Emulsified Solvent Flooding; A Non - Thermal IOR Alternative for Thin, Heavy Oil Reservoirs?

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ABSTRACT

This experimental study evaluates the heavy oil recovery potential of a novel non-thermal IOR process which uses emulsified solvents to displace the oil. The process, if successful, would have wide application in thin heavy oil reservoirs (such as those in Alberta and Saskatchewan) which are unsuitable for thermal methods due to excessive heat losses to underlying and overlying formations.

Several commercially available emulsifiers were screened to formulate stable solvent-in-water emulsions using natural gas condensate or petroleum naphtha as the solvent. These emulsions were characterized by measuring their drop size distribution and viscosity. The emulsion stability was evaluated by measuring changes in drop size distribution with time.

3-D flow-visualization studies in a glass-bead packed physical model and oil displacement tests in a meter-long sandpack were carried out using oils of different viscosities to evaluate the effects of several process parameters. The variables investigated included solvent fraction in the emulsion, emulsifier concentration, oil viscosity, and the flow velocity. The emulsion injection was continued for at least two pore volumes and the displacement performance was assessed by measuring the fraction of the oil displaced by the injected emulsions.

Results show that the emulsified solvent flooding provides superior displacement performance compared to straight solvent injection and conventional water flooding. The displacement efficiency was affected by emulsion stability -- improving with increasing stability of the injected emulsion. The concentrations of the emulsifier and the solvent also affected the performance: increasing either the emulsifier or condensate concentration in the emulsion improved the oil recovery. The process efficiency was found to decrease with increasing viscosity of the oil.

Several promising methods for making the process more cost effective were evaluated: (i) using only a small slug of emulsion followed by the injection of chase water, (ii)

gradually reducing the solvent fraction in the injected emulsion using an optimized grading scheme, and, (iii) replacing a part of the solvent in the emulsion with the lease crude.

1.0 INTRODUCTION

Several Canadian heavy oil reservoirs such as those in the Lloydminster area have very poor primary oil recovery (often <5% OOIP) and are generally characterized by high viscosity oil, thin pay zone, and/or a bottom water zone. Although IOR methods are necessary to produce oil from these thin reservoirs, the thermal methods such as steam stimulation or steam flooding are not considered viable options because of the excessive heat losses likely to occur to the underlying and overlying formations.

The potential for the success of conventional non-thermal recovery methods such as miscible or immiscible flooding is not very encouraging either. Immiscible flooding, say waterflooding, may provide some additional recovery but typically it would be less than 2% OOIP. Miscible flooding with a solvent, too, is not feasible because of the two serious limitations: (i) high solvent requirements (i.e. very high cost) and (ii) adverse mobility ratio between the oil and solvent that will cause severe viscous fingering.

One alternative to miscible displacement could be the **Emulsified Solvent Flooding** because the solvent requirement should be considerably less. Moreover, the mobility of a solvent-in-water (S/W) emulsion is generally much lower than the mobility of the solvent or water alone. That is, a S/W emulsion flood will be less prone to viscous fingering and should lead to an improved sweep efficiency.

2.0 LITERATURE REVIEW

The literature on the use of oil-in-water (O/W) emulsions (prepared at surface and injected into the formation or formed in situ) as the displacing fluid or for mobility control during steam or water flooding is relatively scant. Binder et al. (1965) proposed the use of an O/W emulsion. They recognized that the viscosity was only a part

of the mobility and that the relative permeability could some times be even more important. Therefore, in strongly water wet systems, the low relative permeability to the water may allow one to use only a modest increase in viscosity to overcome viscous fingering. Hence, O/W emulsions may provide lower mobility without using very high viscosity. It was assumed that the mobility of the emulsion in the reservoir will be equal to the product of water mobility and the relative viscosity of the emulsion. Their experimental results showed that an O/W emulsion (containing 30 wt% Primol, 6 wt% emulsifier) was able to provide 78% breakthrough recovery, and 83% final recovery of the same oil (Primol, 140 mPa.s) in a Torpedo sandstone core. According to them, the emulsion can be prepared with any crude oil, naphtha, kerosene, or lighter solvents such as propane and butane and be used as a continuous displacing fluid or may be used as a slug which is then chased by water.

