Integration of 4D Seismic Data and the Dynamic Reservoir Model - Revealing New Targets in Gannet C

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Abstract

Two sets of 4D seismic data gave major new insights into the structure and dynamic behaviour of the Gannet C oil and gas reservoir in the UK Central North Sea. The 4D data revealed major extensions of reservoir units previously presumed to be absent or thin over much of the reservoir. Furthermore, in a subsea field with significant uncertainty of production allocation, 4D also proved an invaluable history matching parameter for the dynamic model. Together, the dynamic model and the 4D data gave rise to the identification of one recompletion opportunity and two infill well opportunities, to produce oil volumes in existing and newly identified reservoir sands.

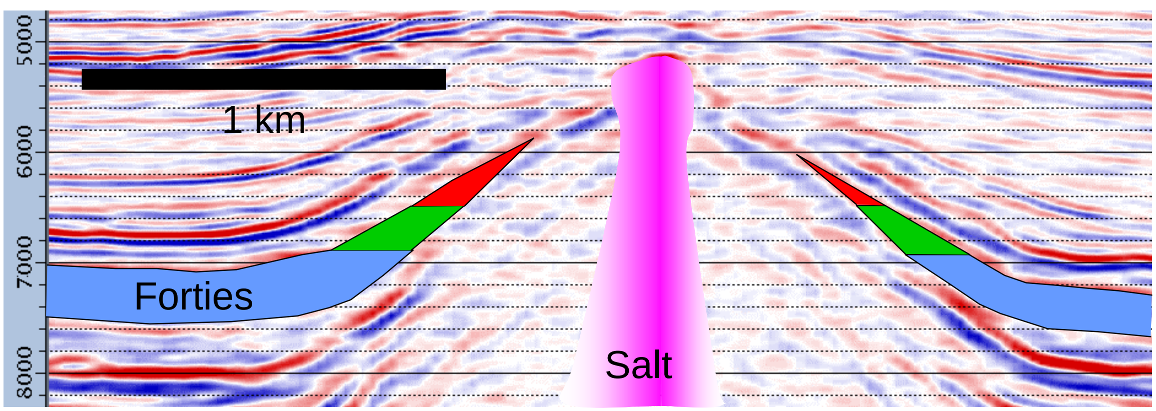

Figure 1. West-east cross section across the northern part of Gannet C showing pre-production fluid distribution in the Forties and very approximate salt structure. All figure depths in ft. (No vertical exaggeration on this figure).

Introduction

The Gannet C field lies in 95m of water in the UK Central North Sea, near the western edge of the Central Graben. It is believed to contain around 160 million bbls of oil and 290 Bcf of gas. Syn- and post-depositional salt diapir growth has resulted in a ring-shaped field, with the Paleocene Forties turbidite sands pierced by the salt. They contain an oil rim some 400 ft thick, below a gas cap at least 500 ft thick (Fig. 1). The sand porosity is typically 28%; the sand is largely clean (though with thin shale stringers), and the oil light (38° API). The syn- and post-depositional uplift resulted in variable reservoir thickness, variable permeability (100-300 mD), and significant radial faulting whose fault seal / baffle potential is uncertain. The Forties is around 500 – 600 ft thick off structure pinching out completely towards the crest of the structure. The field was initially produced by aquifer drive with eight horizontal wells landed around 250 ft up in the oil rim, whilst some of the produced gas-cap gas was reinjected into a deviated well in the south of the field. The current field depletion is around 400 p.s.i.

During early experimentation with time-lapse (4D) seismic in the North Sea, it was recognized that from a rock and fluid perspective, Gannet C represented a good candidate for 4D, and a relatively modern (1993) baseline seismic survey was available, although it was recognized that up-dip imaging remained a challenge (the steep flanks exceed 60° dip in places).

Monitor acquisition

The field is a subsea development (tied back to the Gannet A platform) and therefore there is no surface obstruction to hinder repetition of baseline sail lines. Currents in the region are mild and largely tidal dominated.

