Introduction

In 2018, Equinor released a public dataset comprising all the subsurface data of the Volve oil field. This study presents an integration of the available data to quantify the 4D seismic signal. Located in the central Norwegian North Sea, production commenced in February 2008. Initially, Volve reached the production design capacity of 9000 Sm³/day but water break through occurred earlier than anticipated in early 2009 (pers. comm.) and increased rapidly to greater than 50% in mid-2010 (Figure 1). A reservoir monitoring campaign that included production logging (PLT/RST) and a 4D monitor seismic survey was undertaken to better understand water sweep within the reservoir and to identify potential bypassed pay as targets for improved oil recovery (IOR). Subsequently, a second phase of development prolonged the life of the field to September 2016 after which time the field was abandoned and decommissioned. In this study we calibrate the 4D signal, provide an assessment of the 4D signal uncertainty and suggest ways the 4D data could be used to improve the simulation model.

Figure 1 Stacked well oil production rate and field water cut (blue). Wells F-12 and F-14 drilled in the Phase 1 development campaign produce almost 80% of the total recovered reserves.

Figure 2 Volve field top Hugin depth structure map (CI=10m). Volve is a four-way dip closure with large offset bounding faults on three sides. The reservoir thickens from 5m at the western extent of the field to over 100m at well F-5 in the east. Phase 2 wells were geosteered laterals targeting the upper Hugin for bypassed pay.

Wells; Phase 1: dark green, Phase 2: light green, Water Injection: blue, Exploration: yellow. Reservoir-well intersection as thickened well-path. Field outline in red.

Reservoir

At Volve, the Hugin Fm. reservoir comprises a combination of shallow to marginal marine sandstones of good to excellent quality (Lunde, 2013). The reservoir can be separated into three distinct vertical zones termed; the upper, middle and lower Hugin and are distinguished from one another by their permeability characteristics and by the low permeability layers between them (fine grained marine clastics and/or calcite diagenesis). The middle Hugin which contains two multi-Darcy thief zones had a large impact upon the reservoir’s dynamic behaviour channelling injected water to the producing wells. The impact of the thief sands upon production was first identified using PLT logging in March 2009. Approximately 75% of total production volume originated from the middle Hugin. A second PLT run immediately preceding the seismic monitor in October 2010 reinforced this interpretation with the majority of the produced water also originating from the middle Hugin. Production logging did not give strong indications of the water sweep within the upper and lower Hugin and 4D seismic was required to validate potential reservoir simulation derived IOR targets.
3D and 4D Evaluation

Utilising a combination of 3D well ties and heuristic analysis the data provided was found to be zero phase with a seismic peak corresponding to an increase in acoustic impedance. Reservoir geometry and stratigraphic changes around the reservoir have a large impact upon the reservoir seismic character and interpretation. The Heather and Draupne Formations on-lap the reservoir from the east thinning onto the crest of the field. Where the bright low impedance Draupne Fm. approaches the top reservoir event (also low impedance), the reservoir reflection is subsumed by the broad Draupne trough-peak. Additionally, the reservoir thins to the west where appraisal wells intersected just 5 m of Hugin Fm. Vertical discrimination of water sweep where the reservoir is thin onto the crest of the field was challenged by complications with 3D tuning and seismic resolution.

![Figure 3 West to east arbitrary line through Volve field. Reservoir thins to the west and is on-lapped by the highly reflective Draupne unit. Imaging through the faulted zone around well F-5 is disrupted. The thinnest reservoir intersection in the south-west of the field is 5 m but thickens quickly to over 100 m thickness at well F-5.](image)

The Normalised RMS Difference attribute was used to evaluate the 4D noise which has a mean of 20%. Attribute extractions showed increases to 30% noise below the surface obstructions but there does not appear to be any significant effect on the 4D difference. Quadrature phase volumes of the 4D difference (Figure 4) exhibit a strong hardening event throughout much of the reservoir. Where the reservoir is thickest this event appears to be closest to the base reservoir but moves closer to the top reservoir event and increases in strength over the crest. A strong trough trails the main 4D hardening event and the quality of the 4D signal is broadly aligned with the quality of the 3D imaging weakening or becoming disrupted by steep structural dip and closely spaced internal faulting.

![Figure 4](image)

(a) Quadrature difference with Draupne, top and base reservoir events. The sum of positive amplitude attribute maps show extractions for the upper (b) and lower (c) half of the reservoir zone. Over the crest of the field amplitudes are concentrated in the upper half of the reservoir whilst on the eastern flank they are concentrated in the lower half. There are strong signals around the two injector wells and poor imaging on the highly faulted eastern flank.

