RESEARCH ARTICLE

A Study of Asphaltene Precipitation Problem in Some Wells in Kurdistan Region

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ABSTRACT

Throughout the production and reservoir lifecycle, the asphaltene precipitation is an ever-existing problem that can be controlled by changing the porosity, permeability, and wettability, leading to a decline in production. The conditions that govern asphaltene precipitation vary from well to well and from reservoir conditions of high pressure and temperature to surface conditions and need to be studied case by case. Modeling and predicting the phase behavior and precipitation of asphaltene is paramount for wells in the Kurdistan region because it is developing its oil and gas industry. Crude oil samples from three wells in the Kurdistan region, Iraq were selected for this study. Experimental data such as crude oil composition using gas chromatography, pressure-volume-temperature analysis, and reservoir pressure and temperature were used as input data for the Computer Modelling Group simulator, and a model of asphaltene phase behavior was suggested. The model suggests that the maximum precipitation occurs near the bubble point pressure at reservoir conditions. This is validated and compared with results in the literature indicating similar behavior of crude oil. To predict the asphaltene precipitation at surface condition, a modified colloidal instability index (CII) was used, and the results were validated by a De Boer plot.

Keywords: Asphaltene precipitation, Colloidal Instability, Computer Modelling Group

1. INTRODUCTION

Crude oil is a complex mixture of mainly hydrocarbon components. In addition, there are heteroatom compounds of sulfur, nitrogen, oxygen, and metal organic compounds within this mixture. The hydrocarbon mixture comprises components ranging from the simplest methane to the heavy wax molecules in a homogenous mixture inside the reservoir conditions of high temperature and pressure. Among these fractions, asphaltenes are considered as the most complex fraction of petroleum. They include molecules of high molecular weight and the most polar components in petroleum. At ambient conditions, they are mainly insoluble in normal paraffins such as n-heptane, n-hexane, and n-pentane but soluble in toluene or benzene. One of the most characteristic behaviors of asphaltenes is their tendency to aggregate either with other asphaltene molecules (self-association) or with resin molecules (cross-association). The deposition of asphaltenes has been identified as one of the major problems during the natural depletion of a reservoir. Its precipitation causes serious problems that cause crude oil to flow from the reservoir through the process facilities. Such problems include plugged pores, damage near the wellbore, reduced permeability and porosity, and even blocked well

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bores, which may result in enormous costs for restoration of production. Most commonly, the extent of asphaltene precipitation is associated with decline in crude oil quality and difficulties encountered in recovering crude oil. Understanding the asphaltene precipitation process and the parameters involved has therefore been a subject of interest for both the industry and scholars. The precipitation of asphaltene inside the reservoir has been reported to depend on many parameters such as change in pressure, temperature, flow rate, and composition of crude oil. However, the extent to which asphaltenes create problems by deposition is more related to their stability than to their amount in crude oil. The complex nature of asphaltenes and the way they interact with other molecules on variation in conditions such as pressure, temperature, or crude composition causes difficulties in predicting their phase behavior. In terms of composition, there are two important parameters that govern the stability of the asphaltene particles in crude oil, namely, the ratios of aromatics to saturates and resins to asphaltenes. Decreasing these ratios may cause coalescence and aggregation of asphaltene particles in the crude oil. The complexity of the crude oil composition and the reservoir condition from one side and conditions such as flow rate and change in pressure during production from the other side adds to the complexity of asphaltene precipitation from one reservoir to another. Studies have been conducted to understand the nature of asphaltene precipitation by understanding their structure and phase behavior. Simulation models have been suggested to predict the conditions at which asphaltene might precipitate, in order to take preemptive measures during production. The models suggested are mainly offered for reservoir and surface conditions. The simulation models commonly use modified equations of state (EOSs) such as the Peng-Robinson EOS (PR EOS) or the Soave-Redlich-Kwong EOS models as the framework for the intermolecular interactions and the extent to which precipitation may occur.

In the past decade, the Kurdistan region has started to produce oil from its reservoirs. There has not been much attention to the asphaltene deposition problem in the oilfields of Iraqi-Kurdistan so far. This study aimed to predict the asphaltene deposition in three oil fields by determining the crude oil composition and using the simulator program at reservoir and surface conditions.

