Determination of the Viscosities of Grosmont Reservoir Bitumen, Alberta, Canada

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Summary

The Upper Devonian Grosmont Formation in Alberta, Canada, is a giant bitumen / heavy oil reservoir with minimum estimated minimum of 318 million barrels of OIP. Pilot steam injection tests in the 1980s had highly variable recovery rates. At the time, the reservoir was not deemed commercially viable. In the last 3 years, however, the Grosmont is under consideration for commercial development by several companies and consortia due to technological advances and much higher oil prices.

One part of the work leading up to new pilot sites is the characterization of the petrophysical properties of the reservoir bitumen. Samples were extracted from several stratigraphic levels: Nisku, Upper Ireton and Upper Grosmont 1, 2 and 3. Visually, the bitumen falls into at least two types, i.e., dull-brown and shiny-black. Both types exhibit distinct non-Newtonian behavior at temperatures below 30°C. Therefore, shear rates must be reported along with temperature whenever bitumen viscosity is presented. Within the range of shear rates investigated, i.e., 0.0002 – 6.0000 (1/s), measured dynamic viscosities range from about 10^7 to 10^8 cP at 20°C. In addition, a distinct difference in the degree of 'aging' is observed between 'fresh' samples from recently drilled cores (1-2 years old) and those from 20 to 30 year old 'legacy' cores. The viscosity distribution in the Grosmont shows a general cyclic variability and a dependence to stratigraphic depth.

Introduction

Natural bitumen is defined as hydrocarbon with viscosities greater than 10,000 centipoises (cP) measured at reservoir conditions (Etherington and McDonald, 2004). The Devonian Nisku, Upper Ireton and Grosmont formations (summarily referred to as the "Grosmont Reservoir" or the "Grosmont") in Alberta together host about 400 billion barrels of initial oil in place (IOP), which is the largest carbonate bitumen reservoir in the world (Meyer and Attanasi, 2003). A complex diagenetic history, especially dolomitization at various stages and late karstification, has made the Grosmont a highly heterogeneous reservoir (Dembicki and Machel, 1996). The bitumen in the Grosmont is characterized by extremely high viscosities (more than a million cP on average) and very low API gravities (5° to 9°). The causes and spatial distributions of these variations have never been examined. However, in order to develop a suitable thermal recovery technology for this reservoir, such variation must be understood.

Theory and/or Methods

Traditional reservoir characterization deals with porosity, permeability, and fluid saturations, which is sufficient for describing conventional reservoirs. However, high viscosities become a dominant factor when characterizing heavy oil and bitumen reservoirs, such as the Grosmont. In order to generate useful petrophysical data for bitumen in the Grosmont reservoir, the following methods are used:

1. Viscosity measurement: Sample preparation and technique.

Previous studies showed that viscosity measurements are problematic (Miller et al., 2006; Adams et al., 2008). In this investigation, an in-depth evaluation of viscosity was undertaken as a prerequisite step for reservoir characterization. Core samples are collected from Core Research Center, Calgary and bitumens were extracted from core samples by standard Dean Stark extraction. The extracted bitumens were placed under a fume hood at room temperature for 3 to 5 days to evaporate all the solvents. Occasional stirring is needed as the bitumen is able to trap the solvent once it gets thick. The fluid behaviors of bitumens were then measured by AR-G2 rheometer with a cone & plate geometry (2cm in diameter, 2° cone angle).

2. Characterization of Grosmont reservoir bitumen fluid properties.

It has been suggested that the high viscosities of the Grosmont bitumen resulted mainly from water washing and biodegradation (Connan, 1984; Head et al., 2003). In addition, when bitumen is brought to surface in a core barrel, it will undergo modifications as a result of the influences of light, air, water, and fluctuations in temperature, which are collectively called “aging”. The net result of aging appears to be a marked increase in viscosity. In our study area, most of the available cores are legacy cores that are 20 to 30 years old, whereas there are few fresh cores that are less than 2 years old. Thus, a regional investigation can only be done using legacy cores. This study attempts to: a) clarify how significant the aging effect is in the Grosmont reservoir bitumen; b) introduce a correlation to correct fluid properties of legacy samples to fresh samples and/or in-situ condition.

