Modelling of fluid flow and overpressure - A discussion

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Significant overpressures are either controlled mechanically by the fracture pressure or by the matrix permeability if there is no leakage on fractures. In a recent publication in this journal Nysæther (2006) attempts to explain the degree of overpressure in reservoirs from Haltenbanken based on a pressure cell model. The paper contains interesting data and discussions, but his model is based on much too simplistic assumptions about fluid flow in sedimentary basins.

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In a recent publication in this journal Nysæther (2006) attempts to explain the degree of overpressure in reservoirs from Haltenbanken based on a pressure cell model. He considers reservoir sandstones to be pressure cells which receive an inflow of water from the adjacent shales in their lower parts and export water into shales near the upper parts of the reservoir. The pressure cell is driven by a regional shale pressure gradient and a near hydrostatic gradient in the sandstone.

It is true that the pressure gradients in the shales are normally higher than in the sandstones:

This follows from the Darcy equation that the fluid flux (F) is a function of the permeability (k):

$$F=k.\cdot\nabla P/\mu$$

In subsiding sedimentary basins the fluid flux (F) is a function of the rate of compaction (porosity loss) and water released by dewatering of minerals (Bjørlykke 1993). For a limited depth interval the viscosity (μ) can be taken to be constant and the pressure (potensiometric) gradient (∇P) and the permeability (k) will vary inversely if the fluid flux (F) is constant.

Compaction is a slow process and in subsiding sedimentary basins the rate of mechanical compaction and fluid flux is not likely to vary abruptly. Mechanical compaction is a function of the effective stress which is in turn a function of the overburden and thereby also the sedimentation rate. Overpressure thus provide a negative feedback on the effective stress.

Chemical compaction is a function of temperature and, the resulting fluid flux (F) will be relatively constant over a limited period of geologic time.

The permeability, even in relatively tight sandstones, is 10^{-2}-10^{-3} Darcy and shales often have permabilities less than 10^{-9} Darcy. For practical purposes the pressure gradients in sandstones are hydrostatic which is also assumed by Nysæther (2006) while shales may have high gradients

In shales the pressure gradients may be very much higher because the permeabilities are lower, but shales are not homogeneous as assumed by Nysæther (2006). Mudstones and shales are as heterogeneous as sandstones and limestone and the permeability varies greatly. In addition, the permeability parallel to bedding may be very much higher than vertically both because of the alignment of clay minerals in the shales and because of the alternation of layers with variable contents of silt, sand and carbonate cement. The permeability will vary depending on the clay mineral composition (Mondol et al. 2006).

Nysæther (2006) has assumed that the pressures in shales are controlled by a regional shale pressure gradient (green) which is linear as a function of depth, also close to the sandstones. It is then obvious that water will flow in the way he has indicated (red arrows). However even a very small flux from the shales into the sand would reduce the pressure gradients in the adjacent shales and then reduce the flux. The regional shale pressure gradient is entirely hypothetical. There are no reliable data recording pressure gradient from shales and there is no reason why there should be a linear gradient because also in shales permeabilities vary greatly and the pressure gradient will vary accordingly following the Darcy equation above.

If however the pressures in the shales are close to fracture pressure the pressure gradient can be defined by the