An interesting use of S/W emulsion in an oil recovery process was disclosed by van der Knaap *et al.* (1970). It involved simultaneous injection of a miscible solvent and water for displacing viscous oil. The process started with the injection of water through perforations near the lowest part of the formation until breakthrough to create a communication path near the base of the formation. Although they do not mention this, such communication may exist naturally in reservoirs containing bottom water. After the communication was been established, a miscible solvent and water were injected simultaneously. The density of the injected solvent was less than that of the oil, while water density was higher than the oil density. They argued that gravity segregation of water and solvent in the communication zone caused the solvent to migrate and mix with the overlying oil. This mixing reduced the oil viscosity making it more mobile. The pressure gradient between the injection and production well (maintained by simultaneous injection of water and solvent) transported the diluted oil towards the production well. It was mentioned that the process can be made more effective by using hot water to further reduce the oil viscosity. To overcome the tendency of the solvent to form a separate communication channel of its own near the top of the formation, they recommended the use of an unstable S/W emulsion. The unstable emulsion would force the solvent and water to travel together till the emulsion broke down in the reservoir.

The process visualized by van der Knaap appears to be an attractive option for reservoirs containing a thin bottom water zone. The only shortcoming would be the increasing rate of water injection required to maintain the needed pressure gradient between the injection and production well. In heavy oil reservoirs, this may lead to very high water/oil ratio in the producing well.

Bousaid (1978) describes an interesting modification of S/W flooding process. The surfactant concentration in the emulsion slug is increased as the slug is injected into the formation. This increase can be incremental (in several steps) or continuous. The rationale behind the increasing surfactant concentration is not explained, but one would assume that it is designed to maintain the integrity of the emulsion in face of possible dilution with the chase water.

McAuliffe (1973b) argued that the most effective emulsion for flooding was the one in which the droplet diame-

ters were slightly larger than the pore-throat constrictions in porous media. As a result, emulsion droplets could become trapped in pore-throats and remain there unless there was sufficient pressure to force them through. This would compel the subsequent fluids to travel through the less permeable zones. Thus, the emulsion would decrease the permeability of the medium to subsequent fluids, and the most dramatic drop should occur when the original permeability of the media was high. However, it was also observed that although the emulsion did decrease the permeability of the medium, it did not plug the high permeable zone. Furthermore, when a waterflood followed the emulsion flood, there was a minor improvement in the permeability.

The first field test of an O/W emulsion flood was performed in the late 1960s and was also reported by McAuliffe (1973a). The test was done to determine the effectiveness of an emulsion prepared from petroleum crude oils. Prior to the emulsion injection, fresh water was injected through 3 wells for 4 months to provide a buffer between the emulsion and reservoir brine. The emulsion injection was then carried out for another 4 months using 14% oil. The total volume of the emulsion injected was about 0.03 pore volume (PV). Following the emulsion injection, wells were utilized first to inject 0.04 PV of fresh water, and then to inject saline water. A two-year field monitoring at the offset wells revealed that an increase in oil recovery occurred accompanied by a drop in the WOR at these wells. Thus, a considerable improvement in the volumetric sweep efficiency was achieved.

The use of an emulsion for mobility modification during steam or water flooding has also been reported. Garthoffner (1979) reported that in situ emulsification occurred in certain Californian heavy oil reservoirs as a result of thermal operations, and that these emulsions were of O/W type with much lower viscosities than the oils from which they were formed. It was suggested that these O/W emulsions helped increase the oil production, and therefore, he recommended that such a process should be induced in those reservoirs. However, how in situ emulsification affects the mobility characteristics in the reservoir is not well understood.

Islam and Farouq Ali (1987) examined the effects of emulsion flooding as a mobility controlling agent in waterfloods with bottom water and suggested that emulsion injection improved the oil recovery most effectively when the emulsion viscosity was similar to the oil viscosity. They also suggested that the optimum emulsion slug size was one PV of bottom water zone, and that increasing the slug size in excess of one PV would not improve oil recovery significantly.

Mendoza *et al.* (1991) studied emulsion flooding on heavy crude oils as an alternative to thermal methods. They concluded that slug size, composition, and type of emulsions were important factors in realizing a net improvement in oil recovery.

