A Laboratory Study of the Extraction of Hydrocarbons from Crude Oil
by High Pressure Carbon Dioxide

A Thesis

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Abstract

It is generally accepted that CO_2 develops miscibility with reservoir oils through a dynamic multi-contact vaporizing gas drive in which CO_2 extracts hydrocarbons from the oil resulting in a composition that is miscible with the oil. Also in other processes the extraction only can produce significant amounts of hydrocarbons.

This study experimentally investigates the capacity of CO_2 to extract hydrocarbons from crude oils. The effect of pressure, temperature and oil composition on the extraction capacity of CO_2 were studied. Extraction experiments using CO_2 with Sulimar Queen stock tank oil and Spraberry separator oil samples at pressures varied between 1000 and 1900 psig were performed each at 95 and 138 °F. The experiments were performed by continuously injecting CO_2 through 500-cc of oil placed in a 1.15 liter extraction vessel while continuously producing the upper phase or the CO_2 phase rich with extraction product.

CO_2 extraction capacity was found to be a strong function of pressure and temperature. The extraction capacity increase with increasing pressure and decrease with increasing temperature. For the oils used in this study, the presence of solution gas in the oil does not affect the CO_2 extraction performance.

CO_2-Sulimar Queen oil extraction experiment at constant pressure and temperature of 1200 psig and 95 °F, respectively, was performed for an extended period of time to determine the maximum oil recovery that can be achieved by CO_2 extraction. It was found from the experiment that CO_2 could recover at least 48 vol.% or 43 wt.% of the OOIP. The CO_2 extraction capacity decreased from around 0.3 g oil/g CO_2 injected at the beginning of the extraction to 0.005 g oil/g CO_2 injected at the time of termination. The average value of

the extraction capacity was 0.0345 g oil/g CO_2 injected. Analysis on the produced oil compositions during the course of the experiment shows the smaller hydrocarbon molecules in the oil are extracted more efficiently by CO_2 than are larger ones.

Relationships between CO_2 extraction capacity and CO_2-oil miscibility were determined by comparing the results of the extraction experiments with that of slim tube displacement tests performed for the same CO_2-oil systems. It was found that the slim tube Minimum Miscibility Pressures (MMPs) are near the pressure range at which a drastic increase in CO_2-oil extraction rate occurs. As expected, this implies that CO_2 extraction is a major factor in CO_2-oil miscibility development. This agrees with the widely accepted thought that CO_2 miscibility is developed with an oil through the vaporizing gas drive mechanism. Comparison between the extraction and slim tube tests results also show that the extraction experiment appear to have promise to be used as a CO_2-oil MMP estimation method.

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I. Introduction

Two phenomena influenced the conception of the study of hydrocarbon extraction from crude oil by high pressure carbon dioxide (CO_2). First, the study of increasing recovery in naturally fractured reservoir using CO_2 indicated the possibility of significant oil production by extraction. One test indicated production approaching 50 percent with a significant amount from extraction.[1] The question of whether this high production could result from extraction was posed. Second, extraction is the principal mechanism in the development of multi-contact miscibility by vaporization.

A number of experimental studies are found in the literature concerning the capacity of CO_2 to extract hydrocarbons from crude oils.[8,9,14,16,23,34,35] Each author worked with different experimental methods, variables and parameters of interest, and CO_2-oil systems. In this work the extraction behavior of CO_2 was experimentally investigated using a semi-batch extraction system in which CO_2 was continuously bubbled through a vessel of oil while the upper phase of the CO_2-oil mixture was continuously produced. The objective of this study was to attempt to determine how pressure, temperature and oil composition affect the CO_2 extraction capacity and to what extent CO_2 can recover hydrocarbons from an oil by extraction. In addition, a series of slim tube displacement tests were performed to compare with results obtained from the extraction experiments.

The results of this study may be used to help understand CO_2-oil miscibility development mechanisms and to help determine the process involved in oil production from CO_2 injection into a naturally fractured reservoir.

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II. Literature Review

2.1 CO_2/Oil Phase Behavior Measurements

The phase relationship of a wide variety of binary and ternary systems containing carbon dioxide and hydrocarbons was investigated and reported by several authors.[2-7] The phase behavior of more complex CO_2-hydrocarbon mixtures was examined by Menzie.[8] He experimentally studied recovering reservoir oil by repressuring CO_2. In his experiment, an oil sample was charged into a windowed cell which was kept at a constant temperature. High-pressure CO_2 was injected into the cell and then the cell was agitated until equilibrium was reached. The vapor phase was removed and condensed in a separator at atmospheric pressure. The remaining oil in the cell was recharged with CO_2 and then the cell was agitated until a new equilibrium was reached. The vapor phase was then again removed and condensed. This procedure was repeated five times in each run. Menzie found that this multiple contact process can recover about one-half of the original oil charged into the cell. Using techniques similar to that used in Menzie's experiment, Alsinbili[9] investigated the effect of oil gravity and injection pressure on oil recovery by CO_2 injection. He found that recovery increased with increasing oil gravity and with oil containing more light ends (which usually means a higher API gravity). He also found that the higher the pressure the higher the recovery.

More recently, several authors have measured the phase behavior and fluid properties of different CO_2-oil mixtures in conjunction with their work in EOS tuning,[10-12] for simulation work[13-17] or with displacement tests.[18-20] Each work was done to understand and predict the behavior of the mixtures or the performance of CO_2 displacement. Other authors have measured the phase behavior and fluid properties of other CO_2-oil mixtures to describe the

behavior of CO_2-oil mixture[21-22] or to develop correlations predicting the performance of CO_2 displacements.[23,24] The phase behavior and fluid properties were measured using either a standard PVT apparatus or a continuous multi-contact equilibrium apparatus. The PVT tests were performed as single contact or multi-contact tests similar to that performed by Menzie.[8]

2.2 CO_2/Oil Miscibility Mechanisms

In solvent flooding operations, one of the conditions needed for efficient displacement is that the solvent has to be miscible with the reservoir fluid. A displacement process is defined as miscible when a phase boundaries between the reservoir oil and solvent do not exist. There are at least three types of miscibility referred to in the literature: first-contact miscible, vaporizing gas drive (or high pressure gas drive) and condensing gas drive (or enriched gas drive). A mixture of two fluids is said to be first-contact miscible when the two fluids completely mix, in all proportions, and form a single-phase. In vaporizing and condensing gas drives, miscibility is developed gradually by a mass transfer of components between the solvent and the reservoir fluid. Miscibility generated in such a manner is commonly referred to as multi-contact or dynamic miscibility. In vaporizing gas drive in a reservoir, the solvent extracts a fraction of hydrocarbons from the reservoir oil and, after undergoing several steps of extraction, the enriched solvent becomes miscible with the reservoir fluid. In contrast to a vaporizing gas drive, for a condensing gas drive the component(s) of the solvent dissolves into the reservoir fluid and after several contacts the reservoir fluid is enriched with solvent component(s) and this enriched reservoir fluid becomes miscible with the solvent. These proposed miscibility mechanisms are conceptually well

described using ternary phase diagrams in the literature.[25-27] Several authors have argued that ternary phase diagram cannot adequately represent real miscible flooding systems and miscibility is developed through mechanisms more complex than just simply vaporizing or condensing drive. From experimental as well as modeling studies recent research has indicated that miscibility may also develop through combined vaporizing/condensing drive.[28-30]

Carbon dioxide is not first contact miscible with most reservoir fluids at realistically attainable reservoir pressures. However, it is multiple contact miscible with reservoir fluids at attainable pressure in a broad spectrum of reservoirs. Generally investigators agree that the development of CO_2/oil miscibility is the result of extraction of some hydrocarbons from the oil by dense CO_2. For example, Hutchinson and Brown[26] and Rathmel et al.[31] argued that CO_2 can extract hydrocarbons present in the oil and generate composition paths which avoid two phase regions in displacements with ternary systems. Gardner et al.[16], Orr et al.[32], and Sigmund et al.[33] used such mechanisms to quantitatively predict oil recovery for CO_2-crude oil displacement in slim tubes. Holm and Josendal[35] argued that extraction and dispersion mechanisms are taking place along a miscible displacement path. During flooding CO_2 extracts a fraction of hydrocarbons from the reservoir oils. After multiple contacts, the displacement front has vaporized enough hydrocarbons to develop a composition that is miscible with the oil. At this point the extraction process stops until the developed miscible front breaks down by the dispersion mechanisms. When miscibility is lost, the extraction mechanism again occurs to reestablish miscibility. Thus, the miscible bank is formed, dispersed and reformed throughout the displacement path.

Bahralolom and Orr[36] conducted a series of flow visualization experiments of CO_2 miscible displacement and found that the efficiency of the displacements is more sensitive to the efficiency of extraction of hydrocarbons by CO_2-rich phase than it is to the solubility of CO_2 in the crude oil. Metcalfe and Yarborough[27] argued that temperature and pressure dictates which miscibility process controls the displacement. They feel, vaporizing gas drive processes occur at high pressure and temperature, but if the pressure remains constant while the temperature is lowered, then the miscibility process that controls the displacement is a condensing drive. Orr et al.[15] disagrees with Metcalfe and Yarborough[27] concerning CO_2 miscibility processes at low temperatures. The former argued that liquid-liquid and liquid-liquid-vapor equilibria will occur for CO_2/crude-oil systems at temperatures below 120 °F and that development of miscibility occurs by extraction of hydrocarbons from the oil into a CO_2-rich liquid phase in such systems. Kamath et al.[37] concluded that an increase in the solubility of liquid CO_2 in crude oil at temperatures near the critical temperature of CO_2 should cause more efficient displacement by CO_2. From PVT and core flood studies, Huang and Tracht[38] concluded that at low temperatures the dominant mechanisms for tertiary recovery are the swelling and stripping of hydrocarbons from the oil by the CO_2-rich liquid phase.

In summary, the above review shows that considerable work on the understanding of the development of CO_2/oil miscibility mechanism has been done by many authors. Most the authors generally agree that the development of CO_2/oil miscibility is the result of extraction of some hydrocarbons from the oil by dense CO_2.

2.3 CO$_2$/Oil MMP Measurement Methods

In dynamic miscible floods, oil recovery increases with pressure until a pressure above which further increases of pressure does not significantly improve oil recovery. At and above this optimum pressure the injected solvent is miscible with the reservoir oil. The lowest pressure that allows the injected solvent to achieve dynamic miscibility with the reservoir oil is commonly referred to as the minimum miscibility pressure of the solvent/oil mixture. Minimum miscibility pressure or MMP is an important parameter in the evaluation of gas flooding prospects. It is needed to determine whether a reservoir could be miscibly flooded and also whether it is economically justified to flood the reservoir.

The MMP of a solvent/oil mixture is usually determined experimentally from displacement tests using a slim tube apparatus. The experiment is an attempt to isolate the effect of phase behavior on displacement efficiency in a flow setting that minimizes the effect of viscous instability inherent in the displacement of oil by low viscosity CO$_2$. The center piece of the apparatus is a high pressure sand-packed coiled tube 0.635 to 1.27 cm in internal diameter and 9 to 42 m long.[44,51] The tube is saturated with the oil to be tested at the desired temperature and pressure. Then, the solvent is injected to displace the oil at a rate ranging from 0.6 to 12.2 m/hour. The MMP is determined from the displacement recovery vs. pressure profile.

A variety of MMP criteria have been proposed in the literature by which the MMP can be determined from displacement tests data. The MMP criteria are usually based on the measurement of the fraction of oil recovered in slim tube displacement at a given pressure, and rarely based on the analysis of phase diagrams. Most authors define the MMP as the

pressure at which a certain recovery value (80-100%) is achieved at 1.2 PV of CO_2 injected.[34,35,39,40] Instead of using a certain recovery value as a criterion, Johnson and Pollin[41] use a sharp break point in the slope of the recovery vs. pressure curve as the MMP criteria. Despite the enormous work in this area and also the similarities between the described MMP criteria, there is no standard method or unique criterion for the determination of the MMP. Nevertheless, slim tube tests are used as the standard tool in most displacement studies. With some slight modifications a slim tube apparatus may also be used to study the phase behavior of the transition zone of a displacement process.[42]

The MMP of a CO_2 /oil mixture may also be measured using a Rising Bubble Apparatus (RBA) developed by Christiansen and Haines.[43] Detailed design of this apparatus is described in their paper. During RBA experiments a small bubble of gas is injected at the base of a vessel of oil. The shape of the rising bubbles, which indicate the interfacial tension of the gas/oil mixture, varies with the system pressure. The MMP of the gas/oil mixture is inferred from the pressure dependence of the behavior of rising bubbles. The accuracy of RBA has been evaluated by several authors.[44-48] Elsharkawy *et al.*[44] compared the measurements of CO_2 /oil MMP using a slim-tube apparatus with those using an RBA. They found that the results compare very well and concluded that RBA is faster and more reliable than the slim tube for determining MMP. A similar finding is also reported by Eakin and Mitch[45] and Thomas *et al.*[46] Zhou and Orr[47] reported an analysis of RBA experiments for ternary systems. The authors argued that for vaporizing gas drive RBA can determine the MMP for three-component systems with reasonable accuracy and suggested that additional work is required to establish the reliability of RBA for multi-component systems that show

condensing/ vaporizing behavior. Mihcakan and Poettmann[48] reported that for a ternary system they studied, the MMP as measured by RBA agreed with the determined phase behavior of the ternary system.

Harmon and Grigg[49] introduced an experimental method for estimating the MMP of CO_2/oil mixture based on the solvency properties of CO_2 in oil. The properties are evaluated from a series of tests in a constant-volume visual PVT cell similar to those described by Holm and Josendal.[33] The vapor density method developed by these authors directly measures the ability of CO_2 to extract hydrocarbons from the crude oil, indicated by the density of the injection-gas-rich upper phase, as a function of pressure. The authors found that for CO_2-separator oil mixture around 90 °F, the density of CO_2-rich phase shows a rapid rise at about the same pressure as the MMP from slim tube experiments at the same temperature. The adequacy of the proposed method for high temperature reservoirs was questioned by Chabach[50] because the degree of changes in volatility of the CO_2-extractable oil is not available. He argued further that the measurement of the upper phase density alone may not be sufficient to estimate the MMP above 110 °F. The proposed method is faster than slim tube tests but it has limitations. For example, as described, it is not feasible for live oil since the experiment starts at atmospheric pressure. Also, the accuracy decreases as temperatures increases above 120°F, but to a similar degree this temperature-dependence accuracy is also the case in slim tube tests.

Besides the above described experiment methods, there are several other laboratory experiment procedures that have been developed and used in different CO_2 flooding studies. These include high-pressure volumetric (PVT) and vapor/liquid equilibrium (VLE)

experiments, continuous multi contact experiment, core floods, and micromodel visualization studies. The uses and limitations of the information obtained from some of these experiments were well reviewed by Orr $et\ al.$[51]

2.4 Factors Affecting CO_2 Flood Performance

The phase behavior in CO_2 displacements is affected by pressure, temperature, oil composition and purity of the injection gas. Several authors have investigated how these factors affect CO_2-oil MMPs that is commonly used parameter to represent the performance of CO_2 displacements. The significance of each factor that affects CO_2 displacement can be understood better by reviewing MMP prediction correlations proposed by some of these authors.

Yellig and Metcalfe[39] argued that for the oils used in their study, which varies in C_1-C_6 fractions, there was little or no effects of oil composition on the CO_2 MMP. They proposed a simple correlation to predict the CO_2 MMP that use only displacement temperature as the parameter. A correction has to be applied, however, if the oil bubble point pressure (BPP) is greater than the predicted MMP. In such a case then the BPP is taken as the MMP. For the oils considered in their study, they found that temperature increases the MMP by approximately 15 psi/°F over a range of 95 to 192 °F. Orr and Jensen[22] suggested that, for low temperatures, the CO_2 MMP can be estimated from the extrapolated vapor pressure of CO_2.

Holm and Josendal[34] reported that the displacement of oil by CO_2 does not depend upon the presence of intermediate hydrocarbons (C_2-C_4) and the presence of methane in the reservoir oil reduces the overall recovery efficiency of the displacement. The authors

presented a correlation equating the MMP with temperature and the average molecular weight of the C_{5+} fraction of the oil. Holm and Josendal[35] proposed a second MMP correlation which is similar to their first correlation in that MMP is a function of the temperature and the composition of the oil. They proposed that a characteristic CO_2 density is required for an MMP of a given oil and the MMP is inversely proportional to the amount of extractable hydrocarbons (C_5-C_{30}) present in the reservoir oil. The use of the required CO_2 density at the MMP instead of MMP is meant to accommodate the effect of C_{5+} molecular weight and the temperature on MMP. A high pressure is required at a higher temperature to obtain an equivalent CO_2 density. The MMP is then obtained by determining the pressure required to reach the characteristic CO_2 density at a given temperature. These authors reported that the minimum density of CO_2 required to achieve maximum recovery was 0.42 g/cc, which is close to critical density of CO_2 (0.468 g/cc).

Silva and Orr[23] studied the effect of the distribution of the molecular size present in an oil on the development of miscibility in a CO_2 flood. The authors showed that small hydrocarbon molecules are extracted more efficiently into dense CO_2 than large ones. They argued that the molecular size distribution has a significantly larger impact on miscibility development than the variations in the hydrocarbon structure. In their companion paper[24] they reported that the development of miscibility of CO_2 with an oil is enhanced by the presence of C_2-C_4 hydrocarbons in that oil. However, CO_2 still can develop miscibility with oil that does not contain C_2-C_4 fractions. Orr and Silva[24] further modified the Holm and Josendal correlation to account for smaller size hydrocarbon contribution on MMP by introducing a weighted composition parameter that is based on partitioning coefficients of C_{2+} hydrocarbons.

Rathmel et al.[31] stated that the presence of methane in reservoir increases the MMP. They argued that an immiscible process indicated by the flow of methane bank ahead of the CO_2 bank is caused by the presence of methane in the reservoir oil. Monroe et al.[52] presented several analytical results concerning composition paths for dispersion-free, one dimensional displacement of C_1-C_4-C_{10} systems by carbon dioxide. The authors concluded that the addition of methane to a dead oil has insignificant effect on MMP. The authors argued that methane present in the oil partitions strongly into the more mobile vapor phase forming a methane-rich bank at the leading edge of the transition zone. Furthermore, they concluded that for one dimensional flow, displacement at a pressure below its BPP will be efficient, if the pressure is above the MMP for the same oil with all methane removed. The authors also argued that high displacement efficiency is possible even when the two-phase flow occurs throughout the displacement.

Hagedorn and Orr[17] used a compositional simulator to investigate the effect of hydrocarbon structure on the development of miscibility. They reported that for some oils, a high content of multi-ring aromatics leads to an MMP that is significantly higher than that of a similar molecular weight oil which contains fewer multi-ring aromatics compound. Monger[53] performed static PVT experiments and coreflood using synthetic oils to investigate the effect of oil aromaticity on CO_2 flooding. She reported that increased aromaticity correlates with improved hydrocarbon extraction into CO_2-rich phase and that the oil displacement efficiency is improved by increasing the aromatic content of the oil.

Alston et al.[40] presented an empirical MMP correlation for impure CO_2 displacements. They used displacement temperature, oil composition, and weight-averaged critical

temperature of the injection gas mixtures as the correlating parameters. Cronquist[54] empirically correlated CO_2 MMP with displacement temperature, mole percent of methane in oil, and the molecular weight of the pentane-plus fractions of the oil. Enick et al.[55] presented a graphic EOS-based correlation to predict the MMP of CO_2/oil displacement. They reported that for 157 CO_2/oil MMP values they tested, the average of the ratio between predicted MMP and experimental MMP for these mixtures is 1.09 with a standard deviation of 0.19. The authors warned that at low temperatures and for high-molecular weight oils, a correction has to be used to prevent a predicted increase in the MMP with decreasing temperature. At elevated temperatures (>248 °F), the correlation predicts a decrease in MMP with temperature. Glasø[56] proposed a correlation for predicting MMP in which the MMP is correlated as a function of the molecular weights of injection gas intermediates and reservoir oil heavy ends, the amount of methane and displacement temperature. Johnson and Pollin[41] proposed an empirical correlation to predict the MMP of CO_2/N_2 or CO_2/CH_4 binary mixture with an oil. They correlated the MMP with critical temperature, critical pressure, composition and molecular weight of injection gas; reservoir temperature; and API gravity, and number average molecular weight of oil. Kovarik[57] and Sebastian et al.[58] each proposed a correlation to predict the MMP of impure CO_2 with an oil based on MMP value of the oil with pure CO_2 and the amount of non-CO2 components in the injection gas. In Kovarik's correlation, the effect of gas impurities on MMP is corrected by an amount related to the pseudocritical temperature of the injection gas. In the Sebastian et al. correlation, it is corrected by a factor based on the mole-averaged critical temperature of the CO_2/impurities mixtures. Luks et al.[59] presented an algorithm to calculate MMP, either vaporizing or condensing drive systems, in

a manner consistent with an EOS-based fluid description. They incorporated the multi-contact miscible mechanism in the MMP calculation scheme.

The performance of gas flooding at pressures slightly below the CO_2/oil MMP, usually called near-miscible floods, had been investigated by several authors. Shyeh-Yung[60] concluded from CO_2 displacement study that decreases in core flood oil recovery at pressures below the MMP are not as great as suggested by slim tube tests. Later Shyeh-Yung and Stadler[61] reported that similar phenomenon also occurred in coreflood recovery of hydrocarbon gas injection process. From a compositional simulation study for hydrocarbon gasflood, Pande[62] concluded that the performance of immiscible solvent may not be as poor as predicted from one-dimensional displacement. Pande argued that for some reservoir situations gravity and viscous cross flow can cause immiscible solvents to achieve better overall recovery efficiency than miscible solvents. Burger *et al.*[63] experimentally examined the performance of enriched secondary gas floods and reported a similar finding. In contrast, Grigg *et al.*[64] concluded from a CO_2 displacement study that "the rapid decrease in recovery efficiency as pressure falls below the MMP, as observed in slim tube tests, is authentic and should be taken into account for both reservoir simulation and operation."

III. Experimental Description

This chapter describes the experiments conducted in this study. Two different sets of experiments were performed. The first set was a series of CO_2-oil extraction experiments in which hydrocarbons were extracted from crude oils using high pressure CO_2. The second set of experiment was a series of displacement tests using a slim tube apparatus for comparison with results obtained from the extraction experiments.

3. 1 CO_2-Oil Extraction Experiment

Two series of CO_2-oil extraction experiments were performed. The first series of experiments was conducted to examine the effect of pressure, temperature and crude oil composition on CO_2-oil extraction performance. The second series of tests was performed to study the performance of a CO_2-oil extraction system in an extended extraction time.

The experiment was performed using an extraction apparatus in which CO_2 was continuously injected through a column of oil while the upper phase or the CO_2-rich phase with extraction product was continuously produced. The performances of the extraction systems were evaluated from the measured extraction efficiency, upper phase density and produced oil composition. A detailed description of the apparatus and procedure used for a typical displacement run are described in the following subsections.

3.1.1 Extraction Apparatus

The extraction apparatus used in this study consisted of an extraction vessel, a CO_2 injection system, a recycling pump and a fluid condenser. The schematic diagram of the

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extraction apparatus used in this study is presented in Figure 3.1. Excluding the recycling

pump and the condenser, the apparatus was enclosed in a temperature-controlled air bath.
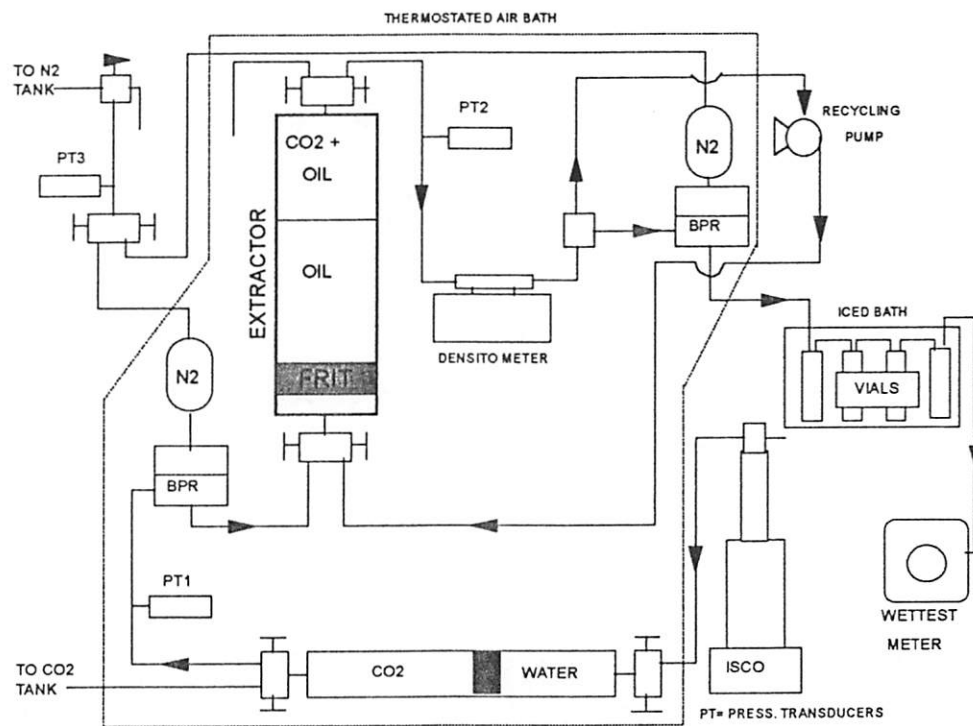
Figure 3.1 Schematic Diagram of the Extraction Apparatus

The extraction vessel is a constant-volume variable-composition blind mixing cell

operated on continuous injection/production basis. The vessel, made by TEMCO and rated at

5000 psig working pressure, was a stainless steel cylinder 6.7 cm in inner diameter and 50 cm

long with a total holding capacity of 1.15 liters. The inlet and outlet ports of this vertically

mounted vessel were located at the bottom and top of the vessel, respectively. The inlet port

was equipped with a 9-mm thick disc-shaped sintered-steel (frit) used to disperse the injected

CO_2 and insure small bubble generation. The frit was inserted at a step in the bore, sealed with an "O" ring and seated by the bottom of the vessel.

The CO_2 injection system consisted of a WELKER 500-cm^3 sliding piston accumulator and an ISCO 375-cm^3 constant rate metering pump. The pressures of the system were controlled using two diaphragm back pressure regulators (BPR), pressure rated at 5000 psig. The first BPR, installed between the extraction vessel and the CO_2 accumulator, was used to control the CO_2 injection pressure. The second BPR, installed at the system outlet, was used to control the pressure at the extraction vessel.

Produced gas leaving the condenser was routed to pass through a wet test meter for a gas rate measurement. The wet test meter was equipped with a strip chart recorder. The system pressures were measured using SENSOTEC (0-2000, ±1 psia) pressure transducers. The density of the exit stream was measured using a high pressure high temperature Paar-Mettler (±0.001 g/cm^3) densitometer installed between the vessel and the second BPR. The connecting lines of the extraction apparatus components were 1/8"-OD high pressure stainless tubing, except for those used at the low pressure condenser which were 1/8"-OD Teflon tubing.

3.1.2 Experimental Procedure for CO_2-Oil Extraction

In the first series of experiments two different oil samples were used, i.e., stock tank oil from the Sulimar Queen field and separator oil from the Spraberry field. Each oil sample was run at a constant temperature of either 95 or 138 °F. The extraction pressures for a particular oil and running temperature were varied between 1000 and 1900 psig. For each

extraction pressure, the mass and volume of produced oils, volume of produced gas, volume of the injected CO_2 and the density of the exit stream were recorded. Throughout the remainder of the report this first series of extraction experiment is referred to as the variable pressure extraction experiments. The matrix of the experiments is presented in Table 3.1.

