A Systematic Workflow Process for Heavy Oil Characterization: Experimental Techniques and Challenges
A.I. Memon, J. Gao, S.D. Taylor, T.L. Davies, N. Jia, SPE, Schlumberger

Abstract

Heavy crude oil reserves are steadily gaining attention as the world’s energy demand increases. The fluid characterization of heavy oil and bitumen is critical in deciding best extraction, production, and processing methods of a heavy oil asset. High viscosity, low API, low saturation pressure, and low GOR impose challenges in measuring fluid properties of heavy oil. Such challenges include fluid sampling, sample handling, cleaning and de-emulsification of heavy samples and slow evolution of gas from oil phase during pressure-volume-temperature (PVT) testing—e.g., constant composition expansion (CCE) experiment. Due to these challenges, the accurate and reliable fluid characterization of heavy oil becomes more difficult. Currently, no industry standards exist for heavy oil property measurements. More often, heavy oil property measurements are performed in the same way as black oil fluid property measurements. This poses a big risk in obtaining erroneous fluid properties measurement for heavy oils.

This paper summarizes the heavy oil fluid characterization technique that includes fluid sample handling, PVT analysis, fluid viscosity, emulsion and rheology, slow kinetics of gas evolution during CCE experiment, solvent solubility study, steam stripping study, and high temperature vapor-liquid equilibrium of oil-solvent-steam systems. The experimental methodologies, including the merits and experimental limitations for these measurements are discussed in detail. Example results of heavy oil property measurements for each technique are presented. Finally, a systematic heavy oil characterization workflow is proposed for various types of production processes such as cold depletion, steam flood and heavy oil flow assurance characterization.

Introduction

Ever increasing energy demand has inflated the production interest in heavy oil and bitumen around the world. One of the keys to meeting this increasing demand for heavy oil is a thorough characterization of the reservoir fluids and the potential variability in fluid characteristics across a heavy oil field. ‘Heavy’ or ‘viscous’ oils are typically defined (based on UNITAR guidelines) as either heavy oil or bitumen. Heavy oils have a API gravity between 22.3 and 10 °API and a viscosity between 100 – 100,000 mPa.s. Bitumens are oils where the API gravity is less than 10 and viscosity exceeds 100,000. Oils with less than 10° API gravity may be referred to as extra-heavy or ultra-heavy oil due to its density being lower than water (Martinez et al, 1987).

Fluid characterization of heavy oils and bitumen is required for several purposes, including oil quality evaluation, selection and optimization of production process, facilities planning, transport planning, and process monitoring. In the case of selecting and optimizing processes to extract heavy oil from a reservoir, fluid characterization efforts are normally focused on understanding the mobility and changes to the mobility under different production conditions. Such understanding and ability to manipulate mobility depends on the knowledge of petroleum fluid thermodynamics, chemistry and transport phenomena.
Data and modeling requirements for fluid characterization will depend on the type of heavy oil production method under consideration. Heavy oil production methods can be divided into four main categories, 1) cold depletion production, 2) waterflood production, 3) thermal production and 4) solvent flood production processes. Cold depletion production methods do not require any addition of heat and can be used when the viscosity of heavy at reservoir conditions are low enough to allow the flow of oil to surface. In some cases, cold production processes will include diluent injections within the wellbore to decrease fluid viscosity prior to an artificial lift pump, such as the usage of electrical submersible pumps (ESPs) and progressing cavity pumps (PCPs) (Rojas, 2001). Waterflooding is a cold secondary oil recovery method to produce heavy oil with relatively low viscosity. This method has not been successful for moderate to high viscosity heavy oil due to several limitations including fingering of waterflood fronts which may result in poor sweep efficiency. In typical thermal methods, steam is injected in several configurations such as huff and puff or steam flooding using a mutiwell process or steam-assisted gravity drainage (SAGD). The solvent flood production process includes the injection of vaporized solvents such as propane or carbon dioxide. Some processes under consideration may combine approaches from these four categories, such as steam-solvent injection processes (Butler and Mokrys, 1989).

Linked to the production method selection are potential flow assurance issues which can significantly impact field development planning (Gonzalez and Jamaluddin, 2006). The prevention and mitigation of flow assurance problems are extremely important for sustained oil production. Of particular interest in flow assurance issues during heavy oil production is heavy oil-water emulsions (Alboudwarej et al, 2007). The water-in-heavy oil emulsions tend to increase the viscosity of heavy oil and often present a challenge to oil-water separation. In addition to emulsion issues, heavy oil contains high amounts of asphaltene which do not precipitate during normal production of heavy oil systems since asphaltene tends to stay in solution with change in pressure and temperature. However, the addition of other hydrocarbon phases such as miscible rich gas and paraffinic solvents (Aboudwarej, et.al., 2003) or diluents (Akbarzadeh, 2005, Wiehe and Kennedy, 2000) are known to induce asphaltene precipitation from heavy oil.

