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Network modelling analysis of a depressurization experiment on a North Sea reservoir core sample

U. Bagudu [a,*], S.R. McDougall [b], E.J. Mackay [b]

[a] *National Grid Gas, Warwick, UK*
[b] *Institute of Petroleum Engineering, Heriot-Watt University, Edinburgh, UK*

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ABSTRACT

Solution gas drive following depressurization of oil reservoirs below the bubble point is the oldest and perhaps one of the most challenging oil recovery mechanisms to quantify. Part of the challenge lies in designing repeatable experiments and then translating experimental observations into practical solutions in the field – laboratory depressurization rates are typically orders of magnitude higher than practical field rates. Using a case study we show how pore network modelling can help make sense of the underlying physical mechanisms governing gas flow behaviour in porous media during solution gas drive whilst also serving as a forward modelling tool for developing relative permeability functions for use in field scale simulators. Core scale simulations performed on a pore network anchored to measured petrophysical properties of a 0.23mD chalk core from a North Sea reservoir show a very weak correlation between depletion rate and critical gas saturation, contrary to observations in higher permeability clastic media. In addition, solution gas drive oil recovery was found to increase with higher initial water saturation.

1. Introduction

1.1. General context

Solution gas drive was one of the first petroleum production techniques to be implemented in the field, essentially due to its simplicity of application — the energy required for oil displacement being provided cheaply through gas and liquid expansion as a consequence of continuous fluid withdrawal from the reservoir. Gas dissolved in the oil is progressively liberated from solution, expands in place and subsequently migrates towards low pressure regions (i.e. towards regions of higher elevation within the reservoir due to hydrostatic forces and towards regions around production wells). During volume expansion of the gaseous phase, equivalent volumes of oil are expelled from the pore space resulting in oil flow towards the producers. For an undersaturated reservoir undergoing solution gas drive, three different stages can be identified:

1. Liquid expansion: oil is displaced from the reservoir through liquid expansion. Reservoir pressure falls quickly due to the low compressibility of the oil

2. Gas liberation: when pressure falls below a certain critical value (known as the *bubble point pressure*), the reservoir becomes a *gas-saturated oil reservoir*, gas is liberated from solution in the form of small gas bubbles and the oil phase begins to shrink. At this point oil production rates generally decrease, since the evolving gas saturation partially fills the host porous medium, thereby decreasing the relative permeability to oil.

3. Continuous gas flow: eventually the gas saturation increases to such an extent that isolated gas clusters become connected to one another and continuous gas flow begins — the minimum gas saturation at which this occurs is commonly referred to as the “critical gas saturation”. During this latter phase, produced gas-oil ratios tend to increase monotonically and oil productivity continues to decline.

Solution-gas drive is generally characterised by a rapid pressure decline and low recovery efficiency and, for this reason, more efficient recovery techniques, such as waterflooding and gasflooding have often been used. Nevertheless, the process of solution gas drive finds renewed interest in many areas of the world under the guise of “reservoir depressurization”: technological advances coupled with diminishing reserves mean that solution gas drive techniques are becoming economically attractive for a range of both virgin and waterflooded reservoirs.

* Corresponding author.
E-mail address: usman.bagudu@nationalgrid.com (U. Bagudu).

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Extensive applications to the former are found in heavy oil recovery (sometimes under the name of cold heavy oil production) especially in Western Canada and Venezuela (De Mirabal et al., 1996; Lago et al., 2002). For waterflooded reservoirs, the technique provides a valuable approach to appreciably extend the life of a reservoir that has undergone waterflooding for many years (Ligthelm et al., 1997; Goodfield and Goodyear, 2003; Petersen et al., 2004; Boge et al., 2005; Bratvold and Thomas, 2015).

Unfortunately, productivity forecasts for solution gas drive are not easily undertaken. The main reason lies in the uncertain determination of the initial reservoir properties (at bubble point pressure), together with our (still) relatively limited understanding of the related physico-chemical mechanisms that take place at the pore scale. Such an understanding is fundamental for generating appropriate input data for use in reservoir simulation studies which, in turn, facilitate efficient and reliable depressurization management.

Previous published works have covered topics ranging from the build-up of supersaturation and related nucleation of embryonic bubbles, to the growth of the gaseous phase, the study of critical gas saturations and the regimes of gas flow. There is a rich catalogue of experimental techniques; from the first attempts utilising simple methane and kerosene mixtures in the presence of calcite and silica crystals (Kennedy and Olson, 1952) to laboratory core tests (Handy, 1958; Firoozabadi et al., 1992; Scherpenisse et al., 1994; Akin and Kovscek, 2002; Piccavet et al., 2006; Alshmakhy and Maini, 2012) and visualization methods using glass-etched micromodels (El Yousfi et al., 1997; Mackay et al., 1998; Bora et al., 2000; Nejad and Danesh, 2005). In addition, a number of different theoretical models for gas phase evolution have been proposed (Moulu and Longeron, 1989; Firoozabadi and Kashchiev, 1996; Li and Yortsos, 1993; Tsimpanogiannis and Yortsos, 2002).