The first monitor survey acquired in 1998 represented the first dedicated 4D survey acquired by Shell in the UK, but learning from previous non-dedicated work, and knowing this survey would ‘pave-the-way’, carefully repeated acquisition and dedicated re-processing resulted in an NRMS noise level (after matching, time-alignment and noise reduction) of just 0.14, a result that we did not improve on elsewhere for several years!

Another monitor survey was acquired in 2004 as part of a regional 4D survey that covered six of the seven Gannet fields. By this time Shell / Concept Systems had developed 4D repeatability monitoring systems (Smit et al, 2005) to ensure the 4D repeatability as well as 3D quality of the data, despite shooting in marginal Autumn weather. All surveys were acquired with conventional streamers.

4D interpretation

Qualitative interpretation was possible over two-thirds of the field, but only limited analysis was possible over the northern parts of the field, where the steepest dips reduced image quality. Most of the interpretation was performed directly on phase rotated difference data (Fig. 2). Quadrature data (pure 90° phase rotation) and bandwidth-reduced pseudo-impedance data (cf. ‘coloured inversion’) were both used to show the aquifer swept zone, though the quadrature data was most appropriate for thin areas of sweep, whilst the bandwidth-reduced data was most appropriate in thicker areas of sweep. To first order, the top of the hardening loop was considered as the produced oil water contact (OWC).

This assumption is only really accurate when the thickness of the swept zone is close to the tuning thickness. Where the swept zone was less than 100 ft thick, the interpreted OWC will be higher than the real contact. Where the sweep thickness exceeded 200 ft (e.g. areas B and C on Fig. 2), the 4D loop loses amplitude and the interpreted OWC may be higher than picked. This means that in some cases it is preferable to pick contacts on incremental cubes (i.e. '98-'93 and '04-'98) where the contact movement is less than on the cumulative cube (i.e. '04-'93). Where the flood zone is so thick that no interference occurs between the original and the producing contact, some interpretation was also performed on reflectivity difference data, with the producing oil-water contact shown as a hardening reflector. At Gannet C, this method was considered both fit-for-purpose and appropriate (given the poor up-dip imaging on this survey), although elsewhere, in Gannet A with better imaging, a stronger DHI, and interference between a moving OWC and GOC, detailed quantitative studies of tuning 4D signals have been performed (Staples et al, 2005).