2. MATERIALS AND METHODS

This research has used experimental data along with reservoir data to model the asphaltene precipitation at both reservoir condition and ambient surface condition. The experimental results obtained from compositional characterization and fluid behavior are used as input in the simulation program for modeling. Three wells in Kurdistan region were selected for this study, and crude oil samples were taken from these fields. For confidentiality reasons, the names and exact locations of these wells are not mentioned in this paper. Two of the three wells are located in Duhok Governorate and the third is located in Erbil Governorate. In this paper, we refer to the wells as A, B, and C. The reservoir data, as obtained from Ministry of Natural Resources, are presented in Table 1.

Table 1: Reservoir and crude oil sample data from wells A–C

Parameter	Well A	Well B	Well C
Reservoir pressure, Psia	5714.70	5091.00	5091.00
Reservoir temperature, °F	210.90	204.80	210.9
Sat. pressure, Psia	3789.00	395.00	390.00
Oil gravity, API	34.4	17.52	18.02
Gas to oil ratio, Scf/stb	1924.44	59.00	61.00
Asphaltene (in stock tank oil), wt%	4.3%	14.2%	13.7%
Density at reservoir T and P, g/cc	0.654	0.9022	0.8929

2.1. Experiment

The compositions of crude oil samples were determined using an Agilent series B gas chromatograph (GC). Nitrogen was used as an unretained mobile phase in these experiments. The GC was priory calibrated to determine the exact concentrations of methane up to C10+ components in the crude oil samples. A visual pressure-volume-temperature (PVT) cell (Sanchez Technologies, model FV) was used in constant mass expansion of crude oil samples. These experiments allowed determination of correct volumes of crude oil samples at selected pressure ranges.

2.2. Asphaltene modeling

Asphaltene phase behavior modeling for the selected samples was done using a software called Computer Modelling Group (CMG). Precipitation is shown using a phase behavior utility program named WinProp by CMG, which incorporates an advanced solid thermodynamic model to model the precipitation of asphaltene during depletion of a reservoir. This program can model up to three fluid phases in equilibrium with the solid. WinProp uses the Peng-Robinson EOS (1976), which is the commonly used EOS to predict the state of oil and gas phases in terms of explicit pressure.

WinProp uses EOS extensively to calculate the phase behavior of reservoir fluids. It also measures and predicts the interaction coefficients introduced to account for the interaction between unrelated molecules. The main steps required to model an asphaltene precipitation model using CMG/WinProp are as illustrated in Figure 1.

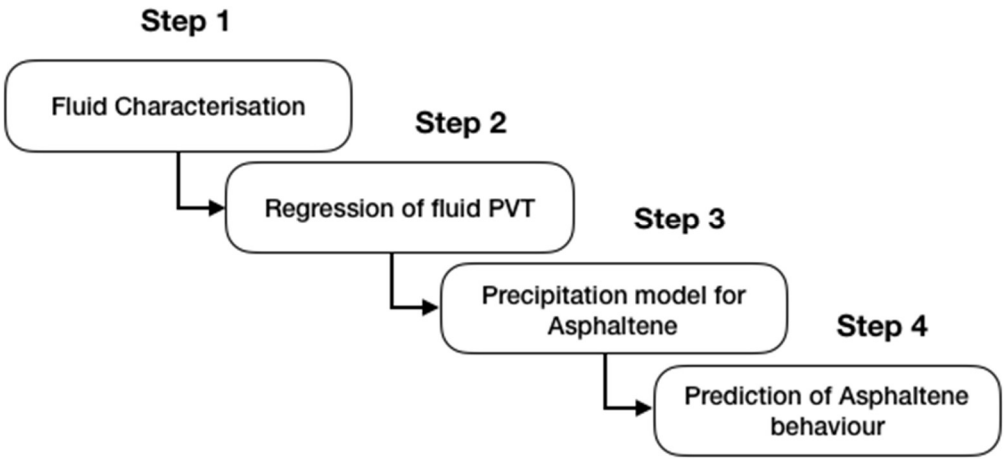

Figure 1. Steps required to obtain a prediction model for asphaltene precipitation

By using the outputs of the experimental work as inputs for the CMG/WinProp simulation program, an adequate asphaltene precipitation curve can be obtained to further aid this study as shown in Figure 2.

