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Natural Fracture Identification and Characterization While Drilling Underbalanced

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Abstract

An algorithm based on data obtained during underbalanced drilling operations is described for identifying the location and properties of productive natural fractures that are intersected by the wellbore. The criteria used to identify natural fracture locations are (i) total gas concentration measurements from mud logs and (ii) mud pit volume. The paper also describes a simple approach for estimating the fracture permeability. The algorithm is applied to data from three sets of horizontal parallel wells with spacing of roughly 700 ft. In two of the three well pairs considered, conductive fracture locations identified in one well aligned with corresponding features in the parallel well. An attraction of the proposed methodology is that it makes use of data that is commonly recorded during drilling, reducing the need for expensive image log tests. The information obtained from this type of analysis can be used to improve hydraulic fracture treatment designs.

Introduction

The economic viability of a well drilled in an unconventional gas reservoir is largely influenced by the level of connectivity between natural fractures, stimulated fractures, and the wellbore. Engineers have the ability to control the wellbore path and, to some extent, the hydraulic fracturing process. On the other hand, natural fracture systems are outside of the engineer's control. While knowledge of the geologic conditions and stress history are helpful to estimate the characteristics of the natural fracture system in a given reservoir, the true extent of the natural fracture system in any specific location is typically unknown (e.g., near wellbore). Several well testing methods are available to the industry to identify natural fractures near the wellbore, including acoustic and resistivity image logs, but the poor-quality results of these techniques do not compensate for the expensive costs in most cases. The desire to learn as much as possible about the natural fracture systems present in tight gas plays while striving to keep drilling and completions costs to a minimum has led researchers to explore the use of drilling data as a means for natural fracture characterization.

Several reports in the literature indicate that it is possible to locate and characterize the permeability of natural fractures intersected by the drillbit during conventional, overbalanced drilling operations through the use of mud loss data (Dyke et al. 1995; Liétard et al. 1999; Lavrov and Tronvoll 2003; Huang et al. 2010). However, many wells in unconventional gas reservoirs are drilled underbalanced. For the case of underbalanced drilling, the downhole pressure condition requires that an alternate approach for natural fracture characterization be developed.

The investigation discussed within this report is essentially an exploitation study to determine whether valuable information concerning natural fracture systems that intersect horizontal wellbores in tight gas reservoirs can be discovered through the use of underbalanced drilling data. Methodologies are developed to determine highly probable conductive natural fracture "zones" and, hence, characterize natural fracture permeability at these locations. The methods make use only of data that is commonly recorded by drilling engineers in practice during underbalanced drilling operations. Due to the high level of uncertainty inherent to this type of analysis, a practical validation analysis is identified and subsequently performed.

Hydraulic fracture simulators that include the effects of complex natural fracture systems have already been developed (e.g., Weng et al. 2011). The quantitative results obtained from the analysis proposed in this study could be directly integrated into simulators of this type, potentially reducing the uncertainty in modeling hydraulic fracture growth.

Identification of Natural Fractures

There are two types of data found in the drilling log and mud log that have been explored as criteria for indicating the location of natural fractures along the wellbore. The basis for the use of these data for natural fracture identification is founded on physical processes as well as drilling engineering experience.

The first criterion is the use of total gas concentration measurements from mud logs. Using a gas chromatograph, the mud logging unit is able to determine the concentration of gas present in the drilling fluid at any given time. The hypothesis is that as a natural fracture is encountered by the drill bit, the volume of gas contained within the fracture will rapidly flow into the wellbore and enter the stream of circulating drilling fluid. This will be seen as a sudden spike in total gas concentration in the mud log, which will eventually return to normal operating levels after all of the trapped gas has exited the fracture. For the purposes of the present research, these spikes have been expressed as "gas peaks", and offer the potential for reliably locating conductive natural features. The use of gas peaks to identify natural fracture locations while drilling underbalanced has been documented previously in the literature (Myal and Frohne 1992).

The second criterion is based on observations of the mud pit volume. It is widely accepted that decreases in mud pit volume (mud losses) correspond to encounters with natural fractures while drilling overbalanced. Drilling engineers have indicated that they are confident that the "reverse" case is also true during underbalanced drilling operations. While underbalanced conditions exist in the wellbore, as a natural fracture is encountered with the drill bit the formation fluid influx will cause a displacement of drilling fluid in the mud pit. This response is similar to a gas kick event and is observable at the surface. An increase in the mud pit volume has been termed a "mud pit volume peak" for the purposes of this research. Determining the location of the drill bit as relatively large mud pit volume increases are observed at the surface will be used to identify natural fracture locations.