Table 3.1. Variable Pressure Extraction Experiment Matrix

Oil Sample	Temperature, °F	Pressure, psig
Spraberry Separator Oil	95	1040, 1050, 1100, 1200, 1400, 1600
	138	1200, 1400, 1500, 1550, 1600, 1700, 1800, 1900
Sulimar Queen Stock Tank Oil	95	1000, 1050, 1065, 1075, 1080, 1100, 1200, 1300, 1400, 1600
	138	1200, 1400, 1450, 1500, 1550, 1600, 1650, 1700, 1800, 1900

In the second series of experiment, which was performed to investigate the behavior of CO_2 extraction over an extended period, the Sulimar Queen oil sample was extracted at the constant pressure of 1200 psig and temperature of 95 °F for a total of 103 hours, during which a total of around 7800 grams of CO_2 was injected into the extraction vessel. This series of experiment is designated as the extended extraction experiment.

The following is a description of procedures used in the extraction experiment. The procedures are divided into three main procedures: oil loading procedure, CO_2 loading

procedure and CO_2 injection procedure. Each of these procedures is basically the same for the variable pressure and extended extraction experiments except for CO_2 injection procedure which, as described later, was slightly different.

A. Oil Loading

Following Grigg *et al.*[64] who produced coreflood transition zones externally using a system similar to that used in this study, the volume of oil loaded into the extraction vessel was 500 cm^3, which was less than one half of the vessel total volume. This was done because the CO_2 swells the oil and sufficient space must be left to prevent the lower phase from being produced with the upper phase production. For Sulimar Queen stock tank oil, the sample loading was performed simply by pouring 500-cm^3 oil sample through the top opening of the extraction vessel. The samples were weighed using laboratory balance before use. For Spraberry oil, a slightly different loading procedure was used because the oil was sampled from a separator at the field and still contained some solution gases. The sample label indicated that the oil was sampled at 36 psig, 72 °F. To avoid solution gas liberation the Spraberry oil sample was transferred from the sample cylinder to the extraction vessel at 100 psig, and at room temperature of around 75 °F. This was achieved by first connecting the top opening of the extraction vessel to the top opening of the oil sample cylinder using 1/8"-OD stainless steel tubing. While keeping the connection closed, the extraction vessel was then pressurized with CO_2 up to 100 psig. By using an ISCO metering pump, distilled water was then injected into the bottom end of the sample cylinder to increase the oil pressure to around 150 psig. Oil transfer was then performed by carefully opening the connection between the

vessel and the sample cylinder while maintaining the system pressure at around 100 psig by continuously injecting water into the cylinder. The water injection continued until 500 cm^3 oil had been transferred into the extraction vessel.

B. CO_2 Loading

To obtain high pressure CO_2 in the accumulator, CO_2 loading was performed at a low temperature by cooling (icing) the accumulator and simultaneously allowing CO_2 to flow from the CO_2 tank to the accumulator. As the temperature of the apparatus was brought to the running temperature, the CO_2 pressure in the accumulator increased accordingly. To obtain around 2000 psig CO_2 in the accumulator at 95 °F, the accumulator was cooled for around one hour. To achieve the same CO_2 pressure but at 138 °F, the accumulator was cooled for around 30 minutes. To avoid contamination of the CO_2, prior to the CO_2 transfer operation the accumulator was evacuated using a vacuum pump.

C. CO_2 Injection

CO_2 was injected into the extraction vessel for two different purposes. First, which was the primary purpose of the injection, was to allow the CO_2 to mix with and extract hydrocarbons from the oil continuously at a constant pressure. The other purpose of the CO_2 injection was to increase the pressure of the extraction vessel. It should be noted that the extraction vessel was a constant-volume cell, and therefore, for a constant temperature system, the pressure of the vessel can only be changed by altering the amount of substance in the vessel.

Prior to injecting CO_2 into the vessel, the dome pressure of the second BPR was set to 10-20 psig above the desired extraction pressure and the system was then brought to the desired extraction temperature. Usually it took about four hours to obtain system temperature equilibrium. High pressure CO_2, usually around 2000 psig, was injected into the extraction vessel to increase the pressure of the vessel from the initial pressure of the vessel to the desired extraction pressure. For Sulimar Queen stock tank oil samples, the initial pressure was at the atmospheric pressure and for Spraberry separator oil samples, it was around 100 psig. Until the vessel pressure reached the desired extraction pressure, no fluid was produced from the vessel; the accumulation of CO_2 in the vessel caused the pressure of the mixture to increase. In all runs the CO_2 mass injection rate during extraction stages was around 40 grams per hour.

To achieve faster equilibrium of the mixture, fluid from the upper phase of the mixture was recycled through the inlet port of the extraction vessel using a recycling pump. The mixture was considered in equilibrium when the vessel pressure remained constant for at least five minutes after CO_2 injection was stopped. Then, when the vessel reached the desired extraction pressure the BPR dome pressure was lowered until the upper phase of the CO_2-oil mixture started to flow into the condenser. At this stage a constant pressure and continuous extraction process was considered to be at its starting point.

The phases of the produced fluids were separated in the condenser at atmospheric pressure. The gas leaving the condenser was routed to pass through a wet test meter for produced-gas volume measurement. CO_2 injection and upper phase fluids production continued until the volume of the liquids collected at the vials had reached about 3 cm^3. The

extraction process was then terminated by stopping the CO_2 injection and the vials were removed from the condenser for produced oil mass determination and compositional analysis.

After increasing the BPR dome pressure to the next desired extraction pressure and replacing new vials into the condenser, the experiment was continued by injecting CO_2 into the vessel. As in the previous experiment stages, CO_2 was injected first to increase the vessel pressure and later to extract hydrocarbons from the oil left in the vessel. For one set of experiments, i.e., one oil sample for a given temperature, the above described extraction procedures were carried out for at least six different extraction pressures. Because for one set of experiments the six extraction tests were carried out consecutively (without renewing the oil sample), the extractions were actually performed using oil sample with different depletion level. The extraction at the first pressure used fresh oil sample and the sixth test used oil sample with about 3 vol.% depletion (3 cm^3 production in each of the previous 5 extraction tests). From several extraction trial runs it was found that oil depletion of up to around 10 vol.% did not affect the extraction performance significantly. Therefore, in this study it was assumed that the behavior of CO_2 extraction using oil sample with depletion level of up to around 10 vol.% would be similar to that using fresh oil. Since the CO_2 accumulator could only inject 400 cm^3 at one time, the experiment was interrupted several time for CO_2 reloadings. After the completion of each run the system was depressurized and the amount of the remaining oil was determined.

To investigate the behavior of CO_2 extraction over an extended period, the Sulimar Queen sample was extracted at constant pressure of 1200 psig and 95 °F for a total of 103 hours, during which a total of around 7800 grams of CO_2 was injected. The 1200 psig

extraction pressure was selected from a series of extraction experiment with varying pressure conducted prior to the extended run, from which it was found that for Sulimar Queen oil extraction at 95 °F, reasonably good recovery rates were obtained when the extraction pressures were at and above 1200 psig.

Unlike the runs for investigating the effect of pressure on the extractive capacity of CO_2 where the produced oils sampling were done on the basis of the volume of oil collected, in this extended run the oil sampling was done on an equal time interval basis. However, as the extraction rate during the course of the extended extraction experiment decreased with time, the interval of the produced oil sampling was adjusted so that in each interval the amount of oil condensed in the vials was sufficient for oil compositional analysis. During the early hours of the experiment, the sampling interval was fifteen minutes. As the test proceeded and production decreased the sampling intervals were increased from fifteen minutes to 30, then 60, and finally up to four hours before the test was terminated. Since the CO_2 accumulator could only inject 400 cm^3 at one time, the experiment was interrupted several times for CO_2 reloading.

3. 2 Slim Tube Displacement Experiment

For comparison with results obtained from the extraction experiments, four series of slim tube displacement tests were performed to determine the MMP of CO_2 with the oils tested in the extraction experiment. The tests were conducted at the same temperature and pressure ranges as in the extraction experiments. A detailed description of the apparatus and procedure used for a typical displacement run are described in the following subsections.

3.2.1 Slim Tube Apparatus

The slim tube apparatus used in this study consisted of a slim tube, oil sample and CO_2 injection systems, and graduated vials. Excluding the vials this apparatus was enclosed in a temperature-controlled air bath. Figure 3.2 is a schematic representation of the slim tube apparatus used in this study.

The center piece of the apparatus was the slim tube. It was a 0.635 cm-ID stainless steel tube packed with 170- to 200-mesh glass beads. The 12.2-m long tube was made from two sections of 11.1-m tube each. The packed tubes were coupled and rolled into an approximately 25-cm coil. It had 120 ml total pore volume and 9700 md permeability as calculated from acetone displacement data. The coiled tube was mounted vertically for downward displacement; CO_2 was injected into the top and fluids were produced from the bottom of the coiled tube.

The inlet side of the slim tube was connected to two WELKER 1000-cm^3 sliding piston accumulators by means of a three-way valve. The first accumulator was used to store and load oil samples into the slim tube while the second accumulator was used to store and inject CO_2 into the slim tube. The two accumulators were connected to a 375-cm^3 ISCO constant rate metering pump by means of a three-way valve. Distilled water was used as the working fluid of the pump-accumulators systems. Between the slim tube and the CO_2 accumulator, a TEMCO diaphragm back pressure regulator was installed to maintain the pressure of CO_2 in the accumulator at the desired injection pressure. In such a set up, it was possible, therefore, to perform CO_2 displacement experiments at constant CO_2 mass rates.
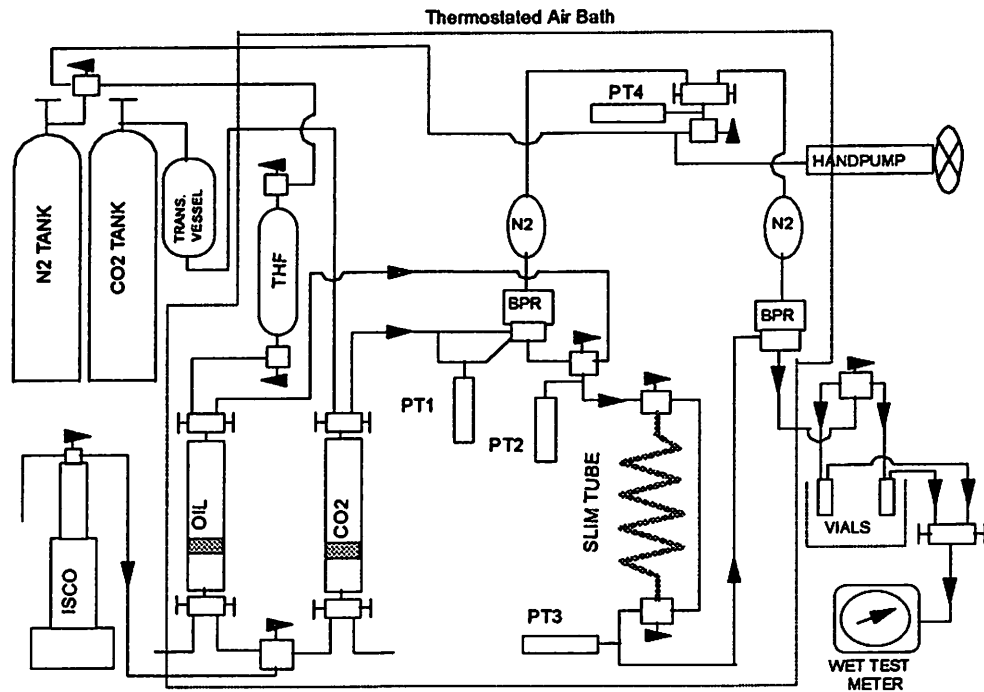
Figure 3.2 Schematic Diagram of the Slim Tube Apparatus

A second BPR was installed at the tube outlet to control the fluid pressures in the slim tube. Unlike conventional slim tube experiments, where the displacement pressures refer to that at the tube outlet, in this study the displacement pressures refer to the pressure at the tube inlet. This procedure is considered more appropriate since the system pressure inlet is more representative of the pressure at the injection front. This is because the pressure drops between the inlet pressure and the injection front is considerably less than that between the injection front and the tube outlet. This is particularly true when the displacement was in its early stage where the space between the tube inlet and the injection front was filled with less viscous CO_2 while the space between the front and the tube outlet was filled with oil.

The displaced fluids were collected and measured using 15-cm^3 vials stored in an ice-cooled thermos. The gas phase leaving the vials was routed to pass through a wet test meter to measure gas production. The wet test meter was equipped with a strip chart recorder to record the gas production profile during displacement runs.

Five SENSOTEC pressure transducers were used to monitor the pressures of the system at different locations namely, the oil sample in the accumulator, the injected CO_2, the fluids at the inlet and outlet of the tube and, the nitrogen gas in the domes of the BPRs. All components of the slim tube apparatus were coupled using 1/8"-OD high pressure stainless tubing, except for those installed after the second (outlet) BPR which were connected using 1/8"-OD Teflon tubing.

3.2.2 Experimental Procedures for Slim Tube Displacement

The following is a description of the procedure used in the slim tube displacement tests. For purposes of description the procedures may be divided into three main procedures: CO_2 loading procedures, oil transfer procedures and CO_2 displacement procedures. Excluding the oil sample transfer procedures which were dependent on the type of oil sample, the other procedures are the same for all runs.

A. CO_2 Loading

The procedure used in the loading of CO_2 into the accumulator was basically the same as that used in the previously described CO_2 loading at the extraction experiment. However, instead of cooling the accumulator directly, in this slim tube experiment the cooling was done at a CO_2 transfer vessel which was placed between the CO_2 bottle and the CO_2 accumulator.

During the CO_2 transfer the connection between the accumulator and the transfer vessel was open to each other so that the accumulator was also cooled by the cold CO_2 vapor coming from the transfer vessel. When the vessel and accumulator heated up to atmospheric temperature, the pressure of the CO_2 in both containers increased accordingly. When the apparatus temperature was increased from room to operating temperature the CO_2 pressure increased further. If a higher CO_2 pressure was required, water was injected to advance the water-driven slipping piston of the accumulator to compress the CO_2.

B. Oil Transfer

There were two steps involved in oil sample transfer operations. The first step was to transfer oil from oil sample bottles into the oil accumulator. The second step was to transfer oil from the oil accumulator into the slim tube. The procedures used in these operations depend on the type of oil sample. When Sulimar Queen stock tank oil samples were used, the oil transfers were carried out by first evacuating the air from the accumulator by means of a vacuum pump and then continued by syphoning oil sample from the sample container into the accumulator. In this procedure the floating piston was located at about the bottom part of the accumulator. The saturation of the slim tube was done by first evacuating the air from the tube and then followed by pumping oil from the oil accumulator into the tube.

When Spraberry separator oil samples were used, the oil transfers were performed at around 150 psig. This was done to avoid gas liberation from the oil sample. The transfer of oil from the oil sample bottle to the oil accumulator was done by first placing the slipping piston at the top end of the accumulator and then followed by displacing the oil from the

sample cylinder into the accumulator while at the same time slowly bleeding the water beneath the piston. The pressurized oil sample entering from the top end of the accumulator advanced the slipping piston, which in turn displaced the water beneath the piston. By adjusting the oil displacement and water bleeding rates, the pressure of the oil during the transfer process could be maintained at the desired level. The slim tube saturation for this oil was done by first saturating and pressurizing the tube with n-decane up to 150 psig, and then the oil sample, which was stored in the accumulator at 500 psig, was allowed to displace the n-decane out of the tube. Constant gas production rate after the solution gas breakthrough was used as an indicator of complete displacement of the decane. For both types of oil samples, the slim tube saturation continued until about 1.5 pore volume (PV) of oil was transferred into the tube. The tube was then pressured up further to the desired displacement pressure.

C. CO_2 Displacement

Prior to running the oil displacement, CO_2 and the oil to be tested were both brought to the desired running pressure and temperature. Before beginning CO_2 injection, the oil was displaced through the tube at the desired flow rate, which was 30 cm³/hour for all runs, to establish a pressure gradient across the tube. By controlling the outlet pressure using the second BPR, the pressure at the tube inlet was brought to the desired running pressure. When the pressure gradient was already established, the three-way valve at the tube inlet and that connecting the pump and accumulators were then immediately switched to the CO_2 accumulator and the displacement run began. During the course of the displacement the inlet fluid was maintained at constant pressure by adjusting the opening of the diaphragm of the

BPR installed at the outlet side of the tube.

During the displacement run the produced fluids collected in the vials and the system pressures and temperature were monitored and recorded every ten minutes. Started when the amount of the injected CO_2 approached 0.8 PV, the appearance of fluids leaving the second BPR were closely observed to determine the CO_2 breakthrough time. When a stock tank oil was used in the displacement test, the breakthrough time was indicated by the appearance of gas in the produced fluids. For a separator oil displacement, it was indicated by a sudden increase in the gas production rate. The displacement continued until no additional oil was produced. Typically, the total amount of CO_2 injected in one complete displacement run was at least 1.5 PV. After the completion of the experiment, the system was flushed with tetrahydrofuran (THF) to remove any remaining oil.

IV. Presentation and Discussion of Results

The results of the experiments conducted in this study are presented and discussed here. Two types of experiments were performed. They were CO_2-oil extraction and slim tube displacement experiments. The extraction and the slim tube experiments used two different oil samples, i.e., Sulimar Queen stock tank and Spraberry separator oils. In total, five series of extraction experiments were conducted. The first four extraction experiments, designated as variable pressure extraction experiments, were performed to investigate the effect of extraction pressure and temperature and oil composition on the capacity of CO_2 in extracting hydrocarbons from crude oils. The other extraction experiment was performed to investigate the performance of CO_2 oil extraction over an extended period of time. To compare with results obtained from the first four extraction experiments, four sets of slim tube displacement tests were conducted.

The results will show that, as expected, the extraction capacities of CO_2 increased with increasing pressure. In each extraction experiment it was found that there was a relatively small pressure range over which a sharp increase in the extraction capacity of CO_2 occurred, above which an additional increase of pressure did not significantly increase the extraction capacity. The effect of pressure on the density of CO_2-oil upper phase in a multi phase system is similar to that on extraction capacity. The density increases with increasing pressure and over a narrow pressure range the density drastically increases, above which an additional increase of pressure does not significantly increase the density. As expected, CO_2 extraction capacity was found to be a strong function of extraction temperature. It decreases

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with an increase of temperature. The pressure at which CO_2 starts to efficiently extract hydrocarbon from an oil increases with an increase of temperature. The presence of solution gas in the oils tested did not affect the CO_2-oil extraction performance. In an extended extraction test, CO_2 can extract approximately 43 wt.% or 48 vol.% of the original oil in place. The CO_2 extraction capacity decreased from around 0.3 g oil/g CO_2 injected at the beginning of the extraction to 0.005 g oil/g CO_2 injected at time of termination.

The results will also show that for all extraction runs the pressure range over which a sharp increase in both extraction capacity and upper phase density occur was in the proximity of the MMP determined from slim tube displacement tests for the CO_2-oil system. This indicates that both extraction capacity and upper phase density measurements appear to have promise to be used as a quick test of CO_2-oil MMP.

The details of the experiment results are presented and discussed in the following subsections. For practical purposes, results from the extraction experiments with variable pressure, temperature and oil composition and those from the slim tube displacement tests are presented and discussed together.

4.1 Effect of Pressure, Temperature and Oil Composition

To investigate the effect of extraction pressure, temperature and oil composition on the extractive capacity of CO_2, four variable pressure extraction experiments were carried out using two different oils, two experiments for each oil. Each oil was tested at a constant temperature of either 95 or 138 °F and at variable pressures of either 1000-1600 psig or 1200-1900 psig, respectively. In each test, 500-cm^3 oil sample was placed in the 1.15 liter

extraction vessel and CO_2 was injected at constant temperature and pressure and at a volumetric rate which gave a constant CO_2 mass injection rate of 38 g/hour. As an example, at 138 °F and 2000 psig the density of CO_2 was 0.562 g/cm^3 and the volumetric injection rate was 68 cm^3/hour. To investigate the effect of pressure, in each test, continuous CO_2 injections and CO_2-oil upper phase productions were performed at, at least, six different pressures. In most experiments the extraction pressures were increased for each test, therefore going from lower to higher pressures. To examine pressure-hysteresis, for some test runs the extraction pressures were changed from higher to lower pressures. The summary of the experimental data is presented in Tables A1-A4, Appendix A.

In this study, the parameter used to evaluate the performance of CO_2-oil extraction in terms of the capability of CO_2 to extract hydrocarbons from crude oils is called CO_2 extraction capacity. It is defined as the ratio of the mass of produced oil to the mass of CO_2 injected to produce that oil. Figures 4.1- 4.4. show the CO_2 extraction capacities as a function of pressure for four CO_2-oil extraction systems tested in this study. For comparison purposes, results of the slim tube displacement experiments, in terms of oil recovery at different displacement pressures, for the corresponding oil and running temperature are also presented in these figures. The summary of the slim tube displacement tests are presented in Tables C1 - C4, Appendix C.

From Figures 4.1-4.4 one can see that all runs have similar CO_2 extraction capacity vs. pressure profile. In each run, the CO_2 extraction capacity increases with increasing extraction pressure and with a drastic increase in extraction capacity over a relatively small pressure range. Then, at pressures above the drastic increase the extraction capacity becomes
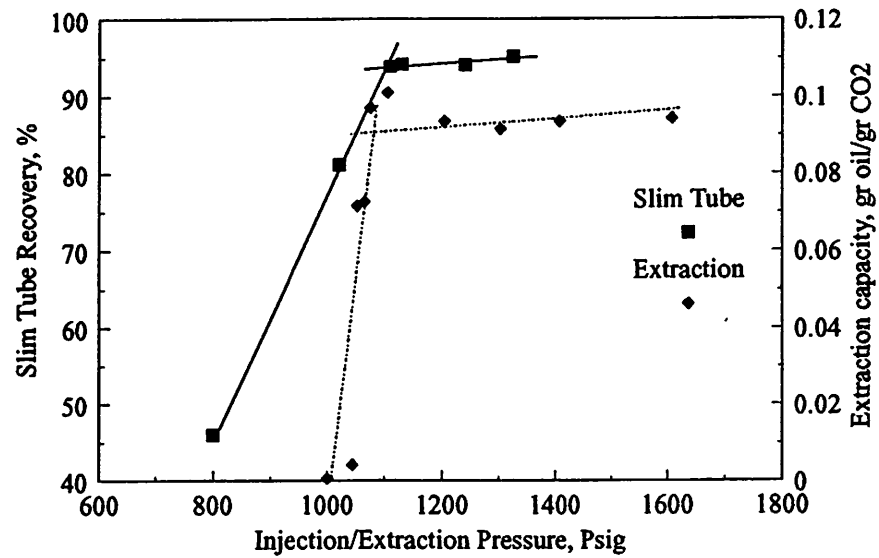
Figure 4.1 Extraction Capacity and Slim Tube Recovery as a
Function of Pressure for Sulimar Queen Oil at 95 °F
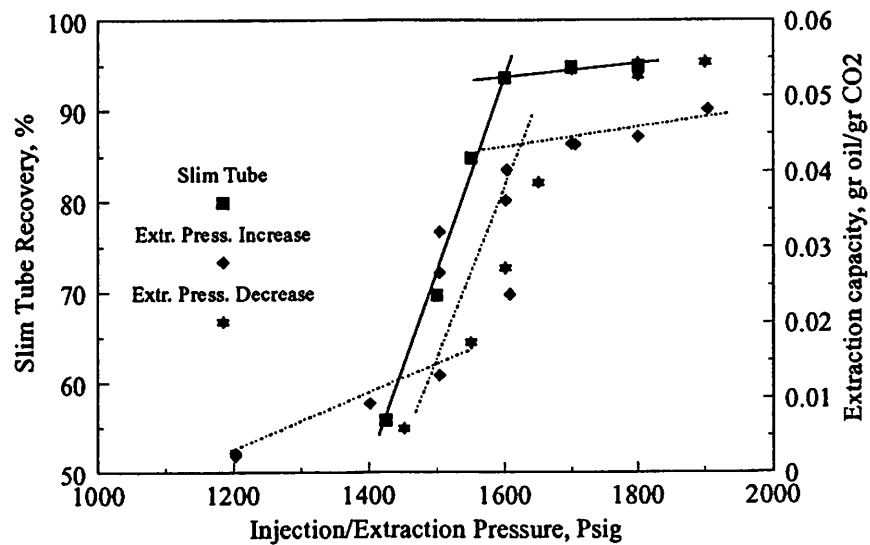
Figure 4.2 Extraction Capacity and Slim Tube Recovery as a
Function of Pressure for Sulimar Queen Oil 138 °F
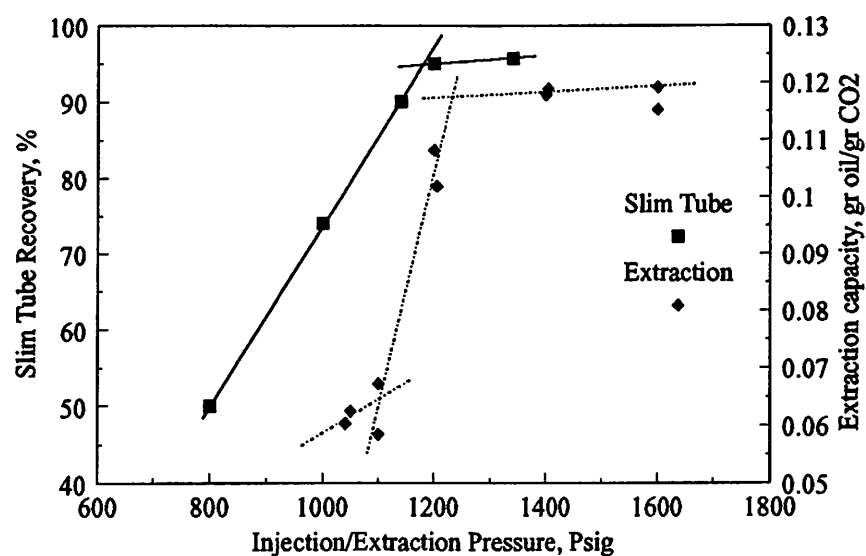
Figure 4.3 Extraction Capacity and Slim Tube Recovery as a
Function of Pressure for Spraberry Oil at 95 °F
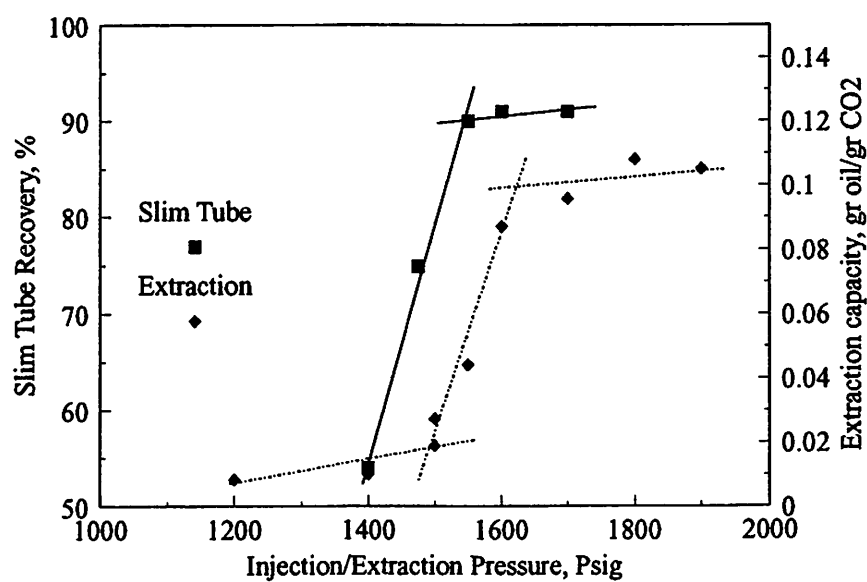
Figure 4.4 Extraction Capacity and Slim Tube Recovery as a
Function of Pressure for Spraberry Oil at 138 °F

relatively constant or with an insignificant increase with further increases of pressure. Comparing the extraction profiles and slim tube recovery profiles, which are also presented in Figures 4.1- 4.4, we see that the slim tube MMPs are in the proximity of the pressures at which the CO_2 extraction capacity either started to drastically increase with a small increase in pressure or had completed their greatest increases in the extraction profiles. In other words the slim tube MMPs are within a range of pressure where the extraction started and completed drastic increases in extraction capacity over a narrow pressure increase range. This range will be referred to as the critical extraction pressure range with its lower and upper limits correspond to pressures when the drastic increase in extraction starts and ends, respectively. As an example, Figure 4.1 shows that the MMP of CO_2 with Sulimar Queen sample determined from slim tube displacement tests at 95°F was 1155 psig. For the same oil, at the same test temperature, the lower and upper limit of the extraction critical pressure ranges of the system are 1040 and 1115 psig, respectively. Table 4.1 lists the slim tube MMPs and the extraction critical pressure ranges of the four extraction experiment runs. In this study, as suggested by Johnson and Pollin,[41] a sharp break point in the slope of the recovery vs. pressure curve was used as the MMP criteria.

