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Research paper

Effective integration of reservoir rock-typing and simulation using near-wellbore upscaling

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Obtaining a fit-for-purpose rock-type classification that adequately incorporates the key depositional and diagenetic heterogeneities is a prime challenge for carbonate reservoirs. Another prevailing issue is to integrate the static and dynamic data consistently with the rock-typing scheme in order to correctly initialise the reservoir flow simulation model. This paper describes a novel near-wellbore rock-typing and upscaling approach adopted to address the crucial challenges of integrating reservoir rock-typing and simulation in carbonate reservoirs. We demonstrate this workflow through a case study for a highly heterogeneous Eocene-Oligocene limestone reservoir, Field X. Geological studies carried out in Field X suggested that the key permeability pathways are strongly related to the mechanism of reservoir porosity and permeability evolution during late-burial corrosion. The rock-typing and upscaling methodology described in this paper involves the geological-petrophysical classification of the key reservoir heterogeneities through systematic evaluation of the main paragenetic events. Associations between the depositional and late-burial corrosion features, and their impact on reservoir flow properties, were accounted for in our workflow. Employing near-wellbore rock-typing and upscaling workflow yielded consistent initialisation of the Field X reservoir simulation model and therefore improved the accuracy of fluids-in-place calculation. Subsequently, the cumulative production curves computed by the reservoir simulation model of Field X showed closer agreement to the historic production data. The revised Field X simulation model is now much better constrained to the reservoir geology and provides an improved geological-prior for history matching.

1. Introduction

Rock-typing describes the process of characterising geological facies in terms of their dynamic behaviour. It is highly challenging to obtain a fit-for-purpose rock-typing scheme that adequately represents the influence of diagenetic processes on the reservoir petrophysical properties, fluid in-place volumes, and hydrocarbon recovery efficiency. This is a classic issue for carbonate reservoirs, which typically contain multi-scale and multi-modal pore types that are difficult to be adequately incorporated into rock-typing (e.g. Gomes et al., 2008; Hollis et al., 2010; van der Land et al., 2013; Skalinski and Kenter, 2015). Another common challenge is to integrate the dynamic data during rock-typing and upscale the petrophysical properties of the rock types to the reservoir model scale using appropriate geostatistical tools to correctly initiate the reservoir simulation model. Furthermore, the difficulties of predicting reservoir quality variations at inter-well scales have long hindered the efficacy of carbonate reservoir rock-typing and simulation (c.f. Agar and Geiger, 2015).

Numerous authors have proposed carbonate rock-typing workflows, trying to address the challenges discussed above. Gomes et al. (2008) discussed the importance of obtaining good understanding of the depositional and diagenetic processes in order to establish better links between lithofacies, petrophysical groups and rock types. Hollis et al. (2010) demonstrated a rock-typing workflow based on pore system characterisation such that each rock type could be defined on the basis of both its

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petrophysical properties and behaviour during hydrocarbon recovery. Van der Land et al. (2013) proposed a general approach towards carbonate rock typing through pore-scale forward modelling of the paragenetic sequences. Skalinski and Kenter (2015) proposed a carbonate petrophysical rock-typing workflow that could account for the role of diagenetic processes on reservoir dynamics, and could also account for the role of fractures. In contrast, the work presented in this paper is aimed to address all of the above issues through an integrated near-wellbore rock-typing and upscaling approach. The novel aspect of the Near-Wellbore Upscaling (NWU) methodology applied in our study is that it enabled explicit modelling of typical multi-scale carbonate heterogeneities such as leaching, stylolites and associated small-scale fractures, which are difficult to account for in existing reservoir rock-typing and simulation workflows. Our methodology allows us to model these multi-scale geological-petrophysical features more robustly at the reservoir grid-block scale in a reservoir simulation model. The rock-typing and upscaling methodology described in this study involves the geological-petrophysical classification of multi-scale heterogeneities in the studied reservoir through systematic evaluation of the key paragenetic events with consideration to the crucial parameters of near-wellbore modelling and upscaling workflow.

1.1. Case study: rock-typing and simulation challenges in Field X

Field X is a giant offshore oil and gas field comprising an Eocene-Oligocene limestone reservoir with long production history. It has a broad, low relief anticline trap structure and consists of a gas column up to 50 m thick, an oil rim of about 20 m thickness, and an underlying aquifer of ground water. Permeability has been identified as one of the biggest uncertainties associated to Field X's reservoir simulation model during previous field studies (Chandra, 2014; Chandra et al., 2015). In addition, the performance predictions were also found to be sensitive to the volumes of fluids initially-in-place and the critical oil saturation. Major modifications of the reservoir model were required in order to obtain a history match. These modifications were not necessarily based in the reservoir geology but comprised numerical adjustments in the dynamic model. For example, horizontal permeability multipliers of 10 and 20 had to be applied in the main reservoir zones, along with multipliers at the wells (Oates et al., 2012; Chandra, 2014; Chandra et al., 2015). Chandra et al., 2015 demonstrated how the computed cumulative oil production decreased when the permeability modifications were removed in the dynamic model (Fig. 1). The irregularities observed between the distributions of fluids based on reservoir simulation predictions and the actual production volumes also imply that the in-place volumes and production characteristics were not properly understood (Calvert and Ballay, 2011). It was hence deemed necessary to re-evaluate the geological-petrophysical model of Field X to increase the reliability of oil-in-place calculations and reservoir model initialisation for simulation predictions.

