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Research paper

Reservoir quality and rock properties modeling – Triassic and Jurassic sandstones, greater Shearwater area, UK Central North Sea

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ABSTRACT

The complex burial and diagenetic histories of the Jurassic Fulmar and Triassic Skagerrak sandstones in the UK Central North Sea present significant challenges with regard to reservoir quality and rock property prediction. Commercial reservoir quality is retained despite deep burial and associated high temperatures and pressures. Shallow marine Fulmar sands are normally compacted (mean IGV = 26 ± 3%) yet have porosities of 21–33%. Porosity was preserved through inhibition of quartz cementation by clay and microquartz coatings, and enhanced by dissolution of framework grains (~5%). Skagerrak fluvial sands are more compacted (mean IGV = 23 ± 2%), exhibit minor feldspar dissolution (<1%), and have porosities of 16–27%. Quartz cement averages only 2 ± 1.5% due to robust chlorite coats that cover 80% (±13%) of quartz surfaces.

We modeled reservoir quality evolution using the forward diagenetic model Touchstone, which simulates porosity loss due to compaction and quartz cementation. Quantitative petrographic analyses and burial history data were used to calibrate Touchstone model parameters. The results were applied to deeper prospects for pre-drill prediction of porosity and permeability. In parallel, petrophysical data were used to characterize the elastic properties of the sandstones to provide a basis for quantitative seismic forward modeling. Experimental data and core-calibrated petrophysical results, reflecting variable *in situ* fluids and saturations, were used to build an elastic properties model. The model is robust and was used to generate fluid-filled sandstone properties, incorporating Touchstone results, for prospect-specific seismic attribute modeling. Well results from exploration wells are in good agreement with pre-drill Touchstone and elastic properties model predictions.

1. Introduction

This study focuses on reservoir and rock properties of sandstones in the deep HPHT (high pressure, high temperature) area of the Central North Sea located in United Kingdom quadrant 22, blocks 24, 29 and 30 (Fig. 1). The shallow marine sandstones of the Middle Jurassic Fulmar Formation and the fluvial sandstones of the Triassic Skagerrak Formation sandstones represent the primary reservoirs for gas condensate and oil production in the area.

Deposition of Mesozoic clastic sediments in the Central North Sea occurred following the formation of Late Permian evaporites of the Zechstein Group (Fig. 2). A thick section of Jurassic and Triassic mudrocks, organic-rich shales, and sandstones lies within elongated, northwest-southeast oriented grabens that formed as a result of Triassic and Jurassic extensional rift tectonics and salt movement (Roberts et al., 1990). The Late Jurassic Kimmeridge Clay is the main petroleum source rock in the HPHT region with lesser contributions from several other units (Isaksen, 2004).

Previous studies have described the sedimentological and diagenetic features that influence reservoir quality of these sands

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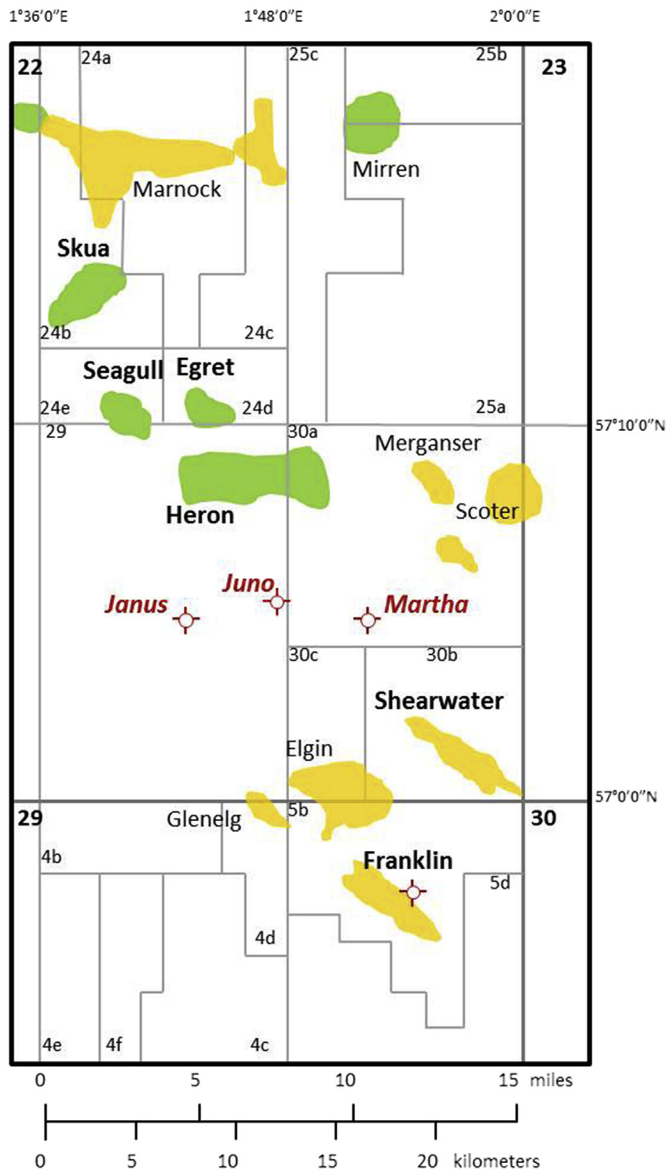