Members from industry are confident that the gas peak (Criterion 1) and mud pit volume peak (Criterion 2) criteria are good indicators of conductive natural fractures. Thus, Criteria 1 and 2 are used to identify candidate natural fracture locations.

It is reasonable to assume that a fracture may exist at locations where all fracture identification criteria are satisfied simultaneously. Additionally, a threshold must be established to determine the magnitude of total gas and mud pit volume response that will be considered as an indication of the presence of a natural fracture. The concept of the "standard deviation coefficient" is now introduced.

In order to ensure the portability of the method between data sets collected at different wells or by different contracting companies, a general statistical approach is used to process the total gas and mud pit volume data. The premise for this analysis is that any gas peaks or mud pit volume peaks that exceed the average level of noise in the data by some threshold are considered of interest. The following formula is used as a cutoff criterion for a particular measurement:

$$M \geq \mu_M + (N \cdot \sigma_M), \qquad N \geq 0 \tag{1}$$

Here M is the value of the measurement of interest, μ_M is the mean of all the measurements, σ_M is the standard deviation of all the measurements, and N is the "standard deviation coefficient." The measurements of interest are the changes in total gas concentration and mud pit volume between two consecutive recordings. The value of N can be controlled by the user to raise the threshold to the desired magnitude. Through the use of Eq. 1, the user is able to define an appropriate level of stringency on the fracture identification criteria based upon the confidence level in the data.

The mean of all the measurements, μ_M, and standard deviation of all the measurements, σ_M, is computed through the following procedure:

$$M_i = X_i - X_{i-1} \tag{2}$$

$$\mu_M = \frac{1}{n-1}\sum_{i=2}^{n}\left|M_i\right| \tag{3}$$

$$\sigma_M = \sqrt{\frac{1}{n-1}\sum_{i=2}^{n}\left(M_i - \mu_M\right)^2} \tag{4}$$

Here X is either the total gas concentration or the mud pit volume depending on the criterion of interest, and n is the total number of data entries. Eq. 2 indicates that the changes in the total gas concentration and mud pit volume measurements are relevant to the present study. This ensures that any sudden spikes in total gas concentration or mud pit volume will be highlighted in the analysis. Using the changes in measurements also has a practical purpose; the method accounts for any gas production from the matrix already entrained within the drilling mud. While the final step in the analysis will only identify increases in total gas concentration or mud pit volume, a sense of the average level of random noise in the data is quantified in Eq. 3 through the use of the absolute value function. Eq. 4 will also provide a sense of the variation within the data.

For a normally distributed random variable, the probabilty that the value of the random variable lies within the range of $\mu_M \pm (N \cdot \sigma_M)$ are well understood. The present analysis takes advantage of this knowledge to define appropriate thresholds for the fracture identification criteria. If a particular measurement has a relatively low probability of occurring with regards to the normal noise found within the data, then perhaps this measurement is the result of abnormal reservoir conditions. If more than one independent, low-probability measurement is observed, then the confidence level in the presence of an abnormal reservoir condition becomes even higher. One abnormal reservoir condition that could be attributed to simultaneous gas peaks and mud pit volume peaks has been identified as a conductive natural fracture feature. Of course, it should be noted that a low-probability event could occur as a result of measurement error as well.

One additional fracture identification criterion is defined to overcome the high variability of the total gas concentration measurements:

$$G_i \geq \frac{1}{50} \sum_{j=i-25}^{i+25} G_j \tag{5}$$

where G is total gas concentration. Eq. 5 effectively represents a rolling average of total gas concentration. This constraint ensures that only true gas peaks will be considered, filtering out any total gas increases that have simply returned to normal operating levels after a short period of low readings. A range of fifty measurements was chosen as an appropriate range over which to perform the rolling average. This corresponds to a range of fifty feet for most log data collected in the U.S.

Three conductive natural fracture criteria have now been established. Eq. 1 constitutes Criterion 1 and Criterion 2 when applied to change in total gas concentration and change in mud pit volume, respectively. Criterion 3 is given by Eq. 5. The user is then free to select an appropriate value of N for a given data set. After applying the fracture identification criteria to a data set, the result is a set of locations where relatively large gas peaks and mud pit volume peaks occurred simultaneously. These locations indicate possible natural fractures that intersect the wellbore.