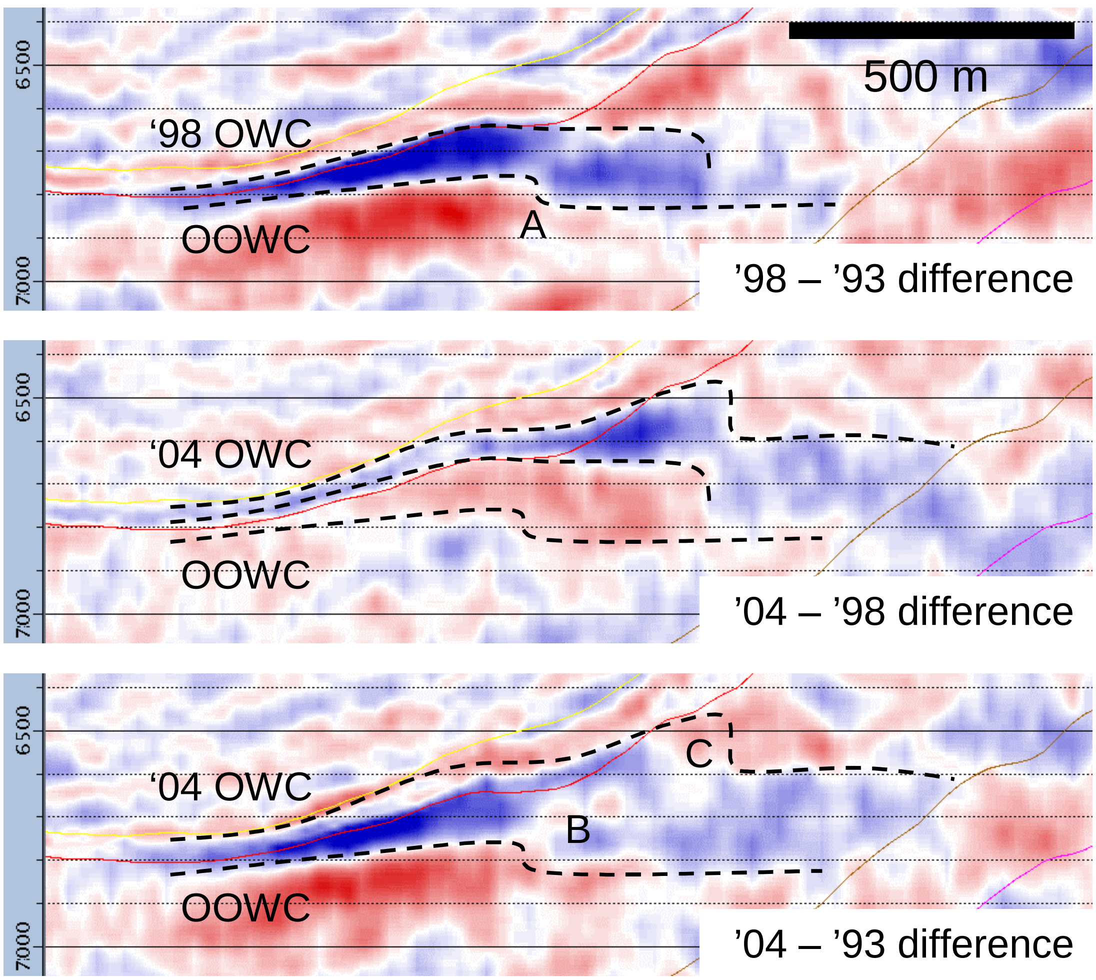

Figure 2. Interpreting contacts on pseudo-impedance difference cubes. The upper two sections represent incremental time-steps, whilst the lowest one represents the whole time period.

Fault communication

A pre-production oil-water contact was visible in many areas on 3D seismic, although due to its interference with lithology and variations in time-depth conversion, there was some uncertainty over the premise that it was completely flat. However, an analysis of the 4D data (in which lithological effects are at least reduced), especially around the south and east of the field, showed that the original contact must have varied in depth across some fault boundaries (i.e. from fault block to fault block) by up to 50 ft (e.g. point A in Fig. 2). The inclusion of this varied original OWC helped in the history matching of the field.

The 1998 data showed that the entire ring-shaped field was being drained (by virtue of the aquifer influx seen on 4D), but that the level of drainage varied from block to block (Fig. 3).

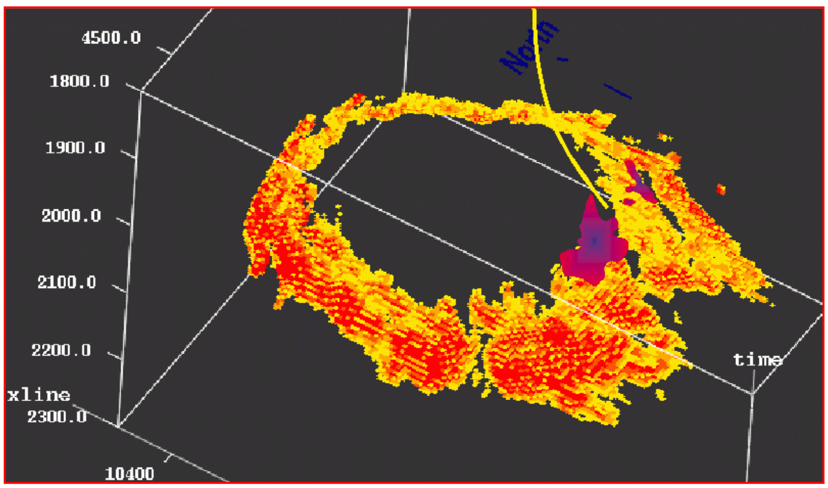

Figure 3. The main 4D hardening signal is shown for '98-'93 around the field (after Kloosterman et al, 2003).