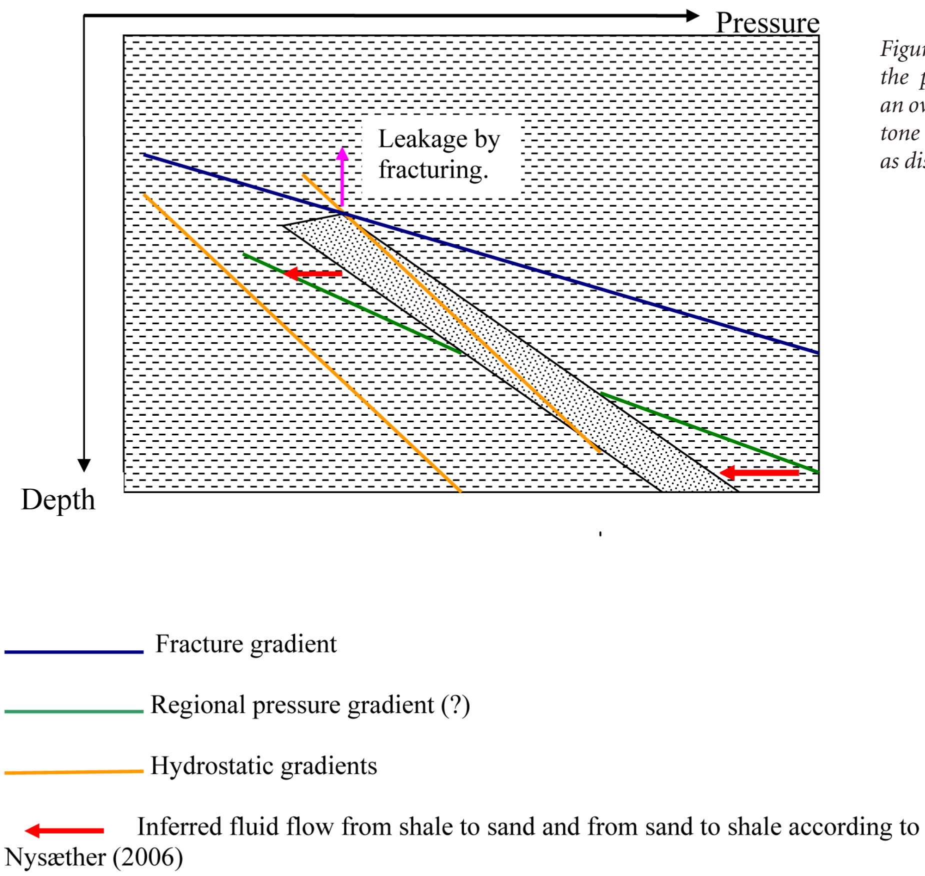

Figure 1. Schematic illustration of the principle pressure gradients in an overpressured basin with a sandstone reservoir surrounded by shales as discussed by Nysæther (2006).

fracture gradients which are relatively linear. The fracture pressure is indicated with a blue line (Fig1) and fracture pressure in the shales would be reached near the top of the sandstone structure. The flow would then be into the sandstone from the shales, also near the top of the structure except at the very top where leakage would occur because of hydrofracturing. When fracture pressure is reached, the matrix permeability of the shales is no longer the main controlling factor for fluid flow.

Calculations of fluid flow and pressures in sedimentary basins can easily become circular. By assuming that the pressure difference between the sandstone and the shale and the permeability remains constant Nysæther (2006) calculates the fluid flow in and out of the sandstone as a function of depth (Nysæther 2006, Table 1). He then arrives at a flow of 104 m^3/Ma for the uppermost 60 m of the reservoir sandstone, and an even higher input near the base without quantifying the supply of the fluids. He admits that his model does not consider the drop in pressure gradients which must result from the flow from the shales. The rate of compaction in the adjacent shales is rate limiting for the flow into the sandstones, not the pressure gradients or the permeability.

The permeability in these calculations is assumed to be 4.18 10^{-21} at 3260 meters depth decreasing linearly to 9.37 10^{-22} at 3900 m. Does the author think that the permeability in sedimentary rocks is a simple function of depth regardless of changes in composition of the sediments? Is this permeability perpendicular to bedding? In the case where shales onlap sandstones the permeability parallel to bedding may be critical.

The pressure cell circulation is also proposed to include the hydrocarbon column and water may flow through the water in the oil saturated part according to Bjørkum et al. 1998, 1999.

If hundreds of m^3 of water should flow through the top of the reservoir as suggested by Nysæther (2006) much of the most soluble hydrocarbons such as methane and benzene will be removed.

The main control on the pressure in Haltenbanken reservoirs is the degree of lateral drainage maintaining nearly hydrostatic pressures in the Smøbukk Field and other fields east of the Klakk fault and overpressures in the reservoirs on the western side of this fault complex (Olstad 1997; Karlsen et al 2004).

While the degree of overpressure in the northern North Sea seems to be controlled by the present day fracture pressure estimated from the Leak Off Tests (LOT) the overpressure in many Haltenbanken reservoirs may be considerably lower.

This has been attributed to leakage caused by high differential horizontal stresses (Hermanrud & Norgaard 2002). Differential stresses (reduced horizontal stress) may also be caused by the relief near the continental shelf and slope to the west (Bjørlykke et al. 2005).

Conclusion:

Significant overpressures are either controlled mechanically by the fracture pressure or by the matrix permeability if there is no leakage on fractures.
In his model (Nysæther 2006) has assumed that the pressure is controlled by the matrix permeability in shales ignoring possible effects of fracture pressures. He has also assumed that the shales are very homogeneous with a regular linear permeability gradient. The fluid flow modeling is based on a constant pressure difference between shales and sandstone disregarding the effects of fluid flow which would lower the pressure gradients. If the pressure cells should include the oil column significant dissolution and removal of the most water soluble hydrocarbons should have occurred.

We still do not fully understand the factors controlling the pressures in some of the reservoir sandstones at Haltenbanken, but the model proposed by Nysæther (2006) is based on unrealistic assumptions.

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