In this paper, a proposed heavy oil characterization workflow to address a variety of heavy oil production and flow assurance scenarios is presented. This heavy oil characterization workflow includes the discussion of various experimental techniques and challenges for heavy oil sample preparation and handling, basic heavy oil PVT – fluid property measurements, and proposed fluid characterization measurements for each production process. Example results of heavy oil property measurements for each technique are also presented.

**Heavy Oil Characterization Workflow**

A summary of proposed heavy oil characterization workflow is presented in Figure 1. It illustrates various stages and fluid property measurement requirements for different types of heavy oil production processes. This workflow was created using a compilation of the authors’ experience in the field of heavy oil characterization so far and will continue to evolve with further technology development and experience. The workflow begins with the common step of sample preparation and sample quality checks followed by standard phase behavior (i.e. PVT) and fluid properties measurements at both atmospheric and original reservoir conditions. Based on the production process under consideration, then workflow then proceeds to a series of to address specific data requirements for each process. All or portions of this workflow may be completed depending on the specific characterization requirements. The details of each stage in this workflow are described in the sections that follow.

**Stage 1: Sample Preparation**

Prior to discussing sample preparation, it is worth noting the importance of collecting a fluid sample from the field location of interest. The primary of objective of fluid sampling is to collect ‘representative’ fluid samples for fluid phase behavior and properties analysis. Care should be taken in evaluation and collection of enough representative fluid samples for various suites of fluid analyses required for efficient reservoir management (Nagarajan et al., 2007). Various options are available to collect representative fluid samples depending upon rock and fluid nature as well as reservoir, and well conditions. Two commonly used sampling techniques are bottomhole sampling and surface sampling. The bottomhole sampling can be further divided in two categories: single-phase bottomhole sampling and conventional bottomhole sampling (Jamaluddin et al., 2002). The surface sampling option includes collection of single-phase wellhead samples, collection of gas and liquid from separator for PVT recombination and collection of dead crude from either wellhead, separator or stock tank. It is worth noting that the high viscosity of heavy oil fluid often prevents the ability to obtain bottomhole samples. While bottom hole fluids taken directly from the zones
of interest are the ideal samples for production evaluation studies, most studies are performed on wellbore or surface samples that are approximated to be ‘representative’ of the fluid in the reservoir. The discussion on sampling technique selection criteria, merits/demerits of each sampling technique and general sampling guideline are beyond the scope of this article.

Based on these two sample acquisition approaches, samples available for laboratory analysis may be either live (i.e. containing soluble gas) or dead oil samples. The live oil samples include all types of bottomhole samples, single-phase wellhead samples and pressurized separator samples. The dead oil samples include atmospheric crude sample collected from anywhere in heavy oil production system. Recombined live oils, created by blending dead oils with a synthetic gas mixture or separator gas, are also viable options for generating data. However, it is important to note that the use of recombined live oils can introduce uncertainties in some fluid property measurements since the gas composition and GOR of heavy oils is often estimated instead being measured directly. Recombined live oils also lead to increased turn-around time for data generation due to the slow dissolution of gas during the sample recombination procedure.

In comparison to convention black oil, heavy oil samples are not only difficult to acquire but also very challenging to handle for fluid phase measurements starting from sample handling. Live heavy oil samples are often collected with free water, mud, sand and emulsion. Upon receiving the live oil samples, opening pressures are often measured by non-intrusive technique and compared with the closing pressure of samples in the field. The measurement of opening pressures provides an insight about potential sample leaks during transportation. Live fluid samples are then homogenized and restored at reservoir temperature and pressure for several days with rocking. The fluid samples are then placed in vertical conditions for required amount of time to allow separation by settling of any free water, mud, sand or any inorganic impurities. Following this, a small amount of heavy oil sample is drawn to measure the dissolved water content in order to check for oil-water emulsion. Often, the dead oil emulsion sample is put under the microscope to qualitatively check the emulsion.