3.0 MOTIVATION

Preliminary tests in a simple highly permeable unscaled bead-packed visual cell (see Fig. 1) showed that the emulsified solvent flooding process was more efficient in displacing viscous oils when compared to the conventional waterflooding or straight solvent flooding. Both

reference, waterflood and solvent flood tests displayed severe effects of viscous fingering; but, in the displacements with the emulsified solvent, the viscous fingering was virtually eliminated. Although these results were from a system far removed from a real reservoir, they nonetheless suggested, intuitively, that this process may be of significant advantage in thin heavy oil reservoirs, and this motivated us to undertake this study.

Issues addressed here are: (i) selection of a low-cost readily available solvent, (ii) selection of emulsifiers to develop a stable S/W emulsion, (iii) evaluation of oil displacement efficiency as a function of the oil viscosity, and (iv) evaluation of the economic viability in the field.

4.0 EXPERIMENTAL WORK

4.1 Experimental Apparatus and Description

The schematic diagram of the apparatus is shown in Fig. 2. The apparatus has a 1-m long coreholder packed with 140-200 mesh Ottawa silica sand. The sandpack was confined within the coreholder under a pressure of 14 MPa. A fully automated data acquisition system was utilized to monitor and record pressure distributions along the sandpack and to measure the amount of produced fluids as functions of the PV injected. Relevant dimensions are listed in Table 1.

Displacements tests are classified into two groups (see Table 2). Group I included 3 tests using a mineral oil (Vitrea-150) and kerosene as the solvent and 1 baseline waterflood. The Group II included 15 tests with Lindbergh and Medicine Hat heavy oils and using a pipeline condensate from the Llyodminster area as the solvent. Fluid properties are presented in Table 3.

The first run in each group (Runs 1 & 5) was carried out to 5 PV of emulsion injection to investigate the long term effects on the cumulative oil production. Later runs were terminated after about 2 PV injection due to time constraints and economic considerations. In Run 4, the displacing fluid comprised of a 8:2 mixture of the water and kerosene, commingled at the point of injection into the sandpack. Runs 11 and 15 were straight solvent floods followed by a brine flood. Runs 13 and 16 were essentially brine floods although in Run 13 an intermediate emulsion slug of 0.5pv was injected after about 2.5 PV.

4.2 Emulsifier Selection and Emulsion Preparation

The emulsifier has two principal roles -- to decrease the IFT between the liquids to form a greatly extended surface, and to stabilize the interface, once it has been formed, against the coalescence. The concentration and type of the emulsifier affect the size and distribution patterns of emulsion droplets. The resulting emulsion must have a low viscosity for easy pumpability, be stable during the displacement test (≈ 7 days), and should contain a low emulsifier concentration (≤ 1 wt%) to minimize the cost. The emulsion stability was assumed to have been attained when no phase separation, coalescence of droplets, or any other visual changes occurred during the gravity segregation test carried over a week.

In this study, 25 emulsifiers were evaluated in three sets of screening tests. Over 75 emulsion test samples were prepared and bench-tested. Based on such an extensive screening, Witco's NP-150, an ethoxylated nonylphenol with an HLB=12.5, was chosen as the most suitable emul-

sifier for Group I displacement tests. For Group II runs, emulsifiers Brij-72 (polyoxyethylene [2] stearyl ether, HLB=4.9) and Brij-721 (polyoxyethylene [2-1] stearyl ether, HLB=15.5) when used in a 7:3 ratio formed a stable emulsion. The HLB of the blend was 9.

4.3 Emulsion Characterization

Emulsions were characterized by their density, viscosity, and the size and distribution patterns of droplets. The densities of the chosen emulsions were correlated with the solvent concentration (Fig. 3) and this correlation was utilized in estimation of the percentage of condensate recovered with the produced fluids.

The viscosities, measured with a low shear rheometer, suggest that the emulsion viscosity was affected by changes in the concentrations of both the emulsifier and condensate (see Fig. 4). When the condensate concentration was increased from 10% to 30%, there was a marked rise in the viscosity, especially at the lower shear rates. At shear rates above 5 s^{-1} , the viscosity appeared to be independent of the shear rate. The viscosity of the emulsion with 40% condensate was not measured because it was unstable and it might have inverted to form a water-in-condensate emulsion during the viscosity measurement.

The emulsifier concentration had an interesting impact on the viscosity. At low concentration of 0.5%, emulsion viscosities were close to that of the water and appeared to be affected only mildly by an increase in the condensate concentration from 5% to 10%; but, when the emulsifier concentration was raised to 2%, there was a marked increase in the viscosity.