Examples

Viscosity is defined as the internal resistance to flow. It is expressed as a ratio between the force applied and the corresponding shear rate obtained. The bitumen in Alberta is traditionally recognized as a Newtonian or mild non-Newtonian fluid (Ward and Clark, 1950; Dealy, 1979), which means viscosity is a nearly constant value regardless of the force applied and the shear rate generated. However, the data from this study shows that the viscosity of Grosmont bitumen is shear rate dependent, exhibiting a shear thinning behaviour (Figure 1). As a result, simply measuring viscosity under a random shear rate is far from comprehensive, especially when measured at temperatures less than 30°C. This may be one of the reasons why the viscosity reported from different labs and studies on same material are so different (e.g. Miller et al., 2006; Adams et al., 2008).

Figure 2 depicts a pair of viscosity logs plotted against depth from a fresh well and a legacy well that is about 9km apart. It clearly shows that the viscosities of fresh samples are about one order of magnitude lower than those from the legacy samples. In addition, although the vertical variation of viscosity is complex in these two adjacent wells, the general curve from each formation (indicated by different colors) is similar. For example, the viscosity in Nisku formation is increasing along the depth; the viscosity profile from Upper Ireton formation has a “C” curve. This suggests that the viscosity distribution is probably formation-related.

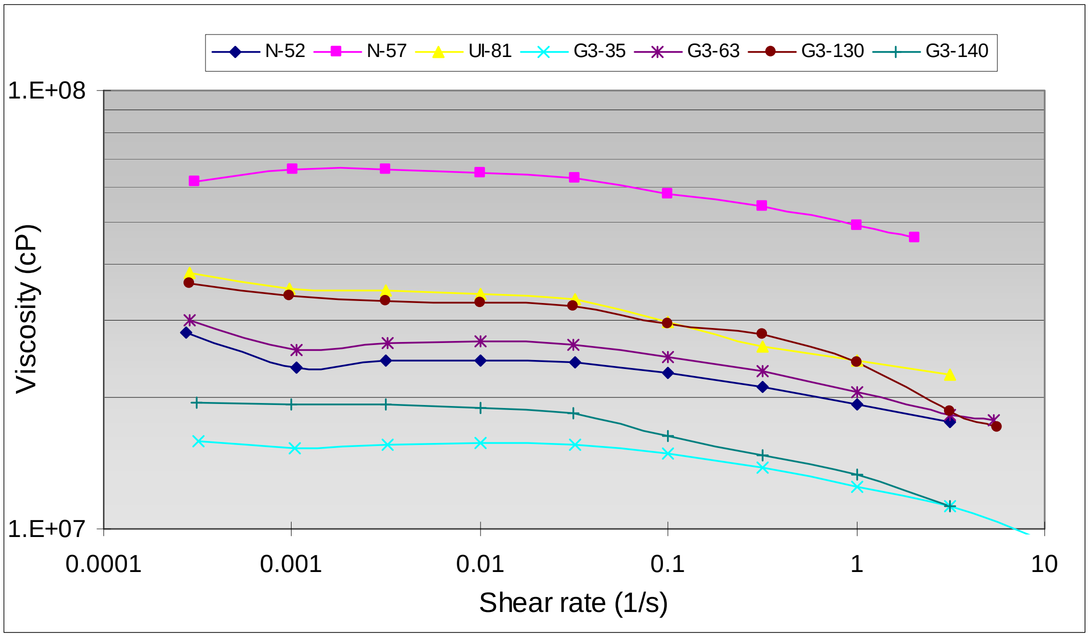

Figure 1 Shear rate-viscosity plot for a series of 20 to 30 years old samples from Nisku (N), Upper Ireton (UI) and Grosmont 3(G3). All the tests are conducted under 20°C with a progressive increasing shear rate. It shows that the bitumens only exhibit Newtonian behavior in a very short shear rate range (roughly changes from 0.001 to 0.02s^{-1}). Notice that the higher viscosity the bitumen has; the shorter Newtonian behavior range it exhibits.

