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Fluid Substitution and Production Effects Imaged for North Sea Oil Field from Quantitative Seismic & CSEM Interpretation

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SUMMARY

Dedicated "Fluids and Fluid Flow"

We have performed a quantitative, joint interpretation of 3D seismic and 3D CSEM data from the Troll Western Oil Province. The presented methodology results in 3D distributions of effective porosity and hydrocarbon saturation. The estimated reservoir property distributions demonstrate how the result of fluid flows due to production and gas injection can be imaged.

Introduction

We have developed a quantitative interpretation workflow that integrates seismic and marine 3D controlled source electromagnetic (CSEM) data. The results determine the 3D distribution of the hydrocarbon pore volume, which can be used to understand reservoir fluid distributions and estimate total hydrocarbon volume. A performance test of the workflow has been carried out on the Troll West Oil Province (TWOP) in the Norwegian North Sea (Figures 1 and 2). This article describes our methodology and presents some of the results pertaining to fluid flow.

Oil production and gas injection at TWOP started in 1995. This has disturbed the equilibrium reservoir state and induced variations in the hydrocarbon saturation. The results from the joint, quantitative seismic and CSEM interpretation predict reservoir property distributions with features that are consistent with the expected saturation distributions, see Figure 2a. In this abstract, will first describe the field we study and the input data, and then outline the methodology applied to obtain 3D distributions for porosity and hydrocarbon saturation. Then, we discuss some of the prominent features apparent in the results, and correlate to expected production effects.

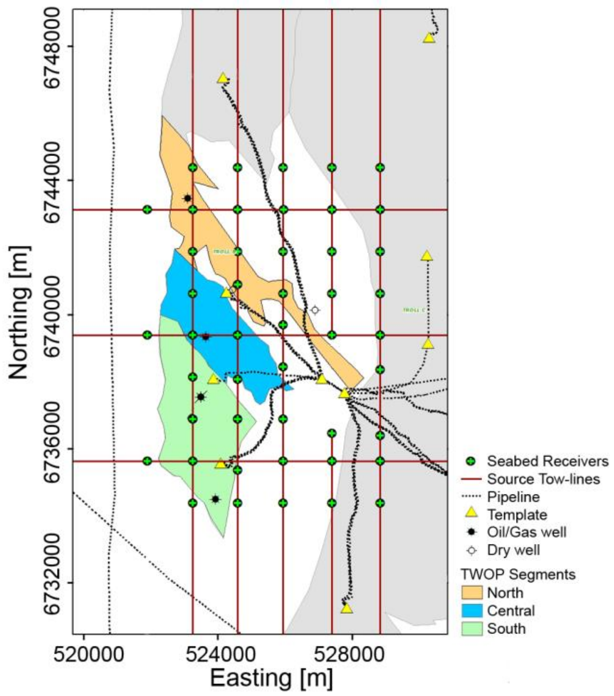
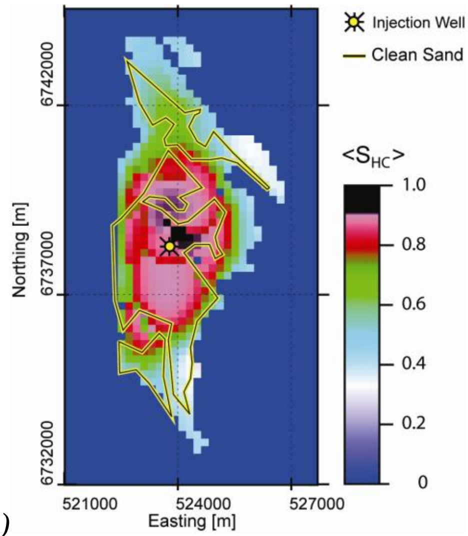