Table 4.1 Slim Tube MMP and Critical Extraction Pressure Ranges

Oil Sample	Temperature °F	Slim Tube MMP psig	Critical Ranges psig
Sulimar Queen Stock Tank Oil	95	1115	1040-1120
	138	1595	1520-1640
Spraberry Separator Oil	95	1190	1120-1220
	138	1540	1500-1640

While this extraction experiment cannot be used to determine a definite value of CO_2-oil MMP, the critical pressure ranges can be used as a rough CO_2-oil MMP estimate. Since the extraction experiment can be performed in about two days while slim tube displacement tests usually take two weeks, the former can be used as a tool to screen the displacement pressures that will be performed in slim tube tests.

The fact that CO_2 MMPs are always within the range of pressures where efficient CO_2-oil extraction started suggests that extraction is the process responsible in the development of CO_2-oil miscibility. This extraction experiment findings support the generally accepted CO_2-oil miscibility development mechanism, i.e., a vaporizing gas drives.

It is shown in Table 4.1 that the widths of critical pressure range for low-temperature extraction systems are narrower than that for high-temperature extraction systems. This is not surprising because CO_2 density, which is believed to be an essential factor in the CO_2-oil extraction, also behaves similarly. At pressures near to the CO_2 critical pressure, CO_2 density increases drastically over a small increase in pressure. At higher temperatures the CO_2 density increases more gradually with increasing pressure.

It is shown in Figures 4.1- 4.4 that the maximum extraction capacities obtained in these experiments are about the same for all runs, i.e., about 0.1 gram of oil per gram of CO_2 injected, except for Sulimar Queen samples at 138°F which, due to unknown reason, was only about one-half of the values obtained from the other three runs.

The Sulimar Queen sample extraction experiment at 138 °F was performed by increasing and decreasing the extraction pressures. From Figure 4.2 and Table 4.1 it is shown that by decreasing the extraction pressure the extraction capacities at some pressures were

slightly higher than that obtained at the same pressures performed by increasing the extraction pressures. However, at other pressures the opposite phenomena were observed. In this experiment the determinations of the extraction capacities of the system at some pressures were repeated at the same pressures two or three times. It was found that repeating the extraction measurement at one pressure did not always give the same extraction capacity values. The magnitudes of the differences of the extraction capacity values due to repeated measurement at one extraction pressure are similar to that obtained due to changing the direction of pressure change. Since these differences appear to be within the experimental accuracy, it is concluded that direction of pressure change does not affect the extraction performance. It might be of interest to note the performance of the CO_2-Sulimar Queen oil extraction at 138 °F shown in Figure 4.2. This experiment was performed without using a recycling pump. The figure shows that the CO_2 extraction capacity figures are more scattered than those found in the other three experiments which used a recycling pump. This is probably because extraction runs that used recycling pump achieved and maintained the system under equilibrium condition better than extraction runs that did not use a recycling pump.

The effect of extraction temperature on the CO_2 -oil extraction performance was evaluated by comparing the lower pressure limit of the critical pressure range of a given oil system extracted at a lower and higher extraction temperatures. The limit indicates the pressure at which the extraction capacity started to drastically increase versus a small pressure increase. Table 4.1 shows that for the Sulimar Queen oil ran at 95 °F, the lower pressure limit was 1040 psig while at 138 °F it was 1520 psig. For Spraberry oil, the lower pressure limits at 95 and 138 °F were 1120 psig and 1500 psig, respectively. These findings are in

agreement with the MMP results obtained from slim tube experiments which determined the

CO_2-oil system MMP at 95 °F to be lower than that at 138 °F. As shown in Table 4.2 the CO_2

-oil MMPs for Sulimar Queen oil at 95 and 138 °F were 1115 and 1495 psig, respectively

while for Spraberry oil they were 1190 and 1595 psig, respectively.

In this study, oil composition is delineated in terms of the mole fraction of the

component carbon number as determined from gas chromatographic analysis. The

compositions of the original oils used in these experiments are presented in Table 4.2 and

Figure 4.5. More details of the oils compositions data are given in Table B1, Appendix B.

Table 4.2 Oil Compositions of Sulimar Queen and Spraberry Oils

Components	Mole Fraction	
	Sulimar Queen	Spraberry
C_1		0.0211
C_2		0.0172
C_3		0.0351
C_4		0.0212
C_5-C_{10}	0.5477	0.5137
C_{11}-C_{20}	0.2660	0.2151
C_{21}-C_{30}	0.0856	0.0710
C_{30}-C_{36}	0.0326	0.0316
C_{37+}	0.0681	0.0740
Molecular Weight	194.8	180.9
API Gravity	40	38
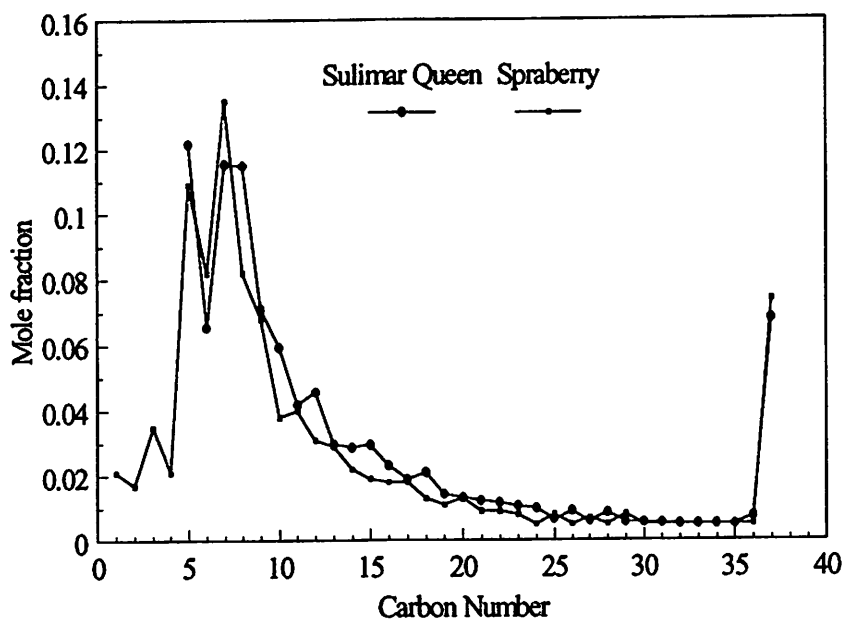
Figure 4.5 Composition of Sulimar Queen and Spraberry Oils

It can be seen from Table 4.2 and Figure 4.5 that the two oils have similar composition. The main difference between the two oils is that the Spraberry oil had 9.5 mole% of solution gas components. Table 4.2 also shows that the two oils also had a similar API gravity. Therefore, comparison of experiment results between the two oils to study the effect of oil composition on the CO_2-oil extraction performance was considered inappropriate. Instead, the experiment results of the two oils were compared to evaluate the effect of the presence of the solution gas in the oil on the extraction performance.

To examine the effect of the presence of solution gas in the oil on the performance of CO_2-oil extraction system, the lower pressure limit of extraction critical pressure ranges of the two oils extracted at the same running temperature were compared. It was found that at 95 °F, as well as at 138 °F, the lower pressure limits for the two oils were about the same. This indicates that the presence of solution gas in the oils used did not affect CO_2-oil extraction performance. However, two different trends were observed in the slim tube tests results. At 95 °F, the MMP of CO_2-oil system that had solution gas was around 50 psig higher than that of the CO_2-oil system with no solution gas. However, a similar magnitude of MMP difference but with opposite direction was found at the higher displacement temperature. It is worth noting that because of the limited data points and subjectivity factor in the determination of the break over point there is always uncertainty in slim tube MMPs. Due to this and due to a combined effect of the accuracy of the equipment and pressure fluctuation during slim tube experiments it is not uncommon that the uncertainty of slim tube MMPs is in the order of ± 25 psig. The differences between the CO_2 MMPs for the two oils that were tested at the same temperature were considered still within the accuracy of the slim tube MMP determination method. Therefore, it was concluded that the effect of the presence of solution gas in the oils used on CO_2 MMP was insignificant. This finding is in agreement with Holm and Josendal[34] who stated that CO_2-oil MMP does not depend on the C_2-C_4 fraction of the oil, but it contradicts Silva and Orr[24] who concluded that C_2-C_4 can improve CO_2-oil MMP development although the CO_2-oil system may develop miscibility without the presence of a C_2-C_4 fractions.

The compositions of the produced oils and extraction residue collected from each test were determined from gas chromatographic (GC) analysis. The results of the analysis of the produced oils for the four extraction experiments are presented in Figures 4.6-4.9. The details of the produced oils compositions data are given in Tables B2 - B5, Appendix B. The C_{37+} fraction was excluded from the composition distribution because it was realized that the accuracy of GC analysis in determining C_{37+} fraction is low. It is worth noting that in GC analysis all errors that occur in the C_1 through C_{36} fractions are lumped and added into the C_{37+} fraction. From Figures 4.6-4.9 we can see that the compositions of the produced oils are similar. It is surprising that the light ends in the produced oils obtained from all runs were small while the original oil samples were high in light ends content and it was reported that smaller hydrocarbon molecules are easier to extract than larger ones.[24] This occurred because, as shown later in the extraction residues analysis, most of the extracted light ends were not condensed in the condenser.

Figures 4.10 and 4.11 show the moles of components of both the original oil and oil left in the extraction vessel or residues collected after each test for the two oil samples. These figures indicate the types of hydrocarbons that were stripped the most by CO_2. As can be seen from both figures that for all runs CO_2 extracted mostly light ends up to around C_{20}. The figures also show that a large portion of the light ends was extracted by CO_2. The fact that C_5 concentration in produced oils are low suggests that this component was not captured by the condenser. As shown later in the extended extraction experiment results discussion the components that were not captured were C_5 through C_8 fractions.
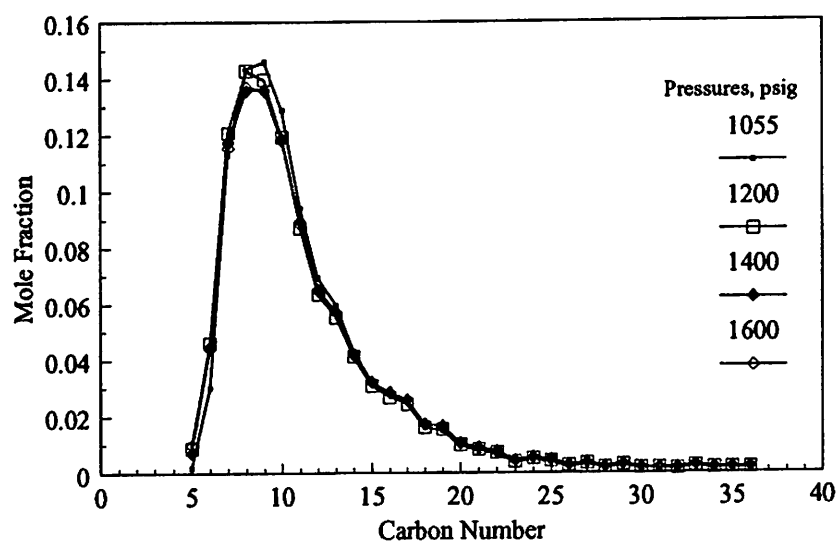
Figure 4.6 Compositions of Produced Oils at Different Extraction
Pressure for Sulimar Queen Oil at 95 °F
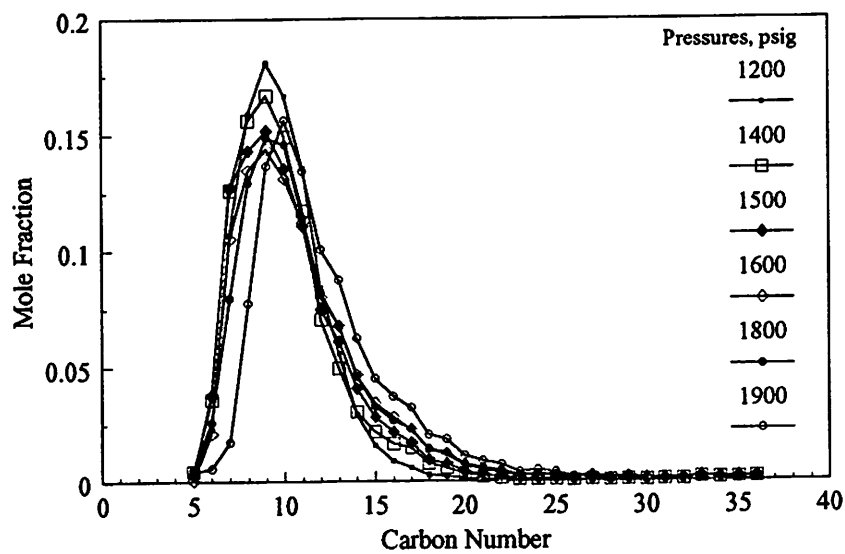
Figure 4.7 Compositions of Produced Oils at Different Extraction
Pressure for Sulimar Queen Oil at 138 °F
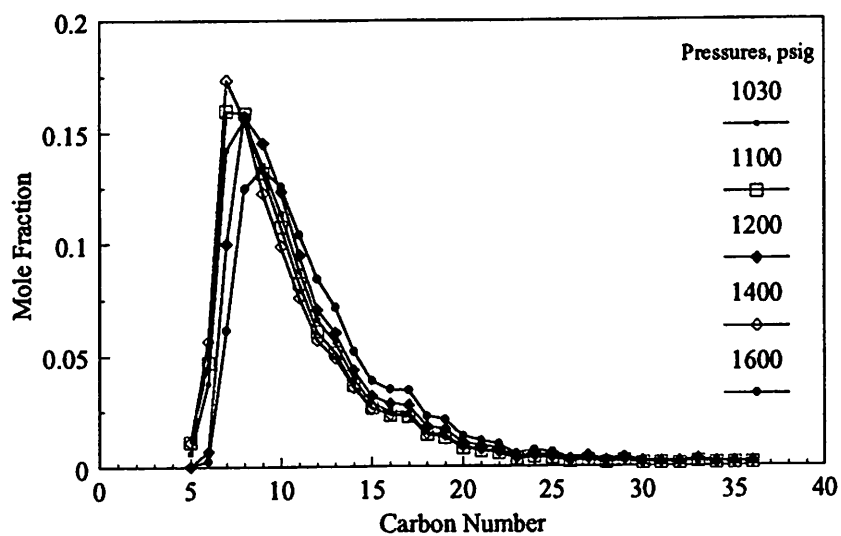
Figure 4.8 Compositions of Produced Oils at Different Extraction
Pressure for Spraberry Oil at 95 °F
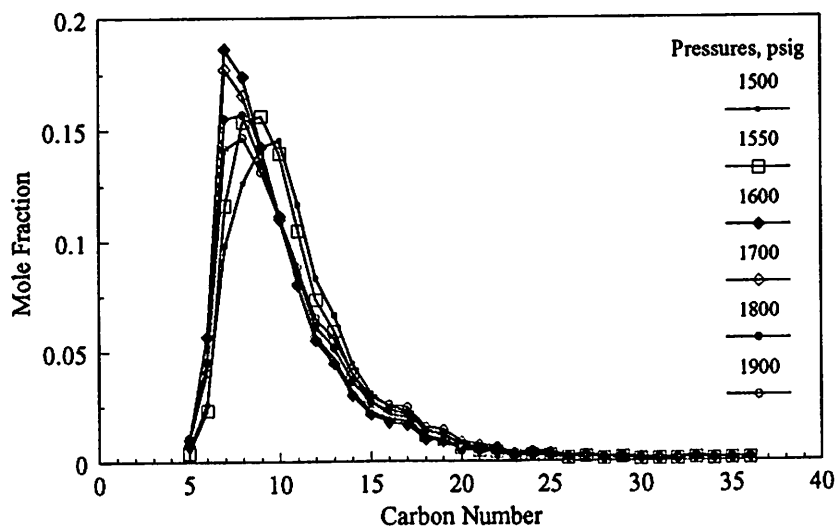
Figure 4.9 Compositions of Produced Oils at Different Extraction
Pressure for Spraberry Oil at 138 °F
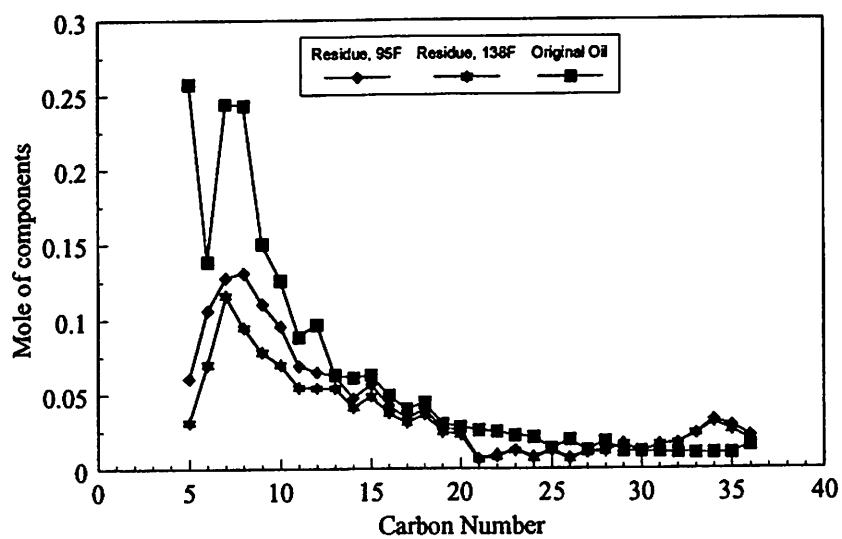
Figure 4.10 Moles of Original Oil and Extraction Residues
for Sulimar Queen Oil at 95 and 138 °F
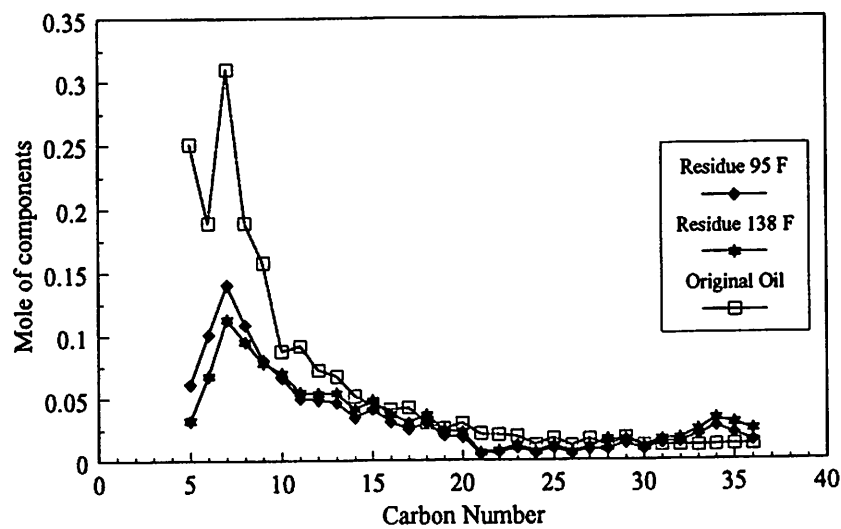
Figure 4.11 Moles of Original Oil and Extraction Residues
for Spraberry Oil at 95 and 138 °F

To accommodate this loss the composition of the produced oils and residues were normalized by removing the C_5-C_8 from the compositions. To reflect the extent of extraction in each extraction pressure, the oil composition was normalized by the amount of oil produced per unit of CO_2 injected at the corresponding extraction pressure. This was performed by multiplying the mole fraction of each component by moles of produced oil per mole CO_2 injected. Therefore, instead of mole fractions, the oil composition is expressed in terms of moles of component produced per moles of CO_2 injected. The normalized compositions of produced oils for the four extraction experiments are presented in Figures 4.12-4.15. It can be seen from the figures that the higher the extraction pressure the higher the values of the moles of component per moles of CO_2 injected. This is not surprising because the compositions of produced oils are relatively the same for all runs but the extraction capacities are higher at higher extraction pressures.

The normalized mole balance between the original oils and the corresponding extraction residues are presented in Figures 4.16 and 4.17. As can be seen from both figures, that for all runs CO_2 extracted mostly light ends up to around C_{20}. The figures show that there is a hump in the C_{30}-C_{36} moles in each extraction residues such that the moles of these fractions are higher than the original oils. This occurred probably because of the GC which is usually less accurate in the analysis of heavy fractions.

The average molecular weights of the produced oils, calculated from oil composition data, range between 145 and 177 g/mole which are smaller than that of the original oils which are both 180 g/mole. As expected the molecular weights of the extraction residues of all runs are higher than that of the original oils because CO_2 preferentially extract light and
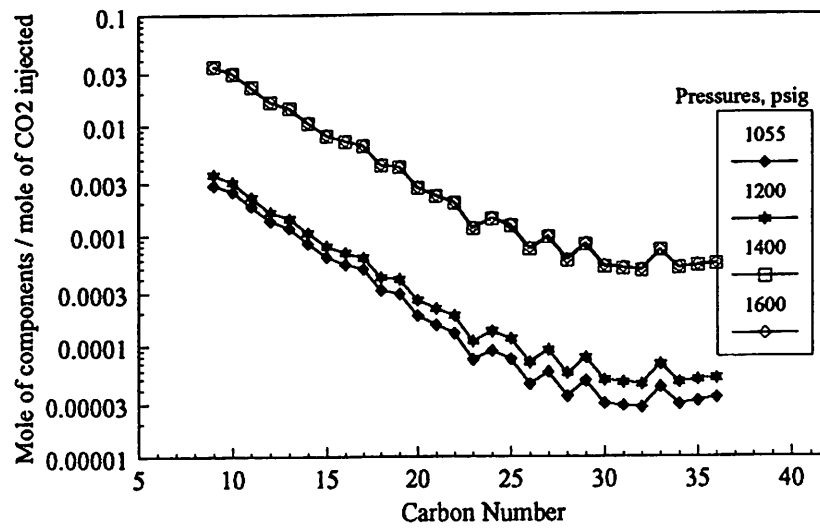
Figure 4.12 Normalized Produced Oils Compositions at Different Extraction Pressures for Sulimar Queen Oil at 95 °F
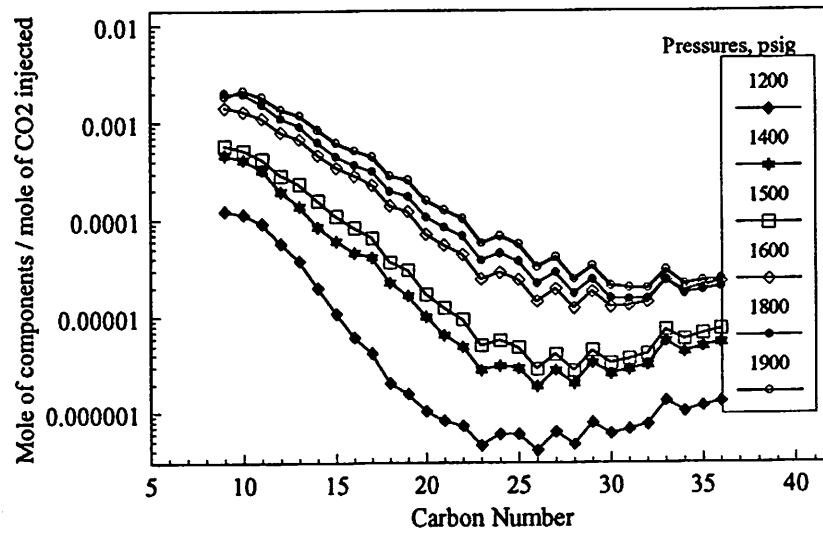
Figure 4.13 Normalized Produced Oils Compositions at Different Extraction Pressures for Sulimar Queen Oil at 138 °F
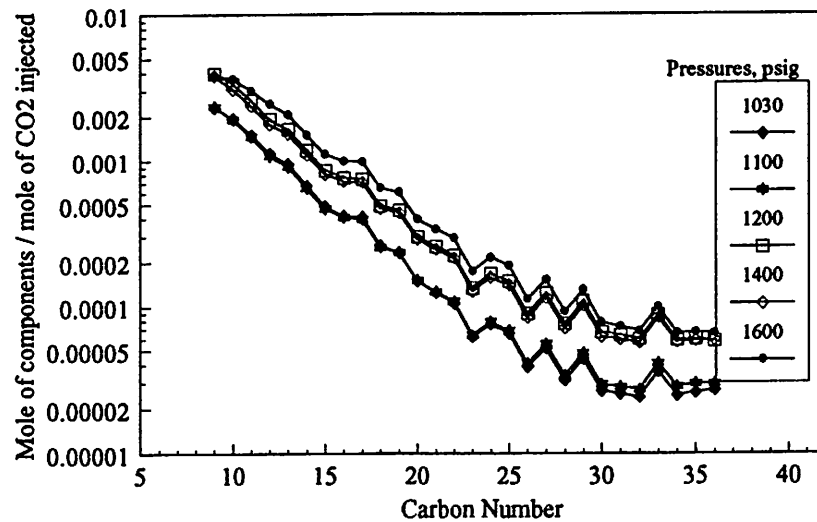
Figure 4.14 Normalized Produced Oils Compositions at Different
Extraction Pressures for Spraberry Oil at 95 °F
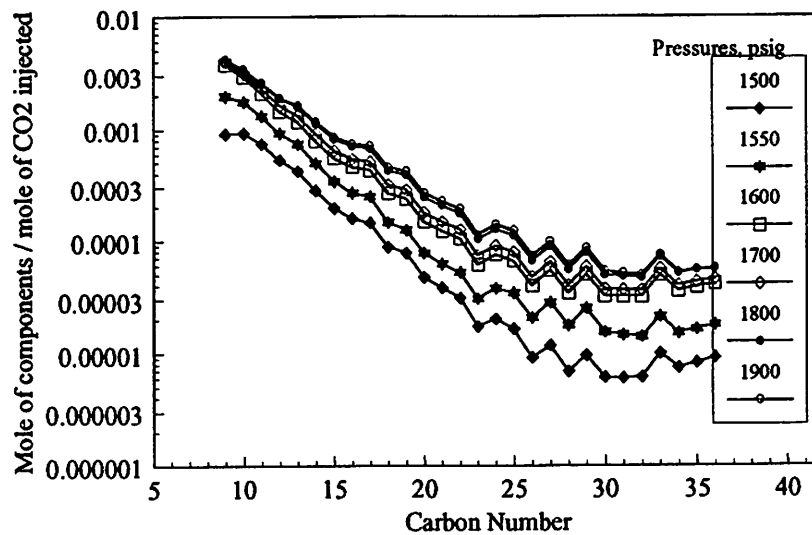
Figure 4.15 Normalized Produced Oils Compositions at Different
Extraction Pressures for Spraberry Oil at 138 °F
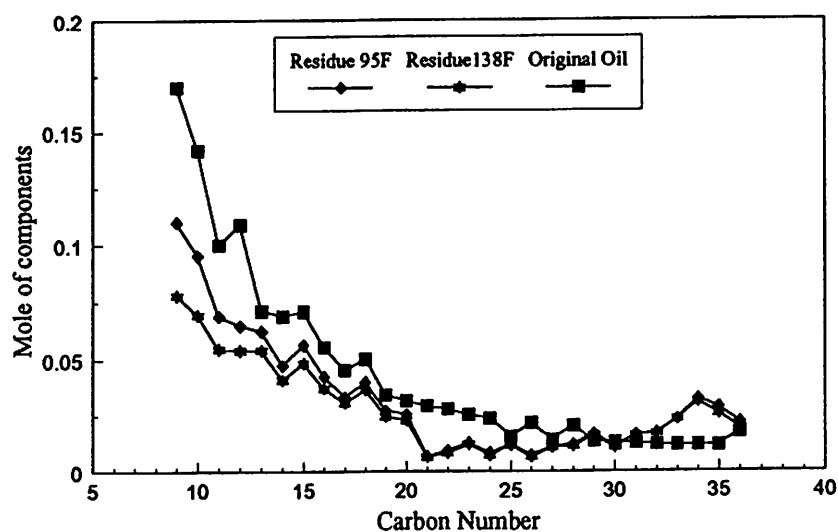
Figure 4.16 Normalized Moles of Original Oil and Extraction
Residues for Sulimar Queen Oil at 95 and 138 °F
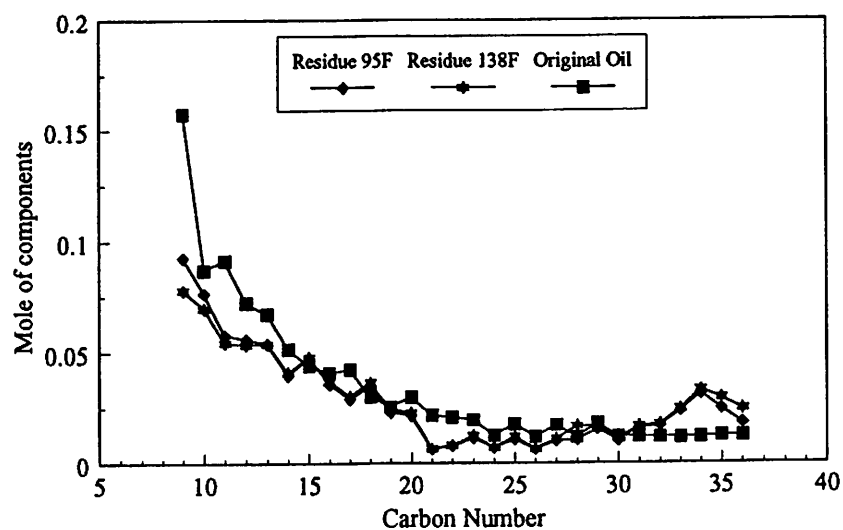
Figure 4.17 Normalized Moles of Original Oil and Extraction
Residues for Spraberry Oil at 95 and 138 °F

intermediate fractions of the oils. They are in the range of between 238 and 271 g/mole. The details of the extraction residues compositions data are given in Table B6, Appendix B.

