



Full Length Article

Pore-scale analysis of condensing solvent bitumen extraction

ZhenBang Qi^a, Ali Abedini^a, Pushan Lele^a, Nader Mosavat^a, Adriana Guerrero^b, David Sinton^{a,*}^a Department of Mechanical and Industrial Engineering and Institute for Sustainable Energy, University of Toronto, 5 King's College Road, Toronto, ON M5S 3G8, Canada^b Suncor Energy Inc., 150 – 6 Ave SW, Calgary, AB T2P 3E5, Canada

HIGHLIGHTS

- Liquid solvent left more residues comparing with the vapor chamber.
- Butane-in-residue emulsions generated during butane runs intensified pore plugging.
- Residuals in liquid zone were majorly asphaltenes as they exhibited low fluorescence.
- Bitumen recovery was most vigorous at the condensing edge due to multi-phase flow.

ARTICLE INFO

Article history:

Received 7 October 2016

Received in revised form 19 December 2016

Accepted 20 December 2016

Keywords:

Micromodel

Pore-scale

Bitumen

Condensing solvent

Asphaltenes

ABSTRACT

Current thermal methods for bitumen recovery are effective but require both environmental and economic performance improvements. Light hydrocarbon solvent injection is an alternative to steam injection that has the potential to reduce greenhouse gas emissions associated with recovery. However, the pore-scale behavior of the solvent-bitumen system is very complex and poorly characterized to date. In this work, a high-pressure high-temperature micromodel with reservoir-relevant geometry combined with imaging tools provides a pore-scale window into solvent injection methods using propane and butane. The combination of two-phase dynamics and solvency at the condensing edge leads to significant bitumen production, similar in both propane and butane injections. In the liquid zone ahead of the condensing edge, butane results in dense, small, and immobile solvent-in-residue emulsions. In contrast, liquid propane produced larger emulsions with some mobility. Spectroscopy combined with fluorescence imaging indicated that the residual immobile emulsions in the butane case are bitumen heavy fractions, and largely asphaltenes. Collectively this work highlights the distinct recovery mechanisms and limitations at both the condensing front and liquid zone for these common solvents.

© 2016 Elsevier Ltd. All rights reserved.

1. Introduction

With steady demand for petroleum products and decline in conventional recovery, the world has become more interested in unconventional resources [1]. Canada has abundant bitumen and heavy oil formations – over 1.8 trillion barrels – which is around 36% of the estimated world total hydrocarbon resource [2,3]. Bitumen reservoirs known as oil sands in Canada, are very challenging to extract as bitumen is extremely heavy and viscous, trapped within sand grains in shallow geological formations with low pressures. Bitumen viscosity is significantly reduced at higher temperatures providing the opportunity to implement *in situ* thermal recovery processes such as cyclic steam stimulation (CSS), steam assisted gravity drainage (SAGD), and *in situ* combustion [4]. How-

ever, majority of these processes are very energy intensive as natural gas is used to generate steam, resulting in high greenhouse gas emissions and associated environmental and economic costs [5,6]. In addition, heat loss to over-burden and under-burden layers in thin formations further lowers the thermal efficiency of the process [6,7]. There is much current interest in alternative approaches to improve or even replace current thermal recovery processes [8–13].

Light hydrocarbon solvent was first incorporated in bitumen extraction in 1974 in which solvent vapor was cyclically injected into the reservoir with bitumen produced from the same well (i.e., cyclic solvent injection) [14]. After the successful introduction of SAGD which employed the heat transfer to reduce the bitumen viscosity, solvent injection methods have been proposed to decrease the viscosity through solvent-bitumen mass transfer; including non-condensing and condensing solvent extraction processes [15,16]. Less heat is required in these solvent processes

* Corresponding author.

E-mail address: sinton@mie.utoronto.ca (D. Sinton).

and heavier components such as asphaltenes can be left in the reservoir, improving the quality of the produced oil [1,17,18]. For a direct comparison of the amount of energy required, the specific heat and latent heat of propane are 1630 J/kgK and 4.28×10^5 J/kg, respectively, which are much lower than the values for water, 4180 J/kgK and 2.257×10^6 J/kg (both specific heat values measured at 25 °C). Thus, steam generation in SAGD requires significantly more energy than vaporizing the propane in solvent injection.

In non-condensing solvent extraction, light hydrocarbon vapor – in direct contact with the bitumen – diffuses into the bitumen, reducing the viscosity, and allowing drainage under gravity [3,19,20]. This method has the advantage of less solvent use, and the disadvantage of low production rates [1,21]. In condensing solvent extraction, solvent vapor is injected at an elevated temperature and pressure such that it condenses at the bitumen interface, similar in principle to SAGD [16,21,22]. The hot solvent transfers latent heat to the bitumen and the condensed solvent dilutes the bitumen, both of which reduce viscosity and promote drainage [22]. Solvent temperatures are typically in the range 30 to 120 °C (depending on the solvent and reservoir condition), which is significantly lower than typical steam temperatures in SAGD (150 to 200 °C). While the solvent needs to be heated, condensing solvent extraction promises significant energy savings over SAGD [21].

