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**AN EXPERIMENTAL STUDY OF OIL RECOVERY
FROM TARMAT RESERVOIRS USING HOT WATER
AND SOLVENT FLOODING**

BY

TAHA MOUSTAFA HAMED OKASHA

A Dissertation Presented to the
FACULTY OF THE COLLEGE OF GRADUATE STUDIES
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In Partial Fulfillment of the
Requirements for the Degree of

DOCTOR OF PHILOSOPHY
In

PETROLEUM ENGINEERING

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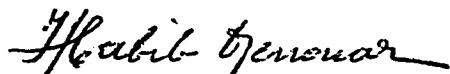
**300 North Zeeb Road
Ann Arbor, MI 48103**

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS
Dhahran, Saudi Arabia


COLLEGE OF GRADUATE STUDIES

This dissertation, written by Mr. Taha Moustafa Hamed Okasha under the direction of his dissertation Advisor and approved by the Dissertation Committee, has been presented to and accepted by the Dean of the College of Graduate Studies, in partial fulfillment of the requirements for the degree of **DOCTOR OF PHILOSOPHY** in Petroleum Engineering .

Dissertation Committee:



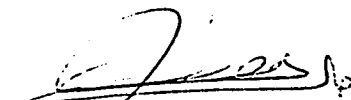
Dr. Habib K. Menouar
Dissertation Advisor



Dr. Sidqi A. Abu-Khamsin
Dissertation Co-Advisor



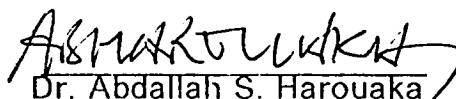
Dr. Muhammad A. Al-Marhoun
Member



Dr. Khalid A. Al-Fossail
Member



Dr. Abdulaziz A. Al-Majed
Member



Dr. Abdallah S. Harouaka
Member (External)



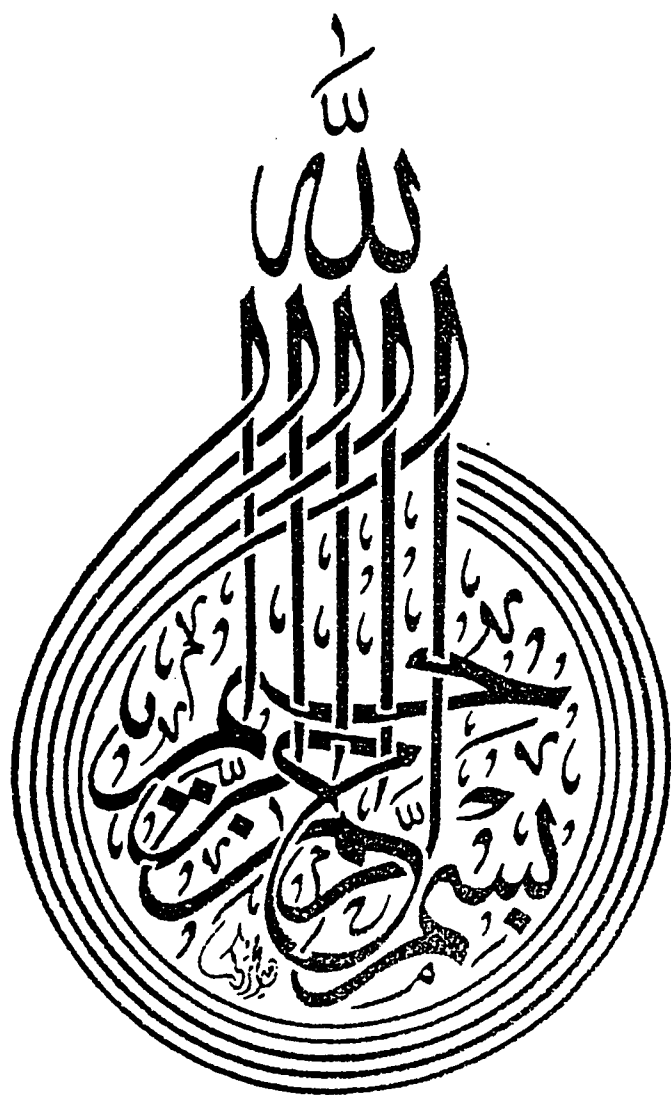
Dr. Khalid A. Al-Fossail
Department Chairman



Dr. Ala H. Al-Raben
Dean, College of Graduate Studies

Date: 9.4.95





DEDICATION

This dissertation is dedicated to my family
{wife, son (Moustafa), and daughter (Shaima)}

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خلاصة الرسالة

اسم الطالب : طه مصطفى حامد عكاشة

عنوان الدراسة : دراسة تجريبية عن استخلاص الزيت من المكامن ذوي الوسائد القطرانية باستخدام

المذيبات والماء الساخن

التخصص : هندسة البترول

إن وجود رواسب القطران في الجزء السفلي من طبقة الزيت في المكامن ذوي الوسائد القطرانية بسبب الكثير من مشاكل الإنتاج خلال المراحل الأولى لاستخلاص الزيت . وهذا يؤدي بدوره إلى عدم الإستفادة من ضغط مستودعات المياه الجوفية أو مشاريع الحقن بالماء مما ينتج عنه نقص في استخلاص الزيت . وكان الهدف الرئيسي من هذه الدراسة هو اختبار وتقييم الاستخدام المتحد للمذيبات والماء الساخن لتعزيز استخلاص الزيت من تلك المكامن بواسطة إزاحة وتشيت طبقة القطران . ولقد تمت معظم تجارب الإزاحة على نموذج مخبري لمكمن ذو وسادة قطرانية حُكِبَتْ فيه منطقتا الزيت والقطران بواسطة اقوار متجاورة من صخر البيريا الرملي (بطول قدم واحد) مشبعة بالزيت والقطران كل على حدة ، وكان معدل الحقن واحد ستيغيمير مكعب في الدقيقة ، وأحياناً أكثر من ذلك .

وأظهرت النتائج أن استخدام الماء الساخن في الإزاحة في عدم وجود القطران يؤدي إلى استخلاص أقل للزيت عن استخدام الماء البارد ، في حين أنه عند وجود طبقة القطران فإن استخدام الماء الساخن يؤدي إلى زيادة جوهريّة في استخلاص الزيت عن استخدام الماء البارد . كما أوضحت النتائج أن عملية حقن كمية من المذيب مدفوعة بالماء الساخن لازاحة القطران قد أدى إلى زيادة ملحوظة في استخلاص الزيت . وقد تبين أن هناك كمية متلى من كل نوع من المذيبات التي تؤدي إلى أعلى نسبة استخلاص للزيت . وفي المقابل فإن استخدام كميات أصغر أو أكبر من المذيب يؤدي إلى نقص في استخلاص الزيت .

