DILUENTS EFFECTS ON FULLA CRUDE OIL DEHYDRATION

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ABSTRACT

Fulla crude is classified as a heavy crude oil. It has a high viscosity 69.42mm²/s at 100 °C, high density (963.2 kg/m³), which has a serious effect on the dehydration process. Reduction of crude density and viscosity for separation improvement at evaluated temperature and blending with naphtha and kerosene (5% -35%), were examined and modeled.

The addition of naphtha was investigated with the other dehydration parameters. The addition of 30wt% naphtha had reduced the dehydration temperature to 90 °C, after a demulsifier addition.

Keywords: Fulla dehydration, blending, linear regression.

1. INTRODUCTION

Fulla crude oil was produced in Western Kordofan region in Almuglad basin, the field had an area of 38468 Sq.Km. Since 1995 the Chinese National Petroleum Company (CNPC) had worked at the field and explored some new fields in Fulla North, Fulla West, Mega, Hadida, Naha, Kaikan and Sifan, which contain over 60 wells that form Fulla mix crude. The proposed expected production rate was 40,000 bpd. The expected reserve from the reservoir was 115 bpd of crude oil with a recovery factor (15-20)%. The coking unit of Khartoum refinery revised the production Fulla field, Chinese National Petroleum Company (CNPC) and Sudan government agreed to build a visbreaking unit to reduce the viscosity from 5000 mPa.s 29°C to 1600 mPa.s 29°C or less to meet the transporting condition of the pipeline, [1].

2. FULLA CRUDE PROBLEMS

Fulla crude is a heavy crude, its density is near to that of water, this would reduce the driving force of settlement defined by Stoke’s law, so the dehydration required well adapted operation conditions.

The high viscosity means that very high temperature should be kept throughout the whole processing operation, which is expensive. The high viscosity and density could be reduced by addition of diluents and demulsifiers. Due to its high calcium content, the heat exchangers in refinery should be retubed due to the scale deposits that reduce the heat transfer rate. The corrosion in the overheads of the distillation columns leads to high cost for maintenance or renewable. The crude has a bacteria aggregation problem, the bacteria attacks the light fractions and reduces the production efficiency. High
efficiency of dehydration and desalting process, with optimum parameters control are significant for production progress with the ever-changing properties of crude.

3. HEAVY CRUDE OIL

Heavy crude oils are chemically complex, very varied in hydrocarbon composition (combined with small amounts of inorganic compounds). While associated produced water often contains a broad and concentrated range of chloride together with other dissolved salts and suspended solids. Heavy oil emulsions are very kinetically stable and very difficult to separate. They resist coalescence mechanisms and high susceptible to drop break up processes. The latter implies that exposure to high shear regions, can generate a finely dispersed emulsion which might become almost impossible to treat. Naturally occurring surfactants are present in high concentrations, the interfacial tension values are significantly lower than those of lighter crude emulsions \(10-30\text{mN/m}\) and the bulk phase viscosity is high \( (> 2000 \text{cP})\), [2]. Heavy crude contains high concentrations of sulfur and several metals, particularly nickel and vanadium (high amount of wax). These are the properties that make them difficult to pump out of the ground or through a pipeline and interfere with refining. These properties also present serious environmental challenges to the growth of heavy oil production and use, [3].

The main parameters that specified heavy crude are:

- Viscosity: Bulk phase viscosity is high \( (> 2000 \text{cP})\).
- Gravity: The oil said to be heavy if it’s API is lower than 20.
- Percentage of light fractions: The residue at 200 °C is often approximately 95%.
- Percentage of sulfur: Very high, about 5% by mass.
- Percentage of asphaltens: High, for example 11% for some Venezuelan cruds,[3].

- Foam problem: This can cause a huge problem in the crude operation, especially in the desalters.

4. FULLA CRUDE ANALYSIS: EVALUATION OF BLOCK SIX CRUDE (FULLA 2004).

Table 1: Properties of Fula Crude, [4]

<table>
<thead>
<tr>
<th>Item</th>
<th>Results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density (15^\circ\text{C}), kg/m³</td>
<td>936.2</td>
</tr>
<tr>
<td>API° (American Petro. Institute)</td>
<td>19.6</td>
</tr>
<tr>
<td>Kinematics viscosity ((100^\circ\text{C})), mm²/s</td>
<td>69.42</td>
</tr>
<tr>
<td>Water content, wt%</td>
<td>0.1</td>
</tr>
<tr>
<td>Salt Content, mgNaCl/L</td>
<td>5.6</td>
</tr>
<tr>
<td>Acid number, mgKOH/g</td>
<td>2.6</td>
</tr>
<tr>
<td>Acid number, mgKOH/g</td>
<td>1287</td>
</tr>
</tbody>
</table>

5. WATER - OIL EMULSION

The natural state of water and oil are immiscible liquids to establish the least contact or smallest surface area. The water dispersed in the oil form spherical drops. Smaller drops coalesce into larger drops and this will create a smaller interface area for a given volume. If no emulsifier is present, the droplets eventually settle to the bottom causing smallest interface area. This type of mixture is true “dispersion”,[2]. An emulsifying agent has a surface active behavior. Some emulsifier elements have a preference for the oil, and other elements are more attracted to water. An emulsifier tends to be insoluble in one of the liquid phases. It thus concentrates at the interface. There are several ways an emulsifier changes dispersion into an emulsion. The action of the emulsifier can be visualized as one or more of the following:

1- It decreases the interfacial tension of the water droplet, thus causing smaller droplet to form. The smaller droplets take longer to coalesce into larger droplets, which can settle quickly.

