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Role of effective permeability distribution in estimating overpressure using basin modelling

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ABSTRACT

Overpressure generation is a function of the rates of sedimentation, compaction, fluid generation from kerogen and dehydration of minerals, and most importantly the lateral distribution of permeability within a basin as this controls lateral drainage. Sedimentary basins, however, are typically highly heterogeneous with respect to primary sedimentary facies, diagenesis and tectonic development. While fluid flow models based on idealised homogeneous basins may further our understanding of the processes that influence overpressure development, the results are very sensitive to the distribution of rock properties, particularly permeability. The absolute permeability of sedimentary rocks varies from more than 1 Darcy to less than 0.01 nanodarcy (nD) (10^{-11} Darcy).

Simple calculations, assuming vertical flow and no lateral drainage within the basin, show that overpressures approaching fracture pressure in the overburden will be reached if the effective permeability of the shale forming the seal is less than 0.1–0.01 nD (1.10^{-22}–1.10^{-23} m^2). The permeability of shales varies greatly as a function of primary textural and minnerlogical composition and it is not possible to accurately predict the effective permeability of a sequence of shales forming pressure barriers. Overpressure in uplifted basins, where there is no compaction taking place, can only be maintained over geological time if the permeabilities are much lower. Overpressure is often controlled by lateral drainage but the effective permeabilities for fluid flow across faults and the offset of permeable layers are also difficult to predict. In most cases, uncalibrated basin modelling is unable to accurately predict the magnitude and distribution of overpressures because the vertical and horizontal permeabilities in sedimentary basins cannot be determined in sufficient detail. In basins that have been extensively explored and developed, incorporation of prior geological knowledge into basin models may allow overpressures to be predicted ahead of the drill bit. However, with such a large body of information already gathered about the basin it is debatable what extra value basin modelling is providing to pressure predictions.

1. Introduction

Basin modelling is in most cases based on relatively simple formulations of geological processes, but for input may require rather detailed descriptions of the distribution of sediments and their physical properties in the basin.

Basin modelling has become a frequently used tool to simulate basin subsidence, sedimentation, compaction and overpressure distribution (e.g. Mudford et al., 1991; Borge, 2002; Lothe et al., 2004; Hansom and Lee, 2005) and increased computing power has made three-dimensional analysis of large parts of sedimentary basins possible. Overpressure development is determined primarily by the permeability of the rocks (usually shales) forming the seal and by fluid flux during compaction. However, the extent to which these parameters can be predicted in any numerical model of a sedimentary basin is limited both by the formulation of the compaction model and by the accuracy of the input data. The result is very sensitive to quite small changes in rock properties, particularly permeability. The main problem is thus to provide accurate input data regarding the distribution of lithologies. This is especially so in areas with little well control, where prediction is most needed. The input requirements for basin modelling include

- Data about the primary composition and distribution of the different rock types.
- A quantitative formulation of the most important physical and chemical processes affecting the sedimentary rocks during burial and uplift (exhumation).

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- Changes in temperature and pressure (stress) as a function of time during burial and uplift.
- A detailed description of the coupling between various processes (e.g. temperature and permeability evolution).

Modelling of overpressure provides a good example to highlight some of the problems with geological modelling. Small-scale heterogeneities such as faults or sandstone pinch-outs may have a huge impact on fluid flow and the distribution of such heterogeneities is often difficult, if not impossible, to obtain from seismic data. Even when extensive core and log data are available it is difficult to determine the effective permeability for fluid flow modelling due to uncertainties in the lateral sediment distribution and their properties after diagenesis. A particular problem is that fluid flow models require very detailed descriptions of the basin and the modelling may then become circular in the sense that the required input is part of what should be predicted.

Modelling of sediment compaction (diagenesis) is critical both for the prediction of fluid flow and for the permeability of the seals during burial and this demands knowledge of the primary mineralogical and textural composition of the sediment as well as the temperature and stress history. Mechanical compaction follows the rules of soil and rock mechanics, but the compaction curves are very different depending on the primary sediment mineralogy and grain-size distribution. This is also true of chemical compaction, which in siliceous rocks is mainly a function of temperature history (Bjørlykke and Høeg, 1997). Clays and mudstones also display great variability, depending on the clay mineralogical composition (Storvoll et al., 2005; Marcussen et al., 2009). Fluid pressure in the subsurface is therefore a complex function of primary lithology, subsidence rate and mechanical and chemical compaction (Fig. 1).

The reservoir quality (porosity loss) of sandstones may be modelled rather successfully (Walderhaug, 1996; Lander and Walderhaug, 1999), but only when there is information on both the surface area available for quartz cementation, and the temperature history. The prediction of reservoir quality therefore becomes very much a question of predicting the primary sediment composition.