ولقد تم اختبار تأثير معدل الحقن على استخلاص الزيت في أنماط حقن مختلفة ، وأوضحت النتائج أن أعلى نسبة استخلاص الزيت تزداد كلما انخفض معدل الحقن . علاوة على ذلك ، فقد تمت دراسة تأثير أسلوب الحقن على استخلاص الزيت . وأشارت النتائج أن تجزئ كمية المذيب المتلى إلى دفعات متساوية تفصل بينها دفعات متساوية من الماء الساخن يؤدي إلى زيادة ملحوظة في استخلاص الزيت عنها في حالة حقن المذيب دفعة واحدة يتبعها الماء الساخن ، وإضافة إلى هذا فإن الاستخدام المتحد للمذيبات والماء الساخن يؤدي إلى انخفاض كبير في ضغط الحقن عنه في حالة حقن الماء الساخن أو البارد وحده .

درجة الدكتوراة في الفلسفة

جامعة الملك فهد للبترول والمعادن

الظهران - المملكة العربية السعودية

فبراير ١٩٩٥م

ABSTRACT

STUDENT NAME : TAHA MOUSTAFA HAMED OKASHA

**TITLE OF STUDY : AN EXPERIMENTAL STUDY OF OIL RECOVERY FROM
TARMAT RESERVOIRS USING HOT WATER AND SOLVENT
FLOODING**

MAJOR FIELD : PETROLEUM ENGINEERING

The existence of tar deposits beneath the oil zone in tarmat reservoirs creates problems of productivity restriction during the primary recovery stage. This affects the performance of water injection projects and natural aquifers and, hence, results in poor hydrocarbon recovery. The principal objective of this study was to investigate and evaluate the combined use of solvent and hot water to improve the hydrocarbon recovery from tarmat reservoirs by displacing and dispersing the tar. Most of the displacements were conducted in one-foot long Berea sandstone composite cores, simulating a tar zone and an oil zone in series, at injection rates of 1 cc/min and higher.

The results show that although the oil recovery from hot water displacement is lower than cold water displacement in the absence of tar, the gain in recovery for hot water is substantial in the presence of tarmat. Driving a slug of solvent with hot water to displace tar increases the hydrocarbon recovery. For the different types of solvents studied, there is an optimum slug size which maximizes the hydrocarbon recovery. It was found that both large and small solvent slugs are less effective than an "optimal" slug.

The effect of injection rate has been investigated applying different displacement schemes. The results showed consistently that the recovery is higher at lower injection rates. Moreover, the effect of injection mode on recovery was examined. The results showed that alternating injection of small slugs of solvent and hot water leads to higher recovery than injecting the solvent slug as one portion followed by hot water flooding. Additionally, the combined use of solvent slug(s) and hot water reduces the injection pressure more than cold or hot water flooding alone.

DOCTOR OF PHILOSOPHY DEGREE

KING FAHD UNIVERSITY OF PETROLEUM AND MINERALS

**Dhahran, Saudi Arabia
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Chapter I

INTRODUCTION

Tarmats are heavy-oil concentrations sandwiched between aquifers and adjoining oil columns. They are reported in the literature to vary widely, ranging from highly viscous hydrocarbon fluids to near solid materials (Tripathy, 1982).

Tarmats are found in many major oil reservoirs in the world and particularly in the Middle East. The thickness of the tarmats varies from place to place in the same reservoir and, sometimes, reaches few hundred feet; while their extension can reach several kilometers. Various authors (Hunt, J.M., 1979, Moore, L.V., 1984 and Hirschberg, A., 1988) have presented theories explaining the formation of tarmats. They indicated that tarmats can be formed as a result of one or more of the following mechanisms:

- 1- Gravitational segregation of hydrocarbons which results in a compositional grading with depth. This could lead to tarmat formation if accompanied by deasphalting of the oil. The maturation process results in lighter fractions moving upstructure and the heavier fractions depositing at the bottom.
- 2- Natural deasphalting where natural gases from source rock enter the formation and rise by buoyancy through the hydrocarbon col-

umn. This action lowers the solubility of asphaltic fractions causing them to precipitate near the oil/water contact.

- 3- Water washing in which a portion of light hydrocarbons is removed leaving asphaltic fractions at the base of the oil accumulation.

In the Middle East, such reservoirs characterized by the presence of tar-mats around their peripheries and usually at the oil/water contact are called tarmat reservoirs. The presence of these tar barriers hinder the effectiveness of water injection projects and natural aquifers resulting in a poor oil recovery. This also results in some production problems at the well such as productivity restriction.

It is, therefore, important to carry out experimental studies to investigate possible solutions to this problem. Accordingly, this study was intended to investigate, experimentally, oil recovery from tarmat reservoirs using hot water and solvent flooding.

Chapter II

LITERATURE REVIEW

In general, the number of published papers on tarmat reservoirs is very limited.

The presence of tarmat at the bottom of oil reservoirs is a common feature in many oil fields. Tarmats have a strong effect on the production of oil from this type of reservoirs. No exact definition of tar has been given in the literature, but Carrigy in 1983 defined tar as an oil too viscous to flow into a well in sufficient quantities . Most of the papers on tar sands state that tar contains crude bitumen with a gravity less than $10^{\circ}API$ at $60^{\circ}F$ or has a viscosity greater than 10,000 cp at reservoir temperature (Barnea, J., et al., 1982). Many reservoirs in the Arabian Gulf area have tar viscosities between 12,000 and 14,000 cp at reservoir temperature. Field experience shows that some of these tarmats are mobile under conditions of moderate differential pressure across them and others are immobile depending on reservoir conditions (Osman, M., 1988).

Tarmat reservoirs are common throughout the world, specially in The Middle East and Africa. Tarmats are reported in some reservoirs in south Iraq and Kuwait. In the Minagish Oolite in Kuwait, tar acts as a partial barrier against water influx (Osman, M.E., 1985). Tissaf et al. (1984) stated that tar-

mats exist in Burgan field in Kuwait. In Saudi Arabia, tarmats exist in many major reservoirs like Ghawar, Khursaniyah, Manifa, and some other fields (Al-Kaabi et al., 1988 & OPEC 1979). The tar zone in Ghawar field extends more than 25 kms and in the Uthmaniya region, which is located in the southern portion of this field, reaches up to 150 meters in thickness. The tar reserves in that specific area exceed 2.3 billion barrels (Osman, M.E., 1985). Nehring, R., (1979) Stated that heavy crude oils between 20° to $25^{\circ}API$ gravity have been found in Arab C in the Ain Dar area of Ghawar, the Arab A and D in Karan, and the Arab C in Manifa.