The size-distribution of emulsion droplets was estimated as % count of various sizes using a Coulter Counter. For all emulsions, about 80% droplets were in the range of 0.794-1.26 micron, and within this narrow range, the 0.794-micron droplets were the most abundant ones (about 40%). Fig. 5 shows the effect of condensate concentration on the droplet size distributions. As the condensate concentration was increased, the percentage of 0.794-micron size droplets shifted from being high (about 45%) at low condensate concentration to being moderate (about 33%) at high concentration. Interestingly, however, for the droplets larger than 1 micron, the trend was just the opposite; that is, greater the condensate concentration, higher was the percentage count of the droplets larger than 1 micron. Furthermore, a similar phenomenon was also observed when percent count of droplet sizes was correlated with the emulsifier concentration in the emulsion (see Fig. 6).

As the anticipated duration for each displacement run was several days, it was important that the emulsion retained its original characteristic (i.e., stability) as much as possible. To investigate if such was the case, the droplet size distribution was estimated for an emulsion with 30% condensate aged over a fortnight (see Fig. 7). But for minor variations in the percentages of 0.794-micron size droplets, there was little or no effect of aging on the droplet distribution. The Coulter Counter measurements were also made to verify the reproducibility of drop size distributions obtained for the similar emulsion prepared at different times. Results were fairly reproducible with only mild deviations occurring mostly in the lower size range of 0.794-1.26 micron.

5.0 RESULTS AND DISCUSSIONS

5.1 Effect of Emulsifier Concentration on Oil Recovery

Fig. 8 shows the effect of varying the emulsifier concentration in a 10 wt% condensate emulsion on the recovery of oil and Fig. 9 shows the simultaneous effects of the emulsifier concentration on the total pressure drop across the sandpack. There was a definite improvement in the oil recovery as the emulsifier concentration increased from 0.5% to 2.0% suggesting that the emulsifier, by itself, played an important role in the oil recovery process. Moreover, increasing the concentration of emulsifier resulted in a more stable emulsion, which in turn enhanced the oil recovery.

When the emulsion had only a short-term stability, as was the case for the emulsion with 0.5% emulsifier concentration, it separated in the vertical transfer vessel into two phases even before its injection into the sandpack -- a condensate-rich phase on the top, and a water-rich phase underneath. Therefore, it was possible that the condensate-rich top phase would enter the sandpack first during pumping followed by the water-rich bottom phase. This probably contributed to the superior initial performance at low values of PV injected, but eventually, to a lower overall displacement efficiency.

5.2 Effect of Solvent Concentration on Oil Recovery

5.2.1 Recovery of Lindbergh Oil

Figs. 10 and 11 show the effects of varying the solvent concentration in the emulsion on the recovery of Lindbergh oil and the pressure drop across the sandpack, respectively.

At the initial stage (<0.75 PV) of emulsion injection, it appeared that higher the solvent concentration, higher was the oil recovery. Beyond 0.75 PV injection, no such trend was noticeable and the maximum difference between the highest and the lowest oil recoveries at 2 PV of emulsion injection was only about 5.5%. Moreover, corresponding pressure drop profiles too suggest that two-third of the total oil recovery had already been attained at the breakthrough. Notice that in the case of the 10% emulsion, the pressure drop profile showed a gentle decline with the injection time which resulted in a continued incremental oil recovery beyond the breakthrough point. Figs. 12 to 13 show the droplet size distributions for the injected emulsions at different stages of injection as indicated. Overall, the general trend was similar; for instance, in all emulsions, the 0.794-micron size droplets were the most abundant ones and the population of droplets larger than 1.26 micron remained negligibly small.

5.2.2 Recovery of Medicine Hat Oil

Fig. 14 shows the effect of the condensate concentration on the recovery of Medicine Hat oil using two emulsions: one with 5% condensate and the other with 10% condensate. These displacements were conducted at 4.27 mL/hr over a 14-day period. In either case, the recovery factor was not encouraging; for example, the cumulative oil recovery after 2 PV of emulsion injection stood at 52% OOIP for the emulsion with 10% condensate, and for the emulsion with 5% condensate it was 33% OOIP. It is possible that both these emulsions were not stable enough, and as result, they broke down either in the transfer vessel while they were being injected or within the sandpack.