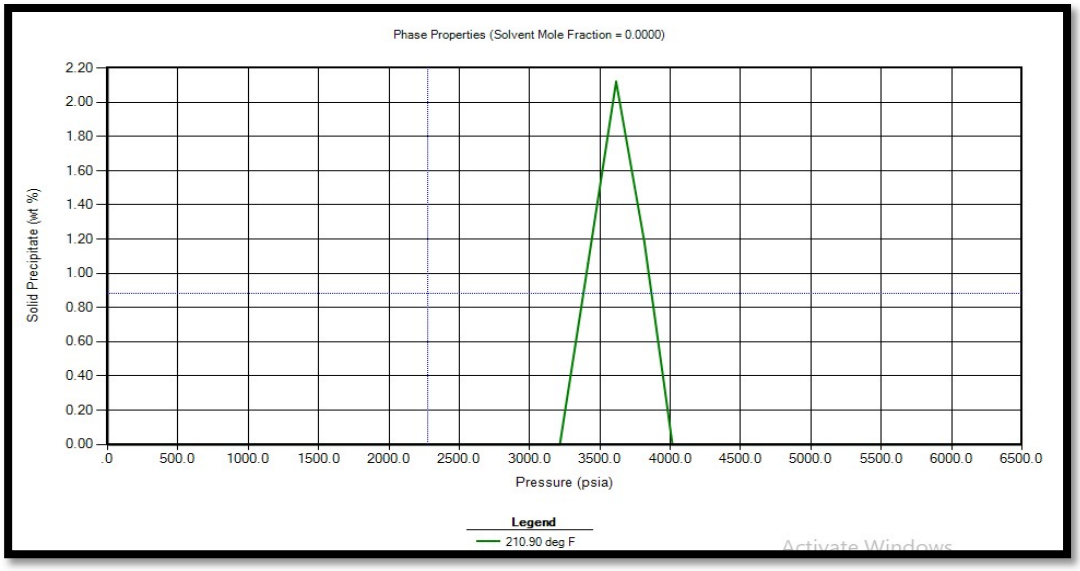

Figure 2. Asphaltene precipitation curve for well A

The same procedure for modeling of asphaltene phase behavior was applied for wells B and C. The results of the precipitation curves for wells B and C are shown in Figures 3 and 4, respectively.

