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Application of Relative Location Techniques to Induced Microseismicity from Hydraulic Fracturing

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Abstract

Microseismic monitoring is routinely used for imaging the fracture network induced by hydrofracture treatments. One of the principal sources of uncertainties in the location of hypocentres is the velocity structure used in the location algorithm, which in most cases is approximated by layered models from sonic logs or estimated from perforation shot arrival times. Hypocentral uncertainties can be reduced by an order of magnitude, and the number of events located significantly increased, by using relative location methods that reduce the location volume to a small region around the seismic source.

Relative location methods are valid provided that the separation between the processed events is small compared to the ray-path lengths between source and receiver. The location is obtained through the inversion of differential travel times with respect to one chosen master event, minimizing the relative moveout residual. In this study, a new step-wise master-event relative-moveout location is applied to microseismic events induced during hydrofracture treatment.

The unique step-wise addition to the technique overcomes the limitations of separation distance by constructing a lattice of master events formed by all available good quality events that are located with a classic location algorithms. The minimization search is extended to the complete fracture volume as defined by the master events, converging to a solution that minimizes the relative moveout residual with respect to any of the available masters within the distance range. The use of arrival time differences with respect to a master event allows the location of events with P- and/or S-wave arrivals. Using the step-wise approach, the increased resolution in seismic location achieved by relative location methods is propagated to the complete set of events in a hydrofracture treatment. Furthermore, the method allows a significantly higher number of events to be located as only one phase (P or S wave) need be identified, assuming the events are in the vicinity of a master event with high quality arrivals.

We provide results from an example data set to illustrate the higher resolution and increase in number of located events that can be obtained through the application of the stepwise relative-moveout location algorithm.

Introduction

The injection of fluid to induce hydraulic fracture well stimulation imposes changes in the local stress and pore pressures of the reservoir rock that can create new fractures or mobilization and extension of existing ones. The energy released in the fracturing process is radiated as seismic waves with a compressional (P wave) and shear (S wave) components. Microseismic (MS) monitoring is the recording of these waveforms in order to obtain an image of the fracturing process and provide real time feedback on the effectiveness of the stimulation; either through the mapping of the fracture progress using MS event location (e.g. Quirein et al., 2007), utilizing continuous amplitude records to investigate hydrofracture mechanics (Pettitt et al., 2009), or complementing locations with size distribution in order to quantify the induced damage and fracture connectivity (Reyes-Montes et al., 2009).

The accurate definition of the induced fracture depends on the number of located MS events and the accuracy of the locations. Low signal-to-noise ratios, often experienced in many hydrofracturing cases for the petroleum industry, due to high