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Quantitative and visual characterization of asphaltenic components of heavy-oil after solvent interaction at different temperatures and pressures

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ABSTRACT

Due to inefficiency of steam injection caused by technical, economic, and operational reasons, solvent methods have received special attention in heavy oil and bitumen recovery recently. Solvent-based recovery processes improves crude oil production and quality because underground in situ upgrading takes place after heavy oil is diluted with a light hydrocarbon solvent. Consequently, crude oil mobility increases due to significant reduction in viscosity caused by the asphaltene precipitation. However, solvent driven recovery processes are quite complex on account of the "asphaltene destabilization" that takes place due to changes in temperature, pressure, crude oil composition, and solvent dissolved in oil. As a result of this destabilization, the asphaltene particles start to flocculate, and eventually may plug the pores in the reservoir due to larger asphaltene particle agglomeration in the reservoir.

In this paper, the deasphalting of a heavy oil sample [8.67°API] was carried out using an optical PVT cell. The experiments were undertaken at different temperature ranges [122 °F (50 °C)–230 °F (110 °C)] and pressure ranges (30–500 psig), which are the suggested ranges applicable to typical Canadian oilsands or similar shallow heavy-oil deposits around the world. Three light hydrocarbon solvents (propane, n-hexane, and n-decane) were used to break the stability of the asphaltene in the crude oil. An experimental methodology for "asphaltene precipitation fraction" was developed in order to determine the effect of temperature, pressure, and solvent type on the amount of asphaltene precipitation. The experimental methodology was complemented through visual observations of asphaltene characteristics on the PVT cell as well as using optical microscopy. In addition, the refractive index measurements at the onset of precipitation were used to evaluate the changes in the oil after interacting with the solvent at different temperatures and pressures.

Overall, the results showed that precipitated asphaltene fraction increases when the concentration of the resins goes down after the deasphalting of crude oil with solvent. In addition, the aggregation of asphaltene particles increases with increasing temperature [122 °F (50 °C)–230 °F (110 °C)] and pressure (from 30 psig to 500 psig), and decreasing solvent carbon number (from C10 to C3). At the end, a comparative analysis of the quantitative and qualitative results from the experiments is provided. Based on these observations, the characteristics of asphaltene were classified in terms of their shape, size, and amount for different oil/solvent types, pressure, and temperature. This study will eventually lead to the identification of the effects of asphaltene characteristics on pore plugging during heavy-oil/bitumen recovery by gravity drainage from oilsands.

1. Introduction

Solvent based applications of heavy-oil recovery have been proposed as an alternative process due to economical, operational, and environmental concerns of thermal recovery processes. The solvent injection process into the reservoir was proposed initially by Butler and Morkys [1]. They introduced this new process as vapour extraction (VAPEX), which mainly consists of deasphalting of the heaviest components of heavy oil, i.e., asphaltene [2–4]. Asphaltene has the highest molecular weight and is the most polar constituent of a crude oil [5,6]. Asphaltenes are insoluble in n-alkanes (e.g. n-heptane and n-pentane) but soluble in aromatics (e.g. benzene and toluene) [5,6]. The asphaltene polydisperse molecules consist mostly of polynuclear aromatic ring systems bearing an alkyl side

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chain [5,6]. Also, hetero-elements (nitrogen, oxygen, and sulfur) and heavy metals (vanadium, nickel, and iron) were identified in the asphaltene structures [5,7,8].

In addition, asphaltene self-association mainly depends of the resins structure type. Resins structure can vary depending of the oil composition [8–11]. Asphaltenes may partly be dissolved and suspended/peptized by resins in the crude oil. The solubility of the asphalentes in the crude oil can decrease by the injection of the light hydrocarbon solvent [9,11,12]. Consequently, asphaltene may form steric-colloidal particles due to the paraffinic injection, which affects the resins fraction as the dispersing agent. The resin molecules generate the desorption from the asphaltenes surface in order to re-establish the thermodynamic equilibrium [9,13,14]. Subsequently, asphaltene particles start to bond to each other until they create clusters of asphaltene nano-aggregates [8,9,11,15,16]. Asphaltene precipitation can be calculated experimentally using a variety of methods. The most widely used methods are the gravimetric (static) method and filtration (dynamic) method. The gravimetric method is the most commonly used in studies of asphaltene phase behavior in a visual PVT cell [17,18].

Asphaltene precipitation during upstream and downstream processes has been studied for decades. Upstream process has been more challenging as asphaltene agglomeration and cluster formation near the wellbore (and in the reservoir) may significantly affect production rate [19,20]. Chemical treatments have been used in order to increase the dispersion of the asphaltene in the fluid [21,22]. An alternative to this is to control pressure and temperature and remain out of the precipitation point [20,22–24], which requires extensive PVT studies to determine this point for the given oil type.

