Geomechanics for Energy and the Environment 2 (2015) 32–44

Contents lists available at ScienceDirect

Geomechanics for Energy and the Environment

journal homepage: www.elsevier.com/locate/gete

Integrated hydro-mechanical and seismic modelling of the Valhall reservoir: A case study of predicting subsidence, AVOA and microseismicity

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HIGHLIGHTS

- We integrate fluid-flow, geomechanical and seismic modelling to the Valhall reservoir.
- We predict surface subsidence, seismic anisotropy and microseismicity and compare with field observations.
- The results are consistent with observation and indicate that the integrated approach can add value to model calibration.

ARTICLE INFO

Article history:
Received 14 November 2014
Received in revised form 19 May 2015
Accepted 19 May 2015
Available online 28 May 2015

Keywords:
AVOA
Coupled fluid-flow and geomechanics
Microseismicity
Rock physics
Subsidence

ABSTRACT

Geomechanical, fluid-flow and seismic modelling have been combined to predict surface subsidence, seismic anisotropy and microseismicity for the Valhall reservoir, North Sea. The constitutive model used in the geomechanical simulation consists primarily of layers having poro-elastic behaviour, but with poro-elasto-plasticity behaviour in the chalk reservoir units. The constitutive model incorporates matrix deformation during simulation, such that areas of compaction and dilation are modelled so that the likely microseismic response of the reservoir can be predicted. In the coupled fluid-flow and geomechanical (hydro-mechanical) workflow, a finite-element geomechanical simulator is coupled to a reservoir fluid-flow simulator and applied to predict seafloor subsidence. Subsequently, the history-matched hydro-mechanical results are transformed into dynamic elastic models suitable for seismic analysis using an empirical static-to-dynamic relationship and stress-dependent rock physics model. The elastic models are then used to predict seismic anisotropy and microseismicity, allowing for an additional assessment of hydro-mechanical simulation via comparison with observed field seismic data. The geomechanical model has been calibrated to reproduce the measured subsidence. Furthermore, the predicted seismic anisotropy extracted from the reflection amplitude variation with offset and azimuth resembles that measured from field seismic data, despite the limited calibration of the rock physics model to the Valhall reservoir rocks. The spatial pattern of modelled microseismicity is consistent with previously published microseismic analyses, where the modelled failure mechanisms are consistent with typical production-induced seismicity.

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http://dx.doi.org/10.1016/j.gete.2015.05.002
2352-3808/

The results of this study indicate that seismic data has the potential to improve the calibration of hydro-mechanical models beyond what is possible from conventional fluid production and surface subsidence data. This is significant as seismic data could provide greater control over the whole field rather than borehole and surface measurements.

1. Introduction

Extraction and injection of fluids within petroleum reservoirs alters the ambient pore pressure leading to changes in the effective stress field within the reservoir and surrounding rocks. From the perspective of seismic monitoring, changes in the stress field can lead to nonlinear changes in seismic velocity observable in time-lapse seismic data (e.g. Barkved et al.[1], Herwanger and Horne[2], Barkved and Kristiansen[3], Kristiansen et al.[4]). However, changes in pore pressure do not necessarily lead to a hydrostatic change in effective stress. For instance, a reduction in fluid pressure within a reservoir is often accompanied by a slower increase of the minimum effective horizontal stress with respect to the vertical effective stress change (e.g. Hillis[5]). This asymmetry can result in the development of stress anisotropy that may promote failure within the rock, such as fault reactivation and casing deformation. This has important implications on the interpretation of time-lapse seismic as well as microseismic data, where stress anisotropy can result in anisotropic perturbations in the velocity field (e.g. Herwanger and Horne[6]) leading to induced seismic anisotropy, offset and azimuthal variations in reflection amplitudes, shear-wave splitting, and microseismicity if the stress exceeds the strength of the rock mass.

Over the past several decades, significant advances have been made in monitoring and predicting changes in physical properties within the subsurface related to petroleum production (e.g. Calvert[7], Fjær and Kristiansen[8], Johnson[9]). Yet uniquely relating surface deformation and time-lapse seismic observations to changes in rock physical properties is challenging (e.g. Herwanger et al.[10]). Recent improvements in the integration of coupled fluid-flow and geomechanical (or hydro-mechanical) simulation with rock physics and seismic modelling have led to a better understanding of changes in the physical properties of the subsurface and their time-lapse seismic signature (e.g. Olden et al.[11], Minkoff et al.[12], Herwanger and Horne[2,6]; Angus et al.[13], Trudeng et al.[14], He et al.[15]). Time-lapse seismic attributes have non-unique interpretations; for instance, observed changes could be due to changes in fluid saturation or to changes in the rock fabric itself (e.g., compaction). Hydro-mechanical modelling combined with seismic measurement and interpretation have the potential to help distinguish between these effects, and hence improve drilling[16] and completion practices, and identify areas where more production can be achieved. If successful, this would help reduce both the costs of conventional and unconventional production by reducing the number of wells necessary to achieve production targets.

In this paper, we integrate geomechanical, fluid-flow and seismic modelling to simulate the stress evolution during production to predict surface deformation and seismic attributes. A finite-element geomechanical simulator (ELFEN) is coupled to a reservoir fluid production simulator (VIP), where the output from the hydro-mechanical simulation is used to model surface subsidence, the seismic attribute AVOA (reflection amplitude versus offset and azimuth), and reservoir and overburden microseismicity. The integrated hydro-mechanical and seismic modelling workflow is applied to the data-rich Valhall oil reservoir in the southern part of the Norwegian sector of the North Sea. The field produces from relatively weak chalk in the Tor and Hod formations of Late Cretaceous age at a depth of about 2400 m. The field likely began deforming elastically, but over time transitioned to plastic deformation in some regions in the form of reservoir compaction, and this accelerated due to water weakening from pressure support. Hence Valhall has presented numerous geomechanical difficulties during its production lifespan. We compared predicted subsidence, AVOA response and microseismicity with observations from field data.

2. Hydro-mechanical and seismic modelling

Recent studies linking numerical coupled fluid-flow and geomechanical simulation with seismic modelling have improved our understanding of the relationship between seismic attributes, fluid properties and mechanical deformation due to reservoir fluid extraction and injection (e.g. Rutqvist et al.[17], Dean et al.[18], Herwanger and Horne[6], Alassi et al.[19], Angus et al.[20], Herwanger et al.[10], Schoenball et al.[21], Verdon et al.[22]). Analytic and semi-analytic approaches using poroelastic formulations for simple geometries have been used previously to understand surface subsidence (e.g. Geertsma[23]), microseismicity (e.g. Segall[24]) and seismic travel-time shifts (e.g. Fjær and Kristiansen[8], Fuck and Tsvankin[25], Fuck et al.[26]) due to pore pressure changes. Within the past decade, there has been significant effort to develop coupled fluid-flow and geomechanical numerical simulators primarily because they can be applied to more realistic geometries (e.g. Rutqvist et al.[17], Dean et al.[18], Minkoff et al.[27], Herwanger and Horne[6], Segura et al.[28]). Numerical hydro-mechanical simulators can integrate the influence of multi-phase fluid-flow as well as deviatoric stress and strain to provide more accurate models of the spatial and temporal behaviour of various rock properties within and outside the reservoir (e.g. Herwanger et al.[10]). Linking changes in reservoir physical properties, such as porosity, permeability and bulk modulus, to changes in seismic attributes is accomplished