Despite this abundance of studies, however, it still appears that no generally accepted theory for gas evolution in porous media has yet been agreed upon; nor has any generalised procedure for estimating critical gas saturation been developed. The conclusion seems to be that gas evolution during solution gas drive depends strongly upon both the experimental set-up under consideration and the subtle interaction between the corresponding rock and fluid properties.

1.2. Motivation

Pore network modelling has shown great potential as a tool for gaining valuable insight into complex experimental situations because of its ability to explicitly represent physical phenomena at a fundamental scale. It is therefore uniquely suited for investigating the complex interplay of the physico-chemical processes during reservoir depressurization below bubble point. Such a process simulator has been developed (McDougall and Mackay, 1998; Bondino et al., 2003; Ezeuko et al., 2010) and has continued to be refined and extended (Bagudu, 2015).

As a result of experimental data recently becoming available from the North Sea, an opportunity has been presented for a detailed investigation of a number of important issues pertaining to pressure depletion in waterflooded chalk. By incorporating experimentally-determined core and fluid data, the process simulator can initially be used to interpret depressurization experiments and subsequently utilised to predict low-rate depletion behaviour over a range of length-scales: from the plug scale to the large core scale. In addition, several different boundary conditions can be considered and any inconsistencies reconciled.

Field A [*a pseudonym*] is a fractured chalk reservoir situated in the Central Graben of the UKCS and has historically been produced via voidage replacement water injection. However, following a few years of injection, an unexpectedly high water-cut has been observed and this has led the field management team to consider a range of revised development plans. The current viewpoint is that water injection into the chalk matrix should be continued until the water cut becomes unacceptable, at which point a depressurization strategy should be invoked in order to displace additional oil. Unfortunately, supporting evidence for the strategy is somewhat lacking at present and it is not possible to carry out an isolated pilot depletion in the field to assess its potential.

In order to address this deficiency and provide some background data for associated simulation studies, a moderate-rate, post-waterflood depletion experiment has been completed. Analysis of the measurements suggests a significant decrease in residual oil saturation from approximately 38%–18% after depressurization – surprisingly, no significant water production was observed during the experiment. However, a number of uncertainties remain with regard to the relevance of the experimental results to the field: (i) the laboratory depletion rate significantly exceeded that practically achievable in the field; (ii) production was restricted to the top of the sample, raising the possibility that buoyancy effects could have biased the results; and (iii) constant composition expansion was assumed to be a suitable model for assessing oil shrinkage but this may not be appropriate.

1.3. Objectives and paper outline

The main objectives of this case study are:

I. To anchor the pore-scale simulator to reservoir samples using petrophysical data obtained in the laboratory.
II. To build a numerical model of the reservoir sample by matching the experimental production profiles.
III. To undertake a parametric study of the depressurization process at the pore-scale, using the pore network model as an investigative tool to offer an interpretation of the experimental trends.
IV. To use this numerical surrogate to examine production and relative permeability issues using different depletion rates and different rock/fluid parameters; and
V. To use the simulation results to re-interpret a range of experimental data and help explain any apparent inconsistencies

Because of the direct relevance of the results to field operations, field units will be used throughout this paper.

2. Model setup

2.1. The Basic Model

The basic network model is a three dimensional lattice of interconnected capillary elements with a coordination number of 6 (Fig. 1). Less well-connected network topologies can be modelled by removing elements at random. Single phase flow through the network is modelled

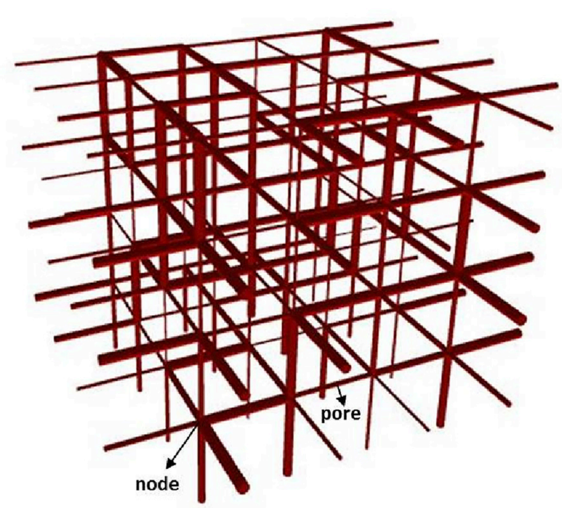

Fig. 1. A three dimensional network model.