The importance of the emulsion stability in enhancing the oil recovery was demonstrated by results of Run 14 where a stable emulsion prepared with 30% condensate and 1% emulsifier was used. As evident from Fig. 15, nearly 85% of the OOIP was recovered at the end of 2 PV of injection, and the trend of the recovery curve suggests that further incremental oil recovery would have been possible had the displacement continued.

5.2.3 Effect of Oil Viscosity

Plotted in Fig. 16 is the corresponding recovery of the Lindbergh oil displaced by a similar emulsion at the same flood rate of 8.97 mL/hr to show how the viscosity of the oil impacted the displacement process. As evident from the Fig., the recovery of the Lindbergh was considerably lower than that of the Medicine Hat oil suggesting that the emulsified solvent flood appeared to be more efficient with a lower viscosity oil.

5.3 Effect of Flood Rate on Oil Recovery

Two flood rates were chosen: 8.97 mL/hr and 4.27 mL/hr for tests with reservoir oils. As Fig. 17 suggests, the lowering of the flood rate by more than half from 8.97 mL/hr to 4.27 mL/hr did not bring any substantial benefits with respect to the incremental recovery of the Medicine Hat oil. Although the lower-rate flood appeared to be more efficient at the initial stage (<0.4 PV of injection), eventually the flood conducted at 8.97 mL/hr recovered 5% more oil at the end of 2 PV of emulsion injection than the flood at 4.27 mL/hr.

Although the effect of rate appears contrary to what one would expect, it has to be borne in mind that the net effect of rate depends on the relative importance of two mechanisms: the reduction of the oil viscosity due to dilution by solvent from the emulsion; and the mobility control provided by the emulsion. The dilution mechanism needs slow rate to be effective as it depends on the breakdown of the emulsion to transfer the solvent to the oil. When the dilution mechanism dominates, higher recovery is to be expected at the slower rate. On the other hand, mobility control requires emulsion stability; i.e., the recovery will be higher at a higher rate due to less time available for the breakdown of the emulsion. Also, the higher velocity provides higher shear energy to keep the solvent emulsified.

5.4 Oil Recovery Performance

When the breakthrough recovery is used as the primary performance criterion, the emulsified solvent flood appears to be the most efficient process followed by the displacement by commingled flow of the water and kerosene. As expected, the waterflood yielded the lowest breakthrough recovery among the three floods even though it was conducted at almost half the rate of other two floods. However, both emulsion flood and commingled fluid injection provide similar ultimate recovery. In experiments with reservoir oils, too, the emulsified solvent flood was superior in recovering oil (see Figs. 18 and 19). In emulsified solvent flood and straight solvent (condensate) flood, the post-breakthrough incremental oil recovery continued with the former yielding a higher recovery for both oils. For floods with the solvent, the recovery after 2 PV of condensate injection were 44% and 50%, respectively, for the Lindbergh and Medicine Hat oils. This was to be expected too as the Medicine Hat oil was much less viscous than the Lindbergh oil. It was.

however, obvious that the primary reason for the highest oil recovery in the emulsified solvent flood was the higher recovery attained in the pre-breakthrough period (<0.5 PV) of the flood.

6.0 ECONOMIC EVALUATION

6.1 Process Optimization

A large fraction of the process cost stems from the cost of the hydrocarbon solvent used in creating the emulsion. Since the cheapest available solvent (Natural Gas Condensate) is already being used, this cost can only be reduced by reducing the volume of solvent injected for recovering each barrel of oil. Simply reducing the volume fraction of solvent in the injected emulsion has not worked since it also reduced the recovery efficiency of the process. Three different methods for reducing the cost of the process were examined: i) using only a small slug of emulsion followed by the injection of chase water; ii) gradually reducing the solvent fraction in the injected emulsion using an optimized grading scheme; iii) replacing a part of the solvent in the emulsion with the lease crude.

Effects of emulsion slug size and quality were studied using the flow visualization model (Fig. 1) and the use of lease crude as the solvent was investigated using the linear coreflood apparatus (Fig. 2).

Slug Size: Fig. 20 presents the cumulative oil recovery as function of the initial slug size. All runs were conducted with an emulsion with 20% solvent content. It is obvious that when the slug size was increased, both the breakthrough and the ultimate cumulative oil recoveries increased. Also, regardless of the slug size, the emulsified solvent flood always recovered significantly higher amount of oil than the straight waterflood. Hence, a small emulsion slug followed by the chase water can be quite effective in displacing heavy oils. Although it does not match the ultimate recovery that can be obtained by continuous emulsion injection, the savings in cost of injected materials more than compensates for the lower recovery.