2- It forms a viscous coating on the droplets that keeps them from coalescing into large droplet when they collide. Since coalescence is
Emulsion stability factors:

**Temperature:** Temperature can affect emulsion stability significantly. It affects the physical properties of oil, water, interfacial, films, and surfactants solubility in the oil and water phases. These, in turn affect the stability of the emulsion. Perhaps the most important effect of temperature is on the viscosity of emulsions, it decreases with increasing temperatures. This decrease is mainly caused by a decrease in the oil viscosity.

**Droplet size:** Emulsion droplet sizes range from less than 1µm to more than 50 µms. Generally emulsions that have smaller sized droplets will be more stable. For water separation, droplets have to coalesce, and the smaller the droplets the longer it will have to separate. The droplet size distribution affects emulsion viscosity, it is higher when the droplets are smaller.

**pH:** Water phase pH has a strong influence on emulsion stability. The stabilizing rigid emulsion film contains organic acids and bases, asphaltenes with ionizable groups, and solid. Adding inorganic acids or bases strongly influences their ionization in the interfacial films and radically changes the physical properties of the films. The pH of the water affects the rigidity of the interfacial films. pH also influences the type of emulsion formed. Low pH (acidic) generally produces W/O emulsions, whereas high pH (basic) produces O/W emulsions.

**Solids:** Fine solid particles present in the crude oil are capable of effectively stabilizing emulsions by diffusing to the oil/water interface where they form rigid structures (films) that can inhibit the coalescence of emulsion droplets, [5].

6. **STOKES’ LAW**

Most oil treating equipment used to separate water droplets computed the design variables stating from stokes’ law,[6]:

\[ V_t = \frac{1.78 \times 10^{-5} (\Delta S.G.) (dm)^2}{\mu} \]

Where:

- \( V_t \) = downward velocity of the water droplet relative to the oil continuous phase, ft/s
- \( dm \) = diameter of the water droplet, micron
- \( \Delta S.G. \) = difference in specific gravity between the oil and water.
- \( \mu \) = dynamic viscosity of the oil continuous phase, centipoises (cp).

Several conclusions can be drawn from Stokes’ Law:

a. The bigger the droplet size the less time it takes for the droplet to settle to the bottom of the vessel and thus the easier it is to treat the oil (drops film deupture, with electrical field or demulsifier addition).

b. The lighter the crude, the easier it is to treat the oil (density difference).

c. It is easier to treat the oil at high temperatures than at low temperatures (temperature raising decreases oil viscosity), [7].

7. **EXPERIMENTAL PROCEDURE:**

The addition of diluents reduces the density of the crude. The light naphtha and kerosene were used because they can be recovered in the delay coking unit (DCU) process in the refinery. The effect of light naphtha and kerosene had been compared. The reduction of the viscosity and density of blended crude with various ratios of the two diluents (5%, 10%, 35%) were investigated.

7.1 **Determination of Crude Density**

The density of the crude blend was determined using a hydrometer (Petrotest EC 0116 02 3401), Figure 1.
DILUENTS EFFECTS ON FULLA CRUDE OIL DEHYDRATION

8. NAPHTHA AND KEROSENE FULLA BLEND:

Applying Stock's law for water oil separation method for Fulla crude oil, the effect of naphtha and kerosene as diluents on density and kinematics' viscosity was examined.

The density and kinematics' viscosity were investigated at various levels of diluents ratio and temperatures, the results were as follow:

Table 1: Density, viscosity of Fulla at elevated temperatures without diluents

<table>
<thead>
<tr>
<th>Temp (°C)</th>
<th>Density 0% N&amp;K (kg/m³)</th>
<th>Viscosity 0% N&amp;K (N.S/m²)</th>
</tr>
</thead>
<tbody>
<tr>
<td>65</td>
<td>905.7</td>
<td>0.29</td>
</tr>
<tr>
<td>73</td>
<td>900.6</td>
<td>0.20</td>
</tr>
<tr>
<td>84</td>
<td>893.7</td>
<td>0.12</td>
</tr>
<tr>
<td>89</td>
<td>890</td>
<td>0.098</td>
</tr>
<tr>
<td>90</td>
<td>889</td>
<td>0.09</td>
</tr>
</tbody>
</table>