Characterization of Fracture Permeability

The major advantage of using underbalanced drilling data over image log techniques is that UBD data provides the opportunity to distinguish natural fractures that actually contribute to flow from fractures that are essentially closed. Since the rates of gas influx from the natural fractures are being measured directly, the fluid flow properties of the fractures, most notably permeability, can be estimated. This concept is truly what makes the prospect of UBD dynamic reservoir characterization so promising. Several reports in the literature have proposed methods to determine formation properties such as reservoir permeability and reservoir pore pressure profiles through the analysis of UBD data (Kardolus and van Kruijsdijk 1997; Larsen and Nilsen 1999; Hunt and Rester 2000; Kneissl 2001; Biswas et al. 2003; Erlend et al. 2003; Friedel et al. 2008). To our knowledge, no reports have specifically attempted to characterize natural fracture properties from analysis of UBD data.

In order to estimate natural fracture permeability, several assumptions are made:

1. All natural fractures that have been intersected by the wellbore are transverse to the wellbore and have circular geometry with finite extent (see **Fig. 1**).
2. Natural fractures have constant aperture.
3. Gas contained within natural fractures is composed 100% of methane. Methane density and viscosity remain constant while flowing through fractures.
4. Fluid flow through fractures follows the cubic law relationship.
5. Matrix permeability is much lower than fracture permeability. No charging of the fractures occurs during the time spans considered.
6. The gas influx volume is equal to the mud pit volume increase.

For practical purposes, the first three assumptions are valid. Previous work has been done on the effects of tortuosity and roughness of fractures, and this could be included in the model if enough information is known. The radial extent of the natural fracture must be estimated by the user. A sensitivity study can be performed to quantify the effect of fracture diameter on the estimates of fracture aperture.

The cubic law relationship assumes steady-state, laminar flow between two parallel plates. The cubic law can be derived from a force balance between the forces due to the pressure gradient and the shear resistance on the boundaries, as opposed to the diffusivity equation which is derived using the principles of conservation of mass. As such, no compressibility term is present in the cubic law relationship. However, the high compressibility of gas will most likely have significant effects on the flow rate through the fracture. Nonetheless, it is assumed that at the high pressure conditions present in many reservoirs, compressibility effects will be negligible over the relatively low magnitude pressure drop between reservoir and bottomhole pressure during drilling.

The final assumption listed above is the most critical. Because no direct measurements of gas flow rate at bottomhole are recorded on today's drilling rigs, it is assumed that the observed mud pit volume increase is equal to the volume of gas that entered the wellbore from the fracture. Again, compressibility effects could be significant and add to the uncertainty of this analysis. Also, it is well known that methane is highly soluble in oil-based drilling mud, and it is has been reported that observations of mud pit volume increase as a response to a gas kick will be reduced because of solubility effects.

The following estimates can be obtained from the drilling and mud log data:

- Gas flow rate
- Pressure drop (underbalance)
- Methane viscosity
- Wellbore radius

If an assumption about the radial extent of the fracture can be made, then fracture aperture can be determined from the cubic law as follows (e.g., Witherspoon et al. 1980):

$$w = \left(\frac{Q}{C\Delta P} \right)^{1/3} \tag{6}$$

Here w is fracture aperture, Q is volumetric flow rate, P is pressure, and C is a constant dependent on the type of flow. For radial flow, the constant C is given by the following equation:

$$C = \left(\frac{1}{12\mu} \right) \left[\frac{2\pi}{\ln\left(R_e / R_w \right)} \right] \tag{7}$$

In this expression, μ is gas viscosity, and R_e/R_w is the ratio of the extent of the fracture to wellbore radius. The fracture permeability can then be estimated using Poiseuille's law (e.g., Chen et al. 2000):