Tarmats are also present in Eid El-Shergi in Qatar where the Arab IV zone is characterized by a massive tar column over 82 meters thick (Bashbush et al., 1983). Tarmat is present in the bottom of No. 3 limestone of the Dukhan field in Qatar and at the bottom of the oil zone in the Maydan, Mehzan, and Bulhamine fields. Sarir, one of the largest oil reservoirs in Libya, has a tarmat at the bottom of the oil zone (Al-Kaabi, et al., 1988). Tarmats are reported to exist in many oil fields in Iran like Ahwaz, Bahrgansar, and Hendijan (Nehring, R., 1979). Prudhoe Bay field in Alaska has a tar layer at the bottom of the oil zone (Killough, J.E., et al., 1982).

The existence of tarmat can be recognized when its effect is noticed. The most important effect of a tarmat is the ineffectiveness of water injection. Bashbush et al. (1983) stated that both geological and reservoir studies of El-Bundug field, located in Abu-Dhabi and Qatar, showed that the tarmat layer was acting like a barrier to fluid movement without being a complete seal.

Moreover, they observed that because of the presence of a tarmat, a peripheral water injection project in the El-Bundug field resulted in a poor (15 %) ultimate oil recovery. The sharp pressure decline during the first two years of production is an indication of the lack of energy support received from the flanks due to the deteriorating quality of the reservoir rock and the presence of the tarmat. The rapid decrease in reservoir pressure leads to an alarming increase in gas/oil ratio. Figure 2.1 is a schematic representation of this field. Hirshberg (1988) reported that production in a North African field was forced to be up-dip due to the effect of tarmat on down-dip water injection.

A comparative analysis was made by Tripathy (1988) to study the effect of the encroachment of water from a large aquifer into a producing reservoir through a continuous tar zone. The purpose of the study was to select the optimal location of water injectors for pressure maintenance purposes. He found that the most important effect of tarmat was the restriction of the movement of potential water influx into the oil zone thus lowering the production of oil and gas. In addition, he concluded that tarmat acted as either a heavy oil or very low permeability matrix forming part of the aquifer and consequently a rigorous characterization of a tar zone is not possible.

Kazou (1982) Discussed pressure maintenance by formation water dumping for the Ratawi limestone oil reservoir in the offshore Khafji field. This reservoir contains light, sweet and undersaturated oil with dissolving sour gas. Below 2225 m subsea, the oil rapidly decreases in gravity down to 9°API and is completely underlain by bottom aquifer at 2250 m subsea. He

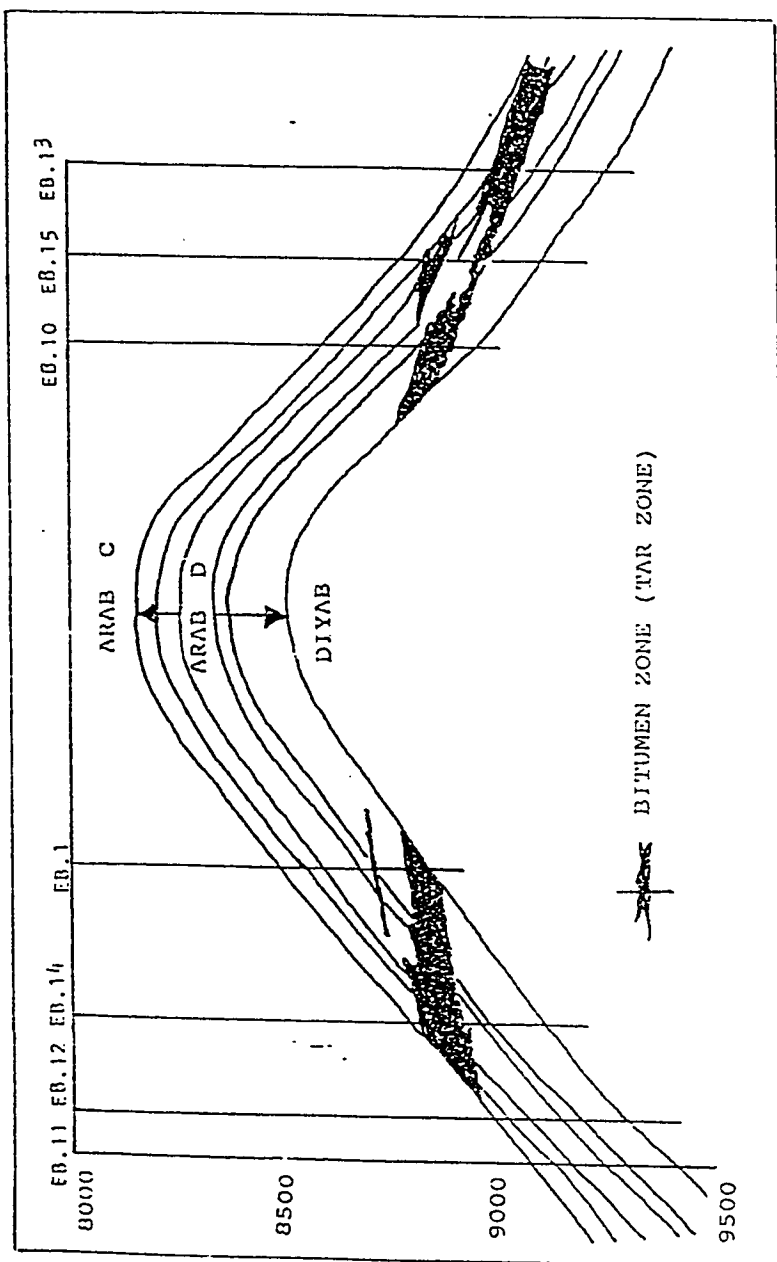


Figure 2.1: Field and Tar Cross-Section (Bashbush, et.al., 1983).

concluded from productivity and injectivity data that dumpwater injection is an effective method to maintain reservoir pressure from rapid decline by natural depletion, but heavy-oil recovery by water dumping is extremely difficult. More sophisticated methods may be required for heavy oil mobilization such as powered injection combined with solvent flooding, steam injection, fire flood,...etc.