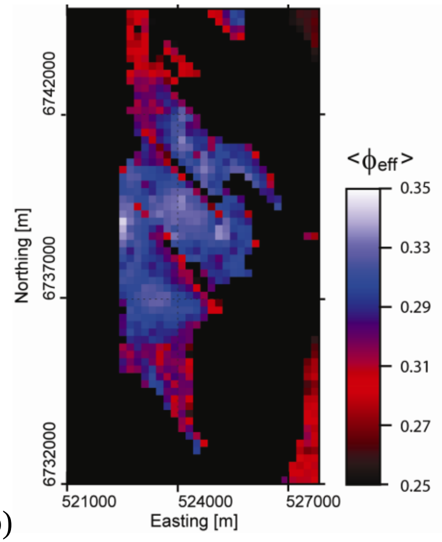
Figure 1: Map view of the Troll West Oil Province showing the production infrastructure and CSEM survey layout.

Field data

The Troll field is the biggest gas field in the North Sea but it also has significant quantities of oil in thin zones under the gas cap. The field has been producing since 1995 (Mikkelsen et al., 2005). Troll extends over three fault blocks tilted east, and is subdivided into Troll East, Troll West Gas Province (TWGP) and Troll West Oil Province (TWOP). In this study, we focus on the TWOP, Figure 1, which is a smaller (25 km^2) segment of the reservoir where the oil column is thicker (15–27 m). The oil is produced from horizontal wells placed close to the oil–water contact. The main drive mechanism is gas cap expansion, with pressure support from one gas injector. The reservoir sediments are part of the Upper Jurassic Sognefjord formation and consist of layers of clean medium to coarse grained, high permeability sand, micaceous fine-grained sand and siltstone with low to medium permeability. The sediments were deposited in a shallow marine environment influenced by tidal and fluvial processes.



a)



b)

Figure 2: Troll West Oil Province a) hydrocarbon saturation, $S_{HC} = 1 - S_w$, and b) effective porosity, ϕ_{eff}, averaged in depth over the hydrocarbon zone. In a), the central part close to the indicated gas injection well, 31/2-B-3, is mapped with anomalously high S_{HC}. The black-yellow polygons show regions at the original gas-oil contact level where the reservoir sands exhibit predominantly high permeability. The expected water intrusion pattern for the south-eastern edge of the field correlates with a small area mapped with low S_{HC}.

The TWOP quantitative interpretation study was performed as a blind test. The hydrocarbon pore volume distribution and total hydrocarbon volume were predicted and then compared with the established reservoir simulation model and knowledge of production history. To simulate the data availability at an appraisal phase of the development, we used only logs from the exploration wells that were drilled during 1984/1985. For the TWOP, 3D seismic data are repeatedly acquired, and we used post-stack data from the 2003 survey. The well and seismic data are publicly available from the Norwegian Petroleum Directorate. Additionally, we used data from a 3D CSEM survey acquired in 2008 as part of an R&D collaboration between Statoil and EMGS (Gabrielsen et al., 2009).

Petrophysics

The publicly available exploration well logs underwent extensive data QC and conditioning. Some logs were not available for any or the whole logged interval; in particular the shear sonic log was lacking. The petrophysical analysis established rock physics models for seismic and electric properties. For the reservoir interval, we obtained a consistent interpretation of the effective water saturation and the effective porosity, which excludes bound water. Effects from calcite and clay inclusions in the reservoir were considered, and are not expected to give significant effects in the seismic and CSEM data.

Our analysis of the well data shows that there are strong correlations between effective porosity and P-impedance, and between resistivity and water saturation. This is consistent with the findings in Hoversten et al. (2006). Thus, separate 3D impedance and resistivity distributions can establish both the pore volume and fluid content. Such information can be obtained from inversion of the seismic and CSEM data. Further analysis of the well data shows that resistivity and P-impedance are weakly correlated. Therefore, we may perform uncoupled inversions on seismic and CSEM data since the two geophysical data are controlled by independent reservoir parameters.

Mapping inversion results to reservoir properties

The aim of the joint interpretation of seismic and CSEM data is to obtain a subsurface model that consistently describes both these measurements. We conducted independent seismic and CSEM inversions to obtain such a model, as the correlation between the reservoir P-impedance and the resistivity is weak. More details about the methodology to obtain 3D reservoir property distributions are given in Morten et al., 2011.