From CO_2 injection calculations for each run it was found that CO_2 started to significantly extract hydrocarbons when its mole percentage reached around 72% to 77%. Maximum extractions took place when the mole percents of CO_2 were in the range of between 80% and 87%. These figures are in agreement with Alsinbili[9] who reported that in order to produce some recoverable oils the injected CO_2 has to be more than 80 mole percent of global composition.

During the course of each extraction run the densities of the upper or produced phase of the CO_2-oil mixture were measured using a Mettler-Paar densitometer. The results of the density measurements as a function of vessel pressure for the four extraction runs are presented in Figures 4.18-4.21. For discussion purposes, the slim tube MMP and the extraction capacity of the corresponding extraction runs are also presented in these figures.

As can be seen from the figures that the extraction started to occur when the upper phase densities were around 0.4 g/cm^3. For the 95 °F extractions, maximum extractions occurred when the upper phase densities were around 0.8 g/cm^3. For the 138 °F extractions, it took place when the upper phase densities were slightly lower, i.e., around 0.7 g/cm^3. This is probably because at elevated temperatures oils have lower densities and, therefore, as shown by Lange,[65] they have lower Hildebrand solubility parameters and need lower CO_2 density to dissolve. In order to have a soluble CO_2-oil mixture, the solubility parameter of CO_2 has to be increased to approach the solubility parameter value of the oil by way of increasing the CO_2 density. This is so because two compounds will dissolve into each other
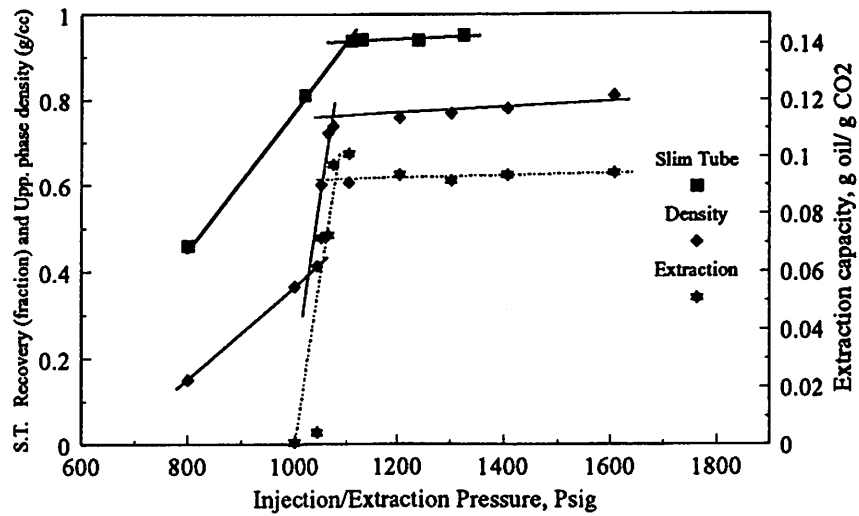
Figure 4.18 Upper Phase Density, Slim Tube Recovery and Extraction Capacity
as a Function of Pressure for Sulimar Queen Oil at 95 °F
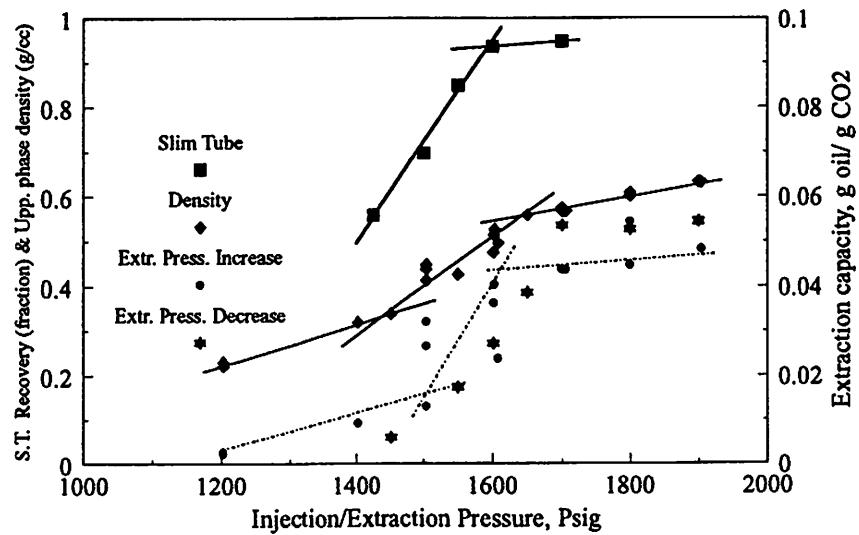
Figure 4.19 Upper Phase Density, Slim Tube Recovery and Extraction Capacity
as a Function of Pressure for Sulimar Queen Oil at 138 °F
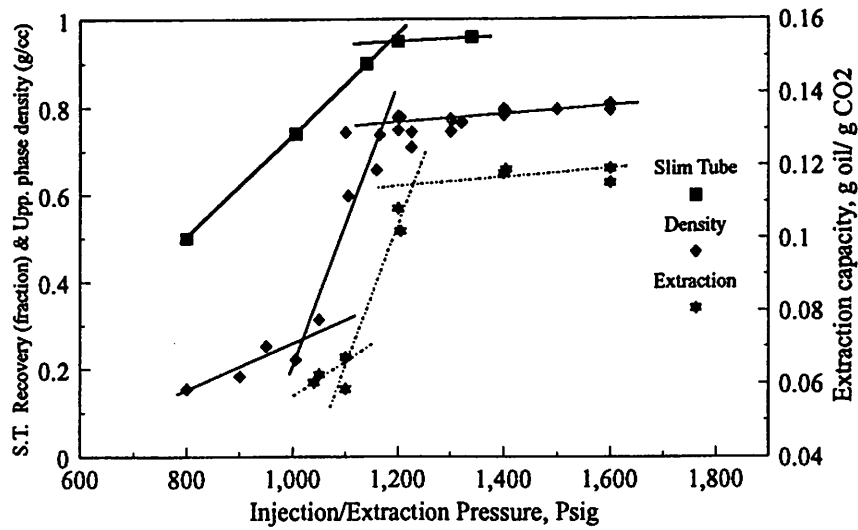
Figure 4.20 Upper Phase Density, Slim Tube Recovery and Extraction Capacity
as a Function of Pressure for Spraberry Oil at 95 °F
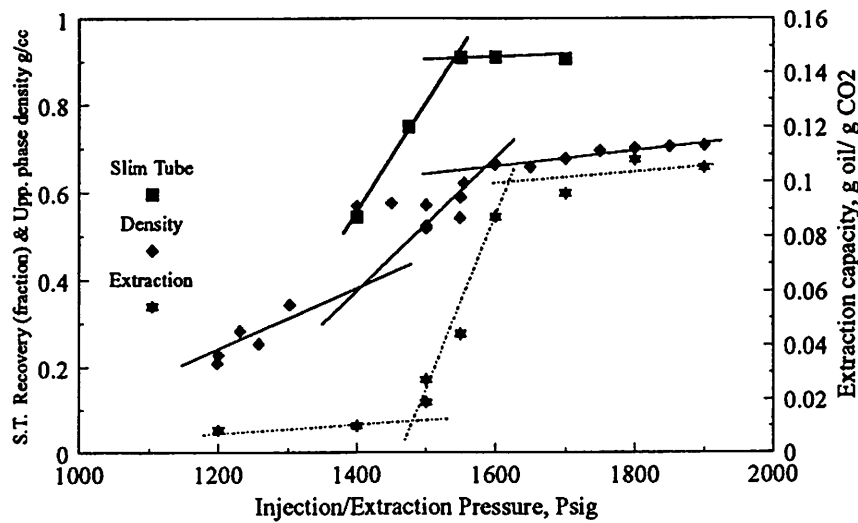
Figure 4.21 Upper Phase Density, Slim Tube Recovery and Extraction Capacity
as a Function of Pressure for Spraberry Oil at 138 °F

if the two compounds have similar solubility parameter values and the solubility parameter of a compound increase with increasing density. Since at higher temperatures the densities of oils are lower, and so are the oil's solubility parameter, a good match of solubility parameters between oil and CO_2 could be made at lower CO_2 density. Therefore, at 138 °F the upper phase densities of CO_2-oil mixture at which maximum CO_2 extraction capacity occur were lower than that at 95 °F.

Figures 4.18- 4.21 show that the shape of upper phase density vs. pressure profiles are similar to extraction capacity vs. pressure profiles. In each run, the density increased with increasing extraction vessel pressure and at a certain pressure it drastically increased with a small increase in pressure and then became relatively constant or insignificantly increased with further increases of pressure. The drastic increases in density, as in the case of extraction capacity, are in the proximity of the corresponding slim tube MMP. As also suggested by Harmon and Grigg,[49] these experimental results suggest that the upper phase density measurement can be used to estimate the MMP of CO_2 with an oil. As in the case of extraction capacity measurements, the MMP estimated from the upper phase density measurement can only be expressed as a range of pressure instead of one definite pressure as in slim tube tests.

It can be seen from Figures 4.18 and 4.20 that for low temperatures the pressures at which the density drastically increases over a narrow increase in pressures are as distinct as in the case of extraction capacity measurements. However, as shown in Figures 4.19 and 4.21, at higher temperatures these pressures are not as distinct as in the extraction capacity measurement. Therefore, the pressure ranges of MMP estimates from upper phase density

measurement at high temperatures are wider than that of extraction capacity measurements. Considering that upper phase density measurements are less time consuming than extraction capacity measurements, it is suggested that for low temperatures upper phase density measurements are sufficient for an MMP estimation. However, at higher temperatures the upper phase density measurement is not sufficient for MMP estimation and the extraction capacity measurement method is a more accurate method.

From material balance calculation for all runs it was found that oil loss during the experiments ranged between 8% and 14% of original oil in place, which were relatively high. This loss may be attributed to the above described unrecovered light ends fractions and also probably due to loss during material handling.

4.2 Extended Extraction Experiment

To examine the behavior of CO_2-oil extraction in an extended period of time, a 750-cm^3 (617 grams) Sulimar Queen oil sample was extracted for a total of 103 hours at constant pressure and temperature of 1200 psig and 95 °F, respectively. During the course of the experiment oil and gas production and the upper phase densities of the CO_2-oil mixture were monitored and recorded. A total of 91 produced oil samples were taken, some of the sample were analyzed by simulated distillation using gas chromatography to determine composition.

It was found from this experiment that from the 750 cm^3 (617 grams) original oil in place 361 cm^3 (266 grams) of liquid extracted by CO_2 was recovered in the condenser. This means that this type of extraction process could result in oil liquid recovery of 48% by volume or 43% by weight. The total amount of CO_2 that was injected to extract that amount of oil

was 7857 grams which means that, on average, 29 grams of CO_2 was required to extract each gram of oil. The weight of the extraction residue was 200 grams implying that the experiment had a mass loss of 24%. It is worth noting, however, that due to the difficulty in the handling of the residue, which was very thick, the accuracy of the weight determination of the residue was rather low. Also the C_5-C_{10} fraction had only 0.34 grams left in the residual oil, but only 46.6 grams was measured in the produced liquid. Thus 78 grams of the total 125 grams (in original oil) was produced with the CO_2 gas stream. If this amount is accounted, the corrected oil recovery is 56 % by weight. During the test the recirculation pump was not being used. The equilibrium might have occurred at a faster rate if equilibrium had been insured. The summary of the extended CO_2-oil extraction experimental data is presented in Table A5, Appendix A.

Figure 4.22 presents the extraction capacity of CO_2 as a function of extraction stage expressed in terms of the weight of the residual oil (left in the vessel) relative to the weight of original oil in place. The figure shows that, as expected, the extraction capacity of CO_2, i.e., grams of produced oil per gram of CO_2 injected, decreases with extraction stage (decreasing percent of residual oil). This was because as hydrocarbon extraction by CO_2 proceeded the amount of residual oil obviously decreased, especially the lighter components or CO_2 extractable components, and the injected CO_2 interacted with less and less oil. In addition, the injected CO_2 was not only spent for oil extraction processes but also was used to compensate pressure losses due to decreasing amount of oil in the vessel.
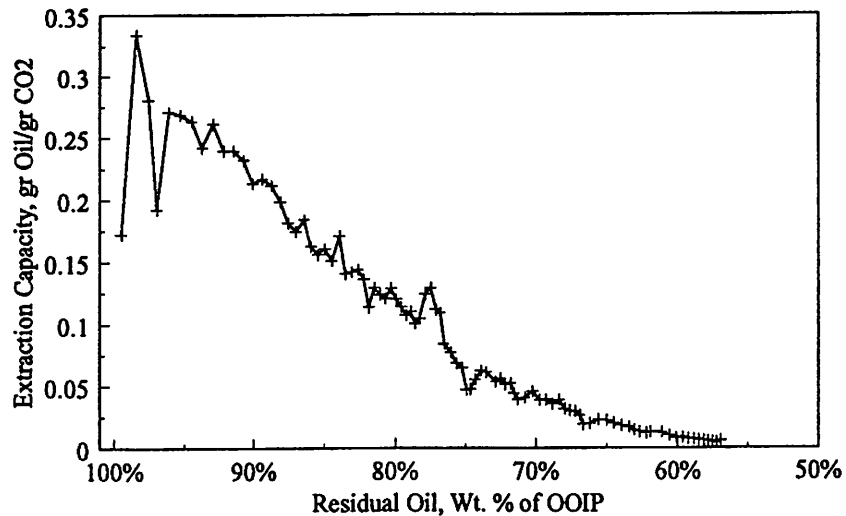
Figure 4.22 Extraction Capacity as a Function of Extraction
Stage for the Extended Extraction Experiment

The CO_2 extraction capacity in this experiment decreased from about 0.3 gram oils

per gram injected CO_2 in the early time of the run to only about 0.006 g oil/g CO_2 at around

the end of the test. It might be of interest to note that this early run extraction capacity figure

is three times higher than that obtained from previously described extraction experiment using

the same oil and run temperature but with variable pressure. This is probably because the

amount of oil in place in this extended extraction (750 cm³) was higher than that in the

variable pressure experiment which was 500 cm³. This argument can be explained as follows.

When the oil was contacted with CO_2, oil first swelled and then as the pressure was

increased extraction started to occur and the oil shrank and two phases were created i.e.,

CO_2-rich or upper phase and oil rich phase. Because the amount of original oil was plentiful,

the level of oil-rich phase was reduced by oil extraction not as much as if there were less original oil in the vessel. Therefore, the space occupied by CO_2-rich phase was less than that might be created if there were less original oil in place. However, this CO_2-rich phase contained more hydrocarbons because the injected CO_2, which contacted more oil, extracted more oil. Therefore, the CO_2-rich phase was more concentrated with hydrocarbons (higher amount of hydrocarbons in less space) than that might be obtained if there were less original oil in place. As a result when this CO_2-rich phase was produced, a higher amount of oil was obtained. As the extraction process proceeded, the level of oil-rich phase decreased and the space for occupied by CO_2-rich phase increased. In the same time the injected CO_2 contacted less and less oil having less light ends and therefore the amount of extracted oil that went into the CO_2 rich phase decreased. Therefore, when this CO_2-rich phase was produced less oil was obtained.

Figure 4.23 presents the composition of produced oils sampled during different extraction stages, as indicated by the legend of the figure which shows the percentage of oil left in the vessel. The complete sets of compositions data of oils produced during the extended CO_2-oil extraction experiment are presented in Table B7, Appendix B. As in the case of extraction experiment with variable pressure described previously in subsection 4.1, the amounts of light ends in produced oils obtained from all runs were small. This was unexpected since the original oil samples, as shown in the figure, had high light ends fractions and it was reported that smaller hydrocarbons partition into dense CO_2 better than larger ones. Because of this and the above mentioned experiment mass loss of 24%, it was suspected that the light ends were extracted by CO_2 but were not condensed in the condenser.
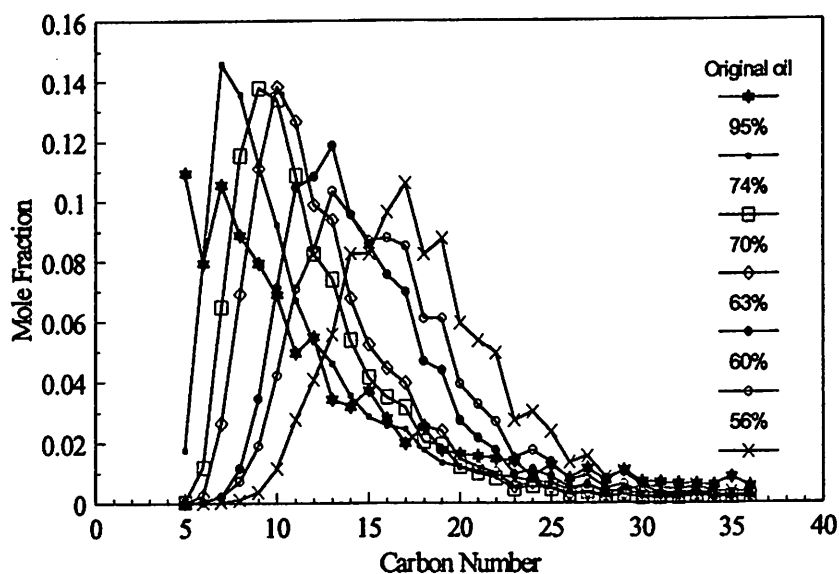
Figure 4.23 Produced Oils Compositions at Different Extraction
Stage for the Extended Extraction Experiment

A component material balance was made to identify the fractions of produced

hydrocarbons that were not recovered by the condenser. The C_{37+} fraction was also excluded

from the balance because the accuracy of Gas Chromatographic (GC) analysis in determining

the C_{37+} fraction is low. Figures 4.24 and 4.25 show the amount of oil components remaining

in the vessel at different stage of extraction in terms of moles and concentration, respectively.

They were calculated based on the composition and weight of produced oils and the original

oil. Figure 4.24 shows that the amount of C_5 in the vessel decreased very slightly throughout

the course of the test indicating that only small amount of this component was extracted.

Since other components were extracted and therefore the total amount of oil decreased, the
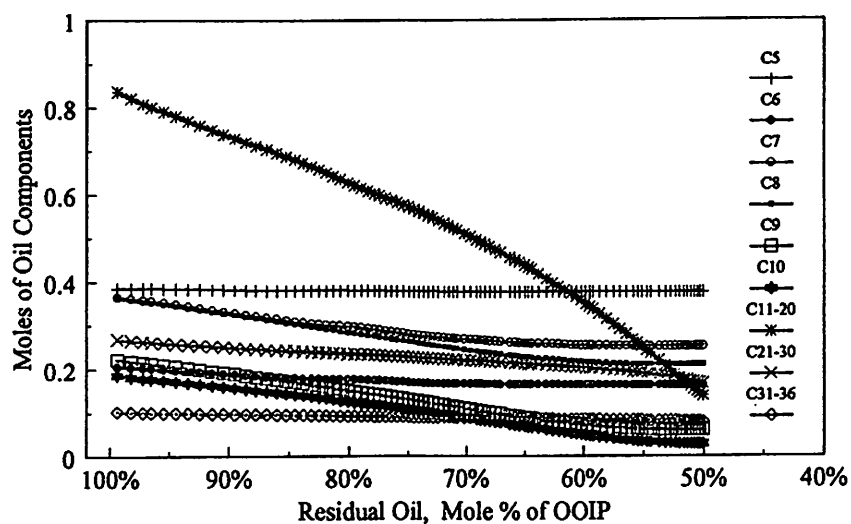
Figure 4.24 Residual Oil Component Distribution
as a Function of Extraction Stage
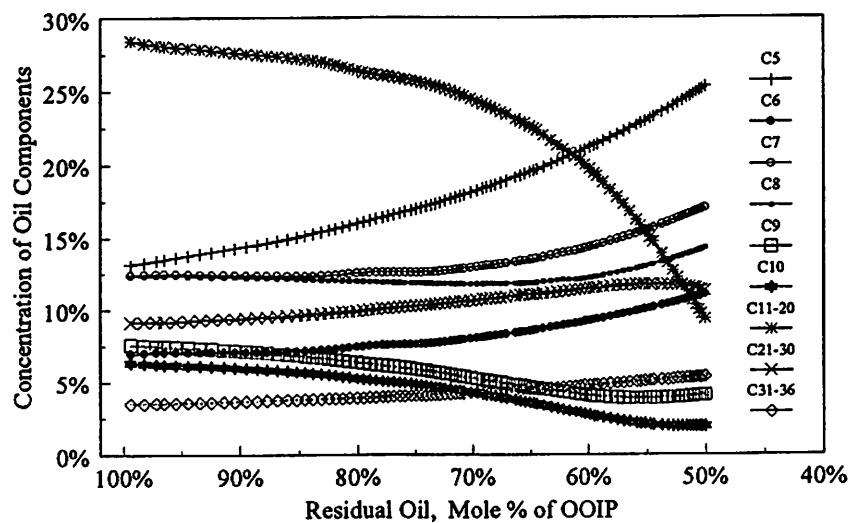
Figure 4.25 Residual Oil Component Relative Distribution
as a Function of Extraction Stage

concentration of C_5, as shown in Figure 4.25, increased with increasing extraction stage. Similar phenomena but at a lower degree of concentration increase also occurred for C_6, C_7, C_8, and the heavy fractions. As for the rests of the light and intermediate fractions, they were significantly produced and, as shown in Figure 4.25, their concentrations decreased with increasing extraction stage. Based on these information only, we might conclude that the CO_2 extracted mostly C_9-C_{20} fractions, and extracted C_5-C_8 and heavy fractions insignificantly. However, compositional analysis of the extraction residue reveals a different phenomenon. Figure 4.26 shows the moles of both the original oil and the extraction residue. The figure indicates that, as expected, most of the light ends were produced and only small portions of the heavy fractions were produced. Since the oil composition of the extraction residue was determined from a direct measurement while those presented in Figure 4.25 were inferred from the produced oil compositions we decided to use the residue data to determine the extracted components that were not captured by the condenser.