Emulsion Quality Grading: The emulsion quality grading was found to provide no additional benefit compared to the injection of a small slug of the emulsion (see Fig. 21). All runs started with an emulsion with 40% solvent content. Subsequently, the solvent content in the emulsion was graded down to 0% in 10 steps at an interval of 5% of the PV injection. The level of oil recovery efficiencies obtained in graded quality injection tests were no higher than those obtained in the tests involving the injection of an equivalent fixed quality slug of the emulsion. However, it needs to be pointed out that the graded emulsion requires much less solvent and may be economically advantageous.

Use of Lease Crude: It was found that some of the solvent in the emulsion can be replaced with lease crude without significant reduction in the displacement efficiency. Tests were carried out with 30% quality O/W emulsions stabilized with 2% surfactant concentration in the aqueous phase. Four different emulsions, differing in the ratio of crude oil and solvent in the dispersed phase, were used. The dispersed phase compositions (on volumetric basis) were as follows:

- Emulsion A - 100% solvent,
- Emulsion B - 25% crude oil, 75% solvent,
- Emulsion C - 50% crude oil, 50% solvent,

Emulsion D- 75% crude oil, 25% solvent.

The particle size distributions (Fig. 22) suggest that the increasing fraction of oil in the dispersed phase moved the drop size distribution towards smaller drops. For example, the 100% oil sample (which displayed the highest viscosity: 85.5 mPa.s) had droplet sizes that were more concentrated in the smaller regions as compared to other less viscous samples.

Fig. 23 compares the oil recovery performance after 1 PV of emulsion injection. It is evident that replacing some of the solvent in the dispersed phase of the emulsion with the crude oil had no detrimental effect on the oil displacement performance of the emulsion. Actually, the emulsion containing 75% crude oil in the dispersed phase produced more oil than the emulsion containing pure solvent. The same trend of relative performance of different emulsions was observed when the total oil recovered after 2 PV of injection was compared (see Fig. 24). These results suggest that the mobility control by plugging of more permeable flow channels may be the dominant mechanism in these displacements. However, the economic benefit provided by this strategy is reduced to some extent by the accompanying reduction in the solvent content of the produced fluids.

6.2 Cost Analysis

The feasibility of the process depends on the following key factors: the cost of injection materials -- emulsifiers and solvents, processing of the produced fluids, recovery and recyclability of produced solvents and emulsifiers, surface handling facilities and expertise.

A simplified economic analysis -- based on the material costs only -- is provided. It puts a value to the recovered and recycled solvent from produced fluids but writes off all emulsifiers used as non-recoverable items. The unit prices of the materials for preparing the emulsions were estimated as following: non-ionic surfactant @\$6.5/kg, water @\$1.5/m³, pipeline condensate @\$180/m³ and oil @\$120/m³. The cost of injected emulsion varies with the amount of surfactant needed to stabilize the emulsion and the volume fraction of emulsified solvent in the emulsion. Table 4 presents the estimated cost for various emulsion types which could be used, and it varies from \$41.30/m³ to \$150.90/m³. It is apparent that we used a relatively expensive displacing fluid in this process. In view of the high cost, the continuous injection of a solvent-in-water emulsion, which requires several m³ of emulsion for each m³ of oil produced, can be eliminated from consideration without any analysis. Only a modified process which requires less than 1 m³ of injected emulsion for each m³ of oil produced can have any chance of being economically attractive.

Table 5 presents costs for a modified process in which a small emulsion slug is injected followed by injection of the chase water for several different slug sizes. It is noted that the lowest material cost per unit volume of the injected emulsion was obtained by injecting a 0.3 PV slug of a fixed quality emulsion. The graded quality emulsion resulted in higher material cost.

The material cost is only a part of the total cost of the process. The full cost can be several times higher when other costs, such as interest on the capital invested, operating costs, transportation cost, taxes and royalties are

also taken into account. In view of the risks involved it is suggested that the material cost should be no more than 30% of the selling price of recovered oil for the process to become economically viable. Therefore, the process would be economically viable if either the oil price becomes favourable or cheaper materials are commercially available in bulk.