$$k_f = \frac{w^2}{12} \tag{8}$$

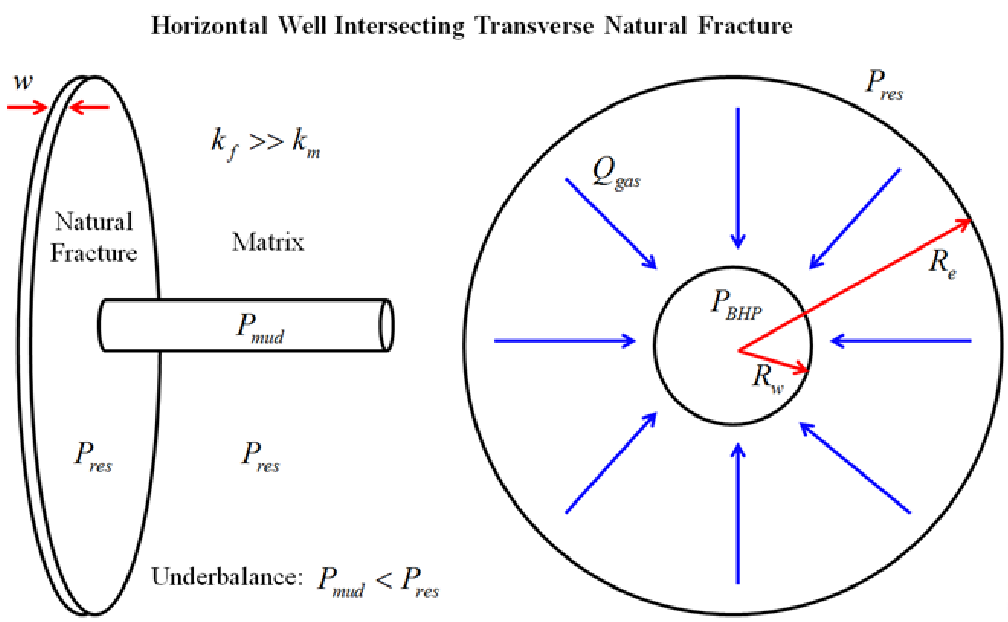

Figure 1. Illustration of the model used for characterization of natural fracture permeability. It is possible to estimate natural fracture permeability using measurements of gas influx rate recorded during drilling.

Field Study

The purpose of this investigation is to evaluate the potential for using drilling data as a practical means for determining natural fracture properties near wellbore. To this end, the methodologies described above are applied to six wells that were drilled underbalanced. Candidate conductive natural fracture locations are determined for each well.

The wells studied herein are from two tight gas shale formations, one located in the U.S. and the other in Canada. The lateral sections of these horizontal wells range from 3,000 to 6,000 ft. It is assumed that no overpressured zones were intersected and the underbalance condition was maintained at all times while drilling the lateral sections of the wells. The lateral sections of all wells were drilled using oil-based mud.

The nature of this problem suggests that it may be very difficult to confirm the accuracy of the results obtained from the fracture characterization analysis. Borehole image logs are not available for any of the wells used for this study, typical of wells drilled in unconventional reservoirs. Therefore, it is necessary to develop validation techniques in an attempt to quantify the level of confidence in the candidate natural fracture locations. The main validation technique used in this study takes advantage of a commonly used horizontal drilling technique in which wells are drilled in parallel. In tight gas reservoirs it is common to drill wells in the direction believed to be perpendicular to the natural fracture system orientation. This practice ensures that the well will intersect the highest possible number of transverse natural fractures. Therefore, it is presumed that if two wells are drilled parallel to each other in close proximity there is a good chance they will penetrate similar natural fracture systems. The six wells selected for study in this investigation constitute three sets of parallel wells drilled to similar elevations. The spacing of these wells is between 500 and 800 ft. The results of the natural fracture identification analysis for each parallel well set are compared to determine if any patterns exist.

Patterns in the locations of conductive natural fracture zones are considered an indication of the orientation of natural fracture planes. If the wells were truly drilled in the direction perpendicular to natural fracture system orientation, then conductive natural fracture locations of the parallel wells should pair up evenly on a plan view. If the natural fracture system is predominantly oriented in a different direction, the conductive natural fracture locations of parallel wells should pair up slightly offset. This approach will be used to evaluate a confidence level for the methodologies developed in this paper.

From visual inspection of the results obtained for Field A two dominant patterns are observed (see **Fig. 2**). A total of seven pairs of natural fractures are aligned at an orientation of roughly N65°E (see **Fig. 3**). Only one identified natural fracture from Well A-2 does not have a corresponding feature in Well A-1. In order to remain objective, more than one pattern orientation must be considered. For Field A, an alternate orientation is observed at which four pairs of natural fractures are aligned at roughly N84°E (see **Fig. 4**). The pattern in Orientation #2 is clearly not as strong in Orientation #1. If the results of this investigation are considered valid, Orientation #1 is recommended to be considered representative of the natural fracture system in Field A.

From visual inspection of the results obtained for Field B a dominant pattern is observed between Wells B-1 and B-2, and a weak pattern is observed between Wells B-3 and B-4 (see **Fig. 5**). A total of nine pairs of natural fractures align at the orientation of roughly N12.5°E across the four wells (see **Fig. 6**). A second pattern is observed for Field B, corresponding to an orientation of N2°E (see **Fig. 7**). A total of seven natural fracture planes are identified assuming this orientation.

Note that no physical connection is implied to exist between pairs of fractures associated with a common fracture plane. The motivation behind these comparisons is that for a given in-situ horizontal stress distribution natural fractures will tend to develop along a particular orientation. It is reasonable to assume that multiple natural fractures will develop along the same line of action in a given region. As it stands, the confidence level in the proposed technique is moderate to high. In two of the three parallel well pairs considered, the application of several fracture identification criteria based upon physical processes has provided a strong indication of the presence of a natural fracture system.