Figure 4.25 indicates that the components that show unexpected increase in concentration with increasing extraction stage, an indication of low production, are the C_5-C_8 fractions. On the other hand, Figure 4.26 shows that the amount of these fractions in the residue are very low as compared to that in the original oil implying that most of these fractions were extracted by CO_2. The fact that the amount of C_5-C_8 fractions found in the produced oil were low suggests that these components were extracted by CO_2, but were not captured by the condenser.
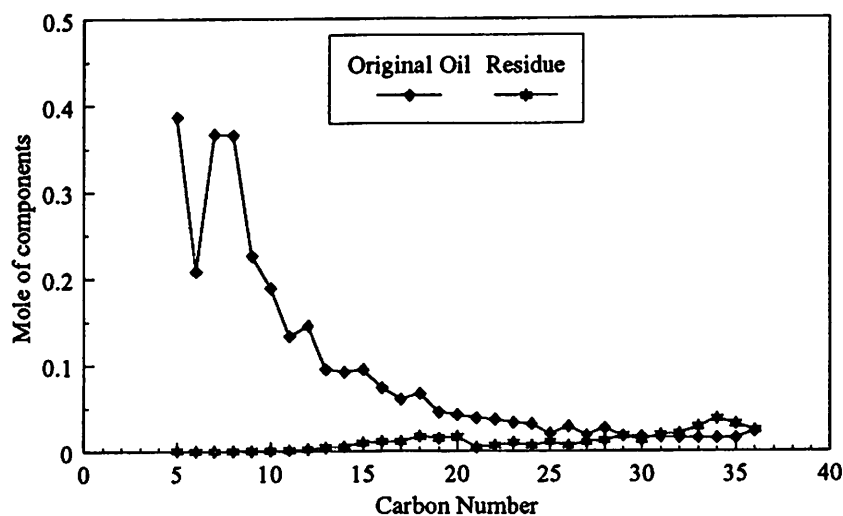
Figure 4.26 Mole Balance Between Original Oil and Extraction
Residue for the Extended Extraction Experiment

To examine the types of oil components that were extracted during the course of the extraction the composition of the produced oils collected at different extraction are plotted in Figures 4.27-4.28. The compositions presented in these figure are normalized compositions in which the C_5-C_8 fractions were removed from the composition. Figure 4.27 presents the normalized compositions of the produced oils at different extraction stages in terms of mole fractions. As comparison, the normalized compositions of the original oil and the extraction residue are also presented in this figure. Figure 4.28 shows the component distribution in the produced oil at different extraction stages expressed in terms of moles per mole of CO_2 injected. This was done to reflect the amount of oil produced at the corresponding extraction stages. To be used for investigating the relationship between types of extracted oil and the
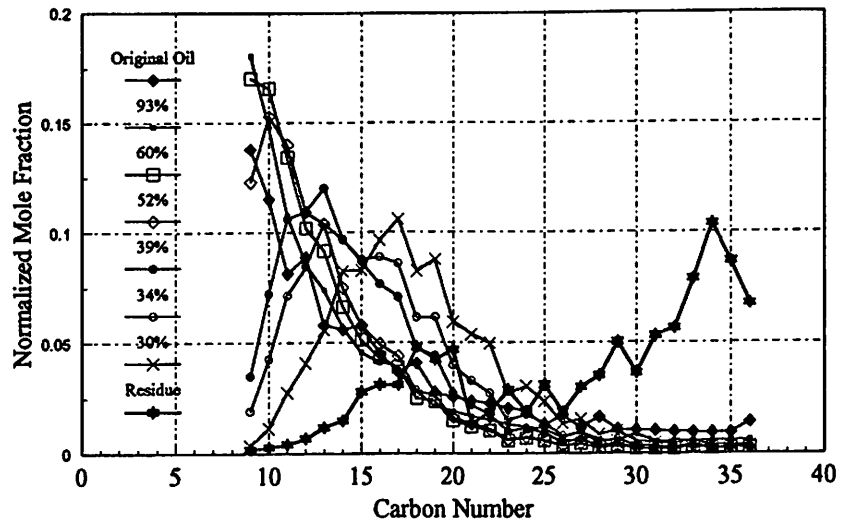
Figure 4.27 Normalized Compositions of Produced Oils at Different Extraction
Stage for the Extended Extraction Experiment
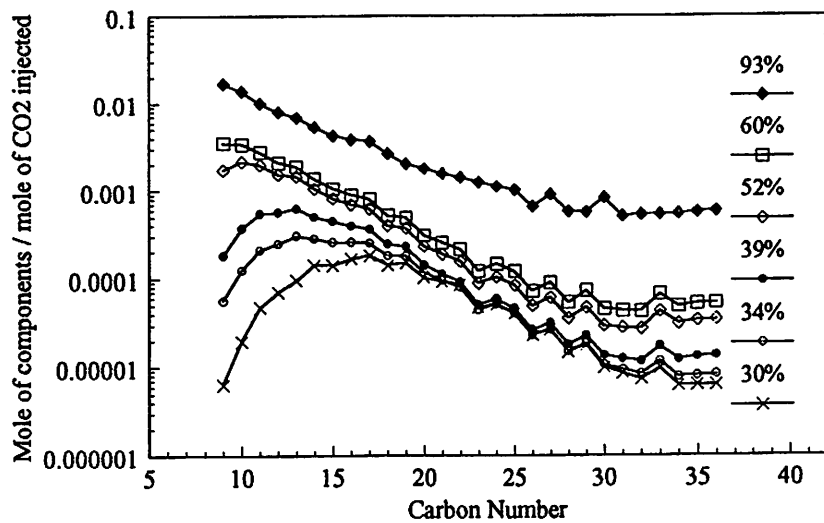
Figure 4.28 Normalized Compositions of Produced Oils per Unit of
CO_2 Injected at Different Extraction Stage for the
Extended Extraction Experiment

composition of oil in the extraction vessel, the component distribution of oil remaining in the vessel was calculated based on information gathered from produced oils analysis. The results of the calculation are presented in Figures 4.29 - 4.30.

It can be seen from both Figure 4.27 and 4.28 that there were a number of shifts in the types of extracted hydrocarbons during the course of the experiment. During the initial until about the middle of the extraction stage, as indicated by "93%" through "52%" in the figure's legend, the peak of the produced oils component distribution is in the lightest fractions (C_9-C_{10}). This occurred because small hydrocarbon molecules are extracted by CO_2 more efficiently than are large ones and the amount of the lighter fractions, as shown in Figure 4.29, at this extraction stage was still sufficient for CO_2 to extract. Comparing Figure 4.29 and Figure 4.27 we can see that even though during the initial stage of the extraction the amount of C_{11}-C_{20} fraction in the vessel was much higher than that of C_9-C_{10} fraction, the C_9-C_{10} fraction were extracted by CO_2 in greater amount than were the C_{11}-C_{20} fraction. When around 61% of OOIP had been produced (residual oil = 39%) the peak of the produced oil component distribution shifted to heavier fractions (C_{12}-C_{14}). This is because at this stage the amount of C_9-C_{10} was already depleted while there were a larger amount of C_{11}-C_{20} remaining in the vessel. At about the end of the extraction, as indicated by "30%", for similar reason, the peak of the composition distribution shifted to higher carbon numbers of around C_{16}-C_{17} fractions. The produced oil and remaining oil compositions development indicate that CO_2 first extracted light and intermediate fractions and then when these fractions became scarce CO_2 extracted heavier hydrocarbons.
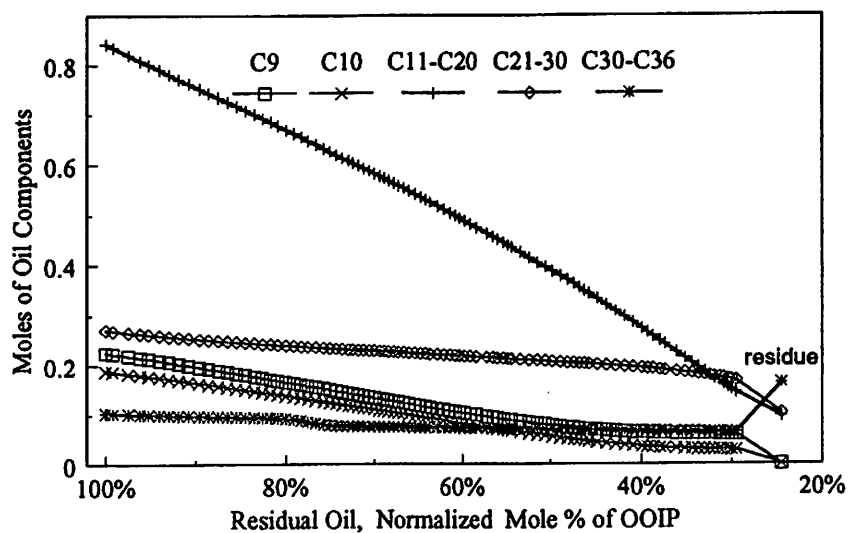
Figure 4.29 Normalized Component Distribution of Residual Oil
as a Function of Extraction Stage for the Extended
Extraction Experiment
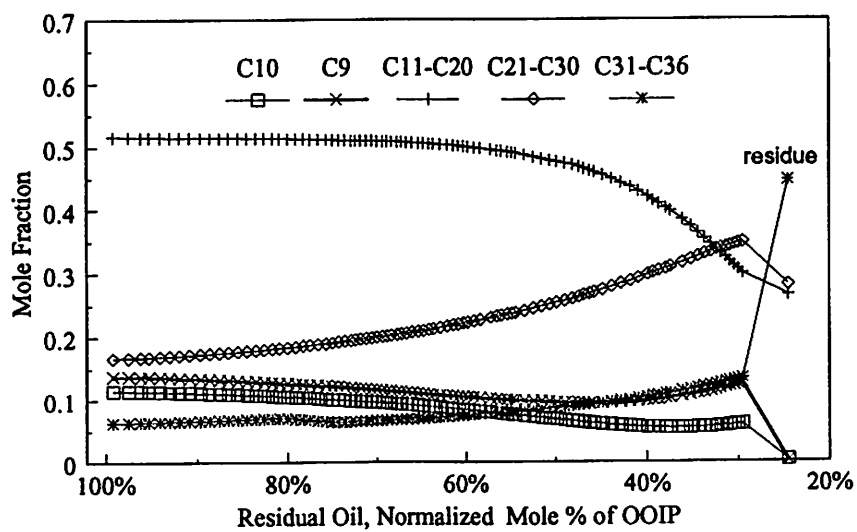
Figure 4.30 Normalized Component Relative Distribution of Residual Oil
as a Function of Extraction Stage for the Extended Extraction
Experiment

Figure 4.28 indicates that, as expected, the moles of components per moles of CO_2 injected for each component decreased with increasing extraction stages. In Figure 4.29 and 4.30 the amount of the extraction residue in terms of moles and mole fractions are also presented. It can be seen from the figure that the number of moles as well as the mole fraction of the oil components at the end of the extraction are larger than that found in the extraction residue except for the C_{30}-C_{36} fraction which is smaller. This discrepancy is probably caused by errors related to the physical condition of the residue which was very thick. The thick and tar-like residue might have caused inaccuracy in the weight determination of the residue, as mentioned previously, and also inaccuracy in the compositional analysis of the residue.

V. Conclusions

The objective of this study was to investigate the effect of pressure, temperature and oil composition on extraction of hydrocarbons by CO_2 from crude oils. The study also investigated the maximum oil recovery from an extended CO_2 extraction. Based on the results of a series of extraction experiments, the following conclusions may be drawn:

1. The CO_2 extraction capacity, defined as the weight of oil extracted per weight unit of CO_2 injected, increases with increasing pressure. In each CO_2-oil system investigated, there is a relatively small pressure range over which a sharp increase in the extraction capacity occurs, above which an additional increase of pressure does not significantly increase the extraction capacity.

2. The effect of pressure on the density of CO_2-oil upper phase in a multi phase system is similar to that on extraction capacity. The density increases with increasing pressure and over a narrow pressure range the density drastically increases, above which an additional increase of pressure does not significantly increase the density.

3. CO_2 extraction capacity is a strong function of extraction temperature. It decreases with an increase of temperature. The pressure at which CO_2 starts to efficiently extract hydrocarbon from an oil increases with an increase of temperature. At 95 and 138 °F, for the materials and conditions involved, extraction is insignificant for extraction pressures below 1100 and 1600 psig, respectively.

4. For the oils used in the study, the presence of solution gas in the oil does not affect both the CO_2 -oil extraction performance and CO_2-oil MMP.

5. In an extended extraction test, CO_2 can extract approximately 43 wt.% or 48 vol.% of the original oil in place. The CO_2 extraction capacity decreased from around 0.3 g oil/g CO_2 injected at the beginning of the extraction to 0.005 g oil/g CO_2 injected at time of termination. The average value of the extraction capacity was 0.0345 g oil/g CO_2 injected.

6. Small hydrocarbon molecules of the oil partition into a CO_2-rich phase preferentially to large molecules. Therefore, oils obtained through extraction have lower molecular weight than do the corresponding original oils.

7. Much of the produced hydrocarbons lighter than C_9 were not condensed in the condenser used in the extraction experiment. Instead, they left the condenser with the produced CO_2. If an experimental set up and procedures similar to this study are used, compositional analysis of the produced gas is recommended.

Based on the comparison between the results of the variable pressure extraction experiments and the results of slim tube displacement tests the following conclusions were made:

1. The slim tube MMPs are near the pressure range at which a drastic increase in CO_2-oil extraction rate occurs. As expected, this implies that CO_2 extraction is a major factor in CO_2-oil miscibility development. This agrees with the widely accepted thought that CO_2 miscibility is developed with an oil through the vaporizing gas drive mechanism.

2. In CO_2-oil extraction experiments, the pressure range over which a sharp increase in both extraction capacity and upper phase density occur is similar to the slim tube MMP of CO_2 with the oil. At higher temperatures the upper phase density measurement is not

very distinct for an MMP estimation. On the other hand the extraction capacity measurement method has a sharper transition area therefore appear to have promise to be used for MMP determination. At lower temperatures the pressure range over which a sharp increase in upper phase density occurs is as distinct as the sharp increase of extraction capacity. The upper phase density measurements are less time consuming than extraction capacity measurements and therefore for low temperatures, CO_2-oil MMP estimates can be made by using upper phase density vs. pressure profile as suggested by Harmon and Grigg.[49]

3. Presently extraction experiments provide a range of pressure where the MMP would be found. A comparison MMP can be found from a conventional MMP determination method such as slim tube tests. Since the extraction experiment can be performed in about two days while slim tube displacement usually take two weeks, the former can be used as a tool to screen the displacement pressures that will be performed in slim tube tests.

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Appendix A

Extraction Experimental Data

Table A.1. Extraction Experimental Data: Sulimar Queen Oil at 95 °F

Inject. Time min.	CO_2 Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO_2 Conc. mole %	Production Oil gram	Production Oil cc	Production Gas liter(*)	Blowdown Oil gr	Blowdown Oil cc	Blowdown Gas liter(*)	Extraction Capacity g /g	Prod. Oil MW g/mole	Remarks
5	3.0	20	0.0298	0.03									pressurizing
13	8.3	70	0.0328	0.10									"
13	8.3	120	0.0235	0.16									"
34	21.7	250	0.0396	0.29									"
26	16.7	350	0.0576	0.37									"
32	20.0	450	0.0687	0.44									"
79	50.0	750	0.1366	0.56									"
16	10.0	800	0.1503	0.58									"
63	40.0	960	0.2922	0.64									"
49	30.8	1000	0.2670	0.67									"
99	62.5	1050	0.4993	0.73									"
99	62.5	1100	0.5554	0.77									"
40	25.3	1105	0.6051	0.77	2.56	3.3	11.9				0.10102		extraction
43	27.0	1159	0.7419	0.79									pressurizing
22	13.7	1200	0.7561	0.79									pressurizing
40	25.3	1204	0.7580	0.80	2.37	3.3	11.3				0.09352	160.0	extraction
8	5.3	1225	0.7560	0.80									pressurizing
24	15.0	1300	0.7783	0.80									pressurizing

Table A.1–continued

Inject. Time min.	CO$_2$ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO$_2$ Conc. mole %	Production Oil gram	Production Oil cc	Production Gas liter(*)	Blowdown Oil gr	Blowdown Oil cc	Blowdown Gas liter(*)	Extraction Capacity g /g	Prod. Oil MW g/mole	Remarks
40	25.3	1302	0.7692	0.81	2.32	3.2	10.2				0.09155		extraction
5	3.0	1320	0.7667	0.81									pressurizing
25	16.0	1400	0.7828	0.82									pressurizing
40	25.3	1407	0.7799	0.82	2.37	3.1	11.0				0.09352	162.5	extraction
29	18.6	1500	0.7949	0.83									pressurizing
26	16.7	1600	0.8090	0.83									pressurizing
40	25.3	1608	0.8114	0.83	2.39	3.2	10.8				0.09431	162.5	extraction
								7.9	10.7	25.5			blowdown
26	16.5	1075	0.7388	0.82	1.6	2.3	8.8				0.09714		extraction
								4.14	5.4	17.0			blowdown
30	19.0	1065	0.7221	0.83	1.38	1.8	8.5				0.07261		extraction
								5.95	8.3	19.8			blowdown
30	19.0	1055	0.6001	0.82	1.36	2.1	10.5				0.07156	160.5	extraction
								3.04	3.8	9.9			blowdown
30	19.0	1044	0.4119	0.82	0.08	0.1	10.2				0.00421		extraction
								2.46	3.3	14.2			blowdown
23	14.6	1000	0.3653	0.82	0.01	0.1	6.8				0.00069		extraction

Note: (*) at atmospheric condition

Table A.1—continued

SUMMARY:

(1) Original Oil in Place, gram — 412
(2) Original Oil in Place, cc — 500

(3) CO_2 Injection Rate, gram/hour — 38
(4) Total Time for Extraction, minute — 339
(5) Total Time for Pressurization, minute — 709
(6) Total Experiment Time (4) + (5), minute — 1048

(7) Injected CO_2 for Extraction, gram — 214.8
(8) Injected CO_2 for pressurization, gram — 448.9
(9) Total Injected CO_2, gram — 663.7

(10) Total Oil Produced by Extraction, gram — 16
(11) Tot. Oil Produced During Blowdown, gram — 23.5
(12) Total Oil Production (10) + (11), gram — 39.9

(17) Total Oil Produced by Extraction, cc — 22.5
(18) Tot. Oil Prod. During Blowdown, cc — 31.5
(19) Total oil production (17) + (18), cc — 54.0

(13) Residual Oil (Expected) (1)−(12), gram — 372.1
(14) Residual Oil (Measured), gram — 337.6
(15) Oil Loss by mass (13)−(14), gram — 34.4
(16) Oil loss (15)/(1)*100, % mass — 8.4%

(20) Residual Oil (Expected) (2)−(19), cc — 446
(21) Residual Oil (Measured), cc — 401
(22) Oil Loss by volume (20)−(21), gram — 45
(23) Oil loss (22)/(2)*100, % volume — 9.0%

(24) Total Gas Produced During Extraction, liter — 99.9
(25) Total Gas Produced During Blowdown, liter — 86.3
(26) Total gas production (24) + (25), liter — 186.2

Table A2. Extraction Experimental Data: Sulimar Queen Oil at 138 °F

Inject. Time min.	CO₂ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO₂ Conc. mole%	Production Oil gram	Oil cc	Gas liter(*)	Blowdown Oil gr	Oil cc	Gas liter(*)	Extraction Capacity g/g	Prod. Oil MW g/mole	Remarks
37	23	140	0.0227	0.19									pressurizing
21	14	221	0.0241	0.27									"
27	17	325	0.0396	0.35									"
81	51	580	0.0942	0.51									"
54	34	785	0.1297	0.58									"
16	10	826	0.1380	0.60									"
50	31	983	0.1736	0.64									"
4	2	992	0.1768	0.65									"
5	3	1002	0.1768	0.65									"
82	52	1106	0.2069	0.70									"
38	24	1178	0.2312	0.72									"
1104	699	1203	0.2298	0.71	1.83	2.7	463				0.0026		extraction
738	467	1203	0.2216	0.73	1.05	1.6	289				0.0022	146	extraction
22	14	1231	0.2532	0.74									pressurizing
21	14	1258	0.2656	0.74									pressurizing
28	18	1302	0.2876	0.76									pressurizing
60	38	1400	0.3193	0.78									pressurizing
315	200	1402	0.3193	0.78	1.84	2.7	131				0.0092	147.5	extraction

Table A.2-continued

Inject. Time	CO₂ Inject.	Vessel Press.	Upr. Phase Density	CO₂ Conc.	Production			Blowdown			Extraction Capacity	Prod. Oil MW	Remarks
					Oil		Gas	Oil		Gas			
min.	gram	psig	g/cc	mole%	gram	cc	liter(*)	gr	cc	liter(*)	g /g	g/mole	
38	25	1467	0.3336	0.79									pressurizing
19	13	1500	0.4117	0.79									pressurizing
228	150	1504	0.4126	0.80	1.95	2.7	89				0.0130		extraction
275	181	1504	0.4367	0.80	5.8	7.1	127				0.0320	151	extraction
168	111	1504	0.4474	0.79	2.94	4.2	75				0.0266		extraction
30	20	1555	0.4836	0.80									pressurizing
28	18	1601	0.4952	0.81									pressurizing
229	151	1608	0.4952	0.81	3.58	5.1	92				0.0237		extraction
60	40	1602	0.5139	0.82	1.43	2.1	25				0.0362	160	extraction
120	79	1603	0.5260	0.82	3.18	4.5	52				0.0403		extraction
30	24	1650	0.5498	0.82									pressurizing
22	17	1700	0.5661	0.83									pressurizing
106	82	1706	0.5675	0.83	3.58	4.9	52				0.0436		extraction
122	95	1700	0.5675	0.83	4.13	6.3	61				0.0437		extraction
17	14	1750	0.5960	0.84									pressurizing
12	10	1800	0.6043	0.84									pressurizing
95	82	1800	0.6025	0.84	3.64	5.2	49				0.0446		extraction
83	71	1800	0.6006	0.85	3.87	5.4	43				0.0543	160	extraction

Table A.2—continued

Inject. Time min.	CO₂ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO₂ Conc. mole%	Production Oil gram	Production Oil cc	Production Gas liter(*)	Blowdown Oil gr	Blowdown Oil cc	Blowdown Gas liter(*)	Extraction Capacity g/g	Prod. Oil MW g/mole	Remarks
12	10	1850	0.6132	0.85									pressurizing
13	11	1900	0.6314	0.85									pressurizing
76	48	1904	0.6319	0.85	2.32	3.1	27				0.0482		extraction
78	49	1900	0.6333	0.85	2.69	3.8	30				0.0545	176	extraction
80	51	1800	0.6086	0.85	2.67	3.5	33	5.11	6.7	2.83	0.0527		blowdown / extraction
85	54	1700	0.5745	0.85	2.88	4.1	41	4.00	5.7	2.83	0.0535		blowdown / extraction
133	84	1650	0.5582	0.85	3.25	4.5	62	4.19	5.8	14.1	0.0386		blowdown / extraction
120	76	1601	0.4747	0.84	2.07	2.8	56	4.51	6.1	14.1	0.0272		blowdown / extraction
102	65	1550	0.4255	0.84	1.13	1.5	48	2.79	3.7	14.1	0.0174		blowdown / extraction
240	152	1452	0.3377	0.84	0.9	1.5	84	3.31	4.4	14.1	0.0059		blowdown / extraction

Note: (*) at atmospheric conditions

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Table A.2—continued

SUMMARY

(1) Original Oil in Place, gram	416	(7) Injected CO_2 for Extraction, gram	2986
(2) Original Oil in Place, cc	500	(8) Injected CO_2 for pressurization, gram	507
		(9) Total Injected CO_2, gram	3493
(3) CO_2 Injection Rate, gram/hour	38		
(4) Total Time for Extraction, minute	4557		
(5) Total Time for Pressurization, minute	765		
(6) Total Experiment Time (4) + (5), minute	5322		
(10) Total Oil Produced by Extraction, gram	57	(17) Total Oil Produced by Extraction, cc	79.1
(11) Tot. Oil Produced During Blowdown,gram	23.9	(18) Tot. Oil Prod. During Blowdown, cc	32.4
(12) Total Oil Production (10) + (11), gram	80.6	(19) Total oil production (17) + (18), cc	111.5
(13) Residual Oil (Expected) (1)−(12), gram	335.4	(20) Residual Oil (Expected) (2)−(19), cc	388.5
(14) Residual Oil (Measured), gram	283.9	(21) Residual Oil (Measured), cc	334
(15) Oil Loss by mass (13)−(14), gram	51.5	(22) Oil Loss by volume (20)−(21), gram	54.5
(16) Oil loss (15)/(1)*100, % mass	12.4%	(23) Oil loss (22)/(2)*100, % volume	10.9%
(24) Total Gas Produced During Extraction, liter	1928		
(25) Total Gas Produced During Blowdown, liter	62		
(26) Total gas production (24) + (25), liter	1990		

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Table A.3. Extraction Experimental Data: Spraberry Oil at 95 °F

Inject. Time min.	CO$_2$ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO$_2$ Conc. mole%	Production Oil gram	Oil cc	Gas liter(*)	Blowdown Oil gr	Oil cc	Gas liter(*)	Extraction Capacity g /g	Prod. Oil MW g/mole	Remarks
14	9	150	0.0367	0.09									pressurizing
15	10	225	0.0817	0.17									-"-
15	10	302	0.0701	0.24									-"-
12	8	355	0.0434	0.28									-"-
10	6	400	0.0629	0.32									-"-
79	50	650	0.1383	0.50									-"-
47	30	800	0.1535	0.57									-"-
39	25	900	0.1822	0.62									-"-
26	16	950	0.2505	0.64									-"-
43	27	1005	0.2207	0.68									-"-
71	45	1050	0.3120	0.72									-"-
87	55	1105	0.5961	0.76									-"-
43	27	1159	0.6554	0.78									-"-
16	10	1200	0.7753	0.78									-"-
20	13	1205	0.7772	0.79	1.29	1.8	4.70				0.10181		extraction
20	13	1200	0.7791	0.79	1.37	1.9	4.70				0.10812	167.5	extraction
13	8	1225	0.7081	0.79									pressurizing
30	19	1300	0.7447	0.80									pressurizing
40	25	1302	0.7692	0.81	2.32	3.2	10.2				0.09155		extraction
4	3	1320	0.7667	0.81									pressurizing
18	11	1400	0.7828	0.81									pressurizing
15	10	1404	0.7904	0.81	1.13	1.8	4.38				0.11891		extraction
15	10	1400	0.7929	0.82	1.12	1.7	4.38				0.11786	155	extraction
20	13	1100	0.7430	0.81	0.74	1.1	4.70	7.87	11.7	16.9	0.05840		blowdown
20	13	1100	0.7430	0.82	0.85	1.15	4.70				0.06708	154	extraction

Table A3.—continued

Inject. Time min.	CO₂ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO₂ Conc. mole%	Production Oil gram	Production Oil cc	Production Gas liter(*)	Blowdown Oil gr	Blowdown Oil cc	Blowdown Gas liter(*)	Extraction Capacity g/g	Prod. Oil MW g/mole	Remarks
27	17	1030	0.7112	0.82	1.03	1.35	9.06				0.06021	157	extraction
20	13	1050	0.7126	0.82	0.79	1	5.66				0.06235		extraction
182	115	1165	0.7370	0.85									pressurizing
18	11	1200	0.7479	0.86									pressurizing
20	13	1225	0.7435	0.86									pressurizing
30	19	1300	0.7740	0.86									pressurizing
5	3	1320	0.7643	0.86									pressurizing
18	11	1400	0.7972	0.87									pressurizing
13	8	1500	0.7949	0.87									pressurizing
11	7	1600	0.8090	0.87									pressurizing
20	13	1600	0.7950	0.87	1.51	2	5.66				0.11917	177	extraction
20	13	1600	0.7941	0.87	1.46	1.7	5.66				0.11523		extraction
20	13	1600	0.7946	0.87	1.02	1.5	5.66				0.08050		extraction
								5.65	8.4				blowdown

Note: (*) at atmospheric conditions

SUMMARY

(1) Original Oil in Place, gram   417
(2) Original Oil in Place, cc   500

(3) CO₂ Injection Rate, gram/hour   38.0
(4) Total Time for Extraction, minute   257
(5) Total Time for Pressurization, minute   879
(6) Total Experiment Time (4) + (5), minute   1136

(7) Injected CO₂ for Extraction, gram   162.8
(8) Injected CO₂ for pressurization, gram   556.9
(9) Total Injected CO₂, gram   719.7

Table A.3.—continued

(10) Total Oil Produced by Extraction, gram ... 14.63
(11) Tot. Oil Produced During Blowdown,gram ... 13.5
(12) Total Oil Production (10) + (11), gram ... 22.5

(13) Residual Oil (Expected) (1) − (12), gram ... 394.0
(14) Residual Oil (Measured), gram ... 337.7
(15) Oil Loss by mass (13) − (14), gram ... 56.3
(16) Oil loss (15)/(1)*100, % mass ... 13.5%

(24) Total Gas Produced During Extraction, liter ... 69.5
(25) Total Gas Produced During Blowdown, liter ... 17.0
(26) Total gas production (24) + (25), liter ... 86.5

(17) Total Oil Produced by Extraction, cc ... 20.2
(18) Tot. Oil Prod. During Blowdown, cc ... 20.1
(19) Total oil production (17) + (18), cc ... 40.3

(20) Residual Oil (Expected) (2) − (19), cc ... 459.7
(21) Residual Oil (Measured), cc ... 402
(22) Oil Loss by volume (20) − (21), gram ... 57.7
(23) Oil loss (22)/(2)*100, % volume ... 11.5%

