Geological implications of a large pressure difference across a small fault in the Viking Graben

C. Childs[1], T. Manzocchi[1], P. Nell[1], J.J. Walsh[1], A.E. Heath[1] & .T.H. Lygren[2] & J. A. Strand[1]

1. Fault Analysis Group, Univeristy College Dublin, Ireland.
2. Norsk Hydro, Oseberg Exploration, Norway.

Two overpressured blocks in the Viking Graben (Block 30/8) have a pore pressure difference of 130bars (Fig. 1). Within the deeper block, which covers the southern part of the Tune Field, the fluids are overpressured by 150 bars, while the shallower block has 22bars of overpressure. The blocks are separated by a fault which has a throw of 100s of metres over most of its length, but the fault trace steps across a relay ramp where it branches into several smaller faults, the largest of which has a throw of ca 50m (Fig.2). This throw is insufficient to completely offset the entire reservoir interval.

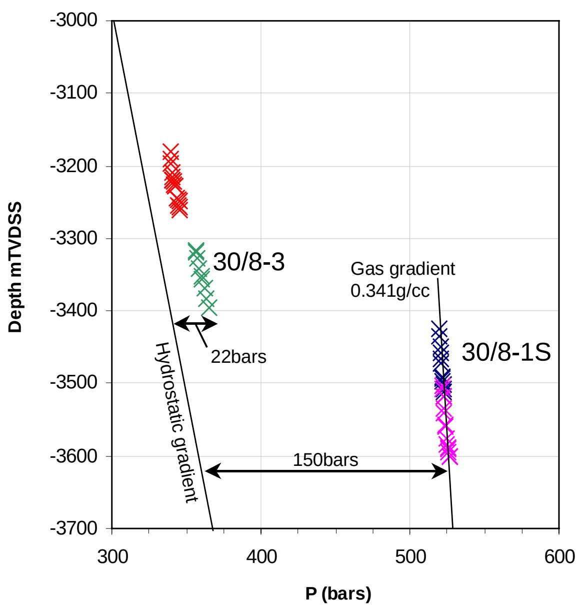

Fig .1. RFT data for wells 30/8-3 and 30/8-1S. The base of the predominantly gas column in 30/8-1S is at 3589m.

Modelling the diffusion of a pressure pulse across the fault, using the diffusion equation of Deming (1994), suggests that the pressure difference could not be supported hydrostatically over a geologically significant period. We have therefore performed single-phase flow modelling to establish the conditions required to sustain high pressure gradients across the

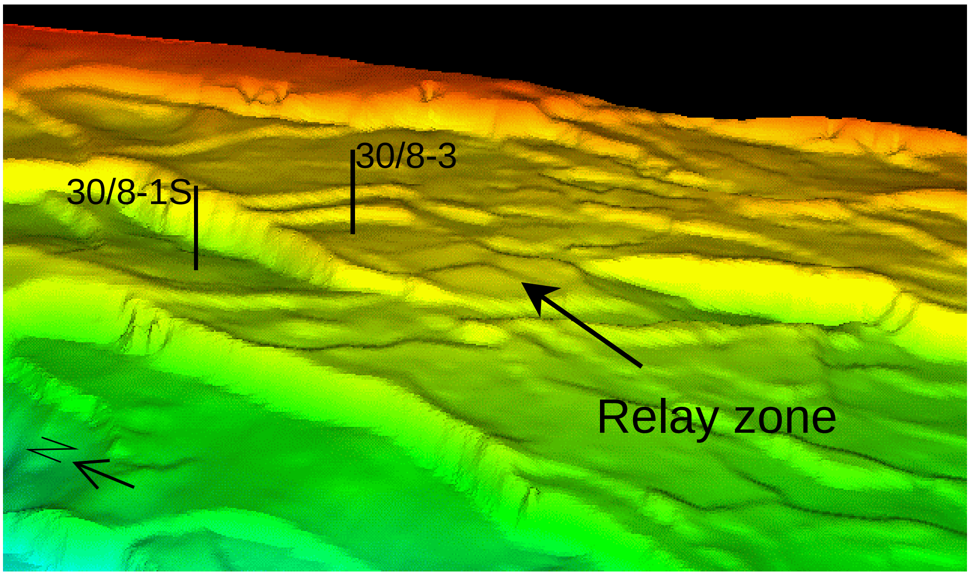

Fig. 2. 3D view of the surface of the Tarbert reservoir, showing the locations of the 30/8-3 and 30/8-1S wells. The fault between the two wells steps to the south across a relay zone.

relatively small offset fault in a hydrodynamic setting: flow is attributed to continuing sediment compaction and/or hydrocarbon generation.

Mapping of the structure between the overpressured blocks provides the basis for construction of a fine scale ECLIPSE model that accurately represents the faulted reservoir geometry and the patterns of across-fault lithological juxtapositions. Transmissibility multipliers are attached to the faulted grid cell faces following the method of Manzocchi et al (1999). In this method, user-defined fault permeability and thickness values can be attached to faults, as transmissibility multipliers, following a variety of geologically based models. One such model, assumes that the percentage shale in the sequence faulted past a point on a fault surface (referred to as Shale Gouge Ratio, SGR) is related to the permeability of the fault rock (Manzocchi et al. 1999), and that the displacement is proportional to fault rock thickness. This model can also include depth-dependent permeability changes. The advantage of geologically based models is that flow modelling results can be interpreted in geological terms (Fig 3). Although indexed to SGR, fault rock permeabilities may be controlled by a variety of processes including shaley gouge formation and quartz cementation.