7.0 SUMMARY AND CONCLUSIONS

Based on the results of this study, and keeping in mind that these results may only apply to the particular fluid system and porous medium used, the following conclusions are drawn:

1. Emulsified solvent flooding does improve the recovery of heavy oil over conventional water or solvent floods. Two mechanisms are involved: mobility control and dilution by the solvent in the emulsion.

2. The displacement efficiency appears to be a function of the emulsion stability; that is, more stable the emulsion, higher is the oil recovery. Moreover, the concentrations of the emulsifier and the condensate in the emulsion play an important role in the oil recovery process -- increasing either the emulsifier or the condensate concentration in the emulsion improves the oil recovery.

3. The process appeared more favourable to lower viscosity heavy oil than to high viscosity oil.

4. The displacement efficiency obtained using graded quality emulsion bank was similar to that obtained by injecting a slug of fixed quality emulsion containing the same amount of solvent.

5. Replacing a part of the solvent in the emulsion with crude oil did not have a significant effect on displacement efficiency.

6. In general, continuous injection of an emulsified solvent does not appear to be an economically viable displacement process unless cheaper emulsifiers and solvents can be found, the process is modified or changed to enhance the recovery of the solvent with the produced fluids, and the price of the heavy improves significantly.

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Table 1: Porous Media

<i>Flow-Visualization Model (cf. Fig. 1)</i>		
Length, cm	50.8	
Width, cm	20.3	
Thickness, cm	1.0	
Glass bead size, μm	590-840	
Porosity, fraction	0.40	
Permeability, μm^2	95.5	
<i>Linear Coreflood Apparatus (cf. Fig. 2)</i>		
Length, cm	100	
Cross-Sectional Area, cm^2	16.1	
Sand Size, Mesh	140-200	
Porosity, fraction	0.34	
Pore Volume, mL	549	
Permeability, μm^2	3.6	
Confining Pressure, MPa	14.0	

Table 3: Fluid Properties at 23 °C

Fluid	ρ (kg/m ³)	μ (mPa.s)
Vitrea-150	879.9	419
Lindbergh Oil	982.0	10500
Medicine Hat Oil	967.0	2830
Condensate	762.7	1
Kerosene	798.0	2.4
Water	997.5	0.94

Table 2: Summary of Displacement Tests

#	Rate mL/hr	Displacing Fluids in Sequence (Compositions in wt. % within parentheses)	Displaced Oil
1	60.0	<i>Group I Tests</i> 5 PV Water	Vitrea-150
2	102.6	2PV Emulsion (20%Kerosene+1%NP-150)	Vitrea-150
3	6.48	2PV Emulsion (20%Kerosene+1%NP-150)	Vitrea-150
4	102.6	2PV Commingled (8:2 water & kerosene)	Vitrea-150
5	8.97	<i>Group II Tests</i> 5PV Emulsion (10% condensate+2%surfactant)	Lindbergh
6	8.97	2PV Emulsion (10% condensate+0.5%surfactant)	Lindbergh
7	8.97	5PV Emulsion (10% condensate+1%surfactant)	Lindbergh
8	8.97	5PV Emulsion (20% condensate+1%surfactant)	Lindbergh
9	8.97	5PV Emulsion (30% condensate+1%surfactant)	Lindbergh
10	8.97	5PV Emulsion (40% condensate+1%surfactant)	Lindbergh
11	8.97	2PV Brine (1%NaCl) $\rightarrow$ 2PV condensate	Lindbergh
12	8.97	1PV Water $\rightarrow$ 0.5PV Water+1%Surf. $\rightarrow$ 0.5PV Emulsion (10%Cond.+1%Surf.)	Lindbergh
13	8.97	2PV Water $\rightarrow$ 0.5 PV Emul(30%Cond+1%Surf) $\rightarrow$ 0.5PV Water $\rightarrow$ 2PV Brine (1% NaCl)	Lindbergh
14	8.97	2PV Emulsion (30% condensate+1%surfactant)	Medicine Hat
15	8.97	1PV Brine(1% NaCl) $\rightarrow$ 2PV Condensate	Medicine Hat
16	8.97	2PV Brine (1%NaCl)	Medicine Hat
17	4.27	2PV Emulsion (5% condensate+0.5%surfactant)	Medicine Hat
18	4.27	2PV Emulsion (10% condensate+0.5%surfactant)	Medicine Hat
19	8.97	5PV Emulsion (10% condensate+0.5%surfactant)	Medicine Hat