A study on waterflooding in a tar-mat reservoir laboratory model was carried out by Abu-Khamsin et al. (1992). In this study, three adjacent oil, tar, and water zones were simulated by composite Berea sandstone cores, saturated respectively with kerosene, asphalt and crude oil mixture, and 1% KCL brine. The effect of tar viscosity and thickness on oil recovery as well as the pressure variation were studied. The authors observed viscous fingering in both tar and oil zones. They also reported that the effective permeability to water in the tar zone is very sensitive to tar viscosity or thickness and it decreases sharply with an increase in the product of those two parameters. The oil recovery slightly decreases as the viscosity - thickness product of the tar zone increases. The injection pressure rises quickly to maximum value after commencement of injection and starts to decrease slowly as the injection proceeds.

Very few investigators have simulated a reservoir with a tar barrier. Al-Kaabi et al. (1984) used a lab setup to simulate a fraction of a tar-mat reservoir with a well producing from the center and studied the behavior of tar-mat reservoir using that physical model and a black-oil numerical model

(BOSS-AIM). Treating the tarmat as an impermeable barrier, they found that establishing communication between the oil and water zone by creating a hole of limited size in the tarmat that otherwise completely covers the reservoir would result in a very poor recovery. However, if the tarmat is of limited extension over the reservoir beneath the well, the effect on oil recovery is not significant.

Another simulation study was carried out by Tripathy (1988). He proposed two approaches to characterize tar in a model and concluded that tarmats should be modeled as a hydrocarbon fluid if the tar viscosity is 100 CP or less. A leaking tarmat with high viscosity should be modeled as an impermeable aquifer rock matrix with a separate relative permeability region assigned to the tar zone.

Al-Ali (1988) conducted a numerical simulation study related to a tarmat reservoir. He investigated different strategies for enhancing oil recoveries from a tarmat reservoir by localized communication. He concluded that initiation of intercommunication between the oil and water zones can enhance oil recovery through gained potential but water conning may be dominant if those openings are small.

Osman (1983) presented a technique to predict the time of tarmat breakdown, response time at the nearest observation well, and differential pressure at the tarmat anywhere in the Minagish Reservoir in Kuwait.

The major problems of tarmat in oil reservoirs are the high resistance to flow of the tar layers in addition to highly unfavorable mobility ratio between tar and water. Hence, these extra highly unfavorable mobility ratios lead to unstable displacement and fingering. Many investigators (Chuoke, R.L., and van Meurs, P., 1959, Rachford, H., 1964, and Meurs, P., 1957) studied this type of instability where mobility ratios up to 200, which can not be directly applied to tar layer with variable thickness and super viscosities.

One obvious solution to displace the tar and increase oil recovery from tarmat reservoirs would be to use EOR methods like solvent, and/or steam injection. Although hot water injection is more viable with deep tarmat reservoirs, it would be useful to review some of the experimental and field studies done with steam and/or solvent injection to recover bitumen and heavy oil from tar sand reservoirs. Thermal-Miscible displacement had been proven to be an efficient process for recovering bitumen from tar sands.

Harouaka and Asar (1990) presented a general summary of two years research program on tar properties and methods of improving injectivity in tarmats using naphtha and steam.

Hernandez (1972) conducted a study on the efficiency of bitumen recovery from the Athabasca tar sand by miscible displacement, steam flooding, and a combination of the two methods using unconsolidated sand. He showed that bitumen recovery was lower at higher displacement rates, and increasing the residence time of the solvent tends to increase bitumen recovery since molecular diffusion of residual bitumen into the solvent is enhanced during prolonged contact.

Snyder (1972) investigated the recovery of bitumen from Athabasca tar sand using naphtha injection with conductive heating, steam injection and naphtha injection followed by steam. The results indicated that naphtha injection was successful in recovering bitumen. The combination of naphtha injection followed by steam gave even more effective results in the case of homogeneous oil packs. He also stated that gravity segregation played an important role in the recovery mechanism when a homogeneous pack is saturated with bitumen and naphtha is injected as a solvent. Alban (1975) confirmed these findings when he investigated the efficiency of miscible displacement in the recovery of bitumen from Athabasca tar sand under the conditions of gravity segregation in a two dimensional box model. His results showed that the recovery of bitumen using naphtha, mobile solvent, and synthetic crude at the average velocity of 2.04 ft/day was efficient.

Sosa de Garcia (1980) studied the development of flow channels in Athabasca tar sands as a result of solvent injection. The results showed that higher injection rates generate more viscous fingering which decrease the flood recovery.

Injection of a solvent followed by steam injection is effective depending on the solvent slug size and homogeneity of the reservoir as found by different authors like Cordero (1976) and Look Yee (1972). Also, steam injection was found to be a successful method but steam stimulation alone was impossible in tar sands because of the high injection pressure required.

Shamsaldeen and Farouq Ali (1985) carried out an extensive experimental study on oil recovery from bottom water drive reservoirs with tar barriers. They tested different recovery techniques in laboratory models simulating tar-mat reservoirs. These techniques included injection of water into the oil zone (internal waterflood), injection of water into the bottom water zone (bottom waterflood), injection of solvent into the tar zone followed by internal waterflood, and injection of steam into (i) the oil zone, (ii) the tar zone, and (iii) the bottom water zone. They concluded that establishing communication between the aquifer and oil zone is highly desirable to improve the recovery. Solvent or steam could be used to establish such communication if the oil zone was completely isolated from the aquifer by the tar zone. Once the communication is attained, an internal waterflood can be very effective. The authors also reported that injection of water into a water zone caused water coning and channeling resulting in low recoveries. The injection of steam into the oil zone eliminated the benefit of the bottom water drive but decreased the production period and a low steam-oil ratio was needed. Injection of steam into the tar zone proved to be effective with a moderate steam-oil ratio, but injection of steam into the bottom water zone required large volumes of steam and the water-oil ratio was very high.

Alikhan and Farouq Ali (1974) studied the steam drive-solvent slug process for heavy oil in a linear cell model packed with glass beads. It was found that the light hydrocarbon slug injected prior to the steam slug improved oil recovery due to improvement in the mobility ratio resulting in a better displacement efficiency.

Doscher et al. (1983) concluded from scaled physical model studies that very viscous crude oils cannot be economically recovered by an unassisted steam drive. Kaleli and Farouq Ali (1987) found from experimental and theoretical studies that bitumen or heavy oil recovery depended strongly on solvent slug size as well as thickness and permeability of the water zone. The optimal thickness of the water zone was found to be one-fifth of the oil thickness.