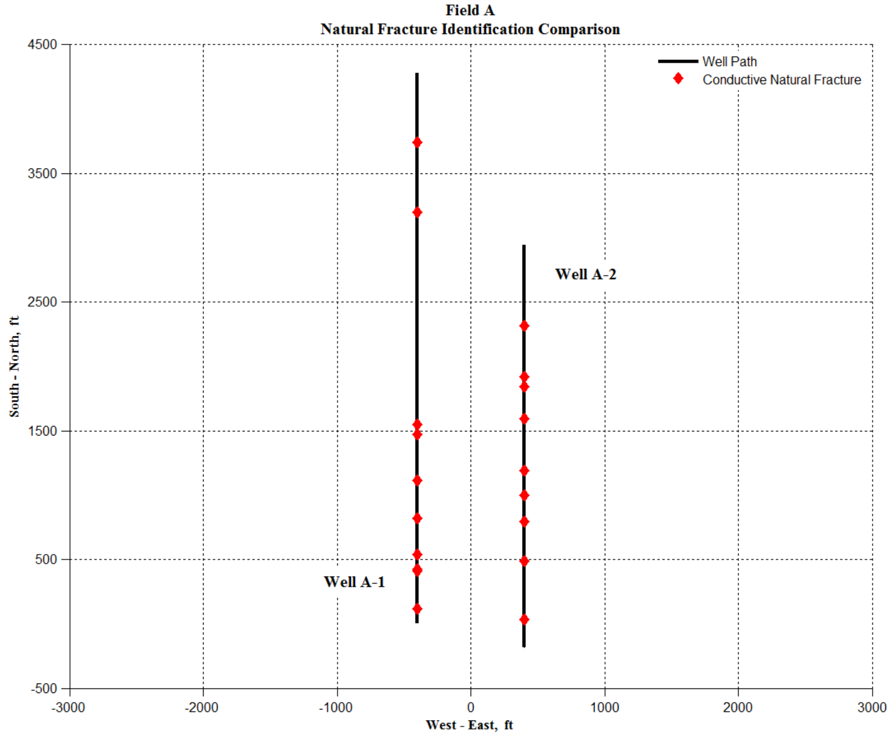

Figure 2. Plan view of Field A. Wells A-1 and A-2 are parallel wells drilled in the South-North direction. The lateral spacing between these wells is roughly 800 ft. Red diamonds indicate the locations of conductive natural fractures determined through the fracture identification analysis.

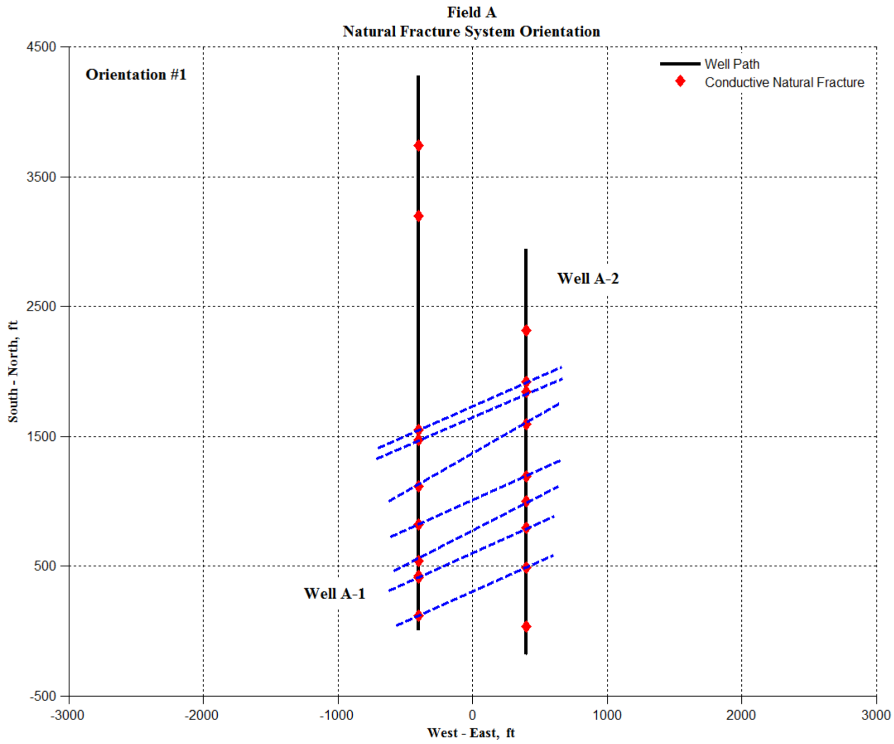

Figure 3. Natural Fracture System Orientation #1 for Field A. A dominant pattern exists that seems to indicate the presence of a natural fracture system oriented at N65°E.

