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Fluid flow pipes triggered by lateral pressure transfer in the deepwater western Niger Delta

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ABSTRACT

Using three-dimensional (3D) seismic data, we establish a simple model for the development of vertical fluid flow pipes in the deepwater western Niger Delta. We analyse two examples of fluid flow pipes that form vertical seismic chimneys that are 400–600 m wide and ~2000–2500 m in height, terminate at the current seabed and have bases located at the crest of rollover anticlines. In both cases we identify buried deepwater channels-complexes located below the pipes that formed prior to the growth of the rollover anticlines. The development of the anticlines caused tilting of these channel complexes and differential loading. We propose the channel complexes represent connected permeable reservoir intervals and that lateral pressure transfer caused the pore pressure at the crest of the structures to reach critical levels, leading to hydraulic fracturing of the overburden. Although hydrocarbons may migrate upwards through the chimney systems, they are not necessarily indicators that the channel complexes were gas or oil charged.

1. Introduction

The occurrence of fluid flow pipes is often linked to the presence of an active petroleum system (Grauls and Baleix, 1994; Ingram and Urai, 1999; Stewart and Davies, 2006; Cartwright et al., 2007) and therefore could be used as a hydrocarbon indicator (Grunau, 1987). Vertical fluid conduits above folds commonly occur in basins with high sedimentation rates (Huuse et al., 2010) on both active margins (Caspian Sea – Stewart and Davies, 2006; Trinidad – Deville et al., 2010; Brunei: Van Rensbergen and Morley, 2003) and passive continental margins, such as the Atlantic Ocean and Gulf of Mexico (Dugan and Flemings, 2000; Seldon and Flemings, 2005; Reilly and Flemings, 2010), the Nile delta (Loncke et al., 2004; Feseker et al., 2010), west Africa (Moss and Cartwright, 2010), and the Niger Delta (Graue, 2000).

Recent research has been focusing on the recognition of fluid flow pipes, mainly from seismic data (Cartwright, 2007; Cartwright et al., 2007; Moss and Cartwright, 2010). Løseth et al. (2010) also compared kilometer-scale fluid flow pipes in the Niger Delta to field examples in Greece. In such environments, it is generally considered that vertical escape pipes result from an escape of buoyant hydrocarbons (Cobbold et al., 2009; Løseth et al., 2010). But vertical conduit systems may be primed and triggered by pressure in reservoir intervals that develops due to the existence of structural relief and connected permeable strata (Bjørkum et al., 1998). The assumption that vertical conduits are the result of hydrocarbons causing seal failure may be erroneous (Bjørkum et al., 1998; Nordgard Bolas and Hermanrud, 2003; Heggland, 2005).

This paper considers the structural and stratigraphic setting of two significant fluid flow pipes in a deepwater environment in order to assess the geological processes leading to critical pressuring and vertical fluid flow. We develop a simple, generally applicable model for a how fine grained deepwater sedimentation, channel development and fold growth, can lead to the establishment of overpressure and catastrophic seal failure without the requirement for a hydrocarbon column.

1.1. Overpressure

High sedimentation rates cause a rapid increase in the vertical stress that is applied onto the stratigraphic column and leads to sediment compaction. In low permeability sediments, pore fluid is prevented from escaping and the lithostatic load is imposed upon

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it. This process is known as disequilibrium compaction (Dickinson, 1953) and is the main cause of overpressure in mudstone-rich Cenozoic basins deltas (Swarbrick and Osborne, 1998). Tilting of permeable reservoir intervals can also cause overpressure due to lateral pressure transfer (Yardley and Swarbrick, 2000), otherwise known as the centroid model (Traugott and Heppard, 1994; Finkbeiner et al., 2001). Lateral pressure transfer is characterized by an upward increase in the pressure gradient, in a sealed reservoir at hydrostatic pressure, as a response to the reservoir interval tilt. In this case study, permeable reservoirs are preserved sands from deepwater turbidite channels and structural deformation is a potential source of lateral pressure transfer.

Fluid flow due to lateral pressure transfer in permeable reservoirs can contribute significantly to increasing pore pressure at the crest of the reservoir (Reilly and Flemings, 2010). At a depth termed the centroid depth, pressure is balanced within the reservoir, between the section of the reservoir that is above and below the centroid depth (Traugott and Heppard, 1997). Pressures can reach the pressure required to cause hydraulic fracturing (Fig. 1). Pore pressure and horizontal stress are coupled (Mourgues and Cobbold, 2003) and can be quantified from well data (Mourgues et al., 2011). Well data were not available for publication in this study, we therefore use estimated pressure values based upon well-known and established gradients, such as the hydrostatic gradient, and the shale gradient combined with the minimum stress gradient, estimated from geological analogues (Heppard et al., 1998; Nashaat, 1998; Swarbrick and Osborne, 1998; Tingay et al., 2009).

1.2. Fluid flow pipes

A hydraulic fracture should develop perpendicular to the direction of minimum compressive stress (Secor, 1965; Hubbert and Willis, 1972). Fluid conduits will form if sufficient pressure is present to reach the hydraulic fracture pressure and breach the caprock of a given reservoir interval (Fig. 1). This mechanism has been recognized in previous studies on vertically-focused fluid flows (Hovland and Judd, 1988; Miller, 1995).