4D interpretation around wells

After a few years of production many of the production wells were showing an increased water cut. It was uncertain whether the water cut represented the general contact level in each block or localised coning / cresting, (no production logging was carried out due to the high cost of subsea well interventions). In the south-western wells 4D data showed that water was being drawn into the whole length of the well (Fig. 4, upper panel), whilst in the south-eastern wells it was being drawn preferentially into the heel (Fig. 4, middle panel). No sharp coning could be clearly distinguished on the seismic, but broad doming of water could be seen around parts of some wells (Fig. 4, lower panel). Such observations were important for history matching.

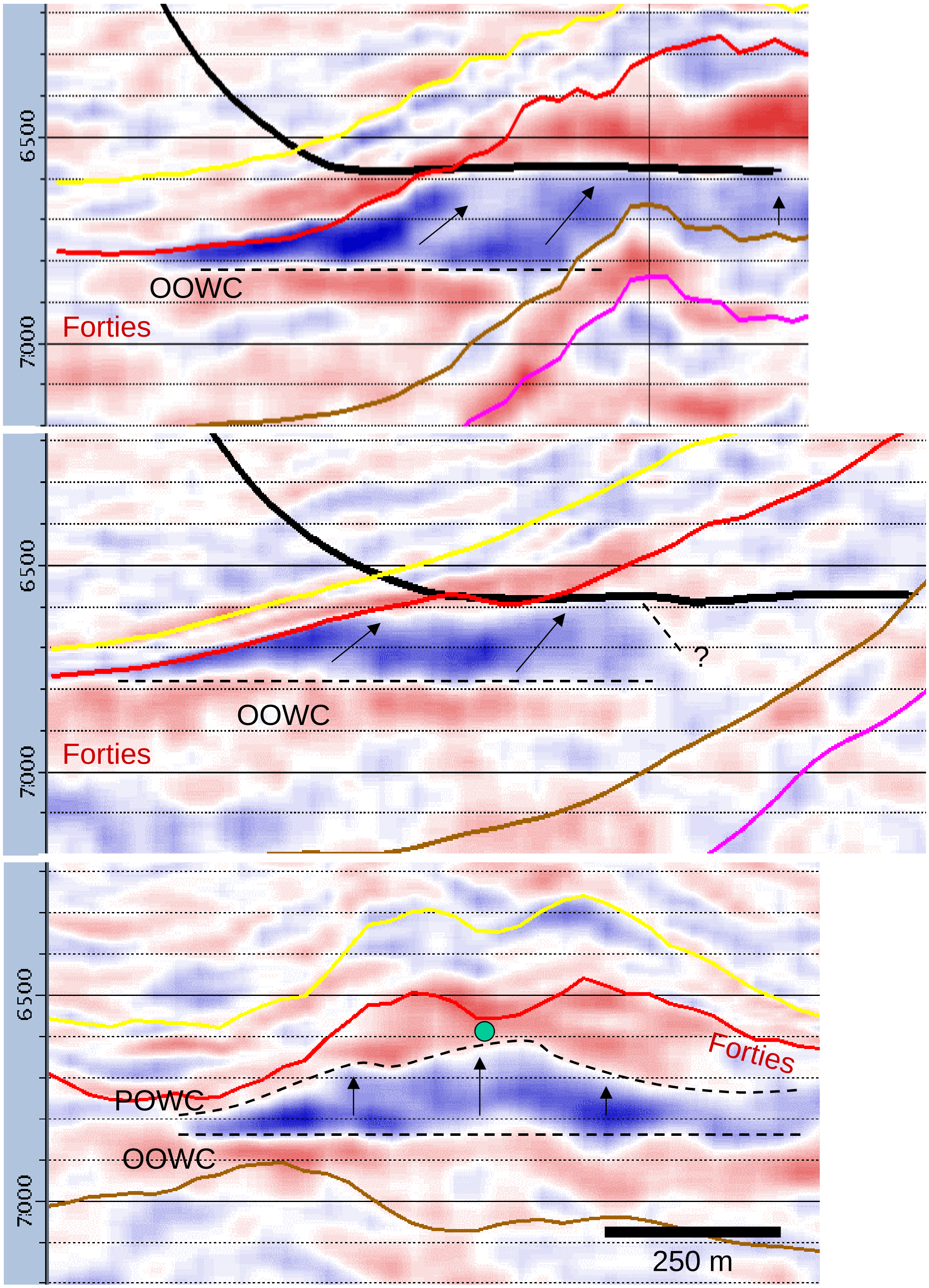

Figure 4. Different flood patterns at well seen on the 98-93 difference cube.
Upper panel: water flood intersecting an entire well trajectory.
Middle panel: water flood intersecting only the heel of a well.
Lower panel: doming orthogonal to a well (green circle).