Crude oil de-emulsification treatment programs are typically used to reduce the basic sediment and water (BS&W) of crude oil to a certain acceptable level. For the purposes of fluid phase behavior and property measurements, the acceptable level of sediment and water is typically specified to be less than 0.1 vol% for sediment content and less than 1 wt% for water content. To reduce the sediment content, the reservoir fluid sample is typically pre-filtered using a filtration process. However, reducing the water content of the oil is more challenging, particularly for live oils, due to the tendency of heavy oils to form stable emulsions and the limited number of non-destructive options for demulsification. The efficiency of oil and water separation by gravity based processes is influenced by a few main factors:

(1) Oil viscosity: The lesser the viscosity of oil, the faster the separation. This is most easily achieved with moderate heating of the heavy oil to the viscosity. Solvent and gas additions will reduce viscosity and help remove the emulsified water, but will also irreversibly alter the composition of the heavy oil sample. Once the composition is altered, the sample is no longer representative and therefore, cannot be used in subsequent phase behavior and property analysis.

(2) Oil density: The closer the density of the oil is to that of the water, the slower the separation.

(3) Stabilizing agents: The stability of the emulsion is influenced by micron sized particles and natural surfactants in the oil that act to prevent water droplets from coalescing and separating. Chemical demulsifiers may be added to overcome these stabilizing agents and help break the emulsions. However, the addition of demulsifier may alter the heavy oil composition or affect the outcome of some measurements, such as asphaltene compatibility tests.

The demulsification of live heavy oil samples can be performed by non-chemical or chemical methods. One of the non-chemical methods is a combination of heat/cool cycles where the live heavy oil sample is repeatedly heated and cooled from low temperature to above reservoir temperature at reservoir pressure (Nagarajan et al 2007). Application of temperature (thermal method) is a known technique to break oil-water emulsion during production (Kokal, 2005). The repeated application of heat and subsequent cooling may destabilize oil-water emulsion by reduction in oil viscosity, destabilization of rigid films, and increased coalescence frequency of water droplets. However, this method is only successful if the density of heavy oil sample is significantly different (lower or higher) that the density of the water phase. The thermal method of demulsification may not work in all cases, such as highly stable water-in-heavy oil emulsions. In such cases, the emulsion may be forced to the top or bottom of a pressure vessel (i.e. creaming) by centrifugation at reservoir pressure and temperature by using high pressure (HP) centrifuge. The heavy oil can then be recovered from the pressure vessel.
If non-chemical demulsification methods are unable to break heavy oil-water emulsions, a chemical demulsification method can be carefully evaluated. Chemical demulsifiers are surface-active compounds which act on oil/water interface by rupturing or weakening the rigid film and thus enhancing the coalescence of water droplets. Demulsifier chemicals often contain surfactants, flocculants, wetting agents and solvents such as benzene, toluene, xylene, heavy aromatic naphtha etc. (Kokal, 2005). The application of these chemicals may change the composition of heavy oil hydrocarbons and can influence the heavy oil fluid properties. Recently the use of water based chemical demulsifier is increasing. It is postulated that the water based chemical demulsifier would stay with free water being separated out of oil-water emulsion and thus the effect of such chemical demulsifier on the remaining water-free heavy oil would be minimal. Hundreds of chemical demulsifiers are commercially available and the compositions of such chemical demulsifiers are mostly proprietary. Therefore, the usage of such chemical demulsifier and its effect on the composition of heavy oil should be carefully evaluated. The usage of chemical demulsifiers to break oil-water emulsion in live or dead samples is generally not recommended due to these uncertainties. The final and least favorable option is to depressurize the live water-in-heavy oil emulsion sample and then centrifuge or distill the dead oil emulsion until water is separated out. The recovered water-free dead oil can then be used to create recombined live heavy oil. It is important to note that this can be time consuming process and there a risk of losing volatile components from the heavy oil that could affect subsequent phase behavior and property measurements.

Stage 2: PVT and Fluid Property Measurements at Original Reservoir Pressure and Temperature

At this stage, a variety of standard fluid property and PVT measurements are performed on dewatered heavy oil samples at reservoir conditions. These measurements typically include:

- single-stage flash of a live oil sample to atmosphere conditions to determine GOR, gas phase composition, liquid phase composition, and overall composition
- constant composition expansion (CCE) experiments to determine bubble point pressure, compressibility, phase volumes, and bulk liquid phase density
- viscosity measurements of live and/or dead oil.

Compared to techniques applied to conventional oils, laboratory techniques for CCE, GOR, and compositional analyses of heavy oil offer unique challenges due to the slow evolution of gas from heavy oil during the flash process, the low amounts of evolved gas that can be difficult to measure accurately, and the high concentration of heavy components that can remain unresolved by Gas Chromatography (GC) techniques.