The conditioned well logs and seismic horizons were used to estimate the wavelet and then create a low-frequency model for the seismic inversion. Using publicly available post-stack migrated seismic data, we carried out full stack inversion. This resulted in a P-impedance model with good well tie. Cross-plotting P-impedance to effective porosity using upscaled well data from the reservoir zone reveals good correlation so that a trend curve can be constructed. Using this trend curve, the 3D P-impedance distribution is transformed into an effective porosity distribution for the reservoir. The reservoir thickness averaged effective porosity is shown in Figure 2b.

An initial model for the anisotropic 3D CSEM inversion was created from profiles resulting from 1D inversion based on a simulated annealing algorithm. A structural constraint for the hydrocarbon zone of the reservoir is determined by the seismic top reservoir horizon and the oil-water contact depth observed in the exploration wells. Using this information, regularization was formulated to favor typical formation resistivity in the background, and allowing anomalously large resistivity associated with hydrocarbons inside the hydrocarbon saturated part of the reservoir. The resistivity model produced by 3D inversion thus incorporates the resistive body due to the TWOP with structure as defined from the top reservoir horizon and oil water contact. The final 3D inversion model generally has data misfit to the observed data which is of the order of the data uncertainty.

In order to go from the vertical resistivity reconstructed inside the hydrocarbon zone of the reservoir to water saturation, a trend curve based on well data was established. To reflect information at the same scale as the CSEM data, the measured well resistivity logs were first upscaled to agree with CSEM resolution, resulting in a vertical and a horizontal resistivity. The well log derived vertical resistivity is then cross-plotted to the water saturation averaged over the pore volume of the depth intervals used for the resistivity log upscaling. The cross-plot reveals a strong trend to which a Simandoux rock physics model is fitted. This model is then used to transform the 3D inversion model for vertical resistivity into a water saturation distribution. The hydrocarbon saturation averaged over the reservoir thickness is shown in Figure 2a.

Saturation variations and development induced fluid flows

In Figure 2a, we show the hydrocarbon saturation averaged over the total hydrocarbon zone pore column, $\sum_z S_{\mathrm{HC}}\, \varphi_{\mathrm{eff}}\, \Delta z \Big/ \left(\sum_z \varphi_{\mathrm{eff}}\, \Delta z \right)$. An anomalously large saturation can be observed close to the indicated position of the gas injection well which provides production pressure support. At the time of the CSEM acquisition, gas injection had been ongoing for 12 years, so local effects on the fluid distribution and saturation can be expected. The exploration well logs analyzed in this work show that typically, the gas zone is associated with lower water saturation and hence larger resistivity than the oil zone. Therefore, an expanded gas cap with a possible local increase in hydrocarbon saturation or volume resulting from the gas injection may be the cause of the observed anomaly in the estimated saturation. The extent of the region with very large hydrocarbon or injected gas saturation seen in Figure 2a seems limited southwards by a known fault with a North-West strike direction.

Owing to production, water intrusion at the edges of the TWOP can be expected. However, the degree of oil substitution by water will depend on reservoir permeability. In areas with highly permeable sands, drainage occurs more efficiently, and more water intrusion should result. The saturation map, Figure 2a, shows a local zone of reduced hydrocarbon saturation in the south-east. Spatially, this region correlates to an area where there is more highly permeable sand, as indicated by the polygon.

Conclusions

We have applied a new methodology for joint quantitative interpretation of 3D CSEM and seismic using data from the TWOP. The results demonstrate the potential to extract large amounts of information about fluid distributions that are a result of the historical production of the field. Specifically, we correlated regions of low and high hydrocarbon saturation as a result of fluid flow in high permeable zones caused by gas injection and water intrusion. We believe that the demonstrated sensitivity to hydrocarbon saturation from the integration of CSEM data with seismic allows to image large-scale effects from fluid flow, with relevance for applications in hydrocarbon exploration, development and production.

Acknowledgements

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