Table A.4. Extraction Experimental Data: Spraberry Oil at 138 °F

Inject. Time min.	CO₂ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO₂ Conc. mole%	Production Oil gram	Production Oil cc	Production Gas liter(*)	Blowdown Oil gr	Blowdown Oil cc	Blowdown Gas liter(*)	Extraction Capacity g/g	Prod. Oil MW g/mole	Remarks
14	9	70	0.023	0.09									pressurizing
41	26	250	0.024	0.28									"
24	15	325	0.041	0.36									"
89	56	550	0.081	0.54									"
59	37	700	0.132	0.61									"
44	28	850	0.136	0.65									"
32	20	950	0.173	0.68									"
14	9	990	0.175	0.69									"
5	3	1000	0.175	0.69									"
42	27	1106	0.207	0.72									"
43	27	1198	0.209	0.74									"
60	38	1200	0.228	0.75	0.32	0.5	17				0.00842	145	extraction
16	10	1231	0.283	0.76									pressurizing
15	10	1258	0.253	0.76									pressurizing
28	18	1302	0.343	0.77									pressurizing
59	37	1400	0.569	0.79									pressurizing
60	38	1400	0.574	0.80	0.38	0.5	20.1				0.01000	145	extraction
30	19	1450	0.575	0.80									pressurizing
30	19	1500	0.571	0.81									pressurizing
33	21	1555	0.621	0.82									pressurizing
28	18	1599	0.663	0.83									pressurizing
60	38	1600	0.666	0.83	3.31	4.9	22.7				0.08708		extraction
39	25	1650	0.659	0.84									pressurizing
26	16	1700	0.677	0.84									pressurizing
60	38	1700	0.678	0.84	3.64	5	22.7				0.09576	147.5	extraction

Table A.4.—continued

Inject. Time min.	CO₂ Inject. gram	Vessel Press. psig	Upr. Phase Density g/cc	CO₂ Conc. mole%	Production Oil gram	Oil cc	Gas liter(*)	Blowdown Oil gr	Oil cc	Gas liter(*)	Extraction Capacity g/g	Prod. Oil MW g/mole	Remarks
23	15	1750	0.695	0.85									pressurizing
16	10	1800	0.701	0.85									pressurizing
60	38	1800	0.701	0.85	4.11	5.6	24.1				0.10812	154	extraction
16	10	1850	0.705	0.85									pressurizing
18	11	1900	0.708	0.86									pressurizing
60	38	1900	0.708	0.86	4	5.5	22.9				0.10523	158	extraction
								6.44	9.9	70.7		158	blowdown
60	38	1500	0.523	0.84	1.04	1.6	17				0.02736	158	extraction
60	38	1500	0.518	0.84	0.72	1	24.1				0.01894		extraction
31	20	1549	0.542	0.84									pressurizing
60	38	1550	0.589	0.85	1.68	2.2	18.4	0.91	1.4		0.04420		extraction

Note: (*) at atmospheric conditions

SUMMARY

(1) Original Oil in Place, gram   417
(2) Original Oil in Place, cc   500

(3) CO₂ Injection Rate, gram/hour   38.0
(4) Total Time for Extraction, minute   540
(5) Total Time for Pressurization, minute   815
(6) Total Experiment Time (4) + (5), minute   1355

(10) Total Oil Produced by Extraction, gram   19.20
(11) Tot. Oil Produced During Blowdown,gram   7.3
(12) Total Oil Production (10) + (11), gram   25.6

(7) Injected CO₂ for Extraction, gram   342.1
(8) Injected CO₂ for pressurization, gram   516.3
(9) Total Injected CO₂, gram   858.4

(17) Total Oil Produced by Extraction, cc   26.8
(18) Tot. Oil Prod. During Blowdown, cc   11.3
(19) Total oil production (17) + (18), cc   38.1

Table A.4.—continued

(13) Residual Oil (Expected) (1)−(12), gram	390.9
(14) Residual Oil (Measured), gram	340.6
(15) Oil Loss by mass (13)−(14), gram	50.3
(16) Oil loss (15)/(1)*100, % mass	12.1%
(20) Residual Oil (Expected) (2)−(19), cc	461.9
(21) Residual Oil (Measured), cc	404
(22) Oil Loss by volume (20)−(21), gram	57.9
(23) Oil loss (22)/(2)*100, % volume	11.6%
(24) Total Gas Produced During Extraction, liter	189.0
(25) Total Gas Produced During Blowdown, liter	70.8
(26) Total gas production (24) + (25), liter	259.8

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Table A.5 Experimental Data: Extended Extraction Experiment of Sulimar Queen Oil at 95 °F

Elapse Time minute	CO_2 Injected gram	Vessel Press. psig	Upp. phase Density gram/ml	CO_2 Conc. mole%	Oil production gram	Oil production ml	Gas Prod. liter(*)	Extraction Capacity g oil/g CO_2	Prod. oil MW g/mole	C_5–C_{10}	C_{11}–C_{20}	C_{20+}	Residual Oil(***) %	Remark
2	3	15	0.0289	1.7										
1	1	20	0.0289	2.5										
6	8	70	0.0152	7.1										
8	10	120	0.0239	12.6										
19	24	255	0.0403	23.3										
14	18	350	0.0586	29.7										
17	22	450	0.0709	36.2										
71	91	750	0.1402	53.8										
17	22	800	0.1559	56.7										
30	38	890	0.1826	61.0										
4	5	900	0.2316	61.5										
30	38	975	0.2627	64.9										
30	38	1010	0.6088	67.8										
31	40	1050	0.7401	70.3										
73	93	1100	0.7497	74.9										
51	65	1160	0.7579	77.4										
9	11	1175	0.7564	77.7										
4	5	1185	0.7737	77.9										
4	5	1195	0.7934	78.1										
15	19	1203	0.8118	78.2	3.3	4.7	11.3	0.17255		53.1	31.2	15.6	99.5	
15	19	1203	0.7964	78.5	6.39	8.3	10.2	0.33412	186	53.2	31.1	15.7	98.4	
15	19	1203	0.7940	78.7	5.37	7.3	9.9	0.28078		53.2	31.0	15.7	97.6	
15	19	1203	0.7935	79.0	3.68	5.3	8.5	0.19242		53.3	31.0	15.7	97.0	
15	19	1203	0.7931	79.3	5.18	6.9	8.5	0.27085	167	53.2	31.0	15.8	96.1	
15	19	1203	0.7916	79.6	5.14	7.2	9.3	0.26876		53.2	30.9	15.9	95.3	
15	19	1203	0.7902	79.9	5.04	7	8.8	0.26353		53.1	30.9	15.9	94.5	
15	19	1203	0.7883	80.2	4.63	6.3	9.1	0.24209	161	53.1	30.9	16.0	93.7	
15	19	1203	0.7863	80.5	5	6.4	7.9	0.26144		53.0	30.9	16.1	92.9	
15	19	1203	0.7854	80.7	4.58	5.9	9.9	0.23948		53.0	30.9	16.1	92.2	CO_2 loading
15	19	1203	0.7844	80.9	4.58	5.9	9.9	0.23948	163	52.9	30.9	16.2	91.4	
15	19	1203	0.7835	81.2	4.44	5.6	9.9	0.23216		52.9	30.9	16.3	90.7	
15	19	1203	0.7825	81.4	4.08	5.3	10.2	0.21333		52.8	30.8	16.4	90.0	
15	19	1203	0.7811	81.6	4.15	5.4	10.5	0.21699		52.8	30.8	16.4	89.4	
15	19	1203	0.7801	81.8	4.05	5.2	10.2	0.21176		52.7	30.8	16.5	88.7	

Table A.5 – continued

Elapse Time minute	CO2 Injected gram	Vessel Press. psig	Upp. phase Density gram/ml	CO2 Conc. mole%	Oil production gram	ml	Gas Prod. liter(*)	Extraction Capacity g oil/g CO2	Prod. oil MW g/mole	Normalized Oil Mole Percent(**) C5-C10	C11-C20	C20+	Residual Oil(***) %	Remark
15	19	1203	0.7796	81.9	3.8	4.9	10.4	0.19869	163	52.7	30.8	16.6	88.1	
15	19	1203	0.7787	82.1	3.47	5	10.6	0.18144		52.6	30.7	16.7	87.5	
15	19	1203	0.7772	82.3	3.34	4.6	10.5	0.17464		52.6	30.7	16.7	87.0	
15	19	1203	0.7758	82.4	3.52	5	10.8	0.18405		52.6	30.6	16.8	86.4	
15	19	1203	0.7758	82.6	3.11	4.5	10.6	0.16261		52.6	30.6	16.9	85.9	
15	19	1203	0.7738	82.7	2.98	4.1	11.0	0.15582		52.6	30.5	16.9	85.4	
15	19	1203	0.7724	82.8	3.07	4.5	10.6	0.16052		52.6	30.4	17.0	84.9	
15	19	1203	0.7714	83.0	2.89	4.3	10.6	0.15111	174.5	52.6	30.3	17.0	84.5	
15	19	1203	0.7705	83.1	3.27	4.3	10.8	0.17098		52.7	30.3	17.1	83.9	
15	19	1203	0.7695	83.2	2.69	3.9	10.7	0.14065		52.7	30.2	17.2	83.5	
15	19	1203	0.7681	83.4	2.72	3.9	10.3	0.14222		52.6	30.1	17.2	83.1	
15	19	1203	0.7676	83.5	2.75	4	11.3	0.14379		52.6	30.1	17.3	82.6	CO2 loading
15	19	1203	0.7671	83.6	2.6	3.9	10.8	0.13595	159	52.6	30.1	17.4	82.2	
15	19	1203	0.7662	83.7	2.17	3.3	11.6	0.11346		52.5	30.0	17.4	81.8	
15	19	1203	0.7642	83.8	2.47	3.3	11.3	0.12915		52.5	30.0	17.5	81.4	
15	19	1203	0.7633	83.9	2.36	3.2	11.3	0.12340		52.5	30.0	17.5	81.1	
15	19	1203	0.7614	84.0	2.3	3.2	11.3	0.12026		52.5	29.9	17.6	80.7	
15	19	1203	0.7604	84.1	2.46	3.2	11.3	0.12863		52.4	29.9	17.6	80.3	
15	19	1203	0.7599	84.2	2.29	3.1	11.3	0.11974	165	52.4	29.9	17.7	79.9	
15	19	1203	0.7590	84.3	2.17	3.2	11.3	0.11346		52.4	29.8	17.8	79.6	
15	19	1203	0.7585	84.3	2.05	3.1	11.3	0.10719		52.4	29.8	17.8	79.2	
15	19	1203	0.7575	84.4	2.1	3.2	11.8	0.10980		52.4	29.7	17.9	78.9	
15	19	1203	0.7561	84.5	1.92	2.8	11.3	0.10039		52.4	29.7	17.9	78.6	
15	19	1203	0.7561	84.6	2	2.8	11.8	0.10458		52.4	29.6	18.0	78.3	
15	19	1203	0.7547	84.6	2.37	3.1	11.6	0.12392		52.4	29.6	18.0	77.9	
15	19	1203	0.7527	84.7	2.47	3.2	11.6	0.12915	171	52.5	29.5	18.1	77.5	
15	19	1203	0.7503	84.8	2.13	2.8	11.3	0.11137		52.5	29.4	18.1	77.1	
15	19	1203	0.7513	84.9	2.08	2.8	11.6	0.10876		52.5	29.3	18.2	76.8	
15	19	1203	0.7499	85.0	1.61	2.1	11.0	0.08418		52.5	29.2	18.3	76.5	CO2 loading
30	38	1203	0.7499	85.1	2.96	3.7	24.1	0.07739		52.5	29.1	18.3	76.1	
30	38	1203	0.7499	85.2	2.62	3.5	21.5	0.06850		52.6	29.0	18.4	75.6	
30	38	1203	0.7499	85.3	2.48	3.2	22.9	0.06484	168	52.6	28.9	18.5	75.2	
30	38	1203	0.7398	85.4	1.81	2.6	23.4	0.04732		52.6	28.8	18.5	74.9	
30	38	1203	0.7379	85.5	1.83	2.8	23.5	0.04784	179	52.7	28.8	18.6	74.6	

Table A.5—continued

Elapse Time minute	CO₂ Injected gram	Vessel Press. psig	Upp. phase Density gram/ml	CO₂ Conc. mole%	Oil production gram	Oil production ml	Gas Prod. liter(*)	Extraction Capacity g oil/g CO₂	Prod. oil MW g/mole	Normalized Oil Mole Percent(**) C₅-C₁₀	C₁₁-C₂₀	C₂₀+	Residual Oil(***) %	Remark
30	38	1203	0.7350	85.5	2.12	3	23.5	0.05542		52.7	28.7	18.6	74.3	CO2 loading
30	38	1203	0.7336	85.6	2.39	3.2	23.4	0.06248	172	52.7	28.6	18.7	73.9	
30	38	1203	0.7321	85.7	2.34	3	23.4	0.06118		52.8	28.4	18.8	73.5	
60	77	1203	0.7293	85.9	4.12	5.5	47.4	0.05386		52.8	28.2	18.9	72.9	
30	38	1203	0.7283	85.9	2.16	3.1	24.0	0.05647	173	52.9	28.1	19.0	72.5	
30	38	1203	0.7264	86.0	1.97	2.6	24.3	0.05150	181	52.9	28.0	19.0	72.2	CO2 loading
30	38	1203	0.7216	86.2	2.42	3.1	24.2	0.05272		53.0	27.9	19.1	71.8	
36	46	1203	0.7168	86.2	1.69	2.4	23.5	0.04442		53.0	27.8	19.1	71.5	CO2 loading
30	38	1203	0.7144	86.3	1.51	2.2	22.6	0.03968		53.1	27.7	19.2	71.3	
60	76	1203	0.7120	86.4	3.13	4.4	47.8	0.04113	184	53.2	27.5	19.3	70.8	CO2 loading
60	76	1203	0.7101	86.5	3.5	4.4	47.7	0.04599		53.4	27.3	19.4	70.2	
60	76	1203	0.7082	86.5	2.98	4	49.5	0.03916	184	53.5	27.0	19.5	69.7	CO2 loading
57	72	1203	0.7063	86.6	2.85	3.9	43.9	0.03942		53.6	26.9	19.5	69.3	
60	76	1203	0.7072	86.8	2.74	3.7	46.7	0.03601	183	53.7	26.7	19.6	68.8	CO2 loading
60	76	1203	0.7039	86.9	2.97	3.8	46.7	0.03903	186	53.7	26.6	19.7	68.3	
60	76	1203	0.7039	86.9	2.44	3.4	47.6	0.03206		53.9	26.4	19.8	67.9	
60	76	1203	0.7039	87.1	2.32	3.1	43.9	0.03049		54.0	26.2	19.8	67.6	CO2 loading
60	76	1203	0.7025	87.2	2.28	3	46.7	0.02996		54.1	26.0	19.9	67.2	
60	76	1203	0.6977	87.2	2.04	2.8	48.1	0.02681		54.3	25.8	20.0	66.9	
60	76	1203	0.6948	87.3	1.47	2.2	48.1	0.01932		54.3	25.7	20.0	66.6	
120	152	1203	0.7015	87.4	3.07	4.4	94.8	0.02017	196	54.6	25.4	20.1	66.1	CO2 loading
120	152	1203	0.6953	87.6	3.54	4.7	92.0	0.02326		54.8	25.0	20.2	65.6	
120	152	1203	0.6881	87.7	3.45	4.5	93.4	0.02267		55.1	24.7	20.3	65.0	CO2 loading
120	152	1203	0.6838	87.8	3.13	4.2	96.3	0.02057		55.3	24.3	20.3	64.5	
136	172	1203	0.6781	87.8	3.22	4.3	110.4	0.01867	204	55.6	24.0	20.4	64.0	CO2 loading
156	198	1203	0.6633	87.9	3.43	4.7	121.7	0.01734		55.9	23.6	20.5	63.4	
120	152	1203	0.6781	88.1	2.31	3	93.4	0.01518	212	56.1	23.3	20.5	63.0	CO2 loading
120	152	1203	0.6776	88.2	2.09	3	93.4	0.01373		56.3	23.1	20.6	62.7	
180	228	1203	0.6810	88.2	2.94	4.2	144.4	0.01288	220	56.6	22.8	20.6	62.2	CO2 loading
110	140	1203	0.6786	88.3	1.88	2.6	87.8	0.01348		56.8	22.6	20.6	61.9	CO2 loading
293	372	1203	0.6671	88.5	4.8	6.3	226.5	0.01292		57.3	22.0	20.7	61.1	CO2 loading
247	313	1203	0.6476	88.7	3.34	4.5	191.1	0.01066	227	57.6	21.6	20.7	60.6	CO2 loading
285	361	1203	0.6405	88.9	3.05	3.8	223.6	0.00844		58.0	21.2	20.8	60.1	CO2 loading
240	304	1203	0.6476	89.0	2.78	3.6	189.7	0.00913	229	58.3	20.9	20.8	59.7	CO2 loading

Table A.5 –continued

Elapse Time minute	CO$_2$ Injected gram	Vessel Press. psig	Upp. phase Density gram/ml	CO$_2$ Conc. mole%	Oil production gram	Oil production ml	Gas Prod. liter(*)	Extraction Capacity g oil/g CO$_2$	Prod. oil MW g/mole	Normalized Oil Mole Percent(**) C$_5$–C$_{10}$	C$_{11}$–C$_{20}$	C$_{20+}$	Residual Oil(***) %	Remark
240	304	1203	0.6405	89.1	2.43	3.3	186.8	0.00798		58.6	20.6	20.8	59.3	CO2 loading
270	342	1203	0.6443	89.4	2.6	3.4	206.7	0.00759	242	58.9	20.3	20.8	58.8	CO2 loading
240	304	1203	0.6400	89.6	2.13	2.9	184.0	0.00700		59.1	20.1	20.8	58.5	CO2 loading
260	330	1203	0.6020	89.7	2.21	2.9	201.0	0.00670	260	59.3	19.9	20.8	58.1	CO2 loading
240	304	1203	0.6324	89.8	1.88	2.5	189.7	0.00618	249	59.5	19.7	20.8	57.8	CO2 loading
277	351	1203	0.6286	90.0	1.94	2.8	212.3	0.00552		59.8	19.5	20.8	57.5	CO2 loading
270	342	1203	0.6267	90.1	1.67	2.2	209.5	0.00488	252	60.0	19.3	20.8	57.2	CO2 loading
252	320	1203	0.6238	90.2	2.08	2.2	198.2	0.00651	258	60.2	19.1	20.7	56.9	CO2 loading

(*) – at atmospheric conditions
(**) – mole % of components in the vessel excluding CO$_2$
(***) – weight % of OOIP in the vessel

SUMMARY

Original Oil in Place, ml	750
Original Oil in Place, gr	617
Total Extraction Time, minutes	6189
Injection pressure, psig	1730
Injection rate, gram/hour	76.5
Injected CO$_2$ for extraction, gram	7857
Injected CO$_2$ for pressure build up, grams	537
Total Oil Produced, ml	361
Total Oil Produced, gram	266
Total Recovery, % by volume	48%
Total Recovery, % by weight	43%
Average CO$_2$ consumption, gr/gr oil recovered	0.033
Residue recovered, grams	200

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Appendix B

Oil Compositions Data

Table B1. Compositions of Original Oils

Carbon #	Sulimar Queen STO		Spraberry Separator Oil	
	Mole Fraction	Cumul. Mol. Frac	Mole Fraction	Cumul. Mol. Frac
1			0.0212	0.0212
2			0.0172	0.0384
3			0.0351	0.0734
4			0.0212	0.0947
5	0.1216	0.1094	0.1089	0.2035
6	0.0654	0.1887	0.0820	0.2856
7	0.1154	0.2941	0.1345	0.4201
8	0.1149	0.3827	0.0820	0.5021
9	0.0710	0.4620	0.0684	0.5705
10	0.0593	0.5308	0.0379	0.6084
11	0.0418	0.5803	0.0398	0.6481
12	0.0456	0.6350	0.0314	0.6795
13	0.0297	0.6691	0.0293	0.7088
14	0.0288	0.7008	0.0224	0.7312
15	0.0296	0.7378	0.0191	0.7503
16	0.0231	0.7656	0.0177	0.7680
17	0.0189	0.7853	0.0184	0.7863
18	0.0209	0.8102	0.0130	0.7993
19	0.0143	0.8276	0.0111	0.8104
20	0.0132	0.8439	0.0130	0.8234
21	0.0122	0.8595	0.0094	0.8328
22	0.0117	0.8742	0.0090	0.8419
23	0.0106	0.8882	0.0085	0.8504
24	0.0100	0.8973	0.0055	0.8558
25	0.0065	0.9099	0.0077	0.8635
26	0.0091	0.9182	0.0052	0.8687
27	0.0059	0.9298	0.0075	0.8762
28	0.0085	0.9374	0.0052	0.8813
29	0.0056	0.9483	0.0078	0.8892
30	0.0055	0.9553	0.0053	0.8944
31	0.0053	0.9621	0.0053	0.8997
32	0.0051	0.9685	0.0052	0.9049
33	0.0050	0.9747	0.0051	0.9100
34	0.0049	0.9807	0.0052	0.9152
35	0.0049	0.9893	0.0054	0.9206
36	0.0074	0.9949	0.0054	0.9260
C_{37+}	0.0681	1.0000	0.0740	1.0000
MW	194.8		180.9	

MW: weighted average molecular weight, g/mole

Table B2: Produced Oil Compositions, CO_2 – Sulimar Queen Oil Extraction at 95 °F

Carbon #	Mole Fraction			
	Extraction Pressures, psig			
	1055	1200	1400	1600
5	0.0019	0.0088	0.0072	0.0098
6	0.0301	0.0459	0.0445	0.0440
7	0.1128	0.1206	0.1173	0.1153
8	0.1433	0.1427	0.1355	0.1370
9	0.1458	0.1395	0.1358	0.1356
10	0.1286	0.1191	0.1185	0.1179
11	0.0939	0.0867	0.0892	0.0882
12	0.0690	0.0632	0.0649	0.0645
13	0.0593	0.0550	0.0568	0.0567
14	0.0429	0.0409	0.0417	0.0417
15	0.0322	0.0307	0.0319	0.0319
16	0.0276	0.0267	0.0283	0.0282
17	0.0248	0.0242	0.0256	0.0257
18	0.0160	0.0160	0.0172	0.0171
19	0.0148	0.0153	0.0164	0.0164
20	0.0094	0.0099	0.0107	0.0107
21	0.0078	0.0083	0.0089	0.0090
22	0.0066	0.0072	0.0077	0.0078
23	0.0038	0.0042	0.0045	0.0046
24	0.0045	0.0052	0.0055	0.0056
25	0.0038	0.0045	0.0048	0.0049
26	0.0023	0.0027	0.0029	0.0030
27	0.0029	0.0035	0.0038	0.0038
28	0.0018	0.0022	0.0023	0.0024
29	0.0025	0.0030	0.0032	0.0033
30	0.0015	0.0019	0.0020	0.0021
31	0.0015	0.0018	0.0019	0.0020
32	0.0014	0.0017	0.0019	0.0019
33	0.0022	0.0026	0.0028	0.0029
34	0.0015	0.0018	0.0020	0.0020
35	0.0016	0.0019	0.0021	0.0021
36	0.0017	0.0020	0.0021	0.0022
C_{37+}	0.0000	0.0000	0.0000	0.0000
MW	161	160	162	163

MW : weighted average molecular weight, g/mole

Table B3: Produced Oil Compositions, CO_2-Sulimar Queen Oil Extraction at 138° F

Carbon #	Mole Fraction					
	Extraction Pressures, psig					
	1200	1400	1500	1600	1800	1900
5	0.0014	0.0046	0.0031	0.0008	0.0055	0.0043
6	0.0230	0.0361	0.0380	0.0211	0.0259	0.0059
7	0.1070	0.1261	0.1271	0.1053	0.0797	0.0174
8	0.1591	0.1563	0.1433	0.1348	0.1293	0.0776
9	0.1813	0.1671	0.1520	0.1441	0.1490	0.1367
10	0.1668	0.1494	0.1356	0.1313	0.1459	0.1564
11	0.1356	0.1172	0.1108	0.1122	0.1143	0.1344
12	0.0842	0.0707	0.0750	0.0801	0.0823	0.1007
13	0.0560	0.0496	0.0612	0.0679	0.0678	0.0875
14	0.0293	0.0306	0.0410	0.0467	0.0462	0.0624
15	0.0160	0.0218	0.0284	0.0345	0.0329	0.0451
16	0.0090	0.0166	0.0218	0.0282	0.0267	0.0373
17	0.0062	0.0149	0.0171	0.0229	0.0232	0.0324
18	0.0030	0.0081	0.0096	0.0140	0.0144	0.0205
19	0.0023	0.0060	0.0080	0.0121	0.0127	0.0185
20	0.0015	0.0036	0.0045	0.0071	0.0078	0.0114
21	0.0012	0.0023	0.0032	0.0055	0.0062	0.0091
22	0.0011	0.0018	0.0025	0.0044	0.0050	0.0075
23	0.0007	0.0010	0.0013	0.0025	0.0028	0.0042
24	0.0009	0.0011	0.0015	0.0029	0.0033	0.0050
25	0.0009	0.0011	0.0013	0.0024	0.0028	0.0041
26	0.0006	0.0007	0.0008	0.0014	0.0016	0.0024
27	0.0009	0.0010	0.0011	0.0019	0.0021	0.0030
28	0.0007	0.0007	0.0007	0.0012	0.0013	0.0018
29	0.0012	0.0012	0.0012	0.0018	0.0018	0.0025
30	0.0009	0.0009	0.0009	0.0013	0.0011	0.0015
31	0.0010	0.0010	0.0010	0.0013	0.0011	0.0015
32	0.0011	0.0011	0.0011	0.0014	0.0011	0.0014
33	0.0020	0.0020	0.0019	0.0024	0.0018	0.0022
34	0.0015	0.0016	0.0015	0.0019	0.0013	0.0016
35	0.0017	0.0018	0.0018	0.0021	0.0014	0.0017
36	0.0019	0.0020	0.0020	0.0023	0.0015	0.0018
C_{37+}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MW	146	148	151	160	160	176

MW : weighted average molecular weight, g/mole

Table B4: Produced Oil Compositions, CO_2-Spraberry Oil Extraction at 95 °F

Carbon #	Mole Fraction				
	Extraction Pressures, psig				
	1030	1100	1200	1400	1600
5	0.0064	0.0112	0.0004	0.0112	0.0002
6	0.0376	0.0471	0.0071	0.0564	0.0028
7	0.1422	0.1594	0.1000	0.1733	0.0615
8	0.1556	0.1583	0.1573	0.1559	0.1247
9	0.1351	0.1317	0.1450	0.1226	0.1333
10	0.1137	0.1075	0.1235	0.0988	0.1256
11	0.0878	0.0822	0.0948	0.0758	0.1040
12	0.0659	0.0606	0.0703	0.0569	0.0842
13	0.0559	0.0513	0.0601	0.0489	0.0714
14	0.0396	0.0366	0.0434	0.0354	0.0519
15	0.0284	0.0263	0.0316	0.0260	0.0384
16	0.0245	0.0230	0.0280	0.0232	0.0344
17	0.0240	0.0222	0.0274	0.0228	0.0341
18	0.0151	0.0143	0.0179	0.0151	0.0224
19	0.0136	0.0131	0.0167	0.0140	0.0209
20	0.0088	0.0084	0.0110	0.0093	0.0136
21	0.0073	0.0071	0.0094	0.0079	0.0116
22	0.0062	0.0060	0.0082	0.0068	0.0101
23	0.0036	0.0036	0.0049	0.0041	0.0060
24	0.0044	0.0044	0.0061	0.0051	0.0075
25	0.0038	0.0038	0.0055	0.0045	0.0066
26	0.0023	0.0023	0.0033	0.0027	0.0039
27	0.0030	0.0031	0.0045	0.0037	0.0053
28	0.0018	0.0019	0.0028	0.0023	0.0032
29	0.0026	0.0027	0.0040	0.0033	0.0045
30	0.0015	0.0016	0.0024	0.0020	0.0027
31	0.0015	0.0016	0.0023	0.0019	0.0025
32	0.0014	0.0015	0.0022	0.0018	0.0024
33	0.0021	0.0023	0.0032	0.0027	0.0034
34	0.0014	0.0016	0.0022	0.0018	0.0023
35	0.0015	0.0017	0.0022	0.0019	0.0023
36	0.0016	0.0017	0.0021	0.0019	0.0023
C_{37+}	0.0000	0.0000	0.0000	0.0000	0.0000
MW	157	154	167	155	177