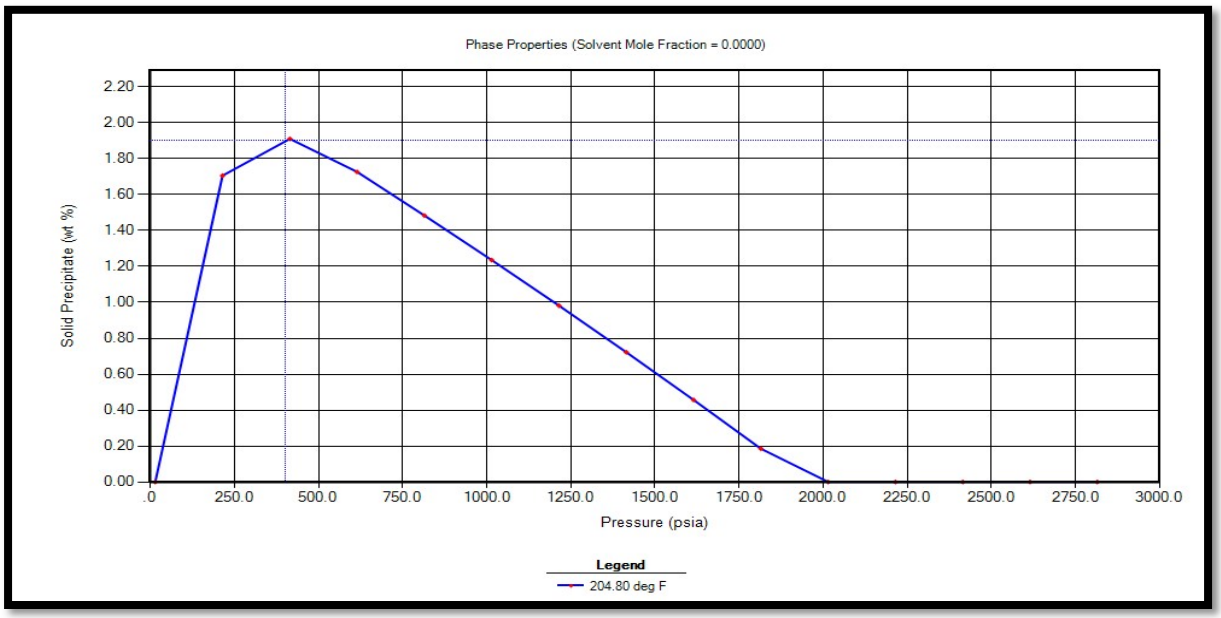

Figure 3. Asphaltene precipitation curve for well B

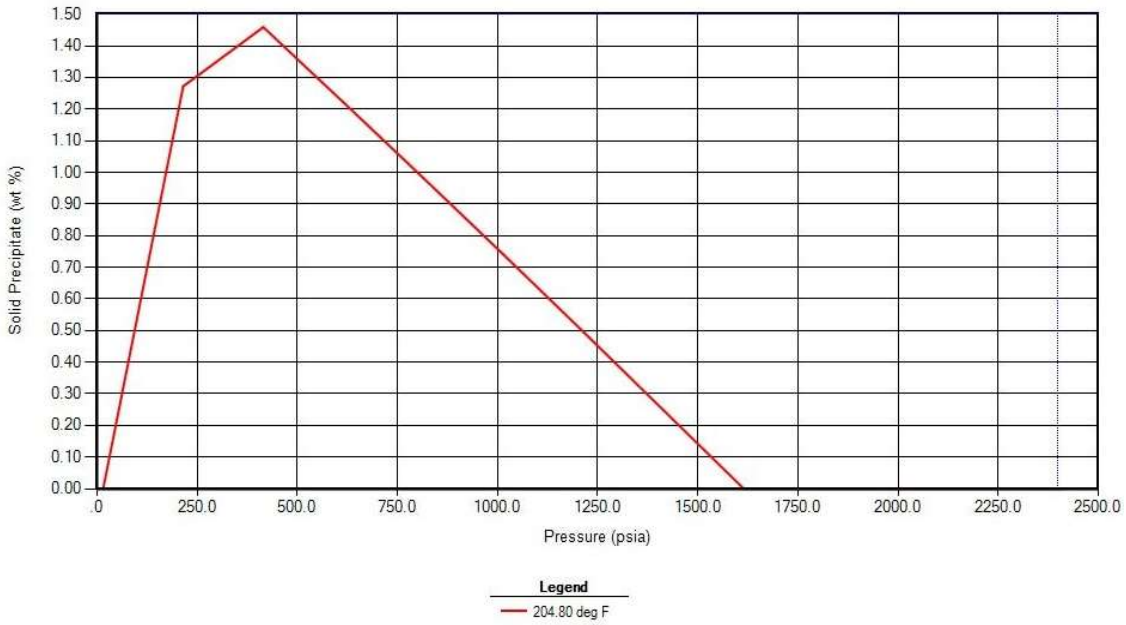

Figure 4. Asphaltene precipitation curve for well C

3. EQUATION DERIVATION

Fan et al., 2002, have worked on 18 samples from different oilfields around the world and have developed a very reliable equation (colloidal instability index [CII]) that will be used and modified according to the availability of parameters in order to be best fitted with the available data from the experiment and simulation. The new equation will be named modified CII; it will suit the needs of oilfields in Kurdistan regions. The reliability of the new equation will be validated by using two methods, which is discussed in the next chapter. CII is shown in the equation below

$$CII = \frac{S_{aturated}+A_{sphalten}}{A_{romatic}+R_{esin}} \quad (1)$$

CII = Colloidal instability index

If CII<0.7, there will be no problem with asphaltene.

If CII>0.9, there will definitely be a problem with asphaltene. If 0.7<CII<0.9, there may be a problem with asphaltene.