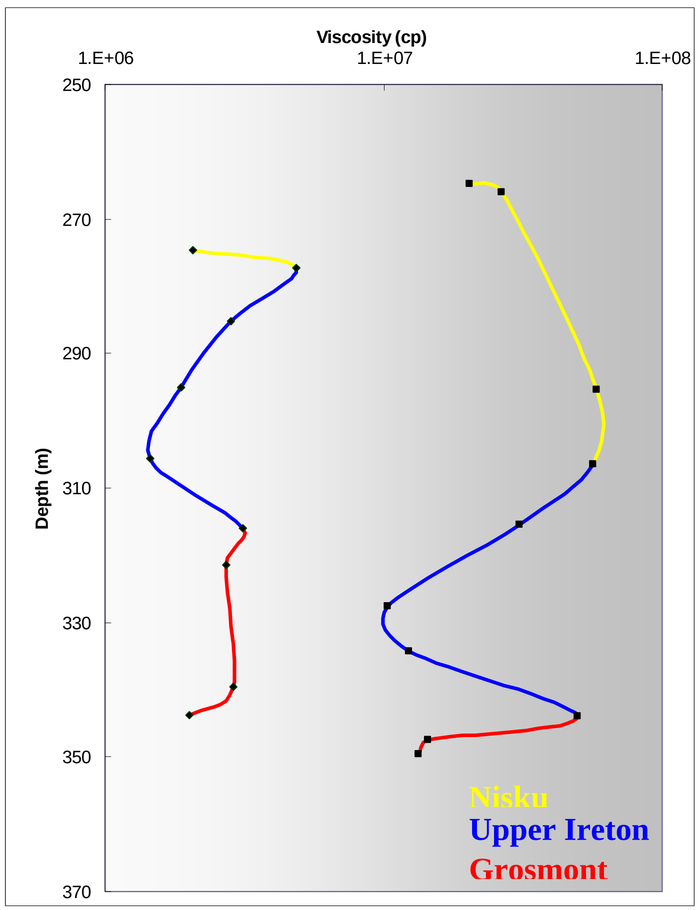

Figure 2 Viscosity logs comparison of fresh well (left) and legacy wells (right) under 20°C. Nisku, Upper Ireton, and Grosmont formations are represented by different colors.

Conclusions

This investigation reveals that the bitumen from the Grosmont reservoir is essentially a non-Newtonian fluid, exhibiting a distinctive shear thinning behavior under low temperature (below 30°C). In other words, the bitumen's viscosity is shear-dependent. Cautions should be taken when measuring viscosity at such conditions and shear rate should be reported along with temperature whenever bitumen viscosity data is presented.

Distinct differences in "aging" were observed between extracted bitumen from legacy and fresh cores. A viscosity difference of one order of magnitude is not uncommon in the comparison. Therefore, viscosity data from legacy cores must corrected for use as reservoir proxies.

The viscosity distribution in Grosmont reservoir is complex, and varies cyclically with depth, although the variation is commonly in one order of magnitude. Moreover, the vertical distribution of viscosity seems formation-related, as similar trend is observed from adjacent wells in Nisku, Upper Ireton and Grosmont respectively.

Acknowledgements

The authors would like to thank Shell Exploration and Production Company for the financial support; Harold Vinegar for his guidance of this project. Profs. Jacob H. Masliyah and Zhenghe Xu generously provided laboratory and equipments for the extractions and viscosity measurements.

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