Challenges in Heavy Oil CCE Measurements

During a CCE measurement, a live oil sample in a PVT cell is usually depressurized from above reservoir pressure in discrete steps. At each step, the fluid in the PVT cell is rigorously mixed and enough time is provided to attain equilibrium. One of the challenges in performing the CCE experiment of heavy oil is the slow kinetics of gas evolution from heavy oil. Figure 2 pictorially demonstrates the process of slow kinetics of gas evolution. The heavy oil can initially behave as a supersaturated liquid phase below the bubble point pressure before solution gas slowly evolves from liquid phase. As more times passes, evolved gas bubbles will start to grow and eventually disengaging from liquid phase to form a separate gas phase. Equilibrium is achieved once all of the evolved gas is disengaged at the given pressure step and separate, stable vapor and liquid phases are formed. Our extensive experience in heavy oil characterization suggests that this process can take a number of hours to days depending on the nature of the heavy oil. Sometimes it may not be practically possible to achieve equilibrium in a reasonable time using a conventional PVT cell, particularly at low reservoir temperatures where the viscosity can be quite high. In case where sufficient time has not been allowed to reach phase equilibrium, then the slow evolution of the gas phase may lead to an underestimation of the bubble point pressure. The time to achieve equilibrium is aided by providing an appropriate level of mixing to the PVT cell, which has been a recent focus of development for the authors. The detail of novel heavy oil PVT cell can be found elsewhere (Na et al, 2010). The effect of mixing on the slow evolution of gas phase is demonstrated in Figure 3. The CCE experiment with heavy oil was performed with discrete depressurization with heavy oil PVT cell with efficient mixing where enough time was provided to separate evolved gas from oil at each pressure step. The same depressurization was repeated with the depressurization rate of 40 psi/hr without mixing. Due to super-saturation of liquid phase, the saturation of heavy can be measured substantially low without mixing. The underestimated saturation pressure of heavy oil can have a huge impact on subsequent heavy oil assets production and processing planning.
Challenges in Heavy Oil Viscosity Measurements

The viscosity of heavy or extra-heavy oil can range up to 1,000,000+ cP and be Newtonian or non-Newtonian depending on the temperature and pressure conditions as well as composition. For example, higher temperatures and the solubilized gas will provide Newtonian behavior while low temperature, dead heavy oils will lead to non-Newtonian behavior. Various options are available to measure the viscosity of heavy or extra-heavy oil such as Cambridge™ electro-magnetic viscometer (EMV), capillary viscometer, parallel plate rheometer, rolling ball viscometer, etc. Each type of viscometer has its own merits and demerits as well as range of application. Figure 4 represents the capillary viscometer set up which is widely used for heavy oil viscosity measurements at temperature and pressure conditions above atmospheric conditions. A case study was undertaken to perform heavy oil viscosity measurements for live heavy oil samples at reservoir conditions using two different viscometers: Cambridge EMV and capillary viscometer. Two types of heavy oil samples, single-phase wellhead sample and bottomhole sample were used in this study. Both samples were taken from the same well and gave compositional and phase behavior measurements that were equal within the error of the measurements. Therefore, both samples were expected to provide the same viscosity values.

The relative viscosity as a function of relative pressure for both samples using each type of viscometer is presented in Figure 5. The relative viscosity is defined as the measured liquid viscosity divided by the bubble point liquid viscosity value of bottomhole sample as measured by capillary viscometer. The relative pressure in this plot is defined as the ratio of measured pressure to the bubble point pressure. Since both types of samples were representative, they should have conferred similar viscosities using each type of viscometer within the limit of experimental accuracies. However, for a given type of sample, the viscosity values as a function pressure differed up to 20% between EMV and capillary viscometer. Also, a significant difference in viscosity was observed between wellhead sample and bottomhole sample for EMV. The viscosity difference between the wellhead sample and bottomhole samples for capillary viscometer was observed to be within the experimental accuracy of such measurements. It is suspected that this observation may be due to the presence of a relatively low concentration of water and/or fine particles observed in both the wellhead and bottomhole samples. The presence of a relatively small amount of impurities appears to have a significant influence in the viscosity value measured using the EMV. This seems reasonable when considering that the fluid moves in a significantly small annular space (gap) in EMV as compared to the fluid movement in the larger diameter tubing of the capillary viscometer. Due to this, the fluid dynamics is less affected by the relatively low concentration of contaminant fine particles or water in capillary viscometer.

Rheometers can also be used the measure the viscosity of heavy oil under live and dead conditions. Various types of rheometer configuration are available for viscosity measurement: high pressure cup and bob rheometer, open cup and bob rheometer and parallel plate. The high pressure rheometer is limited to measuring the viscosity of live saturated fluids since a cushion gas over the oil is required to maintain pressure and hence, it is not suitable to measure the viscosity of undersatured heavy oil. The open cup and bob and parallel plate rheometers are used to measure the viscosity of dead heavy oil at ambient pressure and moderate to low temperature conditions.

Stage 3: Production Process Dependent Fluid Behavior Study

The requirement of fluid phase property measurements for each production processes such as cold depletion, water flooding, thermal production, and solvent flooding are discussed in detail in this section.

Fluid Properties for Cold Depletion and Water Flooding Production Processes

For cold depletion production process, the heavy oil phase behavior and fluid properties should be measured at original reservoir temperature and pressure. This testing is largely covered by stage 2, where such tests as GOR, compositional analysis, CCE testing, density and viscosity are measured at reservoir conditions. Our experience indicates that the values for bubble point pressure, GOR and shrinkage of heavy oil are often quite low, which make differential liberation tests and separator tests difficult to complete and lead to relatively large errors in the measured data. Therefore, differential liberations and separator test may not provide any additional value in the tuning of heavy oil fluid models. It is recommended to perform the baseline fluid property measurements at any deviated reservoir conditions. The foamy oil process can also be studied by performing kinetic CCE experiment at various depressurization rates at reservoir temperature. For water flooding production process, additional analysis will be required to evaluate the stability and related viscosity changes due to the presence of heavy oil-water emulsion. These issues are discussed below in the heavy oil flow assurance characterization section.
Fluid Properties for Thermal Production Process
Thermal production process often employs Huff and Puff or steam flooding utilizing a mutiwell process or steam-assisted gravity drainage (SAGD). For all configurations, the fluid property measurement requirements are similar. In addition to baseline fluid property measurements at original reservoir conditions, the interaction of steam with heavy oil and the influence of heating on heavy oil fluid properties should be studied. For example, the three-phase vapor liquid equilibrium studies are often performed to study the phase behavior of heavy oil-steam system at various temperatures. To demonstrate, a three-phase vapor liquid equilibrium case study is presented which was performed using bitumen, water and diluents. A mixture of bitumen, water and diluent (mass ratio = 6.3:10.0:1.0 respectively) was charged in to high temperature heavy oil PVT cell. The mixture was first mixed and equilibrated at 268 psia and 135 °C. At these conditions, no vapor (steam) phase was observed. The temperature was then increased to 165 °C and 195 °C at the same pressure. A breakthrough of the third vapor phase was observed at 195 °C. The volumetric data for this vapor liquid equilibrium test is presented in Figure 6. The compositional analysis, equilibrium K-values and related equation of modeling results for this can be found elsewhere (Na Jia et al, 2010). The emulsion problems can be encountered with water-steam at high temperature. The detailed suite of flow assurance characterization for steam flooding process is discussed separately.

Fluid Properties for Solvent Flood Production Process
In the solvent flood production process, the vaporized solvent (e.g. CO₂, propane, etc) are injected with or without steam in order to reduce the viscosity and density of heavy oil and thus, increase the mobility of heavy oil. In this situation, it is important to understand how the fluid properties such as viscosity, density and saturation pressures vary with the concentration of solvent under consideration. To demonstrate, a case study with propane, CO₂ and DME solvents with heavy oil was performed where fluid properties such as viscosity, density and saturation pressure were measured. The normalized viscosity for all heavy oil-solvent mixtures is presented in Figure 7. The viscosity can be reduced by two to three orders of magnitudes with the use of vaporized solvents. It can also be observed that propane and DME can be as effective as CO₂. The density reduction of heavy oil with each solvent is shown in Figure 8. Significant reduction in density was noticed for DME and propane additions. The density difference due to CO₂ addition was negligible. The saturation pressure of heavy oil increased with the addition of these solvents and is demonstrated in Figure 9. All fluid property measurements for each solvent were stopped at a particular concentration due to the appearance of a third phase. This third phase can be either solid (i.e. asphaltene) or a second liquid phase at the respective concentration.