Field shape and stratigraphy

Another important observation was the extension of the 4D signal to the south of the originally prognosed field boundary (Fig. 5). It was realised that within the uncertainties of the time-to-depth conversion, it was possible to radically increase the original oil-bearing area, with a thin oil rim to the south of the field. This also gave rise to a plausible spill point in the south of this area.

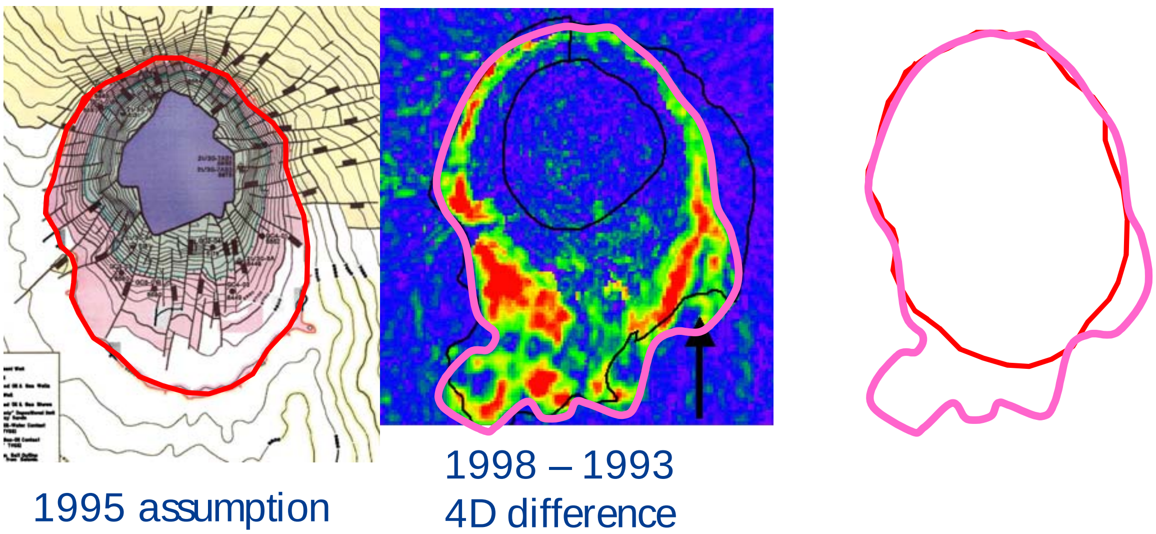

Figure 5. Oil-water contact assumptions compared before and after 4D seismic.

Clear evidence was also seen for water flood within the strata above the Forties. A thin (10-30 ft) Cromarty unit had been seen in some wells. This Cromarty was high porosity (~31%), although with little acoustic contrast with the overlying shale, it was impossible to pick the top of the Cromarty unit on seismic, (the top of the Forties (~28% porosity) presenting the main acoustic/elastic constrast). From the well data (which intersected the Cromarty in the gas leg, or very high in the oil leg) it was presumed the Cromarty thickness was small in terms of overall STOIIP.

The reprocessing of all three datasets showed improved 3D and 4D signal quality as a result of improved 4D processing techniques and the use of Pre-Stack Depth Migration, and on the newly processed data the significance of the Cromarty observation become clear. On these 4D datasets there were thick Cromarty water flood signals over the east of the field (Fig. 6), indicating Cromarty sands downdip of the eastern appraisal wells with the possibility of as much as 150 ft thickness of Cromarty sand at the level of the oil-water contact.