Table 2: Density, viscosity of diluted Fulla (5% kerosene and 5% naphtha)

<table>
<thead>
<tr>
<th>Temp (°C)</th>
<th>ρ 5% K</th>
<th>ρ 5% N</th>
<th>υ 5% K</th>
<th>υ 5% N</th>
</tr>
</thead>
<tbody>
<tr>
<td>56.8</td>
<td>906</td>
<td>899.5</td>
<td>0.343</td>
<td>0.297</td>
</tr>
<tr>
<td>68</td>
<td>899</td>
<td>891.6</td>
<td>0.19</td>
<td>0.16</td>
</tr>
<tr>
<td>73.7</td>
<td>895.4</td>
<td>888</td>
<td>0.14</td>
<td>0.12</td>
</tr>
<tr>
<td>80.2</td>
<td>891.2</td>
<td>883.6</td>
<td>0.11</td>
<td>0.097</td>
</tr>
<tr>
<td>90</td>
<td>884.96</td>
<td>876.95</td>
<td>0.103</td>
<td>0.089</td>
</tr>
</tbody>
</table>

Table 3: Density, viscosity of diluted Fulla (15% kerosene and 15% naphtha)

<table>
<thead>
<tr>
<th>Temp (°C)</th>
<th>ρ 15% K</th>
<th>ρ 15% N</th>
<th>υ 15% K</th>
<th>υ 15% N</th>
</tr>
</thead>
<tbody>
<tr>
<td>42.8</td>
<td>901.6</td>
<td>872.4</td>
<td>0.18</td>
<td>0.104</td>
</tr>
</tbody>
</table>
Figure 5: Density of Fulla VS Temp at 5% naphtha, 5% kerosene

Figure 6: Viscosity of Fulla Vs Temp 5% Naphtha, 5% Kerosene

Figure 7: Density of Fulla Vs Temp at 15% naphtha, 15% Kerosene

Figure 8: Viscosity of Fulla Vs Temp at 15% Naphtha, 15% Kerosene

Figure 9: Density of Fulla vs Temp at 25% Naphtha, 25% Kerosene

Figure 10: Viscosity of Fulla Vs Temp at 25% Naphtha, 25% Kerosene

Figure 11: Density of Fulla Vs Temp at 35% Naphtha, 35% Kerosene

Figure 12: Viscosity of Fulla Vs Temp at 35% Naphtha, 35% Kerosene
9. LINEAR REGRESSION:
Multiple linear regression of Fulla density and viscosity with temperature (T) and blend ratio (K: Kerosene, N: Naphtha) are as follows:

\[ \rho_K = 0.125K - 3.585T + 1147.6 \quad (R^2 = 0.94) \]
\[ \mu_K = -0.0014K - 0.00095T + 0.852 \quad (R^2 = 0.81) \]
\[ \rho_N = -0.469N - 3.164T + 1109.5 \quad (R^2 = 0.97) \]
\[ \mu_N = -0.0002N - 0.0083T + 0.716 \quad (R^2 = 0.80) \]

10. CONCLUSION
1. In spite of low wax content, the high viscosity, high density of the crude due to high content of naphthenic acids, became a hug problem in dehydration of Fulla.
2. Fulla crude was calcified as heavy crude oil; it was fractionated at delay coke unit. The high salt content would poison the catalyst and shortened its life.
3. Dehydration process specifications depend on corrosion problems, crude standers which determined its price and its application fields.
4. Dilution of Fulla crude had helped in viscosity resolution.
5. From the comparison of naphtha and kerosene for properties improvements, recycling ability and the cost. The naphtha was selected for Fulla blend.
6. The density and viscosity reduction helped in solving the stability at low demulsifier addition rate (30 ppm).
7. The naphtha was chosen to thin Fullac crude oil, a fact that will enhance its flow properties, improve the dehydration process and easy separation.
8. The naphtha blend will reduce the dehydration and desalting temperature to 90°C.
9. The ratio of 30% naphtha was chosen because at low level of demulsifier addition (30 ppm), and high level of naphtha diluents(35%), the mixture of crude and water was flashed.
10. Linear regressions of crude properties with temperature assist in data invention.

11. RECOMMENDATION FOR FURTHER WORK
The treatment of Fulla heavy crude poses numbers of significant process challenges. The crude resists coalescence mechanisms and is highly susceptible to droplet break up. These difficulties could be solving by increasing the residence time. Crude blending to reduce the bulk phase viscosity and increasing the droplets size, and the selection of appropriate demulsifier and its rate.

The suggested further work or fields of studies were:
1. Search for a cheap diluents environmentally friend.
2. Analysis of visibility study of diluents addition compared with the properties upgrading.
3. Study the effect of salted water in phase splitting and desalting efficiency.
4. Design of waste water treatment unit for water recycling.

REFERENCES: