Microseismic Monitoring Reveals Natural Fracture Networks*

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Abstract

Microseismic monitoring is used to visualize fracture growth during hydraulic fracture treatments. Naturally occurring fracture networks within the formation of interest, as well as direction of maximum horizontal stress, play significant roles in determining the way that these fractures propagate. Naturally occurring fracture networks may include large-scale faults, parasitic faults associated with the large-scale faults, and smaller-scale fractures. The locations of microseismic events can be used to visualize induced fractures and atypical natural fractures where they exist.

Geological knowledge is valuable to accurately interpret microseismic event locations. Trends in microseismic event locations can illustrate the existence and orientation of naturally occurring fracture networks. Two case studies, one from the Montney Formation in NE British Columbia, Canada, the other from the Barnett Shale in Texas, USA, will demonstrate the effects natural fractures can have on hydrocarbon production.

Microseismic event locations from the Barnett Shale and the Montney Formation show that natural fracture networks exist. Wells connected to these networks show higher production values due in part to the higher permeability associated with open fractures. Variations in productivity between wells may be related to the presence or absence of natural fractures. When natural fracture networks are revealed by microseismic monitoring, that knowledge can then be used to optimize drilling and completion programs, which in turn reduces costs and maximizes production.

Introduction

Microseismic monitoring has become popular in the petroleum industry within the last ten years. This technology allows energy companies to visualize the extent to which a hydraulic fracture treatment is fracturing the formation, as well as the locations of the fractures it creates. More recently, seismic moment tensor inversion (SMTI) techniques have allowed even more information to be gleaned from the data recorded by multiple downhole geophone arrays during microseismic monitoring of stimulation programs. Using SMTI, along with calculated source characteristics, discrete fracture networks (DFN), fracture orientations, and potentially the behaviour of the lithology being fractured can be identified for inclusion in reservoir models.

SMTI Analysis

The seismic moment tensor relates the radiation pattern observed from an earthquake to the modes of failure responsible for causing the event. Mathematically, the seismic moment tensor can be represented as a symmetric 3 x 3 matrix of point forces (Figure 1), which results in 6 independent force couples that comprise the components of the moment tensor. These forces represent the first motions of the event at the hypocentre and so they provide a picture of the instantaneous strain imposed on the rock by the seismic event.

In order to conduct SMTI analysis on a dataset, a microseismic event must be recorded on at least two geophone arrays, and a P-wave must be detected on at least one. Multi-well monitoring thus allows for the option of conducting SMTI analysis on a dataset. First, the condition number of an event is modelled; this calculation determines which regions of the treatment zone are suitable for SMTI analysis based on the geometry of the arrays and underlying velocity structure with respect to the event distribution. A good azimuthal sampling around the event is critical to having low condition numbers such that the inversion for the moment tensor is stable, and is the basis for the stipulation that multiple observation arrays are normally required to determine the moment tensor.

The SMTI analysis reveals the mode of failure of the event, which falls between one of three end-members: isotropic, double-couple (DC), and compensated linear vector dipole (CLVD). Empirically, many of these mechanisms recorded in hydraulic fracturing feature combinations of these three components that are consistent with deformation occurring on a fracture: either tensile opening or closure of fractures, or slip on a fracture surface (DC). The orientation of the fracture is then interpreted from the moment tensor based on which of these classes of fracture-based deformation with which it is consistent. In the case of double-couple (pure shear) failure, the solution for the strike and dip of the crack is non-unique with two orthogonal fracture planes that equally satisfy the waveform data. This ambiguity can be resolved in order to identify the most likely orientation of the fracture created by the DC event. This is done by using methods similar to those of Gephart and Forsyth (1984), which considers an ensemble of DC moment tensors and determines which of each of the fracture planes is most consistent with the underlying stress conditions responsible for the failures. For fracture closure and opening events, the interpretation of the fracture plane orientation is more clear-cut by recognizing that the moment tensor is proportional to strain-rate and determining the principle axes describing this deformation. The opening events are then normal to the tensional axis (along the direction of greatest strain) and, conversely, the closure events are normal to the pressure axis (least strain).

Seismic moment tensors are frequently displayed using a beach ball diagram (Figure 2) (a lower-hemisphere stereographic projection). The beachball is an image of the radiation pattern of the P wave propagating away from an event as well as a representation of the motion and modes of failure. The beachball shows the zones of the rockmass that have experienced compression (filled) and tension (open).