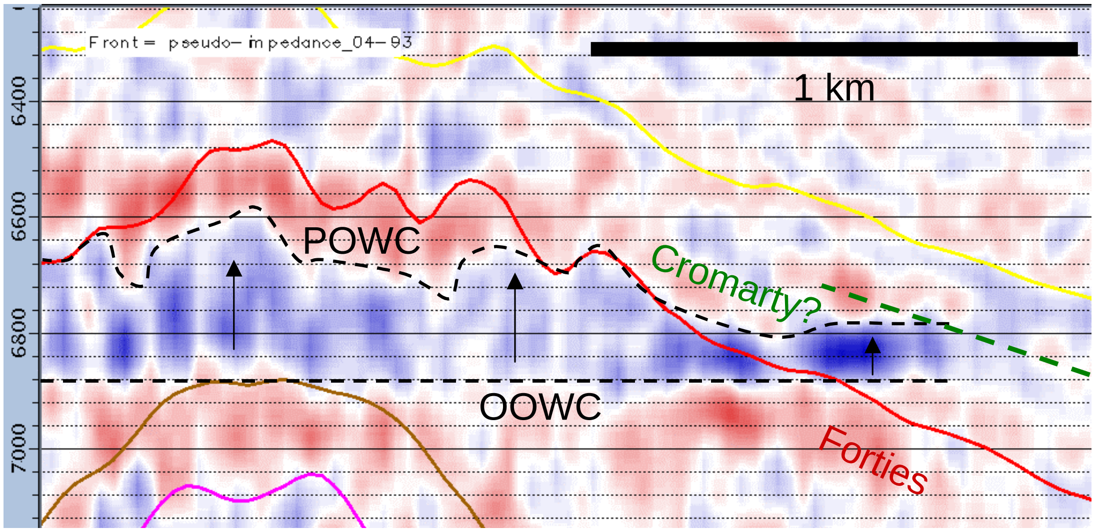

Figure 6. In the south-east of the field, (blue) aquifer influx (hardening) extends well outside the top Forties pick on the 2004-1993 difference cube, indicative of significant Cromarty presence, and connection with the Forties. (Note also the highly variable Forties POWC on this section, caused by significant radial faulting orthogonal to section).

Furthermore it was recognized that there was an anomalous tuning (brightening) on the 3D data around the oil-water contact over much of the field, which diminished downdip. This particular configuration is not normally to be expected for a hard-kick sand, and synthetic 3D modelling revealed it could be attributed to constructive interference where the soft oil-bearing Cromarty overlay the hard water-bearing Forties just at the contact, presenting further evidence for the thickness of the Cromarty where this effect was seen.

History matching

Gannet C is a subsea field with significant uncertainty in the allocation of its historic production and therefore 4D seismic provided a very useful history matching parameter. Highly variable seismic imaging, and the late addition of new layers not present in the original model meant that we did not consider this a case on which to test automated methods. Several cycles were made between the seismic, static and dynamic models. These led to updates of the Forties depth horizons, and to the addition of new thicker Cromarty units in the geological model. In addition to water/gas-cut and pressure data, 4D-specified oil-water contact heights in each block were history matched. Shell's proprietary simulator - synthetic seismic modelling software (MorSyn: Hatchell et al, 2002) allowed us to verify whether the new models matched seismic both in a 3D static geological sense and in a 4D dynamic sense (Fig. 7), and in a few cases mismatches between the synthetic and seismic prompted further model updates.