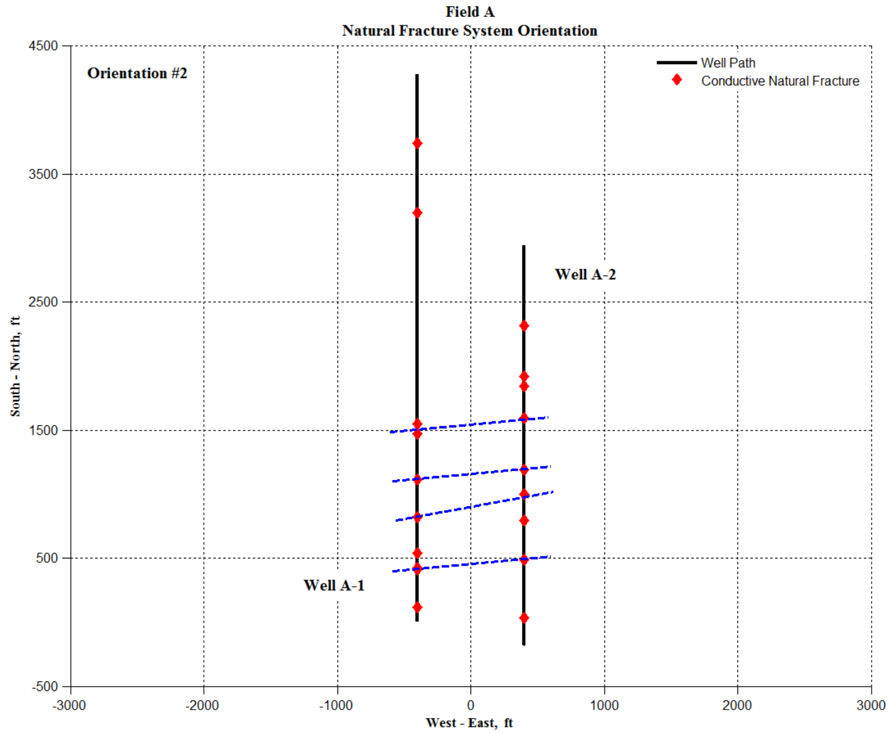

Figure 4. Natural Fracture System Orientation #2 for Field A. A moderate pattern exists that seems to indicate the presence of a natural fracture system oriented at N84°E.