Table 4: Cost of Solvent-in-Water Emulsions

Composition		Cost
Surf. (wt.%)	Cond.(Vol.%)	[\$/m ³]
0.5	5	41.3
0.5	10	45.7
1.0	10	74.9
1.0	20	89.2
1.0	30	100.6
1.0	40	111.9
2.0	10	133.4
2.0	20	141.2
2.0	30	146.1
2.0	40	150.9

Table 5: Material Cost per m³ of Recovered Oil

Emul Qual. (%)	Slug Size (PV)	Oil Prod (PV)	Emul/m ³ (m ³)	Emul Cost/m ³ (\$)	Chase Water/m ³ (m ³)	Material Cost/m ³ (\$)
20	0.7	0.77	0.91	89.2	3.25	86.0
20	0.5	0.69	0.73	89.2	4.0	70.6
20	0.4	0.68	0.59	89.2	4.1	58.6
20	0.3	0.56	0.54	89.2	5.2	56.0
40	0.3*	0.56	0.54	111.9	5.2	68.2
40	0.6**	0.64	0.94	111.9	4.0	111.2

*0.05 PV injected at 40% quality followed by a graded quality bank
 **0.35 PV injected as a slug followed by the graded quality bank.

Fig. 1: Schematic of Flow Visualization Apparatus

Fig. 2: Schematic of Coreholder Apparatus

Fig. 3: Emulsion Density as a Function Solvent Concentration

Fig. 4: Emulsion Viscosity as Function of Concentration

Fig. 5: Drop Size Distribution for 1.0 wt% Emulsifier Emulsion

Fig. 6: Drop Size Distribution for 10 wt% Condensate Emulsion

Fig. 7: Effect of Aging on Drop Size Distribution
(1.0w% Emulsifier, 30w% Condensate Emulsion)

Fig. 8: Effect of Emulsifier Concentration on Oil Recovery
(10% Solvent in Emulsion, Displacing Lindbergh Oil at 8.97 cc/hr)

Fig. 9: Effect of Emulsifier Concentration on Total Pressure Drop
(10% Solvent in Emulsion, Displacing Lindbergh Oil at 8.97 cc/hr)

Fig. 10: Effect of Condensate Concentration on Oil Recovery
(1% Emulsifier in Emulsion, Displacing Lindbergh Oil at 8.97 cc/hr)

Fig. 11: Effect of Condensate Concentration on Total Pressure Drop
(1% Emulsifier in Emulsion, Displacing Lindbergh Oil at 8.97 cc/hr)

Fig. 12: Drop Size Distributions for Emulsion with 1% Emulsifier
and 20% Pipeline Condensate

Fig. 13: Drop Size Distributions for Emulsion with 1% Emulsifier and 30% Pipeline Condensate

Fig. 14: Effect of Condensate Concentration on Oil Recovery (Emulsions with 0.5% Emulsifier displacing Medicine Hat Oil at 4.27cc/hr)

Fig. 15: Comparison of Recoveries of Medicine Hat and Lindbergh Oils (Emulsion with 30% Pipeline Condensate & 1% Emulsifier; Flood Rate=8.97cc/hr)

Fig. 16: Effect of Flood Rate on Oil Recovery (Emulsion with 1% Emulsifier & 10% Pipeline Condensate, Medicine Hat Oil)

Fig. 17: Effect of Flood Rate on Oil Recovery (Emulsion with 1% NP-150 & 20% Kerosene displaing Vitrea-150)

Fig. 18: Oil Recoveries with Different Flooding Processes (Lindbergh Oil, Flood Rate = 8.97 cc/hr)

Fig. 19: Oil Recoveries with Different Flooding Processes
(Medicine Hat Oil, Flood Rate = 8.97 cc/hr)

Fig. 20: Cumulative Oil Recovery as a Function of Emulsion Slug Size
(20% Solvent-in-water Emulsion)

Fig. 21: Effect of Grading the Amount of
Solvent in Emulsion on Cumulative Oil Recovery
(40% Solvent initially, 10 steps of 4% each every 5% P.V.)

Fig. 22: Droplet Size Distributions for 5 Samples with Lease Crude

Fig. 23: Oil Recovery at One Pore Volume Injection

Fig. 24: Oil Recovery at Two Pore Volume Injection