Another way to visualize the seismic moment tensors is to represent them as coloured discs, and in this way, relate the focal mechanism to models of penny-shaped cracks describing the seismic source (Figure 3). The size of the disc represents the source radius of the event (e.g. Walter and Brune, 1993); the orientation of the disc represents the orientation of the plane of failure; the discs are colour-scaled to represent the mode of failure of each microseismic event – warm colours represent crack opening, intermediate colours represent double couple or shear events, and cold colours represent crack closing. Precisely, the colour-scale is a combination of the parameters *k* and *T* defined by Hudson et al. (1989) to describe the deformation style (or source type) that the moment tensor represents. Events are coloured by mechanism, such that events consistent with the opening of tensile cracks have values approaching 1 (red), pure shear events have values near zero (yellow-green), and fracture closure events have values approaching -1 (blue).

By visualizing the moment tensors in this way, it paints a picture of the discrete fracture network created by the stimulation. This valuable information derived from the recorded microseismic data allows for further interpretation of the response of the rockmass to the hydraulic fracture stimulation, beyond just the event locations. This is best demonstrated in the following case study.

Case Study

The geological setting of the case study is a sub-basin of the Western Canada Sedimentary Basin. The rocks of this sub-basin were deposited from the Devonian to the Cretaceous Periods (416-65 Ma). In the Devonian, the area of the basin was situated near the equator, on a continental shelf. This paleoenvironment would have favoured the deposition of shales and limestones, which is consistent with the rock types of the basin. During rapid sea level rise, low sedimentation rates and increased subsidence resulted in a starved, anoxic basin, creating favourable conditions for preserving the organic-rich shales of the basin.

In this case study, two conformable shale units were stimulated for gas production. The lower shale is a medium to dark grey calcareous shale with moderate gamma ray and resistivity readings, and reaching thicknesses of over 270 m. The upper shale is a grey to black, organic-rich shale with variable amounts of carbonate, and it also contains pyrite. It has high gamma ray and resistivity readings, and ranges in thickness from 30 to 60 m. The upper shale is situated at a depth of approximately 2500 m. Overlying the upper shale is another shale that is somewhat similar to the lower shale in that it is reasonably thick but is not organic-rich. Underlying the lower shale is a thin carbonate unit composed of argillaceous limestones and interbedded shales that is about 15 m thick and is regionally traceable. The basin is bounded by a Devonian limestone to the east, and to the west by a major NNE-striking, high angle, reverse fault. This major fault is cross cut by a fault zone striking approximately 45°.

The present day regional maximum horizontal stress direction is approximately 45° (NE), and as such, the wells have been drilled perpendicular to that direction. In order to stimulate both the upper and lower shales of interest, horizontal wells were drilled with laterals contained entirely within a single formation. Within each well, stimulation occurred in several stages. Over 300 events were located for the majority of stages, which indicates that both the upper and lower shales fracture readily, likely due to their high silica contents.

Here, we examine the microseismic events of one stage of one well. Following the methodology outlined above, the microseismic events are first picked and located. Once the events are determined to be well-conditioned for SMTI analysis based on their condition numbers, SMTI analysis is then performed. The results of the SMTI analysis are shown as beachballs in Figure 2.

As described above, the moment tensors are then interpreted as deformation occurring on penny-shaped cracks, and these fracture planes are plotted as coloured discs (Figure 3) to show the orientations of the fractures, as well as the size and mode of failure of the microseismic event. The overall deformation from this stage was predominantly crack-closing, so this implies interaction with a pre-existing set of fractures, likely from a previous stage.

By examining the orientations of the discs, particularly in plan view, it is apparent that the fractures in the upper shale are dominantly horizontal to sub-horizontal, whereas the fractures in the lower shale are dipping. This trend in fracture orientations is more apparent when the poles to the fracture planes are plotted on a stereonet (Figure 4). The vertical poles represent the sub-horizontal fracture planes of the upper shale, and the dipping poles represent the dipping fracture planes of the lower shale. The difference in fracture orientations most likely reflects the behaviour of the different lithologies of the upper and lower shale units.