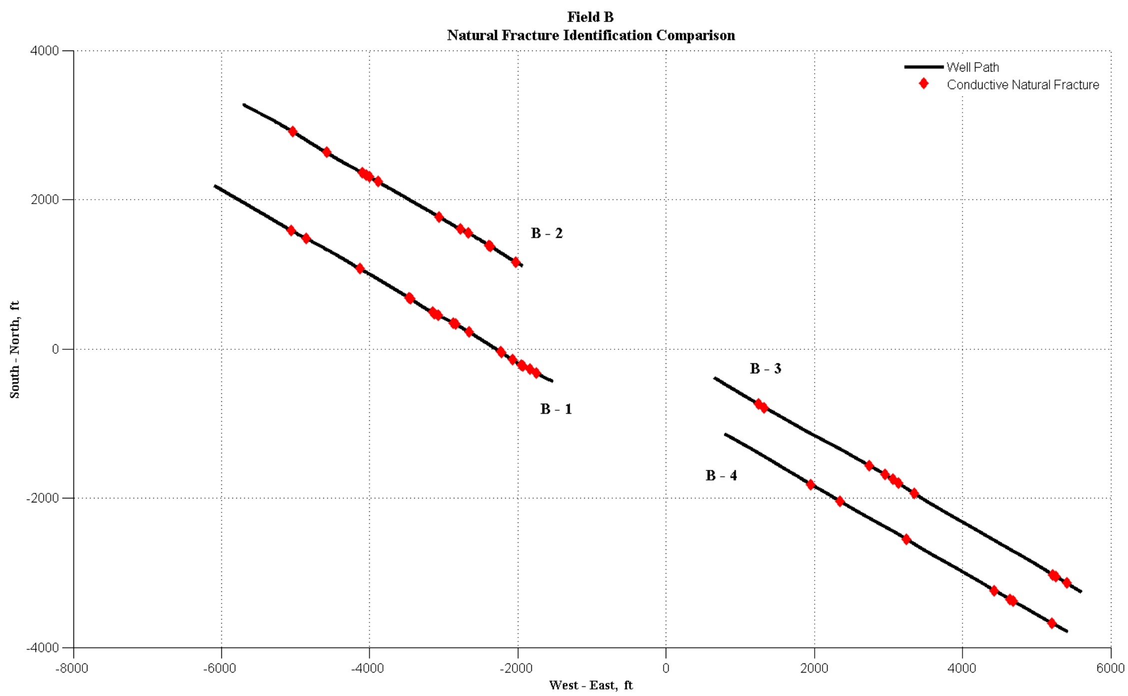

Figure 5. Plan view of Field B. These four wells were drilled from a common pad located near 0,0. Red diamonds indicate the locations of conductive natural fractures determined through the fracture identification analysis.

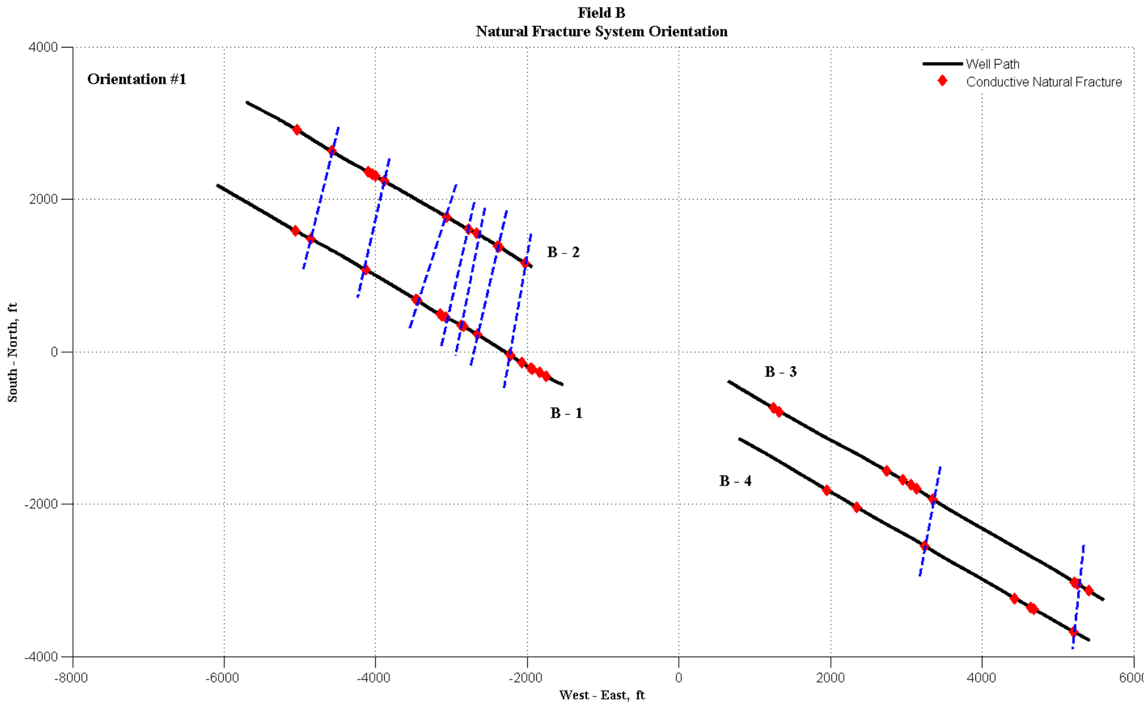

Figure 6. Natural Fracture System Orientation #1 for Field B. A strong pattern exists that seems to indicate the presence of a natural fracture system oriented at N12.5°E.