In 1982, Johnson, et al. applied hot water and steam injection during a pilot test in sandstone zone (1012 m^2 and 14 m thick) saturated with a 13°API bitumen with viscosity greater than 10^6 cp under reservoir conditions. They reported that average efficiency was about 18 % because the production of the light components of the bitumen as a result of thermal distillation caused accumulation of a more viscous residue in the formation.

In 1983, Britton, et al. conducted fracture-assisted steam flooding techniques (FAST) during a pilot test in a tar sand area of 5-acres saturated with heavy tar (- 2°API). The results showed a very good efficiency of more than 50 % on the average. The operator also suggested that this FAST process should be particularly suited for super-viscous tar sand and heavy crude deposits.

Zuleyka Mendez et al. (1992) conducted a laboratory study and field tests on the heavy oil reservoirs in the Bolivar Coast in Western Venezuela. These heavy crudes have a gravity between 9 and 15°API with in-situ oil viscosity between 100 and 100,000 cp. The purpose was to study the possible merits of

the addition of small amounts of solvent as part of the injection process. The results showed that under appropriate conditions, addition of small amounts of solvent to cyclic steam injection is technically capable of improving the productivity.

The effect of temperature on relative permeability has been studied by many authors and received a considerable attention since the mid-1950's due to its importance in the thermal recovery of heavy oils or tars. However, this phenomenon is not clearly understood yet. Polikar and Farouq Ali (1990) found from experimental study of Athabasca bitumen/water relative permeabilities that temperature had little or no effect on the relative permeabilities to water and bitumen over a range from 100 to 250 °C. However, Clossmann et al. (1988) studied the effect of temperature on steady-state, tar/water relative permeabilities in Peace River cores. They found that tar relative permeability and saturation relations varied depending on whether the tar had been thermally altered or not.

Nakornthap and Evans (1986) summarized the previous studies related to the effect of temperature on relative permeability. They concluded that relative permeability to oil increases and relative permeability to water decreases with temperature increase. The residual oil saturation decreases and irreducible water saturation increases as the temperature increases. In addition, they developed a mathematical model to describe the variation of relative permeability with temperature in a water/oil system.

The effect of temperature on relative permeabilities was studied at 70 and 186 °F for unconsolidated Ottawa sand by Sufi et al. (1982). They concluded that relative permeabilities were independent of temperature over that range.

So, many authors agree that at higher temperatures the relative permeability to oil increases or does not change while relative permeability to water is less affected. Also, the residual oil saturation decreases and irreducible water saturation increases with increasing temperature. On the other hand, the test results of the effect of temperature on absolute permeability are inconclusive.

From the above discussion of the literature survey, it can be stated that most investigations have been confined to the problem of recovering bitumen or heavy oil from tar sands using different techniques. In addition, most of the taromat studies used cold waterflooding and little work which employed solvent were done in conjunction with steam in loose porous media. The use of steam is known to be impractical in deep reservoirs.

Up to now, no study has been specifically aimed at improving oil recovery from taromat reservoirs using thermal-miscible flooding through consolidated rock matrix.

Chapter III

STATEMENT OF THE PROBLEM AND STUDY OBJECTIVE

The presence of tar deposits at the oil/water contact in a tarmat reservoir can have serious effects on the effectiveness of secondary recovery projects or natural water drives. In the case of tarmats completely surrounding the oil zone, the oil reservoir behaves like a finite lense where the pressure decreases rapidly as soon as the first well starts producing. This leads to an alarming increase in gas/oil ratio during the primary stage of depletion. The case of Minagish reservoir in Kuwait illustrates clearly the behavior of a tarmat reservoir subjected to water drive (Osman, M., 1983). Another good example is El B'ndug reservoir in Qatar (Bashbush, J.L., et al., 1983).

In another configuration where the tar has some mobility or thins out at some location, a breakdown of tarmat may occur leading to severe water coning as a result of the application of large pressure differentials across the tar layer.

The purpose of this study was to investigate some techniques to improve the tar mobility with the aim of tar displacement in a tarmat reservoir and the effect of such techniques on oil recovery in this kind of reservoir. Specifically, the use of a combination of solvent and hot water to displace the tar was

evaluated. In the course of achieving this objective, the following aspects of the problems were studied:

- 1- The effect of solvent(s) concentration on tar viscosity.
- 2- The effect of temperature on the interfacial tension between the aqueous and oleic phases, fluids viscosity, and relative permeabilities.
- 3- The effect of solvent slug sizes on oil recovery.
- 4- The effect of displacement rates, injection mode, and type of solvent on oil recovery.

Chapter IV

EXPERIMENTAL APPARATUS, MATERIALS AND PROCEDURES

The following sections describe the materials, apparatus and experimental procedures used in this study.

4.1 MATERIALS

4.1.1 Porous Medium

Berea sandstone cores 1 inch in diameter with an average porosity of 23 % and absolute permeability of around 300 md were used in all flooding and relative permeability experiments.

4.1.2 Brine

Analytical grade distilled water with 1 % KCL concentration was used to simulate the aqueous phase.

4.1.3 Oil

Filtered kerosene was used to simulate the oleic phase.

4.1.4 Tar

The tar phase was prepared by evaporating a batch of heavy crude oil until it reaches a viscosity of about 10,000 cp at room temperature.

4.1.5 Solvents

Reformate from Ras Tannura refinery and analytical grade naphtha were selected to be used in this study. They represent the most appropriate solvents according to solubility tests conducted on different solvents.

The physical properties and characteristics of all fluids used in this study are given in chapter 5.

4.2 APPARATUS

A schematic of the experimental apparatus used in this study is shown in Figure 4.1. It consists of the fluid injection system, core holder, an oven, a differential pressure instrument, temperature measurement, recording system and a fraction collector. A brief description of each component of the apparatus is given below:

4.2.1 Core Holder

A Hassler type, stainless steel core holder designed for consolidated core samples up to 31 cm in length and 2.54 cm in diameter was used. It can withstand pressures up to 10,000 psi.

The composite core sample is housed inside a Viton rubber sleeve which is held in place by two ferrules. Each ferrule rests on one end of the core holder body where an 'O' ring is placed in a groove around the rim of the body. These ferrules are pressed against the holder's body by two screw-on end caps.