Petroleum generation from kerogen has also been modelled relatively successfully because it depends mainly on the primary composition (activation energy) of the kerogen and the temperature history (Welte et al., 1997). These parameters can be reasonably well constrained, but the model is sensitive to rather small variations in activation energy and temperature and, to a lesser extent, fluid pressure. Modelling heat and fluid transport in sedimentary basins is more difficult because it depends not only on the properties and processes in a specific rock volume, but also on the flow properties of thick sequences of sedimentary rocks. The thermal conductivity varies between 1 and 5 W/mK (Allen and Allen, 2005; Midttømme and Roaldset, 1999) and is much better constrained than the conductivity (permeability) for fluid flow.

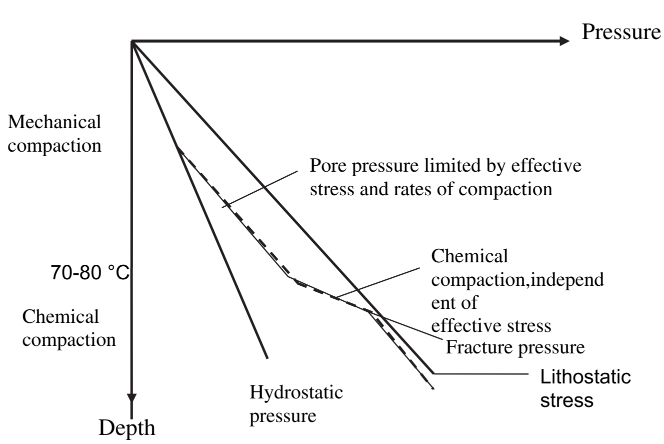

Fig. 1. Simplified presentation of sediment compaction and build-up of high pore pressure (overpressure). When overpressure reduces the effective stress, mechanical compaction stops but chemical compaction continues. During mechanical compaction a build-up of pore pressure will retard compaction and high overpressures must then be due to fluid flow within deeper parts of the basin. At temperatures above 70–80 °C where chemical compaction is dominant, sediment compaction will continue as a function of temperature also at very low effective stresses. Fracture pressures may then be reached by internal compaction.

It is the basic aim of this paper to highlight some of the fundamental constraints on the use of basin modelling for the prediction of overpressure development in sedimentary basins. The paper begins by reviewing the controls on overpressure generation in sedimentary basins. We then go on to estimate the permeability of seals based on geological constraints such as pressure distributions within the subsurface and the thickness of sealing lithologies. Finally, a discussion of pore pressure prediction using basin models is provided.

2. Controls on overpressure generation

Fluid flow modelling is based on the Darcy equation where the fluid flux (F) is a function of the pressure gradient in the fluid phase (ΔP), the viscosity of the fluid phase (μ) and the permeability of the rocks (k):

$$F = k\nabla P/\mu \tag{1}$$

The viscosity of water is mainly a function of temperature and is normally the best constrained parameter. Permeability is an expression of the resistance to fluid flow, relating fluid flux to pressure gradients. It is evident from the Darcy equation that two end-member scenarios may result in overpressure development. First, if permeability is kept constant, an increase in the fluid flux results in an increase in the pressure gradient. Second, reductions in permeability will increase fluid pressure gradients if the flux is constant. The distributions of fluid pressure and pressure gradients in sedimentary basins are therefore functions of both the flux and the permeability *in all directions over long distances* (Bjørlykke, 1997).

Models for the prediction of overpressure are often based on changes in fluid flux, but with less emphasis on the permeability. If the permeability is kept constant, it is possible to model overpressure as a function of other variables such as rates of compaction, hydrocarbon generation and thermal expansion of the porewater (Osborne and Swarbrick, 1997; Luo and Vasseur, 1992; Hansom and Lee, 2005). In the remainder of this section we review the controls on permeability and fluid flux within sedimentary basins. We place particular emphasis on the problems associated with predicting the permeability distribution and the porewater flux.

2.1. Permeability distribution

Permeability is a rock property that varies through an extremely wide range of values, and is by far the most difficult parameter to constrain. The permeability of sedimentary rocks may vary from several Darcys in sandstones to less than 10^{-11} Darcy in shales (Rieke and Chillingarian, 1974). Modelling fluid flow and overpressure requires that the permeability is known along the entire fluid flow pathway up to the surface. Predictions of fluid pressure therefore require that the permeability in large parts of sedimentary basins can be described in great detail, both in space and time. Unfortunately, there are several major constraints on our ability to predict permeability distributions, both at the present time and in the geological past. Direct measurements of permeability can only