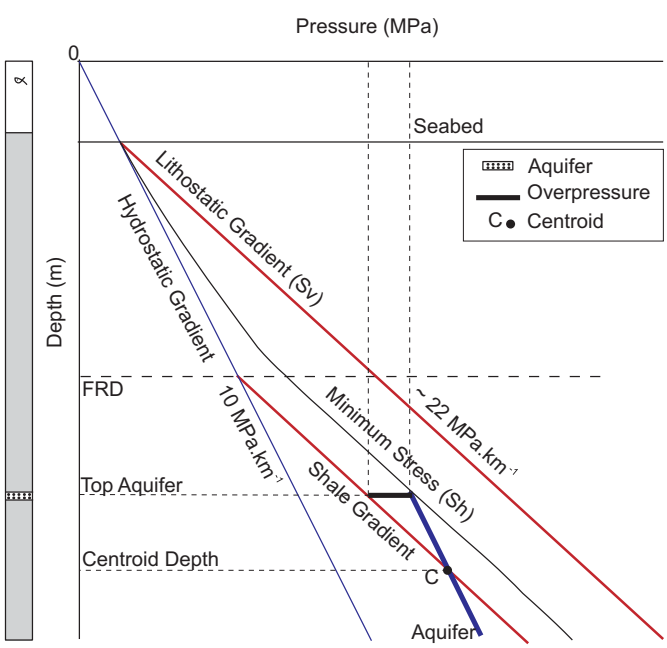

Figure 1. Theoretical pressure–depth plot showing the parameters taken into account to determine overpressure in this case study showing hydrostatic, lithostatic and shale gradient. The shale gradient is drawn from the fluid retention depth (FRD), representing the top of overpressure in the overburden and is function to the local sedimentation rate. The minimum horizontal stress (Sh) is indicated for a structural setting in extension; gradient is obtained from Grauls (1999) and Deville et al. (2010).

Fluid flow pipes can be identified on 3D seismic data as subvertical zones of disturbed reflection or stacked amplitude anomalies (Cartwright, 2007). They can bypass hydrocarbons seals (Cartwright et al., 2007). They were first described in the Niger Delta by Løseth et al. (2010), and literature in the past decade has considered how to recognize fluid flow pipes from 3D seismic data and their morphological, lithological and seismic character (Davies, 2003; Cartwright, 2007; Cartwright et al., 2007 Huuse et al., 2010; Moss and Cartwright, 2010; Løseth et al., 2010).

1.3. Geological setting

The deepwater western Niger Delta, Gulf of Guinea (Fig. 2A) is a mud-rich Cenozoic prograding sedimentary accumulation, where updip extension expressed by regional-scale growth faults is linked to downdip compression with fold-and-thrust belts (Doust and Omatsola, 1990; Morley and Guerin, 1996). This historically has been considered to occur at the first development of overpressure coincident with detachment faults (e.g. Briggs et al., 2006). The 7–10 km-thick succession was deposited from the middle Miocene to the Holocene (Short and Stauble, 1967). It is part of the Agbada and the Benin Formations. In cross-section, the seismic signature is characterized by mid to high amplitude reflection packages, including, high amplitude parallel to chaotic lenses associated with channel–levees complexes. Deposition of sediments at high rates leads to rapid loading and in low permeability sediment can cause overpressure. Unpublished well data in the study area provide an estimate of about 2000 m in 11.6 Ma (approximately 160 m My^{-1}). Overburden undergoes gravity-driven deformation above deeply buried, overpressured strata (Cobbold et al., 2009). Smaller-scale deformation caused by overpressure and sediment remobilization also occurs, for instance fluid flow pipes and mud volcanoes (Graue, 2000; Heggland et al., 2001; Kopf, 2002) and kilometre-scale fluidization features (Davies, 2003) have been described.

1.4. Structural setting

The area of study is located at the periphery of a major growth fault and a lateral strike-slip fault that developed contemporaneously (Fig. 2B). Here extension, strike-slip deformation and compression are kinematically linked (Leduc et al., 2012). Deformation occurred in several stages as the study area was located within the contractional domain of a regional gravity detachment system in the Miocene. A period of reorganization of the regional system then resulted in the development of strike-slip faulting at the margins of the gravitational detachment lobes, resulting in the growth of E–W to NE–SW oriented elongated structures. Finally, more recent delta progradation and resulting structural evolution triggered regional, coast-parallel normal and growth faulting which structures orientation is approximately WNW–ESE.

2. Data and methodology

We use three seismic volumes located in water depths of between 500 and 2000 m on a southwest-dipping slope and cover an area of 4300 km^2. The surveys were acquired in 1998 with a bin spacing of 12.5 m by 18.75 m. Data are zero-phase migrated and are displayed in two-way travel time (twt), with a vertical resolution of about 10–20 m at the depth of our seismic interpretation. The dominant frequency is ~45–50 Hz. We interpret four regional horizon reflections (named 1, 2, 3 and 4) from the deepest to the shallowest (Fig. 3A and B) mapped around a sub-circular structural high. These horizons delineate five stratigraphic units from