Geological studies carried out by the operator suggest that the key static and dynamic reservoir properties in Field X are strongly related to the mechanism of reservoir porosity-permeability evolution during late-burial corrosion (Wright and Barnett, 2011). In this study, late-burial corrosion is referred to as deep burial/mesogenetic corrosion associated with the corrosion of limestone by burial-derived (hypogene) fluids. The uncertainty associated with permeability modelling in Field X was discussed by Oates et al. (2012), Chandra (2014) and Chandra et al. (2013b,c, 2015). Chandra et al. (2015) demonstrated that re-evaluating the permeability model of Field X with considerations to late diagenetic corrosion can significantly improve the reservoir simulation model.

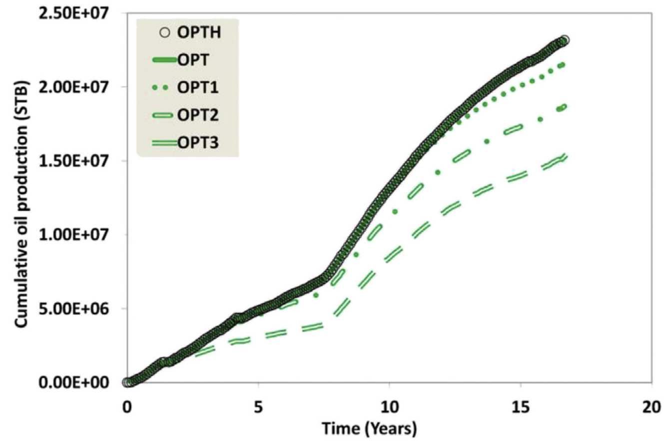

Figure 1. Cumulative oil production curves from Field X. OPT corresponds to the history matched simulation model, which yields a cumulative oil production that is identical to the historic production data OPTH. OPT1 is the simulated production after removing horizontal permeability multipliers (K-multipliers) from the zones. OPT2 is the simulated production after removing zone and local well K-multipliers. OPT3 is the simulated production after removing the well productivity multipliers in addition to the zone and well K-multipliers. STB is the abbreviation for 'Stock Tank Barrels'. Figure modified from Chandra et al., 2015.

The key porosity types present in Field X, such as chalky microporosity, macroporosity including vuggy and moldic pores, leached stylolites and associated tension gashes, were caused by late burial (mesogenetic) dissolution (Wright and Barnett, 2011). Note that microporosity in Field X is defined as pores with a pore throat diameter of 0.5 microns or less.

In order to revise the geomodel of Field X with considerations to the proposed late-burial corrosion model (Wright and Barnett, 2011), it is vital to obtain a fit-for-purpose rock-typing scheme that adequately incorporates the late-burial corrosion heterogeneities. However, conventional rock-typing workflows may not be appropriate to Field X due to the difficulties associated with the petrophysical characterisation and data sampling of the key porosity types such as leached stylolites and associated tension gashes. Besides, upscaling these sub-grid-scale heterogeneities to incorporate them adequately into the reservoir simulation model is another major challenge. The available core plug data suffers from inherent sample bias and insufficiency due to rock-mechanical constrictions and due to the shortcomings of using a regular sampling interval of 1 m (Oates et al., 2012). Due to these challenges, Field X provides an ideal case study for the application of the near-wellbore rock-typing and upscaling methodology. In this study, we thus aim to employ the near-wellbore rock-typing and upscaling methodology to revise the full field geomodel of Field X and generate a properly initialised reservoir simulation model with consistent static and dynamic reservoir properties.

1.2. Field X depositional and diagenetic history

Field X has a broad, low-relief anticlinal trap structure and comprises an Eocene-Oligocene limestone reservoir (Fig. 2A) with an oil rim and an underlying aquifer. The offshore basin comprising Field X is a passive margin basin, split into longitudinal horst and graben stripes by a series of basement controlled NorthWest-SouthEast to North-South trending faults. The major structural feature in the block containing Field X and its neighbouring hydrocarbon fields is the East-fault zone (Fig. 2B). Figure 2B shows the porosity model of Field X and the four wells used in this study. Porosity and permeability came from Routine Core Analysis