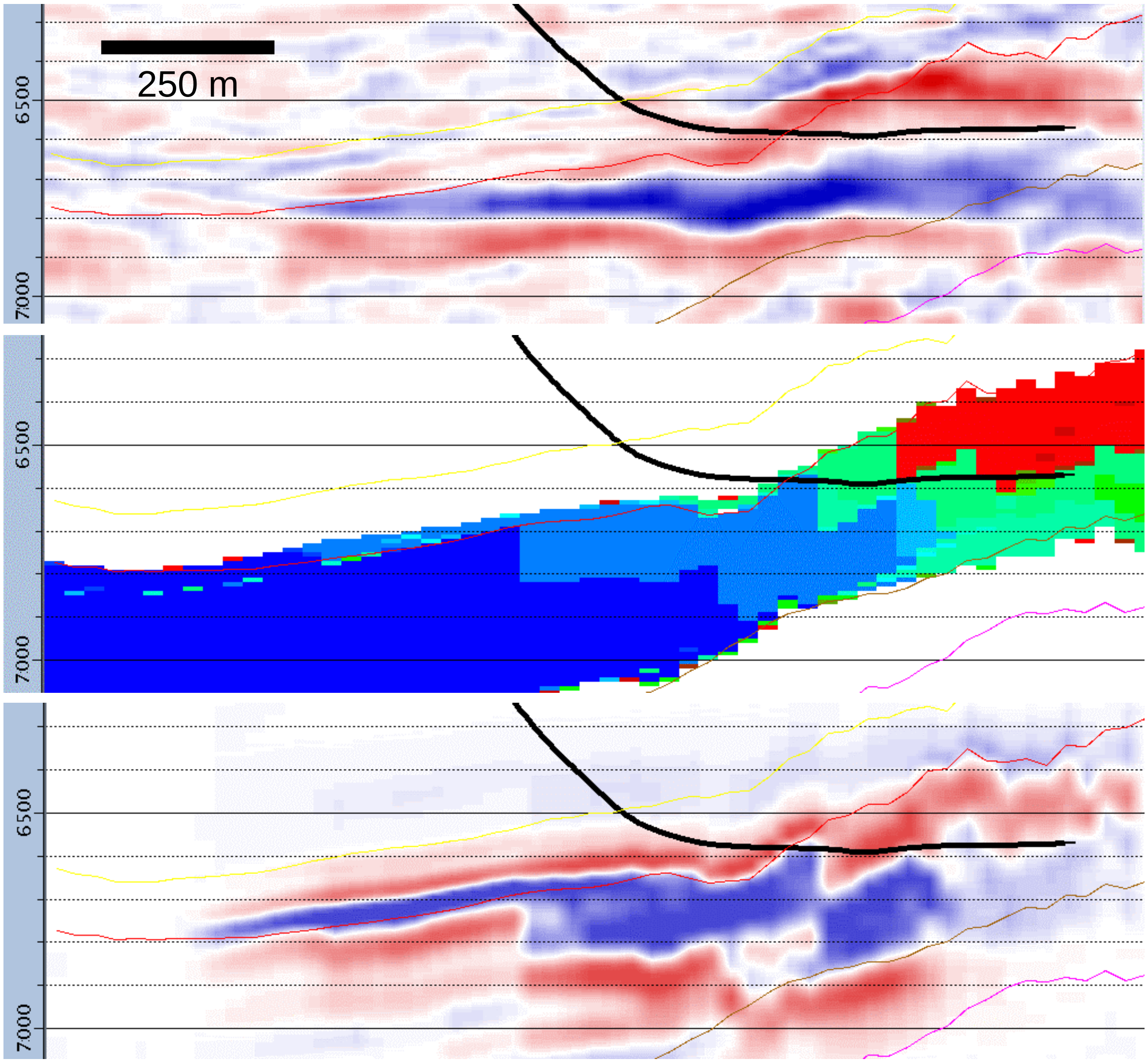

Figure 7. A comparison '98-'93 difference seismic (upper panel), simulation saturations from '98 (middle panel), and the corresponding simulator difference synthetic ('98-'93) during seismic history matching. In this case, the model is showing too much water sweep below the heel of the well and too little water sweep below the toe of the well, compared with the real seismic which shows a more uniform sweep pattern.

Development opportunities

By 2004, the oil-water contact had reached the level of the producers in most areas of the field, and the gas-oil contact was generally predicted to be approximately 50 ft higher than its pre-production location (due to under-injection of gas). In the south of the field, where compartmentalisation from radial faulting was particularly strong, where gas injection had preferentially maintained pressure and reduced water influx, and where the southern extension of oil rim provided additional oil volume, there was one notable volume of remaining oil indicated by 4D and the simulator (Fig. 8). A workover of the injection well in late 2005 confirmed that this was the case with saturation logging revealing a remaining oil rim 190 ft thick, and the well was recompleted as a deviated oil producer with an expected recovery of more than 2 million bbls.