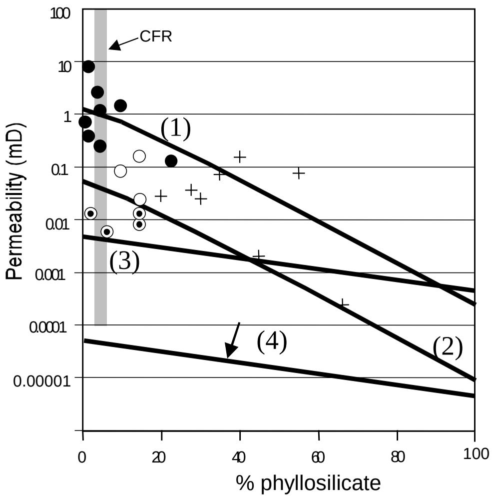

Fig.3. Variation in fault permeability with % phyllosilicate (after Gibson 1998). Heavy lines show four SGR to permeability relationships that were used to assign fault transmissibility multipliers. The lowest permeability case (fourth, arrowed) is the only one to satisfy the known pore pressure distribution. The shaded area labelled CFR is the range of measured permeabilities for cataclastic fault rocks from the North Sea (Knipe et al 1997)

Flow modelling was performed using a variety of boundary conditions. The simplest was controlled by water injection and production at the wells at pressures matched by those observed. Once stable flow was established between the wells, across-fault flow rates were determined. Flow modelling realisations have been conducted using different relationships between SGR and fault permeability (Fig. 3). Each realisation matches the pressures at the wells, but only the lowest permeability case provides the approximately uniform pressures observed within individual fault blocks (Fig. 4).

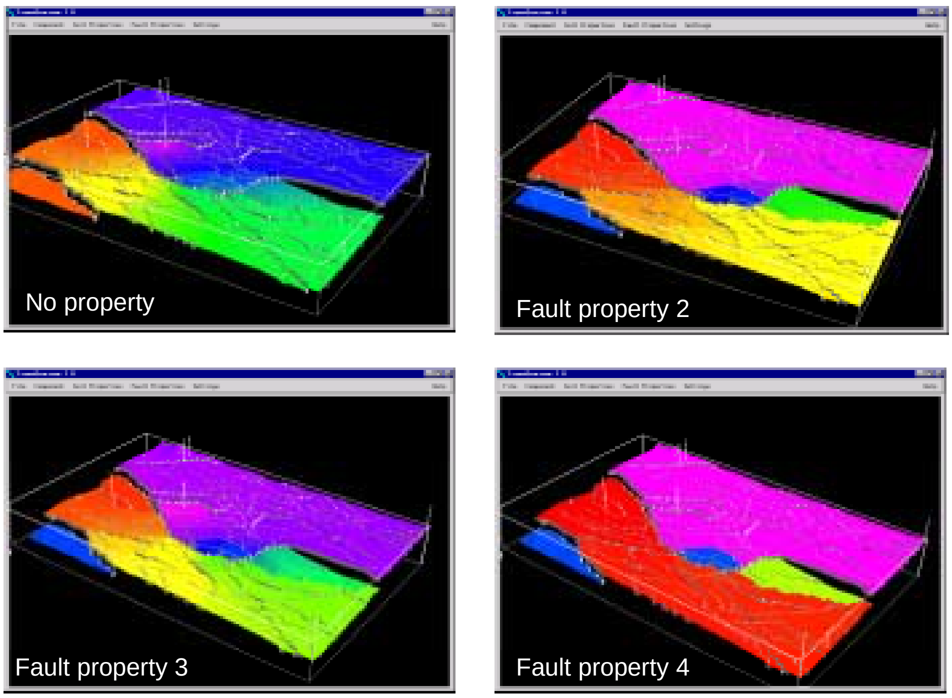

Fig. 4. Pressure distribution within the ECLIPSE model for four different fault property cases (lablled on Fig. 3). The relay zone separating the two fault segments is at the centre of the view and the view is towards NE. Fault property case 4 is the lowest permeability realisation.

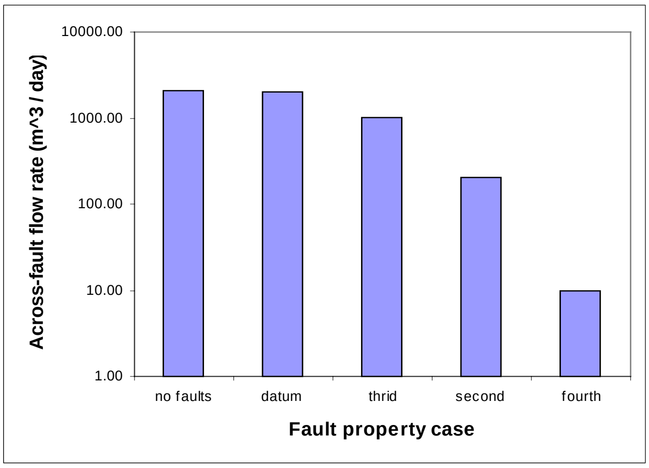

Fig. 5. Across fault flow rates determined for each fault permeability case

This lowest permeability (fourth) case requires not only that the fault permeabilities are lower than the measured range for the expected fault rock types (Fig. 3), but also that the across fault flow rates are very high, ca $10m^3$ per day (Fig. 5). This implies: (i) substantial focussing of fluid flow across the relay structure, (ii) elevated pressures from present-day hydrocarbon generation and/or (iii) extremely low fault rock permeabilities or extensive fault zones, perhaps due to quartz cementation within relatively wide, diffuse zones of small-scale faulting in the ramp.

References

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