Studies on asphaltene precipitation envelopes (APE) were determined mostly for natural pressure depletion processes and showed that asphaltene solubility depends on temperature, pressure, and oil composition. However, the relative effects of these parameters on asphaltene behavior are highly controversial. For example, it has been observed that pressure and oil composition effects are more critical than the temperature effect [9,18,25]. As opposed to this, some found the role of temperature in asphaltene deposition process more important. It was reported that increments in the temperature and pressure influence the asphaltene concentration in the crude oil and, as a consequence of this, asphaltene flocculation may decrease [12,17,26,27]. On the other hand, it was demonstrated that by reducing pressure, the asphaltene precipitation does not increase [28]. Moreover, asphaltene has a tendency to precipitate near the bubble point, but in some cases, asphaltene precipitation may take place even at different conditions from the bubble point, depending on the type of oil composition, temperature, and pressure [12,17,28]. In addition to the above listed experiences, upstream and downstream processes that are involved in the dilution of crude oil with n-alkanes and the effect of temperature, pressure, and solvent on asphaltene flocculation during this process were also reported. Nielsen et al. [16] studied the effect of the temperature, pressure, and n-pentane (n-C5) on particle size distribution using different types of oil composition. They found that higher temperature and pressure operational conditions increase the solubility parameter. The solubility parameter can be calculated based on the mixture between crude oil and n-alkane. Other studies found that based on the refractive index of the mixture, higher hydrocarbon number increases the asphaltene dispersion in the crude oil than the lower hydrocarbon number [29,30]. Similarly, Ferwron et al. [13] and Speight [5] found that lower hydrocarbon solvent decrease the solubility of the mixture due to asphaltene precipitation. Speight [5] concluded that temperature and pressure changes affect the oil composition. Moreover, Akbarzadeh et al. [17] conducted solvent injection experiments using a pressure, volume, temperature (PVT) cell. They concluded that the amount of asphaltene precipitate decrease as pressure and temperature increase. In short, the natural tendency of asphaltene precipitation is quite complex to understand in the reservoir formation due possible wettability alteration, emulsion formation, asphaltene deposition in porous medium, and oil production [31,32].

Definitely, asphaltene precipitation and deposition into the reservoir is one of the main issues with the solvent injection process. Asphaltene precipitation from the crude oil improves the crude oil quality and mobility due to upgrading; however, asphaltene may be flocculated and agglomerated in the fluid stream and on the rock surface. Das and Butler [33] conducted VAPEX experiments using a Hele-Shaw cell. Three Alberta oil sands (Peace River, Cold Lake, and Lloydminster regions) were diluted with propane at operational conditions near the dew point of propane. They concluded that the asphaltene deposited in the porous medium, and wettability alteration does not stop oil flowing out of the reservoir. Similarly, Das [34] concluded that in a Hele-Shaw cell and high-permeability packed beds did not show that asphaltene precipitation caused any serious problem in the oil production. However, they suggested that the precipitated asphaltene may become a problem in finer sands. Note that these experiments were conducted at ambient temperature (VAPEX) conditions.

Later, Butler and Jiang [35] carried out experiments using butane or propane mixtures with a non-condensible gas (methane) at different temperatures and pressures (69.8 °F–80.6 °C and 30–300 psig, respectively). They observed more oil production at higher pressure and temperature conditions and better viscosity reduction at higher solvent/oil rate. In addition, they noticed a higher recovery factor with propane compared to butane or mixture of both. In contrast, Papadimitriou et al. [36] observed remarkable asphaltene deposition in Berea sandstone cores when iso-butane was used as solvent, then the oil production declined in the time. They observed asphaltene migration downstream flow, and defined two critical zones of the asphaltenic material deposition close to the injection and production wells [36,37]. Furthermore, after running several experiments using propane and butane, Haghighat and Maini [31] suggested that in situ upgrading of the oil via asphaltene precipitation in the VAPEX process is not an effective technology due to the permeability reduction and low rate of oil production. In addition, Pathak and Babadagli [38,39] conducted several experiments in an unconsolidated sandpack medium. They concluded that asphaltene deposition on the pore throats promoted reduction of permeability as well as oil production. Earlier studies demonstrated that asphaltene precipitation increases or decreases according to the oil composition, type of paraffin and concentration, pressure and temperature conditions [11,40–43]. These observations indicate that asphaltene deposition, which may cause a negative effect on heavy-oil production due to pore plugging, can be reduced by applying optimal operating conditions.

In this research, the effect of crude composition, temperature, pressure and type/amount of solvent on asphaltene precipitation was investigated. The main objective was to provide a clear understanding of asphaltene precipitation behavior at different pressure and temperature conditions using a specific extra heavy oil (87,651 cp at 25 °C) and to substantiate data to be used in asphaltene deposition in porous medium. A visual PVT cell was used to analyze the phase behavior of heavy crude oil and n-alkane solvents for a range of temperature [from 122 °F (50 °C) to 176 °F (80 °C)] and pressure (from 30 psig to 500 psig). The study was supported by other quantitative and qualitative (visual) measurements (refractive-index analyzer, elementary analyzer, and optical microscopy), and a “map” of asphaltene characteristics