An end plug is inserted into each end of the sleeve and is pressed against the core sample by a retaining screw which threads through the end cap. When core samples less than 31 cm in length are used, spacers are placed in the gap between the end plugs and the retaining screws. Both end plugs have circular grooves to ensure fluid injection and production from the entire cross-section of the core. The annular space between the sleeve and the core holder body is filled with a confining fluid and pressurized by a

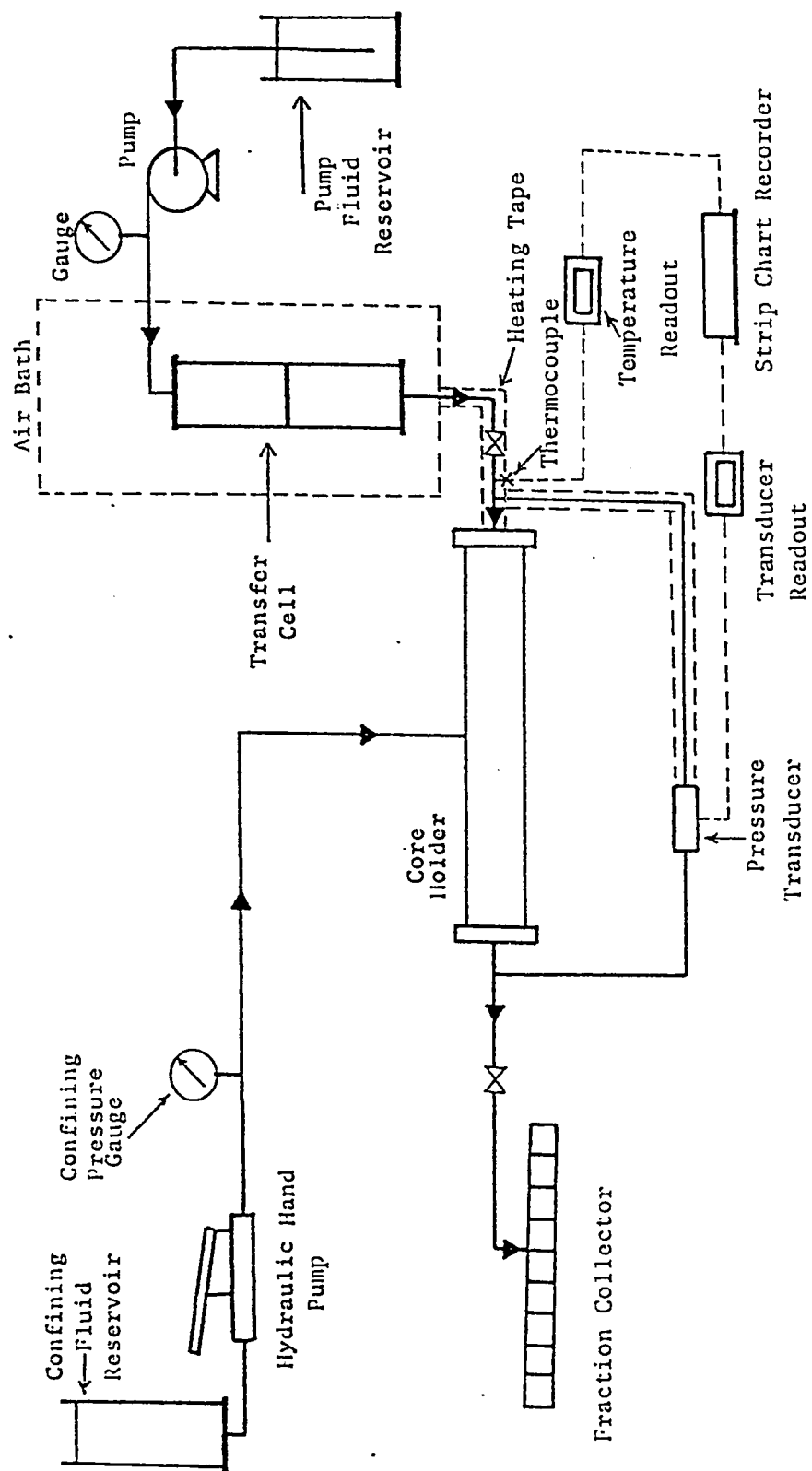


Figure 4.1: Schematic Diagram of Core Flooding Set-Up.

hydraulic hand pump. This pressure simulates reservoir overburden pressure, prevents fluid by-pass, and ensures a good sealing between the ferrules and sleeve. A cross-sectional view of the assembled core holder is shown in Figure 4.2.

A reservoir volume element with sections of the tar and oil zones is simulated by a linear composite core. When a displacement run involves a solvent slug, a piece of core is saturated with the required amount of solvent and placed before the tar core. The configuration of the composite core as it is loaded in the rubber sleeve is shown in Figure 4.3.

4.2.2 Transfer Cells

Three stainless steel transfer cells, manufactured by Core Lab Inc., which can withstand pressures up to 5000 psi were used in the injection of the fluids into the core holder. Each cell, with a capacity of 1000 cc, has a free-floating piston which separates the pump fluid from the injected fluid. Mineral oil, the pump fluid, was pumped into a transfer cell to displace brine, solvent or tar into the core.

4.2.3 Pumps

During tar saturation and displacement runs a constant rate Beckman model 100 A pump which has a pressure limit of 10,000 psi and a maximum rate of 10 cc/min was used. The confining pressure was applied using a hand pump model 3020-008 manufactured by Core Lab Inc.

