) will be used.

Once simulator performance in dual porosity systems has been successfully tested, a parametric study will be done. Simultaneously a user's manual will be prepared to describe the simulator capabilities, input data requirements, and basic assumptions and equations of reservoir simulator.

Task V. Technology Transfer.

Technology transfer continued during this reporting period. During this period, informal weekly and monthly meetings have been held to share information between researchers and other interested parties in engineering, geology, and geophysics. Participants have included students, faculty, and researchers from the University of Oklahoma and industry. The project, through one of the principal investigators, has maintained a naturally fractured reservoir e-mail list server to furnish interested parties with regular updates regarding the project and on other various topics of interest related to naturally fractured reservoirs.

In June 2002, the University of Oklahoma will host a multi-day conference on naturally fractured reservoirs. This will be a cooperative effort between the School of Petroleum and Geological Engineering and the Oklahoma Geological Survey. Abstracts will be solicited from researchers conducting naturally fractured reservoir research and technical program developed.

A general announcement will be made about the conference with attendance open to all interested parties. The conference is being scheduled for June 2 through June 4 in Oklahoma City to allow easy access to the meeting and hotel facilities for those arriving by air.

The research team published or presented the following technical papers during the current reporting period.

Brown, R.L., Parra, J.O. and Xu, P.C.: "Seismic Attenuation and Flow Properties in Fractured Reservoirs," Seventy-First Annual Meeting, SEG International Exposition, Calgary, Expanded Abstracts, 1678-1681.

Chen, H., Brown, R.L., and Castanga, J.P.: "Synthetic Multicomponent AVO Study of Fractured Reservoir Models with Multiple Fracture Sets," presented at the SEG Meeting, San Antonio, TX, October 2001.

Chen, H., Castanga, J.P., Brown, R.L., and Ramos, A.C.B.: "Three-Parameter AVO Crossplotting in Anisotropic Media," *Geophysics*, 66, 1359-1363.

Conclusion

During the current reporting period, research has continued on characterizing and modeling the behavior of naturally fractured reservoir systems. Work has progressed on developing techniques for estimating fracture properties from seismic and well log data, developing naturally fractured wellbore models, and modifying a naturally fractured reservoir simulator. The research is currently on schedule as proposed and no obstacles are anticipated for the next six-month reporting period.

Research efforts during the next period will focus on formalizing the techniques and models developed into an integrated reservoir characterization methodology. This methodology will provide a comprehensive characterization of the reservoir system and yield parameters needed for the naturally fractured reservoir simulator. In addition, parametric and sensitivity studies will be completed using the reservoir simulator to evaluate critically required reservoir data and evaluate various production strategies for naturally fractured reservoirs.

A multi-day naturally fractured reservoir symposium to be hosted by the University of Oklahoma will also be planned during this period. The conference will be held in June 2002 in Oklahoma City. This symposium will invite researchers from industry and academia to submit abstracts for presenting the latest research in this area. This symposium will serve as the major technology transfer activity for this project.

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