First, all the parameters are in weight percent of crude oil, which means that our parameters must be in the same unit. Second, if saturate, aromatic, resin, and asphaltene (SARA) fractions are to be added together, then the result will be the original crude oil, which means that our data should represent the crude oil when added together. At this point, the only candidates for replacing SARA fractions are the components of reservoir fluids obtained from PVT analyses. Since the components in mole percentage and the sum of them equals to 100. The inputs of the equation are in line with original one, but we still need to assign each component so that it goes along with SARA constituents. Table 2 shows each component with its equivalent SARA fractions. The corresponding fractions are not real representations; instead, they are proportional to the inputs that are used in this derivation.

Table 2: Hydrocarbon components with the corresponding SARA fractions

Name	Components	Corresponding SARA
Light components	C1–C5	Aromatics
Medium components	C6–C8	Saturates
Heavy components	C9+	Asphaltenes
Non-Hydrocarbons	CO2, N2, H2S, etc.	Resins

The basis of the classification is the definition of each constituent of SARA analysis and it is based on molecular weight. For example, asphaltenes have the highest molecular weight and aromatics have the lowest. Because there are no resins, the term has been substituted with non-hydrocarbons to account for the lost resin weight percent. Because the summation of CII inputs equals 100 and the summation of the experimental data is also 100, it is possible to manipulate our equation to give similar results with our test data. SARA analysis is performed under standard conditions but our data is from both standard and reservoir conditions. The density of the components is more in reservoir conditions than in standard conditions because of compressibility of the fluids under pressure; therefore, the conditions of CII are slightly adjusted to account for the variations in density. Density is mass per unit volume, and our equation represents the mole percentage; therefore, shifting the mole percentage of heavy hydrocarbons to the denominator would best fit the results and match better with the existing CII equation as illustrated below.

$$\text{Modified CII} = \frac{\text{Lc+}}{\text{Hc+N}} \qquad (2)$$

Lc= Mole percentage of light hydrocarbons

Mc = Mole percentage of medium hydrocarbons

Hc = Mole percentage of heavy hydrocarbons

Nc= Mole percentage of non-hydrocarbons

The steps for calculating the percentage of each component to be used in the modified CII equation are given below. The components are the results of the experimental work on the samples.

- Calculate the mole percentage of each component (Lc, Mc, Hc, and Nc) as shown in Tables 3 and 4 for well A.

Table 3: Different hydrocarbon components

Component	Recombined mole %	Molar weight
Nitrogen	0.316	28.02
Carbon dioxide	2.073	44.01
Hydrogen sulfide	15.354	34.08
Methane	40.986	16.04
Ethane	6.941	30.07
Propane	4.452	44.09
Iso-Butane	0.868	58.12
n-Butane	2.573	58.12

Non-Hydrocarbon components (Nc)

Non-Hydrocarbon components (Nc)

Neopentane	0.019	72.15	Non-Hydrocarbon
Iso-pentane	1.115	72.15	
n-Pentane	1.596	72.15	
Hexane C6	2.640	85.5	
Heptane C7	2.538	95.6	
Octane C8	2.616	107.4	Non-Hydrocarbon
Nonanes C9	2.219	119.4	
Decane plus	13.694	269.5 @0.891gm/cc	
Sum	100		

Table 4: Summation result of different hydrocarbons

Name	Sum of the components (%)
Light hydrocarbons	58.55
Medium hydrocarbons	7.794
Heavy hydrocarbons	15.913
Non-hydrocarbons	17.743

By applying the modified CII equation: $\text{Modified CII} = \frac{Lc+Mc}{Hc+N}$

$$\text{Modified CII} = \frac{58.55+7.794}{15.913+\quad .743} = 1.97 \qquad (3)$$

If modified CII<0.7, there will be no problem with asphaltene.

If modified CII>0.9, there will definitely be a problem with asphaltene.

If 0.7< modified CII<0.9, there may be a problem with asphaltene.

These conditions were taken from the original CII mentioned in the theoretical background of this study page 27. For wells B and C, the same procedure is performed to obtain the values of the modified CII, as follows.

Well B = 0.547

Well C = 0.545

From the results of the equation, it is clear that wells B and C will not have asphaltene-related problems during the production lifecycles. This is not the case for well A because it will eventually have problems with asphaltene during production. Meanwhile, a summary of both simulation and theoretical calculations is shown in Table 5.