Summary

In this study, SMTI techniques have been used with microseismic data recorded in a multi-well configuration for a shale play in western Canada. Based on this approach, a discrete fracture network was defined, consisting of horizontal and dipping fractures. The horizontal fractures were confined to the upper shale unit, and likely, over time, those with opening modes of failure will close. The lower shale unit was dominated by dipping fractures, typically within 30° of the direction of maximum horizontal stress. These fractures defined a well-connected fracture network with significant opening failures, suggesting a well-coupled, effective stimulation

program. The observed distribution also allows for a more accurate resolution of the effective stimulated reservoir volume relative to typical calculations based on the volume encompassing the observed events. These results can be used to further the development of reservoir models and optimize stimulation programs.

References

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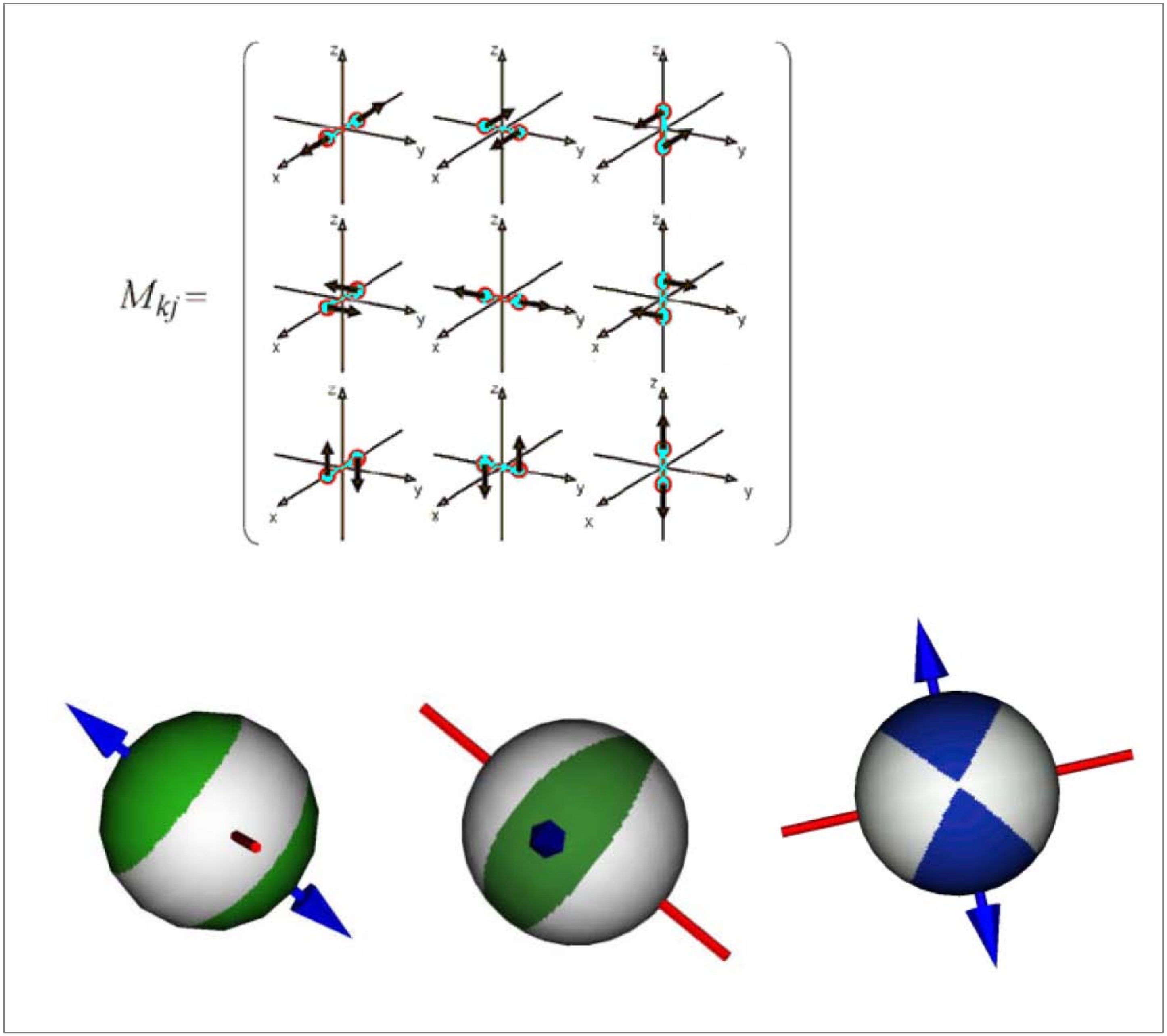

Figure 1. Matrix of force dipoles representing the decomposition of the seismic source. Equal-area stereonet projection coloured by the dominant mode of failure and localized major principal strain axes for events (left to right) of opening events with fracture plane normal to T axis, closure events with fracture plane normal to P axis, and DC events with two possible fracture planes.