Figure 1. Location map for oil and gas fields and key wells used in this study of the Fulmar and Skagerrak reservoirs in the deep Central Graben of the UK Central North Sea. Green fill indicates an oil field; yellow fill indicates a gas condensate field.

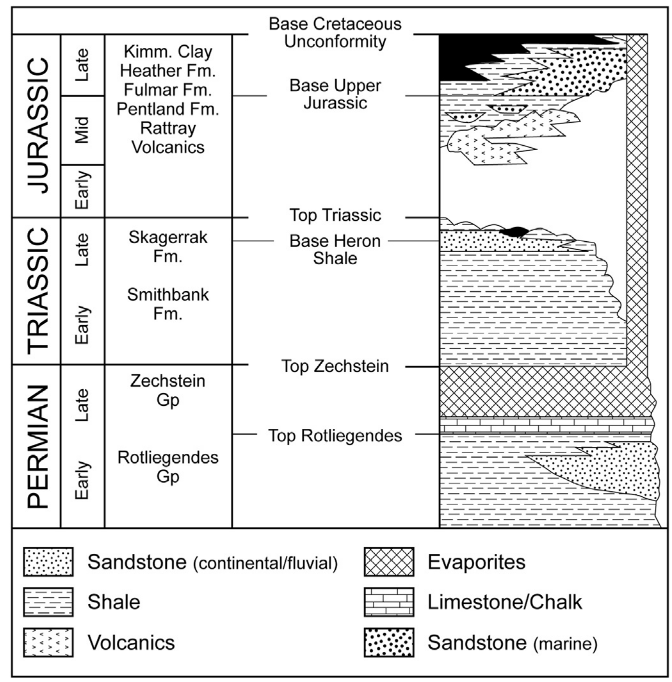

Figure 2. Regional stratigraphy for the Jurassic, Triassic, and Permian of the Central North Sea (after Winefield et al., 2005).

and have assessed the relative importance of the controlling processes (Stewart, 1986; Howell et al., 1996; Saigal et al., 1992; Darby et al., 1996; Wilkinson et al., 1997, 2006; Haszeldine et al., 1999; McKie and Audretsch, 2005). In this study, we integrate quantitative petrographic data, petrophysical data derived from wireline logs and laboratory core measurements, and burial history models to construct diagenetic models that can be used to forecast both reservoir quality and acoustic rock properties.

2. Samples and methods

Samples used for petrographic and petrophysical analyses are from conventional core taken in key wells drilled in the Central Graben area of the Central North Sea (Fig. 1). Standard core plugs (~25 mm diameter) were cut for the initial, routine core analysis programme consisting of unstressed porosity and air permeability measurements. Data such as these can be of general use, but are not considered sufficiently accurate for quantitative rock properties model calibration. A subset of core plug samples was selected for additional specialized measurements utilizing internal laboratory capabilities. The specialized core measurements included porosity and brine permeability at *in situ* and variable stress, and acoustic velocity. These high quality data are used for detailed calibration of both reservoir quality and velocity models.

Thin sections were made from the end trims of the core plugs so that a direct correlation could be made between petrographic analyses and laboratory rock physics measurements. Standard petrographic point counts were performed (300 points) for a representative set that includes all samples for which stressed porosity/permeability and acoustic velocity measurements were made. Grain size and sorting data were obtained by measuring the long axis of 100 framework grains per sample that were selected using a point count grid. One hundred quartz grains per sample were analyzed using digital image analysis techniques to determine grain coat coverage. Scanning electron microscopy (SEM) was performed on a representative subset of samples to characterize clay mineral textures and to verify the occurrence of microcrystalline quartz coatings. Clay mineralogy and composition were determined for a representative suite of samples using x-ray diffraction (XRD) analysis.

3. Fulmar Formation reservoirs

Conventional core samples of Fulmar sandstones from four wells, Martha (22/30a-1), Juno (22/29-6S2), and two wells from Shearwater Field (22/30b-A2; 22/30b-15s1) (Fig. 1) were used in this study. The Martha well encountered a highly porous (~24–33%), water-bearing Fulmar section with no apparent evidence of a previous hydrocarbon accumulation (Winefield et al., 2005). The Juno well penetrated a thick section of porous, oil-