Table 5: A summary of asphaltene problems in wells A, B, and C

Well	At reservoir, using WinProp	During production, using the modified CII
A	Will have problems of asphaltene precipitation	Will have severe problems during production
B	Will have problems of asphaltene precipitation	Will not have asphaltene problems in production tubing
C	Will have problems of asphaltene precipitation	Will not have asphaltene problems in production tubing

3.1. Analysis of Modified Colloidal Instability Index (MCII)

The inputs of this equation have already been established as in the original equation by using different components and grouping of the inputs. In this section, we are going to address the reliability of the MCII equation and if it can be used in other oilfields in Iraq and Kurdistan regions. For this matter, the plot of De Boer et al, 1995, will be used. De Boer and his colleagues worked on different samples around the world, both experimental and theoretical. They were able to produce a very versatile plot that is used nowadays by most scholars. First, because of the versatility of the samples in De Boers' plot, and second, because the plot takes reservoir conditions into consideration, similar to the dataset used as input to our equation. Figure 5 shows the plot.

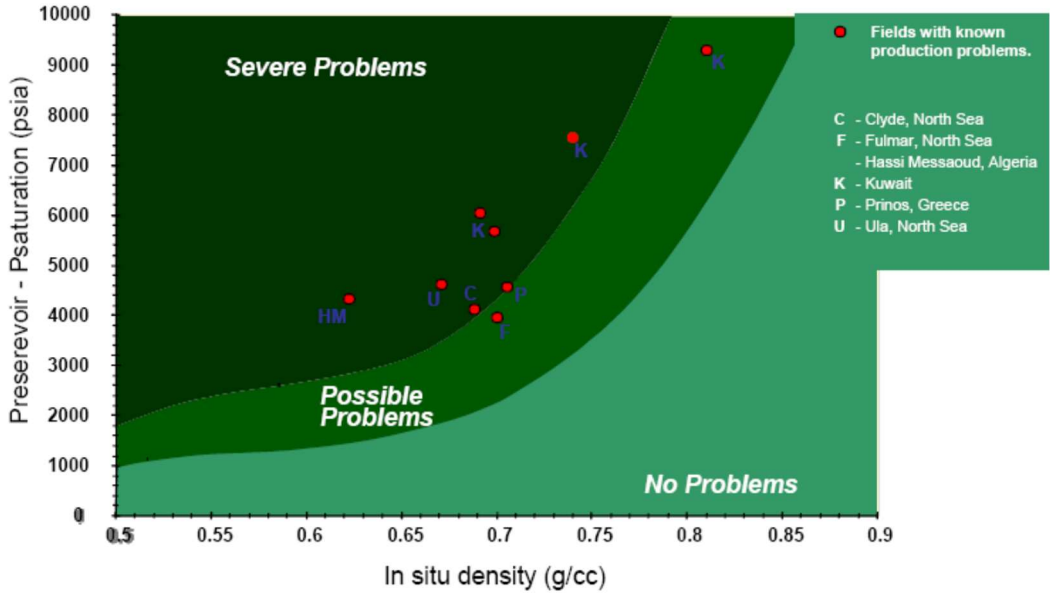

Figure 5. De Boers' plot for asphaltene problem prediction (De Boer et al., 1995)

By using the density, reservoir pressure, and bubble point pressure for the three wells provided in the Data Collected section of this paper, a table can be constructed as shown in Table 6 and a remade version of the same is illustrated in Figure 6.

Table 6: Shows the implementation of the De Boer plot on the three wells (A, B, C)

Well	P_b (psi) P_{bubble}	P_r (psi) $P_{reservoir}$	Density (g/cc)	$P_{reservoir}-P_{bubble\ point}$	De Boer results	MCII results
A	3789	5714.4	0.6521	1925.4	Upper part of possible problems into sever problems	Definitely have problems
B	395	5091	0.9025	4696	No Problems	No problems
C	390	5091	0.8929	4701	No Problems	No Problems