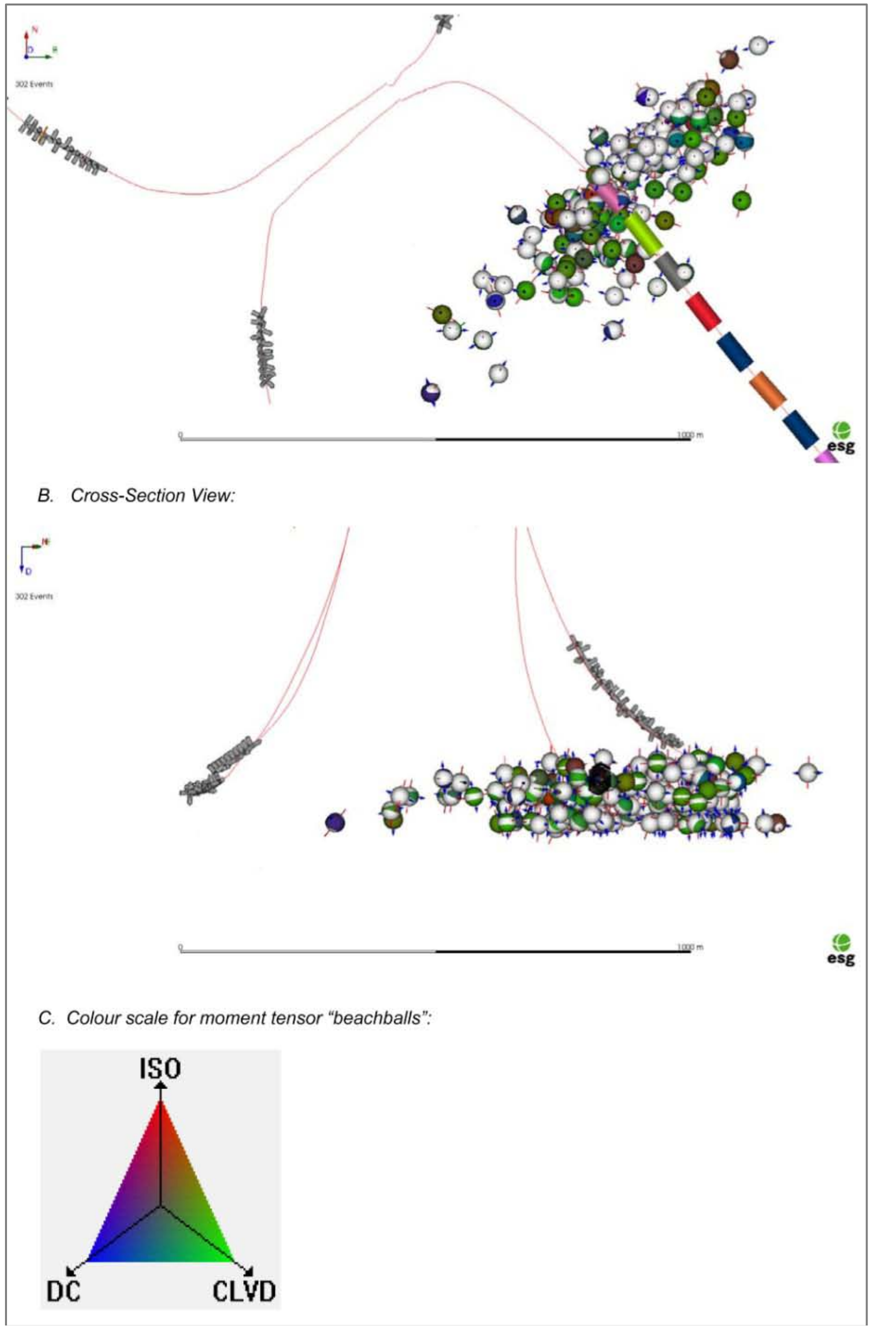

Figure 2. Events of one fracture stage shown as the "beachball" view of SMTI analysis. A) Plan view, B) Cross section view, C) Colour scale for moment tensor "beachballs".

