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Research paper

Estimating pore fluid pressure-stress coupling

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ABSTRACT

Fracture Pressure (FP) prediction is a vital component in well planning for safe drilling in high pressure areas, in the estimation of seal capacity and seal breach risk analysis, for fluid injection and in fracture stimulation for oil/gas recovery from tight reservoirs and mature source rocks.

Coupling of pore fluid pressure (PP) and FP at basin-scale has been recognised for several decades, with coupling ratio values mostly between 0.46 and 0.87, i.e. for every 10 MPa of PP increase at constant depth, FP increases by 4.6–8.7 MPa. These values are similar to estimates for reduction of FP with reservoir depletion of an oil/gas field during production. Poroelasticity has been suggested as the principal reason for coupling. Most previous coupling values were generated by examination of pressure gradients. A new method to estimate pore fluid pressure-stress coupling is proposed which plots the measured value of FP from a Leak Off Test (LOT) minus the expected FP value on the trend for normal pressures (termed the Fracture Pressure Residual, FPr) against overpressure (OP), which is the magnitude of PP above normal at the same depth. The coupling value is now the slope of FPr against OP. FPr:OP coupling values from 11 global basin datasets range from 0.24 to 0.43, approximately half the previous quoted basin-scale coupling values.

A pressure-depth model for rapid deposition on a continental margin, with OP exclusively generated by disequilibrium compaction and no change in effective stress in the overpressured section, represents a base case for compaction OP without poroelasticity. This model helps to reveal (1) that coupling values vary with the ratio of FP to lithostatic pressure (Sv); (2) since the 11 case study coupling values exceed the base case, one or more other (minor) coupling mechanisms are involved, potentially including poroelasticity; (3) values may be independent of tectonic environment; (4) one case study involving carbonate (chalk) is within the same range as those from siliciclastic sediments, and (5) the high coupling pore pressure-stress coupling values in the literature result from using fluid and fracture gradients including the shallow data where PP is normal, which distort the analysis.

1. Introduction

Predicting fracture strength of rocks is required when planning deep boreholes, estimating seal capacity and hydrocarbon retention, planning for injection of fluids into reservoirs, and fracture stimulation including evaluating the potential of these activities to produce induced seismicity. The principal data to calibrate such predictions are borehole fracture tests, both those conducted in short open-hole sections beneath casing shoes in conventional drilling (also known as Leak-Off Tests or LOTs) and during hydraulic fracture tests conducted to stimulate production in reservoirs. These data have led, over time, to the development of predictive algorithms in which fracture pressure (FP) is mainly related to stress and pore fluid pressure (PP). For example, the relationship of Matthews and Kelly (1967) combines vertical stress (Sv) with an effective stress ratio (K_i) in the formula:

FP = K_i*(Sv − PP) + PP, where K_i is the ratio of effective stresses, i.e. ((Shmin − PP)/(Sv − PP)),

and where Shmin is the minimum compressive stress. The calibration dataset for determination of K_i in Matthews and Kelly's paper was South Texas and Louisiana, Gulf of Mexico, and the study includes K_i plots for clay which indicate K_i increasing from about 0.4 near surface to values in excess of 0.9 at 6.0 km (20,000 feet), assuming Sv = 1.0 psi/ft and assuming hydrostatic conditions.

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Eaton (1969), proposed a similar relationship, also based on Gulf of Mexico data, which relates K_i to the Poisson's Ratio, with proposed values of Poisson's Ratio for shales from ~0.25 near the seabed to values in excess of 0.45 at depths of 6.0 km and greater, also assuming Sv = 1.0 psi/ft, and slightly higher values using Gulf of Mexico variable overburden. The formula is:

$$FP = (\mu/(1-\mu))^{*}(Sv - PP) + PP \text{ where } \mu \text{ is Poisson's Ratio.}$$

Several modifications of these two relationships have emerged subsequently, including Pilkington (1978) which effectively combined the use of K_i and Poisson's Ratio values and used locally determined Sv values with depth, and Daines (1982) which incorporates a tectonic stress component into the Eaton formula. We note that all the above relationships consider FP from LOTs to relate to the minimum compressive stress, Shmin, in extensional and strike-slip tectonic environments. Where rocks are lithified, FP includes the tensile strength of the rock, τ, such that FP often overestimates Shmin at depth.