P_{bubble}: pressure at the bubble point; $P_{reservoir}$: reservoir pressure

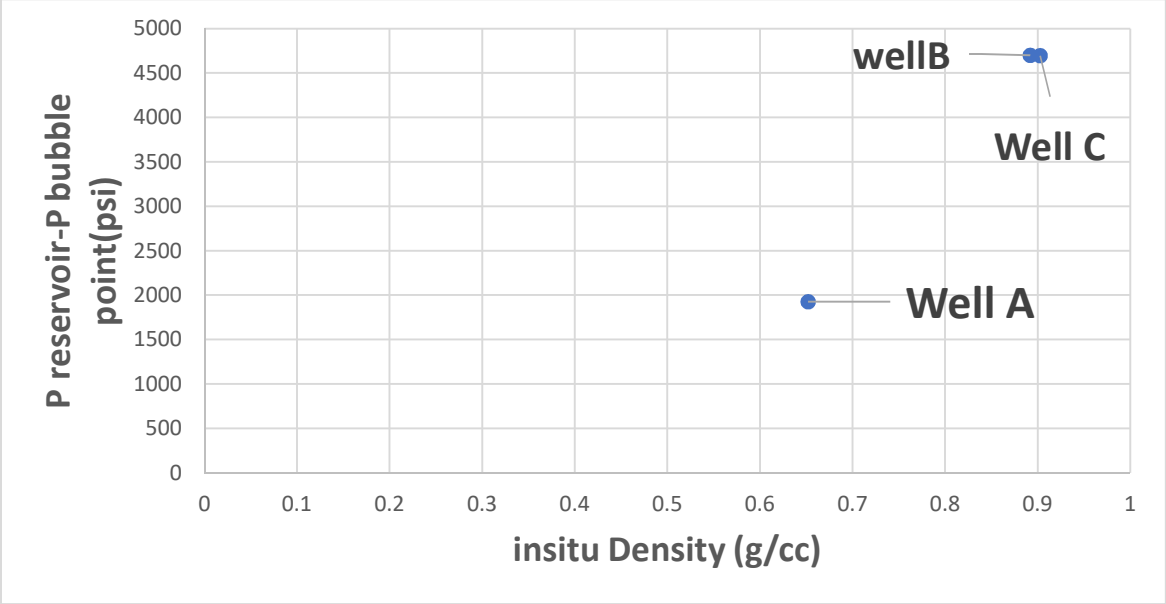

Figure 6. A remade version of the De Boer plot showing the three wells

Generally, the results from the derived equation are acceptable to an extent. The results can be replicated on other wells in the Kurdistan region.

4. DISCUSSION

The results from the experiment and modeling data are discussed to further interpret the results. First, the steps that led to the derivation of the asphaltene precipitation curve must be analyzed to conclude the credibility and reliability of the final curve. Most importantly, the curve provided by the experiment conducted in the laboratory shows the relation between the relative volume of reservoir fluids and the pressure below saturation. This curve can be correlated with the results from the regression test, both before and after regression, and it can be observed that the results from WinProp are satisfactory in the range of the experimental work done in the laboratory, as shown in Figures 8, 9, and 10 for wells A, B, and C, respectively, where the yellow curve shows the experimental work that has been inputted to the simulator and the orange line shows the initial condition of the inputted data according to the EOS. The third gray curve shows the output of the of the simulator after fine-tuning the data (regression). The regression feature in WinProp can be used to fine-tune the EOS to have a good match between the experimental work and the parameters in the EOS so that it can be used to predict accurately the phase behavior of fluids in later steps.

CONCLUSIONS

The following conclusions were observed from this study:

- The study showed a good match between experimental work and simulation. The outputs of the experimental work had been used as inputs for modeling the phase behavior of asphaltene for wells in the Kurdistan region.
- The study showed important steps and procedures required to accomplish a phase behavior model for asphaltene in wells in the Kurdistan region of Iraq by using CMGs/WinProp, which uses EOS and Nghiem for modeling asphaltene behavior. The model used data from GC and PVT analysis to model asphaltene.
- Introduction of a new screening equation called MCII used with findings from the experimental work to facilitate the

identification of asphaltene-related problems.

- The results of this model showed an acceptable range of findings and was deemed to be reliable in terms of general idea and implementation of the concept into a real-life easy-to-understand curve.

RECOMMENDATIONS

To reinforce the conclusions of this paper, further research is required in this domain, especially regarding the new screening equation.

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