MW : weighted average molecular weight, g/mole

Table B5. Produced Oil Compositions: CO_2-Spraberry Oil Extraction at 138 °F

| Carbon # | Mole Fraction | | | | | |
| | Extraction Pressures, psig | | | | | |
	1500	1550	1600	1700	1800	1900
5	0.0059	0.0040	0.0074	0.0100	0.0109	0.0099
6	0.0260	0.0232	0.0565	0.0567	0.0451	0.0405
7	0.0979	0.1163	0.1862	0.1773	0.1551	0.1415
8	0.1265	0.1538	0.1740	0.1656	0.1569	0.1465
9	0.1423	0.1562	0.1426	0.1413	0.1356	0.1313
10	0.1454	0.1395	0.1114	0.1100	0.1109	0.1110
11	0.1166	0.1048	0.0797	0.0806	0.0851	0.0880
12	0.0832	0.0734	0.0549	0.0569	0.0613	0.0650
13	0.0664	0.0591	0.0445	0.0466	0.0515	0.0557
14	0.0444	0.0397	0.0299	0.0321	0.0365	0.0400
15	0.0309	0.0273	0.0211	0.0226	0.0266	0.0294
16	0.0249	0.0214	0.0175	0.0190	0.0230	0.0255
17	0.0228	0.0198	0.0163	0.0179	0.0217	0.0245
18	0.0138	0.0117	0.0101	0.0111	0.0137	0.0156
19	0.0122	0.0099	0.0090	0.0100	0.0126	0.0144
20	0.0074	0.0062	0.0057	0.0063	0.0080	0.0092
21	0.0060	0.0049	0.0047	0.0052	0.0067	0.0078
22	0.0049	0.0042	0.0040	0.0044	0.0057	0.0067
23	0.0027	0.0024	0.0023	0.0026	0.0034	0.0039
24	0.0032	0.0030	0.0029	0.0032	0.0041	0.0048
25	0.0026	0.0027	0.0025	0.0028	0.0036	0.0043
26	0.0014	0.0016	0.0015	0.0017	0.0022	0.0025
27	0.0018	0.0023	0.0021	0.0023	0.0029	0.0034
28	0.0011	0.0014	0.0013	0.0014	0.0018	0.0021
29	0.0015	0.0020	0.0019	0.0021	0.0026	0.0030
30	0.0010	0.0012	0.0012	0.0013	0.0016	0.0018
31	0.0009	0.0012	0.0012	0.0013	0.0016	0.0018
32	0.0010	0.0011	0.0012	0.0013	0.0015	0.0017
33	0.0016	0.0017	0.0019	0.0020	0.0024	0.0026
34	0.0012	0.0012	0.0014	0.0014	0.0017	0.0018
35	0.0013	0.0013	0.0015	0.0015	0.0018	0.0019
36	0.0014	0.0014	0.0016	0.0016	0.0018	0.0019
C_{37+}	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
MW	158	154	146	148	154	158

MW : weighted average molecular weight, g/mole

Table B6. Compositions of Extraction Residues

Carbon #	Mole Fraction				
	Sulimar Queen STO		Spraberry Separator Oil		Extended Exp.
	95°F	138°F	95°F	138°F	
5	0.0405	0.0257	0.0483	0.0247	0.0028
6	0.0707	0.0575	0.0792	0.0516	0.0010
7	0.0852	0.0954	0.1105	0.0860	0.0010
8	0.0873	0.0781	0.0854	0.0725	0.0013
9	0.0736	0.0642	0.0633	0.0595	0.0016
10	0.0637	0.0573	0.0522	0.0532	0.0023
11	0.0460	0.0449	0.0393	0.0415	0.0033
12	0.0433	0.0444	0.0382	0.0408	0.0054
13	0.0416	0.0445	0.0367	0.0411	0.0092
14	0.0317	0.0338	0.0272	0.0313	0.0116
15	0.0376	0.0399	0.0324	0.0365	0.0215
16	0.0284	0.0305	0.0243	0.0281	0.0240
17	0.0223	0.0252	0.0199	0.0232	0.0239
18	0.0266	0.0300	0.0236	0.0277	0.0369
19	0.0182	0.0201	0.0157	0.0187	0.0326
20	0.0170	0.0187	0.0147	0.0174	0.0360
21	0.0045	0.0053	0.0043	0.0050	0.0104
22	0.0064	0.0067	0.0053	0.0061	0.0146
23	0.0085	0.0100	0.0077	0.0095	0.0222
24	0.0057	0.0059	0.0048	0.0054	0.0146
25	0.0081	0.0096	0.0073	0.0092	0.0239
26	0.0050	0.0054	0.0043	0.0050	0.0145
27	0.0073	0.0088	0.0069	0.0084	0.0230
28	0.0082	0.0093	0.0073	0.0129	0.0270
29	0.0112	0.0133	0.0105	0.0126	0.0387
30	0.0076	0.0089	0.0070	0.0085	0.0280
31	0.0109	0.0134	0.0108	0.0128	0.0409
32	0.0115	0.0140	0.0116	0.0134	0.0435
33	0.0157	0.0193	0.0161	0.0187	0.0607
34	0.0217	0.0256	0.0214	0.0253	0.0800
35	0.0191	0.0213	0.0169	0.0225	0.0668
36	0.0146	0.0159	0.0125	0.0187	0.0521
C_{37+}	0.1003	0.0966	0.1343	0.1524	0.2249
MW	238	248	245	271	421

MW: weighted average molecular weight, g/mole

Table B7. Produced Oil Compositions: Extended Extraction Experiment

Carbon #	Mole Fraction					
	Sample Number *)					
	98.0	95.0	94.0	90.7	87.5	84.5
5	0.0032	0.0176	0.0236	0.0250	0.0029	0.0002
6	0.0233	0.0797	0.0685	0.0714	0.0429	0.0020
7	0.0819	0.1458	0.1411	0.1323	0.1311	0.0548
8	0.1159	0.1354	0.1444	0.1343	0.1543	0.1342
9	0.1195	0.1122	0.1195	0.1230	0.1352	0.1510
10	0.1083	0.0921	0.1003	0.1024	0.1090	0.1410
11	0.0868	0.0670	0.0720	0.0707	0.0821	0.1059
12	0.0649	0.0531	0.0524	0.0619	0.0586	0.0752
13	0.0596	0.0460	0.0471	0.0488	0.0519	0.0649
14	0.0454	0.0354	0.0349	0.0356	0.0379	0.0478
15	0.0375	0.0283	0.0279	0.0274	0.0298	0.0365
16	0.0338	0.0255	0.0248	0.0247	0.0262	0.0315
17	0.0334	0.0243	0.0234	0.0227	0.0244	0.0291
18	0.0228	0.0175	0.0159	0.0160	0.0164	0.0194
19	0.0239	0.0134	0.0163	0.0122	0.0164	0.0191
20	0.0166	0.0119	0.0110	0.0107	0.0109	0.0126
21	0.0148	0.0104	0.0097	0.0093	0.0095	0.0108
22	0.0138	0.0094	0.0088	0.0083	0.0084	0.0095
23	0.0086	0.0083	0.0054	0.0071	0.0051	0.0057
24	0.0111	0.0074	0.0069	0.0063	0.0064	0.0071
25	0.0101	0.0068	0.0062	0.0057	0.0056	0.0062
26	0.0067	0.0044	0.0040	0.0036	0.0036	0.0039
27	0.0089	0.0060	0.0053	0.0050	0.0047	0.0050
28	0.0058	0.0039	0.0034	0.0032	0.0030	0.0031
29	0.0081	0.0038	0.0048	0.0031	0.0041	0.0043
30	0.0053	0.0055	0.0031	0.0046	0.0027	0.0027
31	0.0050	0.0034	0.0030	0.0030	0.0026	0.0026
32	0.0048	0.0035	0.0029	0.0030	0.0025	0.0025
33	0.0069	0.0036	0.0043	0.0031	0.0037	0.0037
34	0.0045	0.0036	0.0029	0.0032	0.0026	0.0025
35	0.0045	0.0038	0.0030	0.0034	0.0027	0.0026
36	0.0044	0.0039	0.0029	0.0035	0.0027	0.0026
C_{37+}	0.0000	0.0070	0.0000	0.0054	0.0000	0.0000
MW	186	167	161	163	163	175

*) Sample number 98 means that the sample was taken when the vessel still
contained 98 wt.% of the original oil in place
**) MW : weighted average molecular weight, g/mole

Table B7: — continued

Carbon #	Mole Fraction					
	Sample Number *)					
	82.2	80.0	77.1	75.2	74.6	74.0
5	0.0163	0.0154	0.0002	0.0037	0.0013	0.0004
6	0.0554	0.0565	0.0035	0.0161	0.0160	0.0119
7	0.1308	0.1226	0.0574	0.0575	0.0703	0.0647
8	0.1479	0.1279	0.1306	0.1077	0.1068	0.1153
9	0.1338	0.1312	0.1526	0.1464	0.1201	0.1376
10	0.1095	0.1092	0.1380	0.1491	0.1209	0.1338
11	0.0818	0.0808	0.1060	0.1130	0.1076	0.1085
12	0.0589	0.0633	0.0803	0.0828	0.0777	0.0824
13	0.0523	0.0528	0.0694	0.0742	0.0692	0.0739
14	0.0377	0.0392	0.0498	0.0509	0.0510	0.0536
15	0.0292	0.0311	0.0383	0.0409	0.0437	0.0414
16	0.0253	0.0295	0.0326	0.0339	0.0395	0.0349
17	0.0230	0.0262	0.0294	0.0300	0.0352	0.0314
18	0.0153	0.0175	0.0192	0.0185	0.0250	0.0202
19	0.0150	0.0131	0.0184	0.0168	0.0185	0.0192
20	0.0098	0.0111	0.0118	0.0104	0.0156	0.0120
21	0.0084	0.0094	0.0099	0.0084	0.0129	0.0099
22	0.0073	0.0081	0.0085	0.0070	0.0107	0.0083
23	0.0044	0.0068	0.0050	0.0040	0.0086	0.0048
24	0.0054	0.0058	0.0060	0.0047	0.0071	0.0057
25	0.0047	0.0051	0.0051	0.0039	0.0060	0.0047
26	0.0029	0.0031	0.0031	0.0023	0.0035	0.0028
27	0.0038	0.0042	0.0039	0.0028	0.0046	0.0035
28	0.0023	0.0026	0.0024	0.0017	0.0027	0.0021
29	0.0032	0.0026	0.0033	0.0023	0.0026	0.0029
30	0.0021	0.0038	0.0021	0.0014	0.0037	0.0018
31	0.0020	0.0025	0.0020	0.0014	0.0024	0.0017
32	0.0019	0.0025	0.0019	0.0013	0.0024	0.0017
33	0.0030	0.0027	0.0029	0.0021	0.0026	0.0026
34	0.0021	0.0028	0.0021	0.0015	0.0028	0.0019
35	0.0022	0.0030	0.0022	0.0017	0.0030	0.0021
36	0.0022	0.0033	0.0022	0.0017	0.0033	0.0021
C_{37+}	0.0000	0.0045	0.0000	0.0000	0.0027	0.0000
MW, all	158	165	172	169	179	172

*) Sample number 82.2 means that the sample was taken when the vessel still contained 82.2 wt.% of the original oil in place

**) MW : weighted average molecular weight, g/mole

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Table B7: — continued

Carbon #	Mole Fraction					
	Sample Number *)					
	72.5	72.2	70.7	69.7	68.3	67.9
5	0.0003	0.0004	0.0002	0.0002	0.0021	0.0002
6	0.0085	0.0071	0.0002	0.0025	0.0195	0.0008
7	0.0511	0.0731	0.0122	0.0263	0.0747	0.0188
8	0.1063	0.1113	0.0613	0.0691	0.1123	0.0631
9	0.1381	0.1291	0.1158	0.1109	0.1205	0.1087
10	0.1426	0.1182	0.1469	0.1380	0.1160	0.1322
11	0.1121	0.0965	0.1257	0.1264	0.0917	0.1222
12	0.0853	0.0732	0.1066	0.0987	0.0699	0.1043
13	0.0764	0.0660	0.0968	0.0936	0.0628	0.0947
14	0.0557	0.0480	0.0658	0.0676	0.0466	0.0706
15	0.0457	0.0414	0.0561	0.0521	0.0430	0.0571
16	0.0378	0.0377	0.0465	0.0444	0.0395	0.0484
17	0.0345	0.0371	0.0415	0.0395	0.0357	0.0458
18	0.0213	0.0238	0.0259	0.0253	0.0257	0.0278
19	0.0189	0.0238	0.0229	0.0237	0.0226	0.0253
20	0.0116	0.0179	0.0140	0.0148	0.0180	0.0153
21	0.0095	0.0167	0.0113	0.0121	0.0157	0.0122
22	0.0079	0.0161	0.0093	0.0100	0.0136	0.0100
23	0.0045	0.0121	0.0053	0.0056	0.0108	0.0056
24	0.0053	0.0097	0.0062	0.0067	0.0086	0.0066
25	0.0044	0.0077	0.0050	0.0054	0.0071	0.0053
26	0.0026	0.0044	0.0030	0.0032	0.0041	0.0031
27	0.0032	0.0053	0.0036	0.0039	0.0053	0.0038
28	0.0019	0.0031	0.0021	0.0023	0.0031	0.0022
29	0.0025	0.0027	0.0028	0.0030	0.0029	0.0029
30	0.0016	0.0037	0.0017	0.0019	0.0042	0.0018
31	0.0015	0.0022	0.0016	0.0018	0.0027	0.0016
32	0.0014	0.0021	0.0016	0.0018	0.0027	0.0016
33	0.0022	0.0020	0.0024	0.0028	0.0029	0.0024
34	0.0016	0.0019	0.0017	0.0020	0.0031	0.0017
35	0.0017	0.0019	0.0019	0.0022	0.0034	0.0017
36	0.0018	0.0020	0.0019	0.0022	0.0035	0.0020
C_{37+}	0.0000	0.0016	0.0000	0.0000	0.0057	0.0000
MW, all	173	181	184	184	183	186

*) Sample number 72.5 means that the sample was taken when the vessel still contained 72.5 wt.% of the original oil in place

**) MW : weighted average molecular weight, g/mole

Table B7: — continued

Carbon #	Mole Fraction					
	Sample Number *)					
	66.1	63.9	63.0	62.2	60.6	59.7
5	0.0003	0.0002	0.0003	0.0002	0.0003	0.0003
6	0.0013	0.0007	0.0003	0.0004	0.0002	0.0005
7	0.0133	0.0067	0.0021	0.0037	0.0009	0.0023
8	0.0418	0.0253	0.0115	0.0148	0.0056	0.0073
9	0.0792	0.0559	0.0345	0.0366	0.0183	0.0190
10	0.1140	0.0972	0.0711	0.0733	0.0425	0.0419
11	0.1228	0.1162	0.1046	0.0957	0.0727	0.0708
12	0.1048	0.1057	0.1080	0.1320	0.0856	0.0835
13	0.1027	0.1079	0.1185	0.0981	0.1036	0.1031
14	0.0780	0.0862	0.0954	0.0772	0.0936	0.0955
15	0.0657	0.0744	0.0855	0.0694	0.0953	0.0869
16	0.0565	0.0656	0.0754	0.0636	0.0892	0.0876
17	0.0519	0.0603	0.0696	0.0592	0.0905	0.0848
18	0.0334	0.0399	0.0467	0.0482	0.0681	0.0607
19	0.0316	0.0378	0.0437	0.0366	0.0601	0.0608
20	0.0197	0.0236	0.0271	0.0358	0.0383	0.0393
21	0.0160	0.0192	0.0215	0.0383	0.0297	0.0324
22	0.0132	0.0157	0.0175	0.0223	0.0236	0.0269
23	0.0074	0.0088	0.0097	0.0180	0.0130	0.0151
24	0.0087	0.0102	0.0112	0.0140	0.0148	0.0174
25	0.0069	0.0081	0.0089	0.0108	0.0115	0.0137
26	0.0040	0.0047	0.0051	0.0059	0.0065	0.0078
27	0.0048	0.0056	0.0060	0.0072	0.0076	0.0091
28	0.0028	0.0032	0.0035	0.0039	0.0042	0.0051
29	0.0036	0.0041	0.0044	0.0035	0.0052	0.0063
30	0.0022	0.0024	0.0026	0.0047	0.0030	0.0036
31	0.0020	0.0022	0.0024	0.0028	0.0027	0.0032
32	0.0019	0.0021	0.0022	0.0027	0.0024	0.0028
33	0.0029	0.0032	0.0033	0.0027	0.0035	0.0040
34	0.0020	0.0023	0.0023	0.0028	0.0024	0.0026
35	0.0022	0.0024	0.0025	0.0030	0.0025	0.0027
36	0.0023	0.0025	0.0026	0.0032	0.0026	0.0028
C_{37+}	0.0000	0.0000	0.0000	0.0096	0.0000	0.0000
MW, all	196	204	212	220	227	229

*) Sample number 66.1 means that the sample was taken when the vessel still
contained 66.1 wt.% of the original oil in place
**) MW : weighted average molecular weight, g/mole

Table B7: — continued

Carbon #	Mole Fraction				
	Sample Number *)				
	58.8	58.1	57.8	57.2	56.0
5	0.0003	0.0004	0.0003	0.0003	0.0004
6	0.0002	0.0002	0.0002	0.0002	0.0003
7	0.0007	0.0003	0.0004	0.0004	0.0004
8	0.0030	0.0008	0.0015	0.0014	0.0011
9	0.0094	0.0035	0.0059	0.0049	0.0037
10	0.0237	0.0136	0.0206	0.0149	0.0113
11	0.0457	0.0348	0.0474	0.0340	0.0275
12	0.0597	0.0513	0.0724	0.0491	0.0405
13	0.0860	0.0787	0.0941	0.0742	0.0555
14	0.0881	0.0824	0.0834	0.0839	0.0823
15	0.0885	0.0904	0.0803	0.0865	0.0823
16	0.0964	0.1028	0.0822	0.0948	0.0961
17	0.1106	0.1087	0.0750	0.0992	0.1058
18	0.0760	0.0786	0.0541	0.0773	0.0821
19	0.0740	0.0806	0.0507	0.0828	0.0874
20	0.0493	0.0566	0.0463	0.0556	0.0593
21	0.0415	0.0465	0.0432	0.0489	0.0535
22	0.0337	0.0398	0.0389	0.0421	0.0496
23	0.0185	0.0219	0.0348	0.0244	0.0273
24	0.0210	0.0245	0.0315	0.0285	0.0301
25	0.0164	0.0190	0.0261	0.0218	0.0236
26	0.0093	0.0107	0.0144	0.0124	0.0135
27	0.0108	0.0123	0.0174	0.0145	0.0155
28	0.0060	0.0068	0.0093	0.0080	0.0087
29	0.0073	0.0082	0.0082	0.0098	0.0104
30	0.0041	0.0046	0.0103	0.0055	0.0058
31	0.0036	0.0040	0.0057	0.0047	0.0049
32	0.0031	0.0035	0.0052	0.0041	0.0043
33	0.0043	0.0048	0.0050	0.0054	0.0057
34	0.0029	0.0032	0.0050	0.0034	0.0036
35	0.0030	0.0033	0.0052	0.0034	0.0037
36	0.0030	0.0033	0.0053	0.0034	0.0037
C_{37+}	0.0000	0.0000	0.0196	0.0000	0.0000
MW, all	242	257	249	252	258

*) Sample number 58.8 means that the sample was taken when the vessel still
contained 58.8 wt.% of the original oil in place
**) MW : weighted average molecular weight, g/mole

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Appendix C

Slim Tube Displacement Data

Table C1: Slim Tube Experimental Data: Sulimar Queen Oil at 95 °F

Oil Sample   : Sulimar Queen STO
Temperature   : 95 °F
Pressure   : 800 psig
Injecion rate   : 30 ml/hr

Time	CO_2 Injected	Slim Tube			Recovery			Remark
		P in	P out	dP		Cumulative		
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	809	697	112	4	4	3.4	
15	6.3	805	702	103	2.8	6.8	5.8	
45	18.9	802	691	111	3.2	10	8.5	
60	25.2	806	702	104	4	14	11.9	
80	33.6	808	710	98	2.9	16.9	14.3	
100	42.0	802	701	101	4.2	21.1	17.9	
120	50.4	800	711	89	3.2	24.3	20.6	
140	58.8	798	722	76	1.8	26.1	22.2	
160	67.2	793	728	65	2.1	28.2	23.9	
180	75.6	801	742	59	2.4	30.6	26.0	
200	84.0	803	749	54	2.2	32.8	27.8	
220	92.4	808	761	47	3.9	36.7	31.1	
240	100.8	802	768	34	3.9	40.6	34.5	
260	109.2	800	771	29	2.5	43.1	36.6	
280	117.6	795	777	18	2.3	45.4	38.5	
300	126.1	798	785	13	2.6	48	40.7	
320	134.5	803	793	10	2.6	50.6	42.9	BT
340	142.9	803	796	7	1	51.6	43.8	
360	151.3	808	805	3	1	52.6	44.6	
380	159.7	810	804	6	1.1	53.7	45.6	
400	168.1	811	807	4	1	54.7	46.4	
420	176.5	811	806	5	0	54.7	46.4	

Average gas rate after breakthrough: 3.4 l/hr   BT= CO_2 breakthrough

Table C1: —continued

Oil Sample   : Sulimar Queen STO
Temperature   : 95 °F
Pressure   : 1020 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 | Slim Tube | | | Recovery | | | Remark |
min.	Injected %PV	P in psig	P out psig	dP psi	ml	Cumulative ml	%	
10	4.2	1028	826	202	2.8	2.8	2.4	
15	6.3	1026	821	205	1.5	4.3	3.6	
30	12.6	1023	825	198	4.6	8.9	7.6	
45	18.9	1021	912	109	5.5	14.4	12.2	
60	25.2	1019	919	100	3.4	17.8	15.1	
80	33.6	1019	921	98	9.1	26.9	22.8	
100	42.0	1022	933	89	6.2	33.1	28.1	
120	50.4	1026	950	76	3.9	37	31.4	
140	58.8	1019	954	65	8.3	45.3	38.4	
160	67.2	1020	965	55	6.1	51.4	43.6	
180	75.6	1020	997	23	11.1	62.5	53.0	
200	84.0	1018	1006	12	7.9	70.4	59.8	
220	92.4	1019	1010	9	8.9	79.3	67.3	
240	100.8	1017	1009	8	7.8	87.1	73.9	BT
260	109.2	1021	1013	8	3.1	90.2	76.6	
280	117.6	1023	1018	5	3.1	93.3	79.2	
300	126.1	1024	1020	4	2.2	95.5	81.1	
320	134.5	1023	1018	5	0.2	95.7	81.2	
340	142.9	1022	1019	3	0	95.7	81.2	
360	151.3	1024	1022	2	0	95.7	81.2	
380	159.7	1024	1018	6	0	95.7	81.2	
400	168.1	1026	1019	7	0	95.7	81.2	

Average gas rate after breakthrough: 4.5 l/hr   BT= CO_2 breakthrough

Table C1:—continued

Oil Sample   : Sulimar Queen STO
Temperature   : 95 °F
Pressure   : 1100 psig
Injecion rate   : 30 ml/hr

Time	CO$_2$ Injected	Slim Tube				Recovery		Remark
		P in	P out	dP			Cumulative		
min.	%PV	psig	psig	psi	ml	ml	%	
10	4.2	1103	1053	50	3.2	3.2	2.8	
15	6.3	1111	1055	56	1.8	5	4.3	
30	12.6	1109	1056	53	1.8	6.8	5.9	
45	18.9	1113	1068	45	0.8	7.6	6.6	
60	25.2	1113	1066	47	2.1	9.7	8.4	
80	33.6	1108	1052	56	3.9	13.6	11.8	
100	42.0	1114	1063	51	13.1	26.7	23.1	
120	50.4	1116	1069	47	9.1	35.8	31.0	
140	58.8	1115	1072	43	8.4	44.2	38.3	
160	67.2	1117	1072	45	1.9	46.1	39.9	
180	75.6	1107	1073	34	7.2	53.3	46.1	
200	84.0	1105	1079	26	10.1	63.4	54.9	
220	92.4	1112	1088	24	8.4	71.8	62.1	
240	100.8	1111	1088	23	10.5	82.3	71.2	
260	109.2	1114	1091	23	5.9	88.2	76.3	
280	117.6	1116	1100	16	11.3	99.5	86.1	
300	126.1	1112	1104	8	4.5	104	90.0	BT
320	134.5	1109	1103	6	2.6	106.6	92.3	
340	142.9	1105	1098	7	1.8	108.4	93.8	
360	151.3	1107	1103	4	0.1	108.5	93.9	
380	159.7	1109	1102	7	0	108.5	93.9	
400	168.1	1108	1099	9	0	108.5	93.9	
420	176.5	1112	1108	4	0	108.5	93.9	

Average gas rate after breakthrough: 6.35 l/hr   BT= CO$_2$ breakthrough

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Table C1:—continued

Oil Sample : Sulimar Queen STO
Temperature : 95 °F
Pressure   : 1130 psig
Injecion rate : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%PV	psig	psig	psi	ml	ml	%	
10	4.2	1129	1044	85	3.2	3.2	2.8	
15	6.3	1131	1053	78	2.8	6	5.2	
30	12.6	1129	1061	68	6.5	12.5	10.8	
45	18.9	1130	1043	87	7.6	20.1	17.4	
60	25.2	1130	1044	86	5.4	25.5	22.1	
80	33.6	1129	1064	65	7.9	33.4	28.9	
100	42.0	1131	1076	55	4.7	38.1	33.0	
120	50.4	1136	1089	47	1.3	39.4	34.1	
140	58.8	1131	1090	41	6.6	46	39.8	
160	67.2	1132	1087	45	6.1	52.1	45.1	
180	75.6	1129	1095	34	2.3	54.4	47.1	
200	84.0	1128	1096	32	11.4	65.8	57.0	
220	92.4	1132	1108	24	8.9	74.7	64.7	
240	100.8	1131	1112	19	10.1	84.8	73.4	
260	109.2	1133	1120	13	11.8	96.6	83.6	
280	117.6	1132	1123	9	4.5	101.1	87.5	BT
300	126.1	1132	1124	8	5	106.1	91.8	
320	134.5	1129	1123	6	2.1	108.2	93.7	
340	142.9	1125	1118	7	0.5	108.7	94.1	
360	151.3	1127	1123	4	0.1	108.8	94.2	
380	159.7	1129	1122	7	0	108.8	94.2	
400	168.1	1128	1119	9	0	108.8	94.2	
420	176.5	1132	1128	4	0	108.8	94.2	