Breckles and van Eekelen (1982) presented empirical relationships between horizontal stress (Shmin) and overpressure related only to depth, i.e. without the need for a relationship with Sv, based on data from Venezuela, Brunei and the North Sea, as well as the Gulf of Mexico. In effect their depth term is a proxy for vertical stress, Sv. A coupling term was introduced relating the magnitude of FP to the overpressure (OP), with values of 0.46 from Gulf of Mexico data and 0.49 from Brunei data. Both basins contain young clastic rocks. Engelder and Fischer (1994) observed that at depth, based on data from the North Sea and from the Scotian Shelf, offshore Canada, the deeper and older, lithified rocks have high pore fluid pressures with fracture pressures which they argued were in excess of those estimated assuming conventional friction envelopes (i.e. $\mu = 0.6$; Zoback and Healy, 1984). Their explanation for a high Shmin is poroelasticity, and their method of analysis compares PP gradients with Shmin gradients, led to coupling values of ~0.7 in both basins (Engelder and Fischer, 1994). Hillis (2001) generated ΔShmin:ΔPP coupling values of 0.73 from gradients in the Ekofisk field area, Central North Sea. Hillis (2003) generated ΔShmin:ΔPP coupling values of 0.75 for the NW Australian shelf and 0.76 for Scotian Shelf, whilst Tingay et al. (2003) determines a coupling value of 0.59 for Brunei. All these coupling values were obtained using PP and FP gradients, i.e. pressures normalised by depth.

In the method described in this paper fluid/fracture pressure coupling is determined from analysis of FPs from LOT data, and OP values from PP estimates, using data from several basins around the world. A new method is introduced which assesses the increase in PP above normal with a corresponding increase in FP above normal at the same depth. This approach avoids the need to normalise to depth, a feature of other approaches to estimating coupling. Three contrasting case studies with data from European and SE Asian basins are used to explore the methodology proposed, with comparisons from contrasting tectonic environments. Coupling values from three additional case studies in Lahann and Swarbrick (submitted for publication) and from five unpublished regional pressure studies by Ikon GeoPressure provide a comparison of 11 datasets in total, spanning different tectonic environments and contrasting lithology. Modelling of a schematic PP profile representing typical clastic continental margin rock sequences is used to determine coupling values undergoing burial with overpressure generation by disequilibrium compaction. We compare, using the model data, coupling relationships using both pressures above normal and gradients, and why the use of gradients and single gradient lithostatic stress values can lead to error in coupling estimates. We conclude that coupling is an inherent feature of undercompaction, and challenge the assumption that the coupling is exclusively related to poroelasticity.

2. Methodology to estimate coupling ratio

Under normal pressure conditions FP can be shown to have a direct relationship with Sv, as illustrated in Fig. 1a and b using published data from the Scotian Shelf, offshore Canada (Bell, 1990) and Nile Delta, Egypt (Nashaat, 1998) respectively. FP:Sv ratios under normal fluid pressure conditions vary from 0.81 to 0.89 (Table 1) for a selection of extensional and compressional basins.

The FP:Sv ratio is used as a reference for normal pressure conditions and is applied to all depths, and LOT data are then compared with this trend over the full depth range (Long dashed line in Fig. 2). The difference between the actual LOT and the LOT on the normal trend, termed the fracture pressure residual, FPr (light grey area), is plotted against the estimated OP (dark grey area) at each LOT depth, (Fig. 2). A hydrostatic gradient is used to determine overpressure (OP), where OP = PP − Phydr. The OP and FPr values are cross-plotted to determine the slope (inset, Fig. 2) which is ΔFPr/ΔOP, i.e. the FPr:OP coupling ratio.

3. Case studies

The approach to estimating FPr:OP coupling, including derivation of FP:Sv ratio, is illustrated with three case studies: (1) Mid-Norway; (2) Central North Sea; and (3) a SE Asian compressional basin. These studies include data from basins with contrasting lithologies, temperature and pressure regimes and include both extensional and compressional tectonic settings. Later the results are compared with other basins from two main sources: three case studies in Lahann and Swarbrick (submitted for publication) and five unpublished regional pressure studies with which the authors were involved, with permission of Ikon GeoPressure.

3.1. Case study 1: Asgard-Smorbykk field area, mid-Norway

The Haltenbanken area of mid-Norway includes Jurassic and Triassic reservoirs with highly variable magnitude of overpressure (Hermanrud et al., 1998; Nysaether, 2006), offering a test dataset. The data were selected from an area around the Asgard-Smorbykk fields contained LOTs from 12 wells plus sufficient direct PP measurements from reservoirs to establish the PP trends at all depths. All wells share the same stratigraphy, and above the Base Cretaceous unconformity they share the same PP regime. However, below Base Cretaceous, the four wells located to the west of a major fault system have high OP in the Jurassic-Triassic reservoirs, compared to the eight wells to the east of the fault system with low to no OP (Fig. 3). Since the LOTs in each well are located close to top reservoir, the OP has been related to the PP profiles and their proximity to known reservoir pressures in 11 out of the 12 wells. Plotting the LOT data against depth below sea level (Fig. 3) illustrates:

- At depths from 230 m to 2320 m TVD seabed LOTs have similar magnitude for all wells.
- Below 3300 m is a group of “high” LOT pressures (“High LOT” ellipse), and a group of “low” LOT pressures (“Low LOT” ellipse).
- The “high” LOTs are from wells with a high PP trend (black dotted line) and the “low” LOTs come from wells where the PP has low or no OP (grey dashed line).

The data have been analysed using the method described above, including reconstruction of a semi-regional lithostatic gradient from available density data. LOT data from depths less than 1200 m,