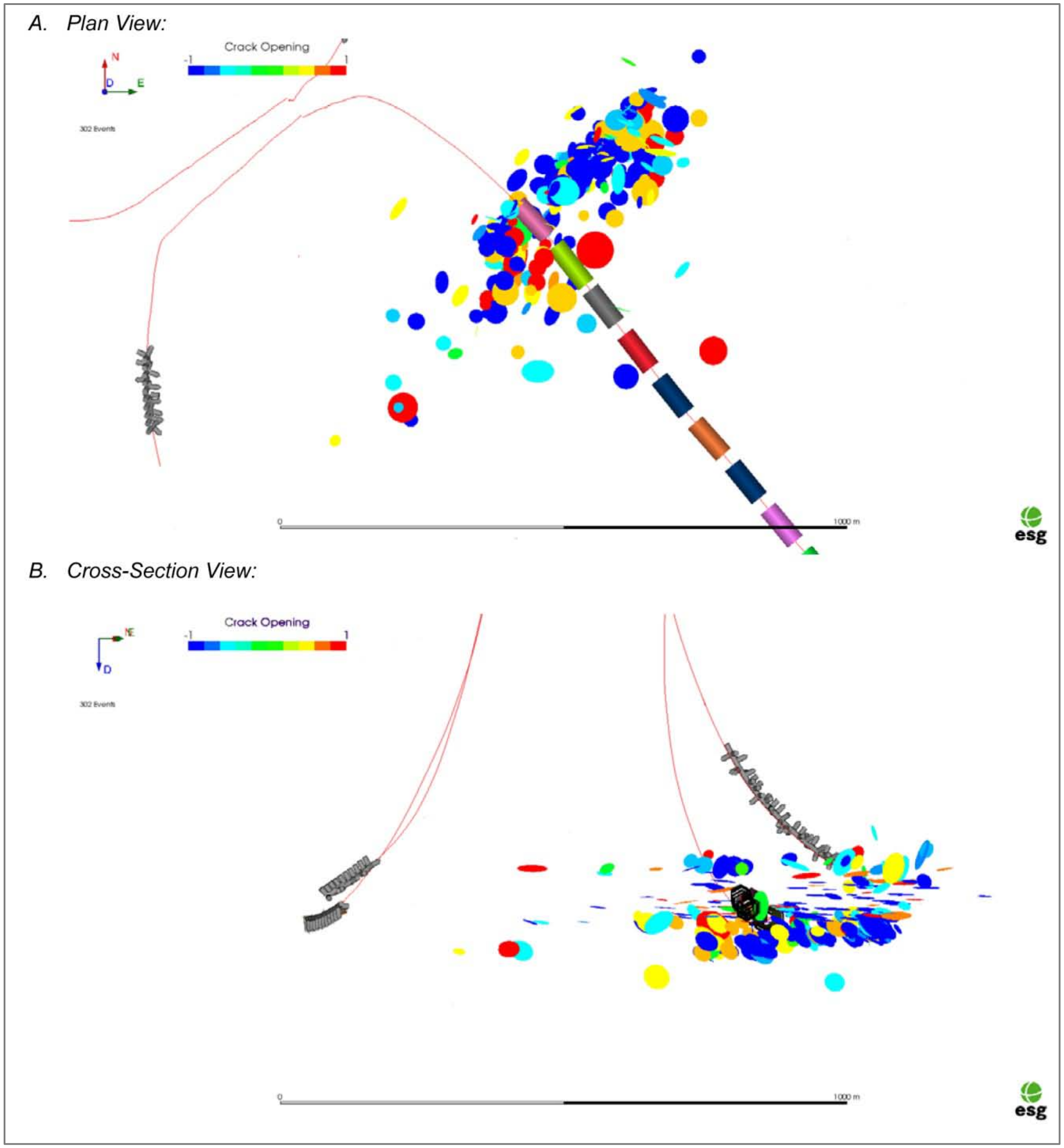

Figure 3. Events of the same fracture stage displayed as discs, showing the discrete fracture network. The individual fractures are presented as penny-shaped discs, such that, in cross-section view, the horizontal fractures appear highly elliptical, whereas the same fractures appear nearly circular in plan view.