Average gas rate after breakthrough: 11.56 l/hr   BT= CO_2 breakthrough

Table C1:—continued

Oil Sample : Sulimar Queen STO
Temperature : 95 °F
Pressure : 1240 psig
Injecion rate : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%PV	psig	psig	psi	ml	ml	%	
10	4.2	1250	1140	110	3.1	3.1	2.7	
15	6.3	1244	1123	121	5.1	8.2	7.1	
30	12.6	1241	1130	111	2.6	10.8	9.3	
45	18.9	1242	1124	118	6.6	17.4	15.1	
60	25.2	1241	1132	109	5.3	22.7	19.6	
80	33.6	1238	1143	95	7.4	30.1	26.1	
100	42.0	1238	1150	88	12.3	42.4	36.7	
120	50.4	1239	1168	71	8.9	51.3	44.4	
140	58.8	1238	1182	56	12.7	64	55.4	
160	67.2	1237	1192	45	11.1	75.1	65.0	
180	75.6	1241	1207	34	10.8	85.9	74.4	
200	84.0	1243	1230	13	9.7	95.6	82.7	
220	92.4	1242	1233	9	4.6	100.2	86.7	BT
240	100.8	1244	1236	8	4.4	104.6	90.5	
260	109.2	1241	1234	7	2	106.6	92.3	
280	117.6	1239	1231	8	1.5	108.1	93.6	
300	126.1	1239	1233	6	0.4	108.5	93.9	
320	134.5	1238	1229	9	0.1	108.6	94.0	
340	142.9	1235	1230	5	0.1	108.7	94.1	
360	151.3	1239	1236	3	0	108.7	94.1	
380	159.7	1240	1238	2	0	108.7	94.1	
400	168.1	1243	1237	6	0	108.7	94.1	
420	176.5	1245	1241	4	0	108.7	94.1	

Average gas rate after breakthrough: 11.68 l/hr   BT= CO_2 breakthrough

Table C1: — continued

Oil Sample : Sulimar Queen STO
Temperature : 95 °F
Pressure : 1325 psig
Injecion rate : 30 ml/hr

Time	CO_2	Slim Tube			Recovery			Remark
	Injected	P in	P out	dP			Cumulative	
min.	%PV	psig	psig	psi	ml	ml	%	
10	4.2	1320	1202	118	3	3	2.6	
20	8.4	1323	1213	110	4.1	7.1	6.2	
30	12.6	1322	1213	109	6	13.1	11.4	
40	16.8	1320	1221	99	2.7	15.8	13.8	
60	25.2	1324	1242	82	4	24.3	21.2	
80	33.6	1325	1250	75	3	31.3	27.4	
100	42.0	1326	1257	69	4	40.1	35.0	
110	46.2	1323	1258	65	2.2	42.3	37.0	
120	50.4	1324	1263	61	5	47.3	41.3	
140	58.8	1325	1258	67	4.7	59	51.6	
160	67.2	1323	1258	65	2.7	67.5	59.0	
180	75.6	1325	1270	55	4.2	75.2	65.7	
190	79.8	1326	1281	45	5.4	80.6	70.4	
200	84.0	1326	1292	34	4.3	84.9	74.2	
220	92.4	1329	1315	14	2.8	91.7	80.1	
230	96.6	1330	1320	10	4.8	96.5	84.3	BT
240	100.8	1328	1323	5	4	100.5	87.8	
250	105.0	1325	1321	4	3.5	104	90.9	
260	109.2	1324	1318	6	1.4	105.4	92.1	
270	113.4	1321	1318	3	0.4	105.8	92.5	
280	117.6	1320	1315	5	1.4	107.2	93.7	
290	121.8	1322	1315	7	0.7	107.9	94.3	
320	134.5	1326	1321	5	0.1	108.9	95.2	
340	142.9	1328	1324	4	0.1	109	95.3	
360	151.3	1329	1325	4	0	109	95.3	
370	155.5	1330	1324	6	0	109	95.3	

Average gas rate after breakthrough: 12.8 l/hr   BT= CO_2 breakthrough

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Table C2: Slim Tube Experimental Data: Sulimar Queen Oil at 138 °F

Oil Sample   : Sulimar Queen STO
Temperature   : 138 °F
Pressure   : 1425 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
15	6.3	1429	1302	127	6	6	5.1	
30	12.6	1425	1312	113	6	12	10.3	
45	18.9	1422	1313	109	2	14	12.0	
60	25.2	1424	1333	91	9	23	19.7	
80	33.6	1426	1349	77	8	31	26.6	
100	42.0	1425	1352	73	4	35	30.0	
120	50.4	1433	1384	49	6	41	35.1	
140	58.8	1423	1392	31	4	45	38.6	
160	67.2	1424	1407	17	6	51	43.7	
180	75.6	1427	1416	11	5.5	56.5	48.4	
200	84.0	1429	1423	6	5.3	61.8	53.0	
210	88.2	1425	1420	5	2	63.8	54.7	BT
220	92.4	1424	1421	3	1.1	64.9	55.6	
240	100.8	1427	1424	3	0.2	65.1	55.8	
260	109.2	1431	1428	3	0	65.1	55.8	
290	121.8	1427	1424	3	0	65.1	55.8	
310	130.3	1427	1425	3	0	65.1	55.8	

Gas flow rate after break through: 11.64 l/hr   BT= CO_2 breakthrough

Table C2: — continued

Oil Sample   : Sulimar Queen STO
Temperature   : 138 °F
Pressure   : 1500 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 | Slim Tube | | | Recovery | | | Remark |
| | Injected | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
15	6.3	1503	1406	97	10	10	8.7	
30	12.6	1501	1400	101	3.1	13.1	11.3	
45	18.9	1497	1398	99	5.5	18.6	16.1	
60	25.2	1502	1402	100	1.4	20	17.3	
80	33.6	1496	1401	95	8.6	28.6	24.8	
100	42.0	1499	1423	76	3.7	32.3	28.0	
120	50.4	1503	1438	65	6.5	38.8	33.6	
140	58.8	1499	1457	42	6.7	45.5	39.4	
160	67.2	1500	1471	29	5.9	51.4	44.5	
180	75.6	1503	1480	23	4.6	56	48.5	
200	84.0	1499	1484	15	5.5	61.5	53.2	
220	92.4	1499	1490	9	8.3	69.8	60.4	
225	94.5	1502	1497	5	6.5	76.3	66.0	BT
240	100.8	1496	1493	3	3.9	80.2	69.4	
260	109.2	1498	1494	4	0.2	80.4	69.6	
280	117.6	1500	1496	4	0.1	80.5	69.7	
300	126.1	1502	1496	6	0	80.5	69.7	

Gas flow rate after break through: 13.82 l/hr   BT= CO_2 breakthrough

Table C2: − continued

Oil Sample   : Sulimar Queen STO
Temperature   : 138 °F
Pressure   : 1550 psig
Injecion rate   : 30 ml/hr

Time	CO$_2$ Injected	Slim Tube			Recovery			Remark
		P in	P out	dP			Cumulative	
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1562	1425	137	3	3	2.8	
15	6.3	1551	1426	125	11	14	13.2	
30	12.6	1552	1443	109	4	18	17.0	
45	18.9	1550	1450	100	8	26	24.6	
60	25.2	1549	1466	83	3	29	27.4	
80	33.6	1552	1489	63	7.8	36.8	34.8	
100	42.0	1554	1502	52	9.2	46	43.5	
120	50.4	1558	1515	43	8.1	54.1	51.1	
140	58.8	1554	1519	35	4.5	58.6	55.4	
160	67.2	1550	1521	29	3	61.6	58.2	
180	75.6	1556	1538	18	6.6	68.2	64.5	
200	84.0	1560	1547	13	5.3	73.5	69.5	
220	92.4	1548	1539	9	4.8	78.3	74.0	
240	100.8	1548	1544	4	7.2	85.5	80.8	BT
260	109.2	1550	1547	3	2.9	88.4	83.6	
280	117.6	1547	1545	2	1.2	89.6	84.7	
300	126.1	1559	1555	4	0.1	89.7	84.8	
330	138.7	1555	1549	6	0	89.7	84.8	

Gas flow rate after break through: 16.58 l/hr   BT= CO$_2$ breakthrough

Table C2: —continued

Oil Sample   : Sulimar Queen STO
Temperature   : 138 °F
Pressure   : 1600 psig
Injecion rate   : 30 ml/hr

Time	CO_2	Slim Tube			Recovery			Remark
	Injected	P in	P out	dP		Cumulative		
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1611	1488	123	3.5	3.5	3.1	
15	6.3	1600	1500	100	3.9	7.4	6.5	
30	12.6	1603	1491	112	4.6	12	10.5	
45	18.9	1603	1501	102	4.3	16.3	14.2	
60	25.2	1599	1502	97	5	21.3	18.6	
80	33.6	1598	1512	86	9.2	30.5	26.7	
100	42.0	1600	1522	78	9.4	39.9	34.9	
120	50.4	1607	1542	65	9.1	49	42.8	
140	58.8	1609	1553	56	8.1	57.1	49.9	
160	67.2	1601	1553	48	7	64.1	56.0	
180	75.6	1598	1564	34	7.3	71.4	62.4	
200	84.0	1595	1572	23	9.2	80.6	70.4	
220	92.4	1598	1587	11	7.9	88.5	77.3	
240	100.8	1600	1593	7	10.3	98.8	86.3	BT
260	109.2	1597	1593	4	3	101.8	89.0	
280	117.6	1599	1596	3	2.8	104.6	91.4	
300	126.1	1601	1595	6	2.4	107	93.5	
320	134.5	1604	1597	7	0.1	107.1	93.6	
340	142.9	1609	1604	5	0	107.1	93.6	

Ave. gas flow rate after breakthrough   18.24 l/hr   BT= CO_2 breakthrough

Table C2: — continued

Oil Sample   : Sulimar Queen STO
Temperature   : 138 °F
Pressure   : 1700 psig
Injecion rate   : 30 ml/hr

Time	CO_2 Injected	Slim Tube P in	Slim Tube P out	Slim Tube dP	Recovery ml	Recovery Cumulative ml	Recovery Cumulative %	Remark
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1709	1580	129	4	4	3.5	
15	6.3	1701	1585	116	4	8	7.1	
30	12.6	1703	1579	124	5	13	11.5	
45	18.9	1702	1594	108	6.1	19.1	16.9	
60	25.2	1709	1613	96	8.1	27.2	24.0	
80	33.6	1703	1616	87	6.4	33.6	29.6	
100	42.0	1698	1629	69	5.9	39.5	34.9	
120	50.4	1696	1642	54	9	48.5	42.8	
140	58.8	1700	1657	43	12.2	60.7	53.6	
160	67.2	1699	1664	35	8.2	68.9	60.8	
180	75.6	1695	1667	28	8.2	77.1	68.0	
200	84.0	1698	1677	21	5.6	82.7	73.0	
220	92.4	1701	1690	11	7.2	89.9	79.3	
230	96.6	1704	1697	7	9.5	99.4	87.7	BT
240	100.8	1703	1697	6	3.8	103.2	91.1	
260	109.2	1708	1703	5	4	107.2	94.6	
280	117.6	1709	1706	3	0.1	107.3	94.7	
300	126.1	1710	1705	5	0.1	107.4	94.8	
320	134.5	1712	1705	7	0	107.4	94.8	
330	138.7	1709	1706	3	0	107.4	94.8	

Ave. gas flow rate after breakthrough   19.23 l/hr   BT= CO_2 breakthrough

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Table C3: Slim Tube Experimental Data: Spraberry Oil at 95 °F

Oil Sample   : Spraberry Separator Oil
Temperature   : 95 ° F
Pressure   : 800 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
minute	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	803	690	113	4	4	3.5	
40	16.8	800	699	101	6.1	10.1	8.8	
75	31.5	801	712	89	4	14.1	12.3	
95	39.9	803	724	79	3.8	17.9	15.6	
125	52.5	802	746	56	6.6	24.5	21.4	
145	60.9	798	751	47	2.3	26.8	23.4	
165	69.3	799	765	34	6.1	32.9	28.8	
190	79.8	802	779	23	3.8	36.7	32.1	
220	92.4	801	783	18	5.1	41.8	36.5	
240	100.8	798	787	11	4.9	46.7	40.8	
245	102.9	799	790	9	7.5	54.2	47.4	BT
260	109.2	800	794	6	2.1	56.3	49.2	
275	115.5	799	792	7	0.7	57	49.8	
290	121.8	802	794	8	0.2	57.2	50.0	
305	128.2	801	799	2	0	57.2	50.0	
320	134.5	801	799	2	0	57.2	50.0	
335	140.8	798	793	5	0	57.2	50.0	
360	151.3	803	800	3	0	57.2	50.0	

Average gas production: BT= CO_2 breakthrough
Before breakthrough   0.096 l/hr
After breakthrough   3.54 l/hr

Table C3:—continued

Oil Sample   : Spraberry Separator Oil
Temperature   : 95 °F
Pressure   : 1000 psig
Injecion rate   : 30 ml/hr

Time	CO_2	Slim Tube			Recovery			Remark
	Injected	P in	P out	dP		Cumulative		
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1002	910	92	4.3	4.3	3.8	
15	6.3	1003	917	86	5.2	9.5	8.5	
45	18.9	1003	923	80	2.1	11.6	10.3	
60	25.2	1001	923	78	2.6	14.2	12.6	
80	33.6	999	934	65	3.9	18.1	16.1	
100	42.0	1002	957	45	2.9	21	18.7	
120	50.4	1001	967	34	5.2	26.2	23.3	
140	58.8	1005	971	34	5.1	31.3	27.9	
160	67.2	997	969	28	6.1	37.4	33.3	
180	75.6	998	974	24	5.8	43.2	38.5	
200	84.0	999	982	17	9.3	52.5	46.8	
220	92.4	998	984	14	2.8	55.3	49.3	
240	100.8	1001	990	11	7.8	63.1	56.2	
260	109.2	1002	993	9	8.2	71.3	63.5	
280	117.6	1002	995	7	7.7	79	70.4	BT
300	126.1	1001	996	5	2	81	72.2	
320	134.5	1000	997	3	1.4	82.4	73.4	
340	142.9	1004	996	8	0.4	82.8	73.8	
360	151.3	1006	1002	4	0.3	83.1	74.0	
380	159.7	1002	1000	2	0	83.1	74.0	

Average gas production: BT= CO_2 breakthrough
Before breakthrough   0.076 l/hr
After breakthrough   8.95 l/hr

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Table C3: —continued

Oil Sample   : Spraberry Separator Oil
Temperature   : 95 ° F
Pressure   : 1140 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | | Recovery | | Remark |
| | | P in | P out | dP | | | Cumulative | |
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1140	1025	115	6	6	5.4	
15	6.3	1142	1022	120	6.1	12.1	10.9	
30	12.6	1143	1041	102	3.3	15.4	13.8	
45	18.9	1138	1040	98	4.2	19.6	17.6	
60	25.2	1139	1048	91	5.6	25.2	22.7	
80	33.6	1140	1053	87	10.8	36	32.4	
100	42.0	1138	1062	76	9.3	45.3	40.7	
120	50.4	1142	1075	67	11.1	56.4	50.7	
140	58.8	1148	1089	59	7.9	64.3	57.8	
180	75.6	1144	1099	45	7.2	71.5	64.3	
210	88.2	1139	1107	32	12.9	84.4	75.9	
230	96.6	1141	1122	19	4.5	88.9	79.9	
260	109.2	1141	1132	9	6	94.9	85.3	BT
290	121.8	1143	1139	4	4	98.9	88.9	
300	126.1	1138	1133	5	0.9	99.8	89.7	
330	138.7	1139	1132	7	0.3	100.1	90.0	
360	151.3	1146	1141	5	0	100.1	90.0	

Average gas production: BT= CO_2 breakthrough
Before breakthrough   0.138 l/hr
After breakthrough   9.67 l/hr

Table C3: —continued

Oil Sample : Spraberry Separator Oil
Temperature : 95 °F
Pressure   : 1205 psig
Injecion rate : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1209	1104	105	9.2	9.2	8.34	
15	6.3	1205	1104	101	6.1	15.3	13.9	
30	12.6	1206	1102	104	7.3	22.6	20.5	
45	18.9	1203	1111	92	11.9	34.5	31.3	
60	25.2	1198	1102	96	4.8	39.3	35.7	
80	33.6	1204	1122	82	9.4	48.7	44.2	
100	42.0	1208	1122	86	6.9	55.6	50.5	
120	50.4	1203	1129	74	7.7	63.3	57.4	
140	58.8	1199	1132	67	9.6	72.9	66.2	
160	67.2	1199	1154	45	4.3	77.2	70.1	
180	75.6	1197	1170	27	5.7	82.9	75.2	
200	84.0	1202	1183	19	7.2	90.1	81.8	
220	92.4	1209	1197	12	2.5	92.6	84.0	
235	98.7	1208	1202	6	6.9	99.5	90.3	BT
240	100.8	1205	1199	6	4.4	103.9	94.3	
270	113.4	1199	1193	6	0.8	104.7	95.0	
300	126.1	1203	1197	6	0.1	104.8	95.1	
330	138.7	1203	1197	6	0	104.8	95.1	
360	151.3	1206	1200	6	0	104.8	95.1	

Average gas production: BT= CO_2 breakthrough
Before breakthrough 0.187 l/hr
After breakthrough   11.3 l/hr

Table C3: —continued

Oil Sample　　　　: Spraberry Separator Oil
Temperature　　　: 95 ° F
Pressure　　　　　: 1340 psig
Injecion rate　　　: 30 ml/hr

| Time | CO_2 | Slim Tube | | | Recovery | | | Remark |
| | Injected | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1350	1180	170	3.8	3.8	3.5	
15	6.3	1340	1190	150	4.2	8	7.4	
30	12.6	1340	1198	142	4	12	11.1	
60	25.2	1340	1220	120	4.8	16.8	15.5	
80	33.6	1340	1250	90	4.2	21	19.4	
100	42.0	1340	1264	76	5	26	24.0	
120	50.4	1340	1272	68	7.5	33.5	31.0	
140	58.8	1340	1283	57	6.2	39.7	36.7	
160	67.2	1340	1297	43	11.6	51.3	47.4	
180	75.6	1340	1304	36	8.8	60.1	55.6	
200	84.0	1340	1314	26	11.1	71.2	65.8	
220	92.4	1340	1325	15	11.2	82.4	76.2	
230	96.6	1340	1331	9	10	92.4	85.4	BT
240	100.8	1340	1333	7	4	96.4	89.1	
270	113.4	1340	1334	6	2.9	99.3	91.8	
300	126.1	1340	1332	8	2	101.3	93.6	
330	138.7	1340	1336	4	1.6	102.9	95.1	
360	151.3	1340	1337	3	0.6	103.5	95.7	
390	163.9	1340	1338	2	0.1	103.6	95.8	
420	176.5	1340	1332	8	0	103.6	95.8	
450	189.1	1340	1334	6	0	103.6	95.8	
480	201.7	1340	1335	5	0	103.6	95.8	

Average gas production:　　　　　　　　　　　BT= CO_2 breakthrough
Before breakthrough　　　　0.196 l/hr
After breakthrough　　　　　13.6 l/hr

Table C4: Slim Tube Experimental Data: Spraberry Oil at 138 °F

Oil Sample : Spraberry Separator Oil
Temperature : 138 °F
Pressure : 1400 psig
Injecion rate : 30 ml/hr

Time	CO_2	Slim Tube			Recovery			Remark
	Injected	P in	P out	dP		Cumulative		
min.	%P.V	psig	psig	psi	ml	ml	%	
10	4.2	1397	1330	67	3	3	2.6	
20	8.4	1402	1335	67	1.5	4.5	4.0	
30	12.6	1400	1340	60	6.5	11	9.7	
40	16.8	1399	1345	54	2	13	11.5	
60	25.2	1399	1353	46	3	16	14.1	
70	29.4	1397	1361	36	3.5	19.5	17.2	
90	37.8	1401	1366	35	1.7	21.2	18.7	
110	46.2	1400	1371	29	4.3	25.5	22.5	
120	50.4	1402	1368	34	3.5	29	25.6	
140	58.8	1403	1379	24	3	32	28.2	
150	63.0	1404	1386	18	3.4	35.4	31.2	
160	67.2	1400	1385	15	4.5	39.9	35.2	
180	75.6	1400	1388	12	6.5	46.4	40.9	
200	84.0	1403	1396	7	5.5	51.9	45.8	BT
220	92.4	1400	1394	6	5.4	57.3	50.6	
240	100.8	1399	1391	8	3.4	60.7	53.6	
260	109.2	1400	1391	9	0.5	61.2	54.0	
270	113.4	1402	1398	4	0.2	61.4	54.2	
290	121.8	1403	1400	3	0.1	61.5	54.3	
310	130.3	1401	1396	5	0	61.5	54.3	
330	138.7	1405	1403	2	0	61.5	54.3	

Average gas production: BT= CO_2 breakthrough
Before break through   0.144 l/hr
After break through   5.6 l/hr

Table C4: —continued

Oil Sample   : Spraberry Separator Oil
Temperature   : 138 °F
Pressure   : 1475 psig
Injecion rate   : 30 ml/hr

Time	CO_2 Injected	Slim Tube			Recovery			Remark
		P in	P out	dP		Cumulative		
min.	%P.V	psig	psig	psi	ml	ml	%	
20	8.4	1477	1412	65	5.3	5.3	5.1	
30	12.6	1475	1414	61	8	13.3	12.8	
40	16.8	1479	1414	65	4.1	17.4	16.8	
60	25.2	1473	1416	57	8.3	25.7	24.8	
80	33.6	1475	1423	52	8.2	33.9	32.7	
90	37.8	1475	1428	47	4.2	38.1	36.7	
110	46.2	1474	1432	42	7.3	45.4	43.7	
130	54.6	1474	1434	40	3.3	48.7	46.9	
140	58.8	1478	1440	38	2.1	50.8	49.0	
150	63.0	1476	1440	36	7.2	58	55.9	
160	67.2	1475	1441	34	1.9	59.9	57.7	
170	71.4	1474	1450	24	3.5	63.4	61.1	
180	75.6	1474	1456	18	4.4	67.8	65.3	
200	84.0	1475	1465	10	7.4	75.2	72.5	BT
210	88.2	1475	1464	11	1.3	76.5	73.7	
230	96.6	1478	1470	8	1	77.5	74.7	
240	100.8	1477	1473	4	0.2	77.7	74.9	
260	109.2	1475	1470	5	0	77.7	74.9	
280	117.6	1475	1472	3	0	77.7	74.9	
300	126.1	1479	1477	2	0	77.7	74.9	

Average gas production: BT= CO_2 breakthrough
Before break through   0.16 l/hr
After break through   9.33 l/hr

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Table C4: –continued

Oil Sample   : Spraberry Separator Oil
Temperature   : 138 °F
Pressure   : 1550 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
min.	%P.V	P in psig	P out psig	dP psi	ml	Cumulative ml	%	
20	8.4	1554	1459	95	6	6	5.4	
30	12.6	1550	1466	84	3	9	8.1	
60	25.2	1551	1486	65	13.2	22.2	20.0	
70	29.4	1551	1493	58	3.3	25.5	22.9	
90	37.8	1550	1494	56	6.7	32.2	29.0	
110	46.2	1548	1497	51	9.3	41.5	37.3	
130	54.6	1548	1503	45	7.1	48.6	43.7	
140	58.8	1530	1510	20	8.5	57.1	51.3	
160	67.2	1544	1525	19	7.2	64.3	57.8	
180	75.6	1548	1530	18	8.5	72.8	65.5	
200	84.0	1549	1532	17	7.7	80.5	72.4	
210	88.2	1551	1535	16	3.2	83.7	75.3	
220	92.4	1549	1536	13	4.5	88.2	79.3	
230	96.6	1539	1530	9	3.8	92	82.7	BT
240	100.8	1548	1541	7	5.5	97.5	87.7	
253	106.3	1551	1543	8	2.6	100.1	90.0	
260	109.2	1549	1545	4	0.4	100.5	90.4	
280	117.6	1553	1550	3	0.2	100.7	90.5	
300	126.1	1549	1543	6	0.2	100.9	90.7	
320	134.5	1554	1545	9	0	100.9	90.7	
340	142.9	1549	1546	3	0	100.9	90.7	
360	151.3	1549	1546	3	0	100.9	90.7	

Average gas production: BT= CO_2 breakthrough
Before break through   0.18 l/hr
After break through   7.9 l/hr

Table C4: —continued

Oil Sample   : Spraberry Separator Oil
Temperature   : 138 °F
Pressure   : 1600 psig
Injecion rate   : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
5	2.1	1615	1495	120	3.5	3.5	3.2	
10	4.2	1600	1495	105	3	6.5	5.9	
15	6.3	1603	1503	100	4	10.5	9.5	
23	9.7	1604	1512	92	3.8	14.3	13.0	
60	25.2	1602	1518	84	5.5	19.8	18.0	
80	33.6	1599	1523	76	9	28.8	26.1	
90	37.8	1603	1532	71	6.2	35	31.8	
110	46.2	1602	1536	66	8.4	43.4	39.4	
130	54.6	1604	1546	58	9.3	52.7	47.8	
145	60.9	1605	1552	53	10.1	62.8	57.0	
170	71.4	1601	1557	44	7.7	70.5	64.0	
190	79.8	1600	1561	39	7.5	78	70.8	
200	84.0	1600	1566	34	12.5	90.5	82.1	
213	89.5	1605	1594	11	5	95.5	86.7	BT
220	92.4	1603	1595	8	2.6	98.1	89.0	
240	100.8	1599	1590	9	1.5	99.6	90.4	
260	109.2	1597	1593	4	0.5	100.1	90.8	
300	126.1	1598	1589	9	0.2	100.3	91.0	
340	142.9	1600	1596	4	0.2	100.5	91.2	
380	159.7	1603	1599	4	0	100.5	91.2	

Average gas production: BT= CO_2 breakthrough
Before break through   0.14 l/hr
After break through   10 l/hr

Table C4:—continued

Oil Sample : Spraberry Separator Oil
Temperature : 138 °F
Pressure : 1700 psig
Injecion rate : 30 ml/hr

| Time | CO_2 Injected | Slim Tube | | | Recovery | | | Remark |
| | | P in | P out | dP | | Cumulative | | |
min.	%P.V	psig	psig	psi	ml	ml	%	
20	8.4	1702	1612	90	7	7	6.5	
30	12.6	1700	1615	85	7.5	14.5	13.4	
60	25.2	1703	1621	82	11.5	26	24.0	
80	33.6	1699	1620	79	1.2	27.2	25.1	
103	43.3	1702	1624	78	12	39.2	36.2	
120	50.4	1700	1623	77	7.9	47.1	43.5	
140	58.8	1703	1629	74	9.8	56.9	52.6	
160	67.2	1698	1643	55	7.1	64	59.2	
170	71.4	1704	1659	45	4.4	68.4	63.2	
180	75.6	1700	1680	20	6.8	75.2	69.5	
200	84.0	1702	1685	17	4.9	80.1	74.0	
210	88.2	1701	1693	8	7.2	87.3	80.7	
225	94.5	1699	1694	5	5.5	92.8	85.8	BT
230	96.6	1698	1694	4	2.1	94.9	87.7	
240	100.8	1697	1694	3	2.1	97	89.7	
260	109.2	1700	1695	5	0.9	97.9	90.5	
280	117.6	1703	1699	4	0.1	98	90.6	
300	126.1	1699	1696	3	0	98	90.6	
320	134.5	1702	1695	7	0	98	90.6	
340	142.9	1703	1700	3	0	98	90.6	
360	151.3	1703	1699	4	0	98	90.6	
380	159.7	1705	1702	3	0	98	90.6	

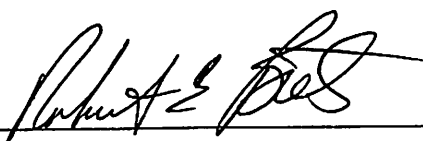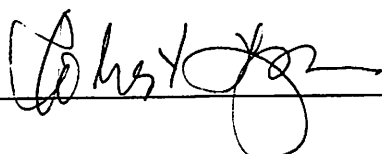Average gas production: BT= CO_2 breakthrough
Before break through 0.24 l/hr
After break through 14.25 l/hr

This thesis is accepted on behalf of the faculty

of the institute by the following committee:

_____
Advisor

_____

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_____ 6/24/97

27 June 1997
Date