Heavy Oil Flow Assurance Characterization
One of the biggest flow assurance issues encountered during heavy oil production is formation of heavy oil-emulsions. The formation of heavy oil-water emulsion can lead to an increase in the apparent viscosity of the oil (Alboudwarej et al, 2007). The separation of stable of oil-water emulsion also significantly increases the cost of heavy oil production (Kokal 2005). Therefore, the stability of heavy oil-water emulsion under dead and live conditions, and the viscosity measurements of heavy oil-water emulsions are important measurements for heavy oil flow assurance characterization.

Emulsion stability analysis is first usually performed on dead oil and water samples at atmospheric pressure, often performed using a bottle test. While atmospheric testing is normally considered adequate for the design and optimization of surface separation facilities, there are situations where an understanding of the emulsion stability and viscosity under elevated temperature and pressure conditions is required. In these situations, testing of emulsion stability and viscosity at dead condition only provide the screening before embarking the tests at live conditions. For emulsion stability measurement, various mixtures of heavy oil and water are created by applying external mixing. The heavy oil-water emulsion is then kept for some time and separation of oil from water is observed. The photographs oil-water emulsions are usually taken intermittently. An example study result for heavy oil-water emulsion stability is shown in Figure 10 (Alboudwarej et al, 2007). For this case, 50% water emulsion was found to be stable for up to 24 hours whereas 85% water cut showed instantaneous segregation of oil and water. For the same oil, a live oil-water emulsion stability testing was performed in PVT cell where the live oil-water emulsion was prepared in shear cell. The 85% water cut emulsions was also observed to be unstable, as shown in Figure 11 (Alboudwarej et al, 2007). Kokal and Al-Dokhi (2008) observed that for one of the cases of black oil with 25 °API (very close to heavy oil), the emulsion were not stable at reservoir conditions. However, the oil-water emulsion became tighter with the reduction of pressure and temperature, from reservoir to wellhead. These studies demonstrate that the heavy oil-water emulsion stability testing should be done at a wide variety of conditions ranging from STO to wellhead to reservoir.

An example result of heavy oil-water viscosity is shown in Figure 12 where the viscosity of the same oil-water emulsion was measured with capillary viscometer (Alboudwarej et al, 2007). The viscosity of heavy oil-water emulsion increased with increase in water cut at a constant temperature and pressure. The viscosity of oil-water emulsion decreased with increase in pressure as the
amount of solution gas increased. As expected, the viscosity of oil-water emulsion decreased with increase in temperature. The viscosity for heavy oil-water emulsion was not found to be shear dependent. The viscosity of emulsion decreased after achieving the inversion point from where the water-in-oil emulsion becomes oil-in-water.

Asphaltene precipitation can be encountered in heavy oil production where another hydrocarbon phase such as miscible gas, solvents or other diluents are injected in the reservoir. An example result of asphaltene precipitation due to propane injection in heavy oil is shown in Figure 13, where series of high pressure microscope (HPM) photographs are presented at various concentration of propane addition in heavy oil. The original heavy oil contained some dissolved water which resulted in some background noise in all HPM photographs. A thorough examination of all photomicrographs along with HPM movies suggested that asphaltene precipitation was observed starting from 15 wt% of propane injection in heavy oil. Such type of asphaltene compatibility study should be performed in order to evaluate the risk of asphaltene precipitation due to the injection solvent in heavy oil.

**Summary and Conclusions**

The following conclusions can be drawn from this article:

- A compilation of fluid property measurement requirements based on the production processed for heavy oil characterization and a comprehensive heavy oil characterization workflow is presented.
- Experimental techniques and technical challenges for fluid sample handling, baseline PVT analysis for heavy oil, fluid viscosity, emulsion stability testing and its viscosity measurement, vapor liquid equilibrium (VLE) testing for steam flooding operation, fluid property measurements for solvent flood production process and heavy oil flow assurance characterization are discussed in detail.
- Viscosity measurement results indicate that the capillary viscometer is a better choice for heavy oil viscosity measurements over other type of viscometers.
- Asphaltene precipitation can be encountered where another hydrocarbon phase such as miscible gas, solvent or diluents are injected in heavy oil reservoirs.

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References


Figures

Figure 1: Heavy Oil Characterization Workflow
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Figure 3: Challenges in Heavy Oil PVT Analysis – Effect of Mixing

Discrete depressurization

\( dP/dt = 40 \text{ psi/hr, without mixing} \)

Super-saturation
Figure 4: Capillary Viscometer Set-up

Figure 5: Effect of Viscometer Type on Heavy Oil Viscosity
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