In two other regions of the field (the due west and due east) limited drawdown at the toe of long horizontal wells gave rise to reduced sweep as imaged by the 4D data. This reduced sweep results in a larger thickness of remaining oil rim. The eastern target also had the potential to drain the Cromarty sand above a region where it appeared to be particularly thick and have shown only limited drainage. Since gas reinjection is no longer planned, we expect water influx will continue to cause an upward movement of the oil leg, and the two new horizontal wells (drilling Q4 2005 and Q1 2006) are therefore planned at a higher level than previous producers, just above the currently prognosed gas-oil contact. These two wells are also planned with a trajectory that penetrates the Forties reservoir high on structure, so that when they (and the other 9 wells) are no longer used for oil production, they can be worked over to provide gas production wells close to the crest of the structure, for gas cap blowdown.

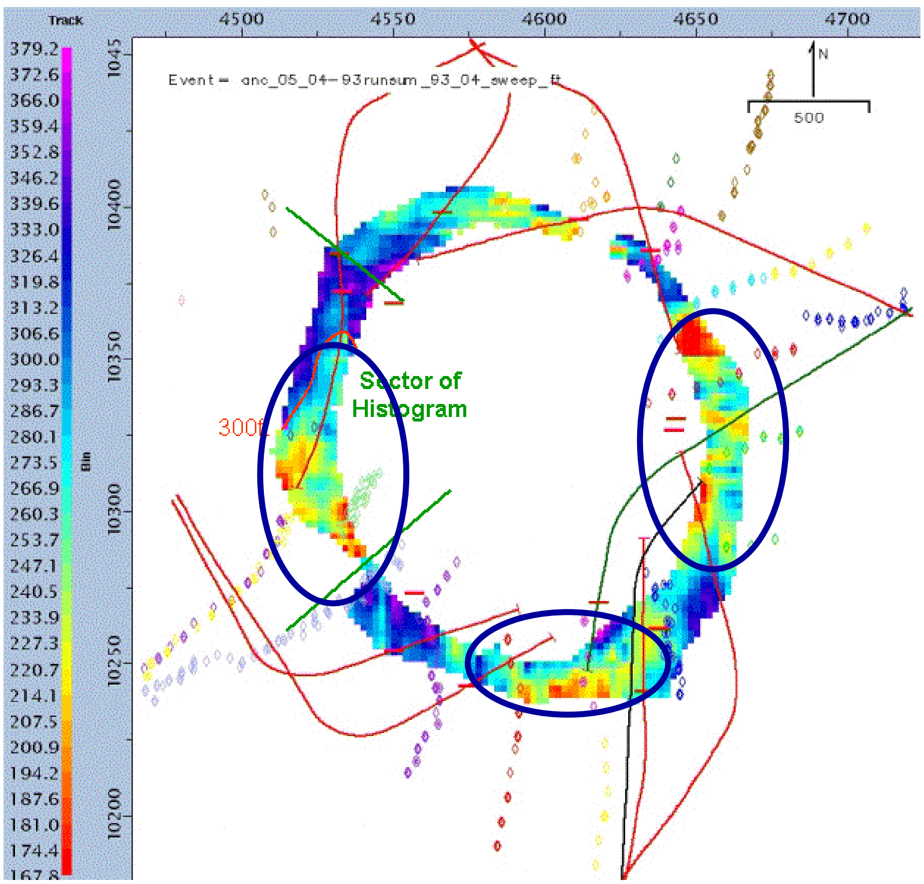

Figure 8. Map of Forties sweep thickness (feet) derived from 2004-1993 4D difference seismic, indicating the injector to producer workover area (south), and the two infill well targets (west and east).

Conclusions

4D seismic data was used on a steeply dipping turbiditic aquifer-driven oil/gas field to reveal:

a major southern flank to the field (previously missed due to uncertainty in the time-depth conversion),

a thick additional Cromarty unit previously presumed to be absent / thin over much of the reservoir

water sweep levels and indications of fault compartmentalisation

the general location of water cut along well profiles

The 4D was used to improve history matching, with a manual history matching cycle including updates to the static model. As a result, we have performed one workover (converting a gas injector to an oil producer), and two infill wells are being drilled, with total expectation recoveries of more than 10 million bbls.

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