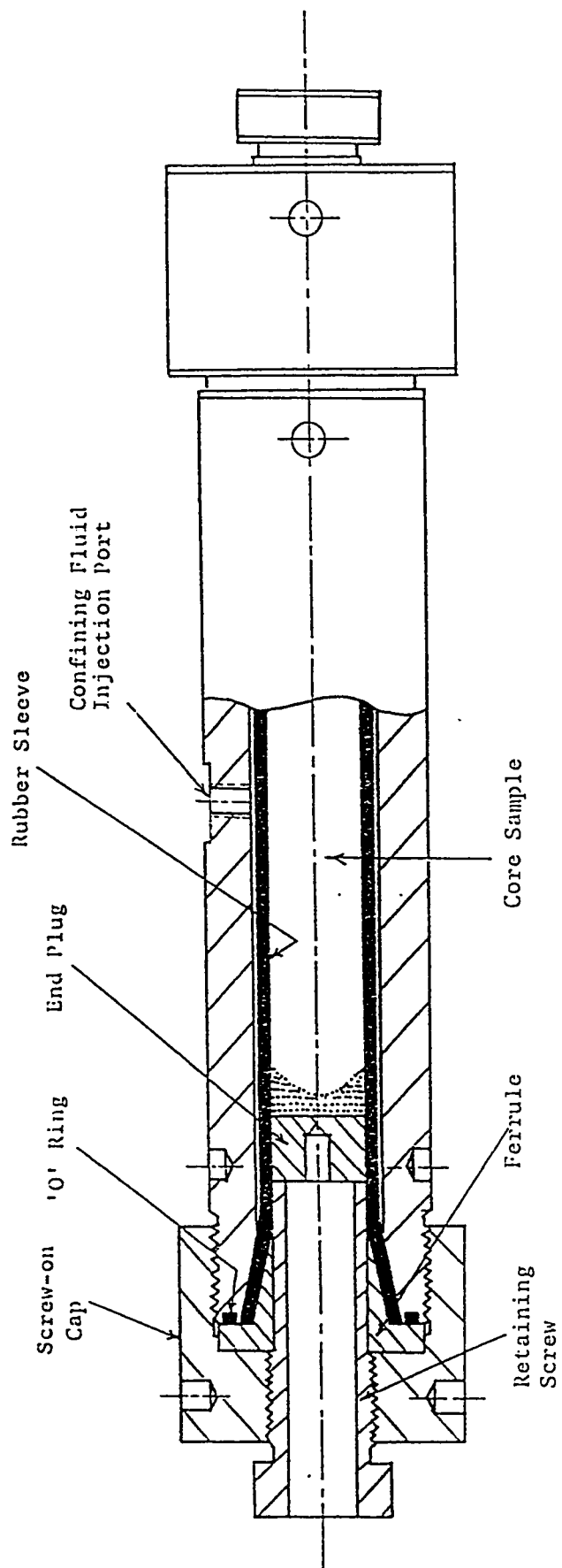


Figure 4.2: Cross-Sectional View of Assembled Core Holder.

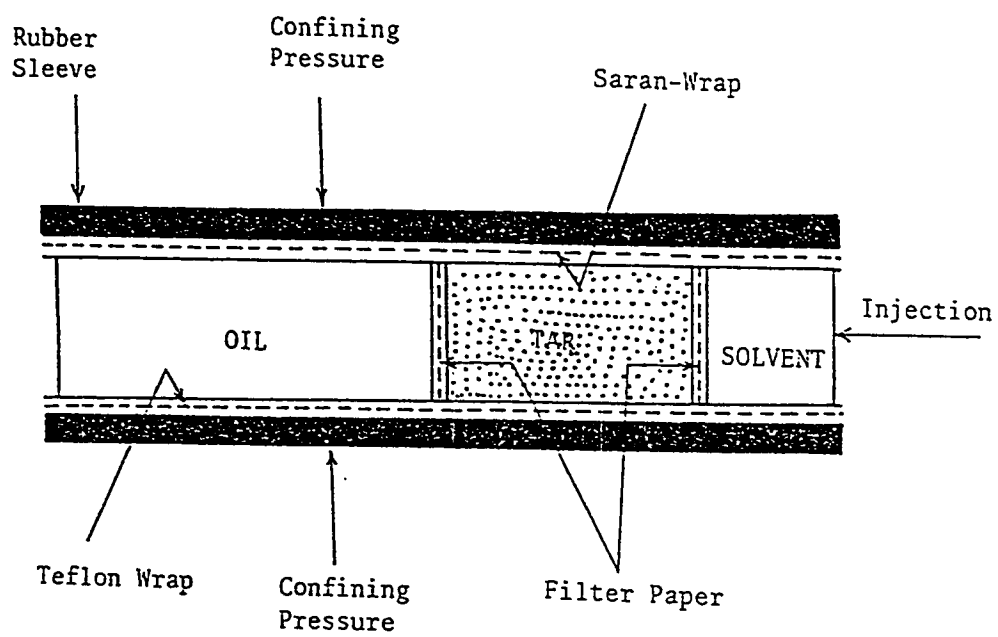


Figure 4.3: Cross-Section of the Linear Composite Core Arrangement.

4.2.4 Vacuum Pump

A Pfeiffer Balzer vacuum pump model DUO-008 was used for air evacuation during core saturation.

4.2.5 Pressure Multiplier

A pressure multiplier, manufactured by Cor Lab Inc., operating with mineral oil was used to provide the required confining pressures from a low pressure source (low pressure Nitrogen cylinder).

4.2.6 Oven

During relative permeability runs, the core holder and the transfer cells were placed inside a temperature controlled oven, model, D-6072, manufactured by Karl Kolb Co. This oven has a temperature range from 5 °C above room temperature to 270 °C with natural convection and half full sight glass doors. It also has two ducts at the sides to allow access to the oven chamber.

4.2.7 Pressure Measurement System

The differential pressure across the core during flooding and relative permeability runs was measured using a Validyne model DP 303 pressure transducer with a digital display model CD23. The working range of the transducer can be varied using different diaphragms. The output signal of the transducer was continuously recorded by a Soltec strip-chart recorder model 1243.

4.2.8 Temperature Measurement System

The temperature of the injected fluid was measured using a type-K thermocouple. This thermocouple was inserted in the inlet end plug of the core holder and connected to the digital temperature readout. The output signal of the thermocouple was continuously recorded by a Soltec strip-chart recorder model 1243.

4.2.9 Fraction Collector

An Eldex Universal fraction collector model U-1A which can accommodate 200 graduated glass tubes of 10 cc each was used for collecting the effluent fluids.

4.2.10 Viscometer

A Plate-Cone type, Contraves low shear 30 viscometer which is equipped with a HAAKE M circulated temperature oil bath was used for measuring fluid viscosities at different temperatures.

4.2.11 Tensiometer

A digital-tensiometer model K10 which is equipped with a circulated water bath was used for measuring the interfacial tension between tar and brine as well as between tar/solvent mixtures and brine.

4.2.12 Auxiliary Equipment and Tools

Many other equipments and tools were used during this study. These include: pressure gauges, vacuum oven, blender, heating tapes, valves, core cutting machine, soxhlet glass tubes, swagelock fittings, electric furnace, hot plate, insulation tapes, glass wool, Dean Stark Distillation Unit, weighing balance, flasks, pycnometer, hydrometer,etc.

4.3 PROCEDURES

4.3.1 Core Preparation & Saturation

All cores were fired at 800 °C for 24 hours in an electric furnace to vitrify any clays. The core plugs were then flushed with isopropyl alcohol and dried in a vacuum oven. Saturation of the core plugs with oil or solvent was carried out at room temperature. The plugs were first placed in a large flask and evacuated for more than 4 hours. Then, the desired fluid was slowly introduced to saturate the cores through a valve on the top of the flask while evacuation was continuing until the cores were fully submerged.