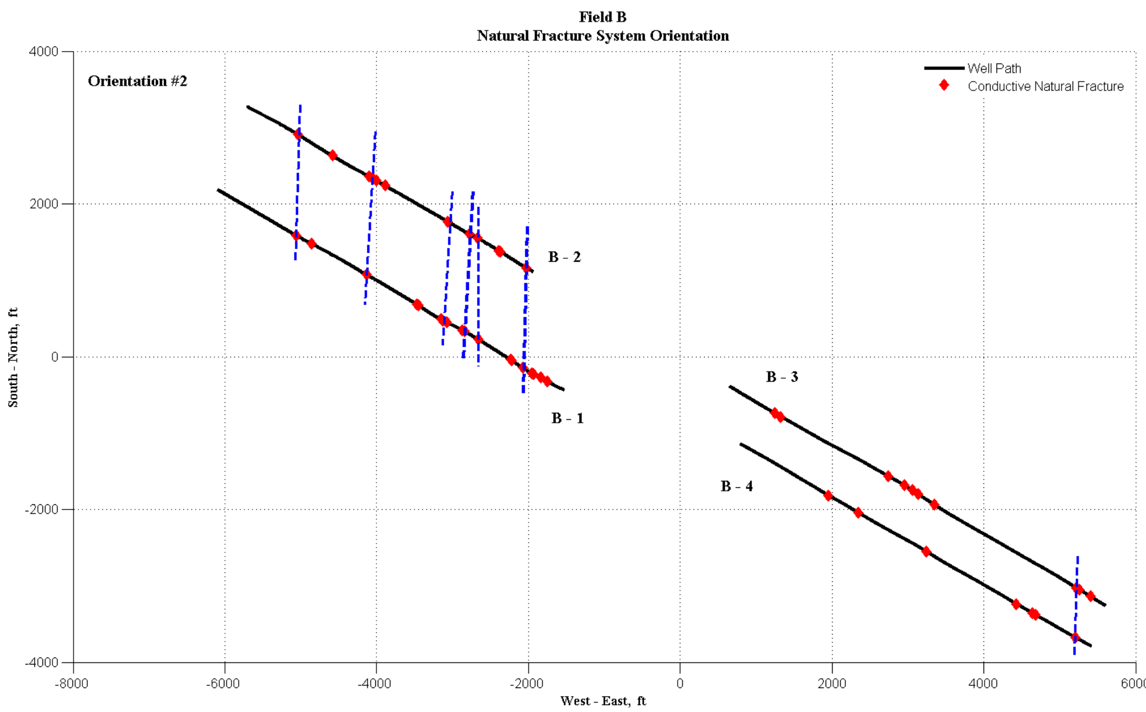

Figure 7. Natural Fracture System Orientation #2 for Field B. A moderately strong pattern exists that seems to indicate the presence of a natural fracture system oriented at N2°E.

Concluding Remarks

Drilling data from six horizontal wells in tight gas reservoirs that were drilled underbalanced have been analyzed to determine whether useful information about the natural fracture system near wellbore can be gained from this type of data. Two practical fracture identification criteria have been defined as gas peaks from the mud log and mud pit volume peaks from the drilling log. Simultaneous gas and mud pit volume peaks are used to identify probable conductive natural fracture locations. An approach to estimate the permeability of the identified natural fractures based on the cubic law has been described.

The six wells studied in this investigation constitute three sets of parallel wells. The fracture identification criteria were applied to the drilling and mud log data from each well, and the identified fracture locations were compared for each pair of wells. Overall, the results of the analysis are encouraging. In two of the three well pairs considered, the majority of identified conductive fracture locations in one well aligned with a corresponding feature in the parallel well. This result suggests that natural fractures in these regions are predominantly aligned at a particular orientation.

The results warrant further research in the area of dynamic reservoir and fracture characterization. This type of analysis would benefit from additional validation techniques, such as comparison to image log tests or geologic data (i.e., in-situ stress conditions, predominant fracture orientation).

Knowledge of information about the natural fracture system in a given region has extreme economic implications for tight gas reservoirs. Natural fracture systems clearly affect the mobility of gas on a field-wide scale. In addition, the presence of natural fractures near-wellbore directly impacts the hydraulic fracture treatment process. This study has presented an inexpensive method to mine useful information about natural fracture systems near-wellbore from data sets that are already commonly available.

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Notation

C	Constant used in cubic law relationship, $\left[L^{-1}t^{-1}\right]$
G	Total gas concentration, $[units]$
k_f	Fracture permeability, $\left[L^2\right]$
M	Measurement of interest; either mud pit volume peak or gas peak, $\left[L^3\right]$ or $[units]$
n	Total number of rows of data in drilling and mud log data, $[dimensionless]$
N	Standard deviation coefficient, $[dimensionless]$
P	Pressure, $\left[F/L^2\right]$
Q	Fluid flow rate, $\left[L^3/t\right]$
R_e	Radial extent of fracture, $[L]$
R_w	Wellbore radius, $[L]$
w	Fracture aperture, $[L]$
X	Mud pit volume level or total gas concentration, $\left[L^3\right]$ or $[units]$

<u>Greek Symbols</u>

μ	Fluid viscosity, $\left[F \cdot t/L^2\right]$
μ_M	Average of measurement of interest, $\left[L^3\right]$ or $[units]$
π	Pi, dimensionless
σ_M	Standard deviation of measurement of interest, $\left[L^3\right]$ or $[units]$

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