The most common conventional methods used to assess oil recovery processes are coreflooding, sand-pack flooding, and reservoir simulations [23–25]. Although these methods provide some insight, they are not able to resolve the actual processes occurring inside the porous media. Consequently, pore-scale recovery mechanisms, phase interactions, and interface behavior remain unknown. In particular, data on condensing solvent extraction – a relatively new multiphase solvent-based process – are scarce; studies have only reported the recovery rate during the process without resolving the pore-scale mechanisms and interfacial behavior that enable recovery [26,27]. Additionally, various attempts have been made to visualize the non-condensing solvent process inside cores and sand-packs, but these methods fall short of pore-scale resolution [28,29].

Micromodels or microvisual platforms have a long history [30–35]. More recently, advances in micro/nanofabrication and imaging are being leveraged to provide a highly-controlled environment and excellent optical access to the porespace. In a dual-permeability pore-network constructed with homogeneous patterns on a silicon-glass chip, liquid CO₂-water displacement was studied to investigate interfacial phenomena that occur in the process of CO₂ sub-sequestration into deep aquifers [36]. To better reflect reservoir pore geometries, silicon-glass chips were designed and fabricated with pore networks obtained off SEM images of reservoir rocks, and applied to visualize multi-phase flows such as water-oil displacement [37,38]. With a similar platform, CO₂-water imbibition experiments were conducted to investigate immobilization and trapping of CO₂ during sequestration [39]. Furthermore, the effects of nanoparticle-stabilized CO₂ foam flooding in light, medium and heavy oil reservoirs were compared [40]. Glass-glass chips are also used to enable full-field imaging of the micromodel and direct quantification of the oil saturation. A 10 cm × 10 cm glass-glass micromodel was used to quantify alkaline SAGD bitumen recovery and the overall production rate [41,42]. A glass-glass micromodel was also employed to investigate the associated pore-scale mechanisms, wettability, and contact angle during carbonated water injection [43]. The simultaneous optical and thermal imaging techniques were used to study the pore-scale of two-phase flow and heat transfer between phases [44,45]. Moreover, Researchers have incorporated geological materials in the micromodels in order to match the pore wall properties

to that of the reservoir material. For instance, a pore network was etched on calcite crystal to probe different displacement processes in a carbonate reservoir [46], and likewise shale was used as a micromodel substrate with impressively high pressures (8.6 MPa and 50 °C) [47]. In a hybrid approach, clay particles were deposited within a glass-glass micromodel to include reservoir-relevant geochemistry [48]. There is also some precedent for assessing solvent-based recovery with micromodels [15,20,49–53]. For miscible flooding, formation of residual oil was visualized and mechanisms were studied in a micromodel [49]. A high pressure (35 MPa) chip was built to investigate the microscopic mechanisms in near-miscible gas injection [50,51]. In terms of solvent-based methods analogous to SAGD, Das and Butler used a Hele-Shaw cell to visualize the dissolution of bitumen and developed an equation to predict the production rate for non-condensing solvent extraction in a porous media [15,20]. James and Chatzis also investigated non-condensing solvent extraction and its associated pore-scale mechanisms using a large micromodel with particles ranged from 1.06 to 2.00 mm in diameter [52]. Mohammadzadeh et al. studied the combination of solvent and steam for oil recovery with the same micromodel as above, where bitumen dilution and asphaltene precipitation were observed in the pores as solvent condensed into liquid [53]. The full potential of micromodels can be realized only if there is a strong match of all reservoir conditions and characteristics – specifically reservoir-relevant pressures, temperatures, fluids and pore geometries. Condensing solvent has not been characterized in such a micromodel, despite the growing importance of this recovery approach.

In this paper, we employ a microchip matching the relevant reservoir conditions and pore geometry and a suite microscopy tools to resolve the pore-scale behavior of the condensing solvent extraction processes using two commonly practiced solvents, propane and butane. We resolve the interface, pore-scale mechanisms, displacement efficiency, and precipitation phenomena in distinct regions generated during solvent injection. The combination of transmittance spectroscopy and advanced microscopy and imaging tools (i.e., pore-scale imaging, thermal (IR) imaging, dark-field microscopy, and fluorescence microscopy) enable the differentiation of solvent-based recovery mechanisms with both propane and butane.

2. Experimental

2.1. Materials

A bitumen sample was procured from the Athabasca oil sands in Alberta. The measured molecular weight and density of the bitumen sample were $MW_{Bit} = 588.8$ g/mol, $\rho_{Bit} = 1020$ kg/m³, respectively. The viscosity of the bitumen was measured at atmospheric pressure and three different temperatures of 80, 150, and 200 °C, with the values are reported in Table 1. The bitumen viscosity at ~20 °C is estimated to be over 10⁶ mPa·s. Table 1 also summarizes the compositional analysis of the bitumen, showing that the weight percentage of components ranging C₁–C₁₀s is less than 0.1 wt% while weight percentage of C₃₀₊ fraction is ~69 wt%. It is also noteworthy that the sample employed here was dead oil, that is no light fractions were present. In these relatively shallow, low-pressure bitumen formations, there are very low concentrations of light hydrocarbons and do not appreciably alter the physical properties. The n-C₅ asphaltene content of the sample was also determined to be 43.3 wt% using the standard ASTM D2007 [54]. Pure propane (99.5 mol%) and pure butane (99.5 mol%), purchased from Praxair Canada, were used as hydrocarbon solvents during experiments. Liquid pentane (99.0 mol%) purchased from Sigma-Aldrich was also used as one of the

Download English Version:

<https://daneshyari.com/en/article/6474947>

Download Persian Version:

<https://daneshyari.com/article/6474947>

[Daneshyari.com](https://daneshyari.com)