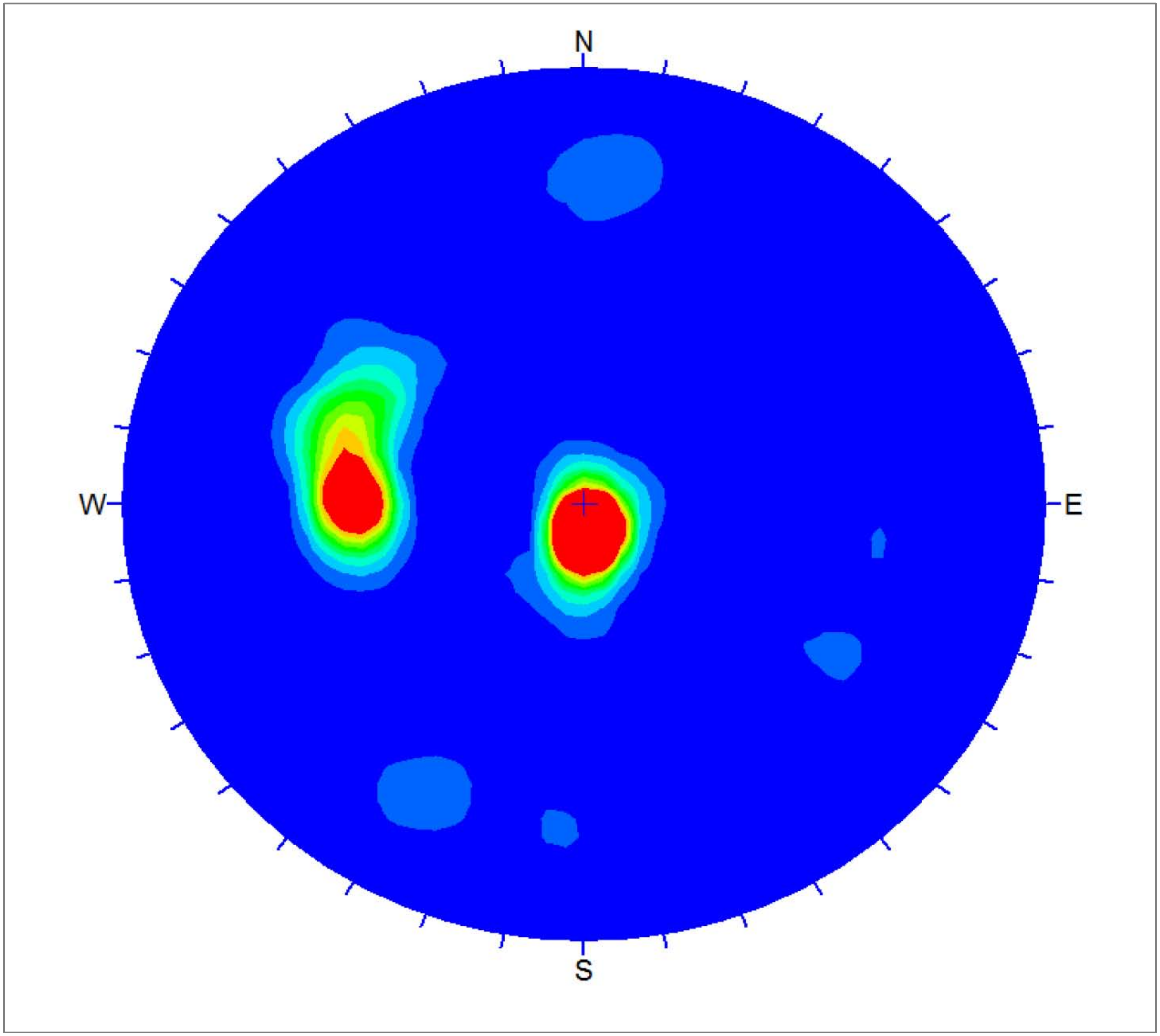

Figure 4. Poles to fracture planes plotted on an equal-angle stereonet. Note that the poles form two tight clusters. Each cluster represents the fractures of one shale unit.