PEM calibration and sensitivity analysis

Characteralisation of the 4D signal and 4D forward modelling relied upon the development of a 4D Petro-Elastic Model (PEM). A simple Voigt-Reuss-Hill average of a two phase sand-shale system, combined with critical porosity (Nur et al., 1995) and the rock stress-sensitivity (MacBeth, 2004) was
optimised to match the elastic logs (P-wave & S-wave velocity and density) from five wells included in the Volve dataset (Hallam et al., 2020). Estimates for the reservoir stress-sensitivity parameters $E$ and $P$ were derived by fitting available core laboratory measurements of the dry-rock velocity. The remaining unknown rock model parameters (mineral phase bulk and shear modulus and critical porosity) were resolved using a genetic optimisation algorithm with phase determined by the volume shale log.

The PEM was then used to assess the 4D sensitivity of the Hugin reservoir. During production the field experiences a maximum drop in pressure of approximately 7MPa prior to the commencement of water injection after which pressures restabilises. At the time of the monitor survey only small (~1-3MPa) changes in the reservoir pressure are measured. Relative permeability curves used to model the field have critical oil and water saturation values of 20 and 80%, limiting the maximum water sweep to approximately 60% of the pore volume. Figure 5 details the anticipated change in acoustic impedance of the reservoir for a fixed VSH (0.2) and porosity (20%). The low impact of pressure is due to the stiffness of the reservoir rock with saturation changes dominating the expected 4D response. At maximum sweep the change in acoustic impedance is estimated to be 3-4%.

4D well modelling

The coincident timing of RST logging in well F-4 and the 4D seismic monitor facilitates 4D well tie modelling where the logs undergo fluid and pressure substitution using the PEM to create time-stamped synthetic traces. The difference of these two traces is compared with the observed 4D difference extracted along the well bore (Figure 6).

![Figure 5 Changes in impedance for VSH=0.2 and porosity of 20%. Modelled using the calibrated dynamic PEM saturation effects dominate the overall impedance response in the reservoir. Constant pressure and constant saturation are extracted along purple initial condition lines at 20% water saturation and pore pressure of 32 MPa.](image)

![Figure 6 4D quadrature difference synthetics for well F-4. Original saturation (orange) and modelled saturation (blue); (a) as recorded September 2010 RST, (b) additional sweep in lower Hugin weakens the base response trough, and (c) reduced saturation changes in the upper Hugin and Thief Sand 1 better matches the observed quadrature difference at the well location (far right).](image)

When the logged saturation is used, the modelled response shows two peaks corresponding to the two thief sands, this is not consistent with general response through the thicker portion of the reservoir
where at the top reservoir event a weak trough is followed by a strong peak-trough pair closer to base of the reservoir. Hypothesis testing of the water sweep based upon the vertical zonation of the reservoir demonstrated that introducing sweep to the lower Hugin would soften the bottom reservoir trough and that reducing the saturation change in the upper Hugin and first thief sand resulted in the best match to the observed quadrature difference.

Translating these results to the 4D interpretation suggests that water sweep may be focussed within the lower thief sand before migrating up the stratigraphy closer to the production locations as the reservoir thins. The strength of the trailing trough at the base of the reservoir could be used as an indicator for bypassed pay in the lower Hugin zone.

Conclusions

Initial interpretation of the Volve 4D signal suffered from ambiguity and uncertainty due to the poor 4D signal-to-noise ratio, variable reservoir geometry, the lateral extent within the reservoir and poor imaging in places. We have worked to systematically address these concerns by integrating and interpreting the available data.

Although changes to the acoustic impedance between the baseline and monitor surveys are small our calibration of the 4D PEM indicates that the observable signal is dominated by changes in saturation, reducing pressure related 4D amplitude changes to a second order issue. While it is difficult to be confident in the 4D signal over the crest of the field, where the reservoir is thicker, 4D well ties have demonstrated that the extent of water sweep in the three reservoir zones can be inferred from the quadrature difference attribute. We are confident the 4D signal in the thicker parts of the reservoir provides qualitative information about the extent of water sweep in each zone and could be used to guide close-the-loop workflows such as seismic history matching. Internal mapping of the reservoir stratigraphy using the 4D difference or via 4D inversion could be pursued to improve the static model.

Finally, the extensive distribution of a 4D signal within the reservoir was unusual, typical 4D programs aim to map water flood fronts and gas dissolution but neither of these scenarios can be applied to Volve. The late timing of the 4D relative to water breakthrough dictates that the 4D signal be pervasive within the reservoir but careful analysis of the signal and modelling has revealed coded information within the 4D signal about vertical sweep.

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References