Saturation of the core plugs with tar was done at higher temperatures (80 - 90 °C) using the core holder. A schematic diagram of the tar saturation set-up is shown in Figure 4.4. The cores were loaded inside the core holder and a 2000 psi confining pressure was applied. Vacuum was then applied for several hours while the core holder and transfer cell containing tar were being heated to the desired temperature. The injection of tar was then started at a very low rate while maintaining the injection pressure lower than the confining pressure. Vacuum was continuously applied during the tar injection to help in moving the tar toward the production end. After the appearance of tar at the outlet, vacuum was stopped immediately while injection was continued long enough to ensure 100 % saturation. The core holder was then dismantled and the saturated cores were submerged in the same tar in a perfectly sealed container until ready for use.

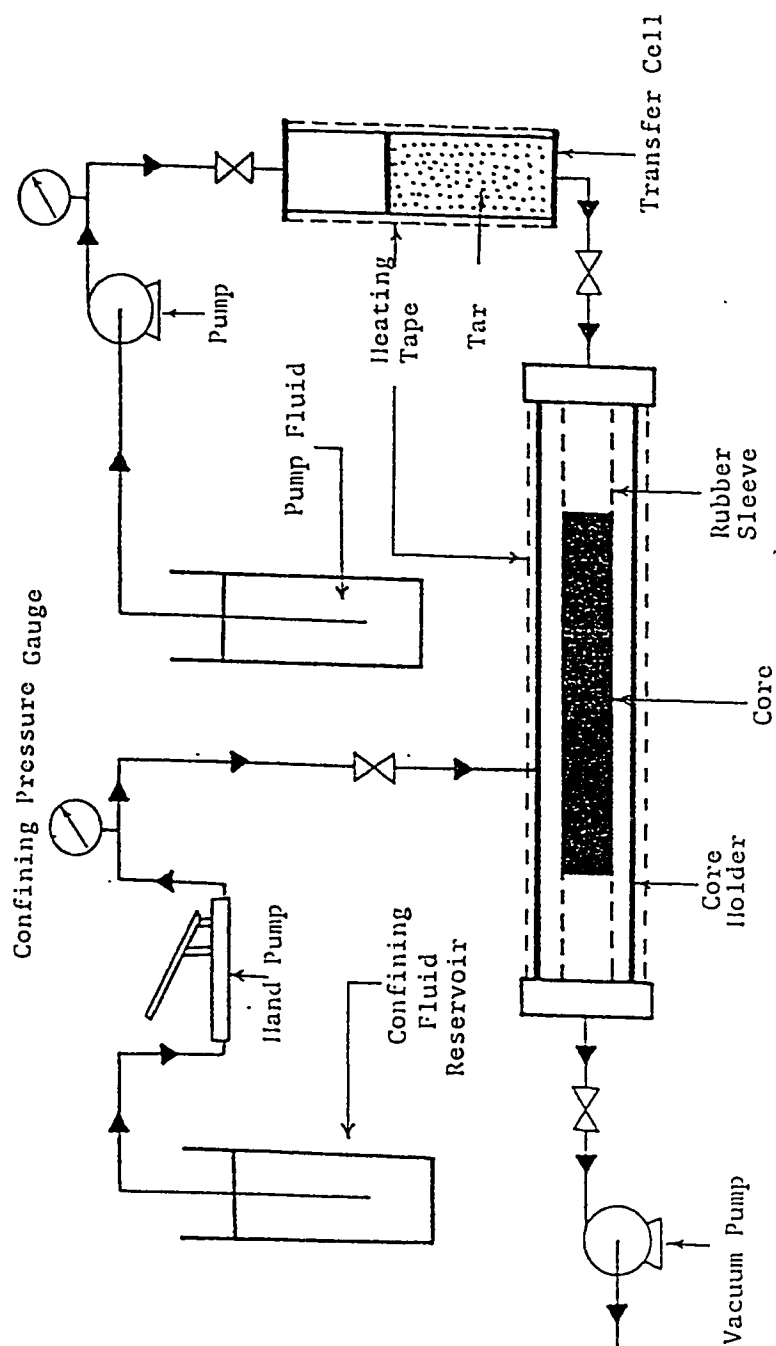


Figure 4.4: Tar Saturation Set-Up.

4.3.2 Porosity Measurements

The porosity of the core plugs was measured in conjunction with the saturation method as described in section 4.3.1. Porosities were determined from the weights of saturated and dry cores, dimensions of the cores, and fluid density.

4.3.3 Flooding Experiments

The saturated core plugs were always arranged in the order shown in Figure 4.3. Filter paper was placed between core plugs to allow better contact and capillary continuity. The cores were wrapped with a layer of Saran-Wrap and a layer of Teflon tape to ensure that no gap exists between the core plugs and the rubber sleeve. The composite core was then loaded into the rubber sleeve and the core holder was assembled and connected to the apparatus as shown in Figure 4.1.

To conduct a flooding run, the following steps were followed:

- 1- A confining pressure of 2000 psi was applied while the transfer cell containing brine (1 % KCL) was heated up inside the oven. Flexible heating tapes wrapped around injection tubing, transducer tubing, and inlet end plug were then switched on. These tubings were also wrapped with insulation tapes and glass wool.
- 2- Trapped air inside the injection and the pressure transducer tubings was circulated out with hot brine until the inlet end plug temperature stabilizes at the desired level.

- 3- After temperature equilibration, the injection of hot water or solvent slug driven by hot water was started at the desired displacement rate. Simultaneously, the fraction collector and the strip chart recorder were started.
- 4- The effluent fluids were collected in graduated tubes and the injection pressure as well as the inlet temperature were continuously recorded.
- 5- After completion of a run, the core holder was dismantled and the cores were extracted for brine saturation.

4.3.4 Permeability Measurements

The core holder was used to determine the absolute permeability, the effective permeability to the oleic phase (40% reformat - 60% tar which represent the tar/solvent mixture at optimum slug size), and the effective permeability to brine at different temperatures. Figure 4.5 shows the permeability measurements set-up.

Berea sandstone cores having the same length as the tar zone were saturated with brine and loaded into the core holder using a heat resistant Viton rubber sleeve. This assembly was placed in the core holder with the end pieces clamped over the sleeve and the caps fixed. The core holder was then placed in the oven and a confining pressure of 2000 psi was applied.

To measure the absolute permeability of the cores, the relative permeability to oil, and the relative permeability to water the following steps were followed:

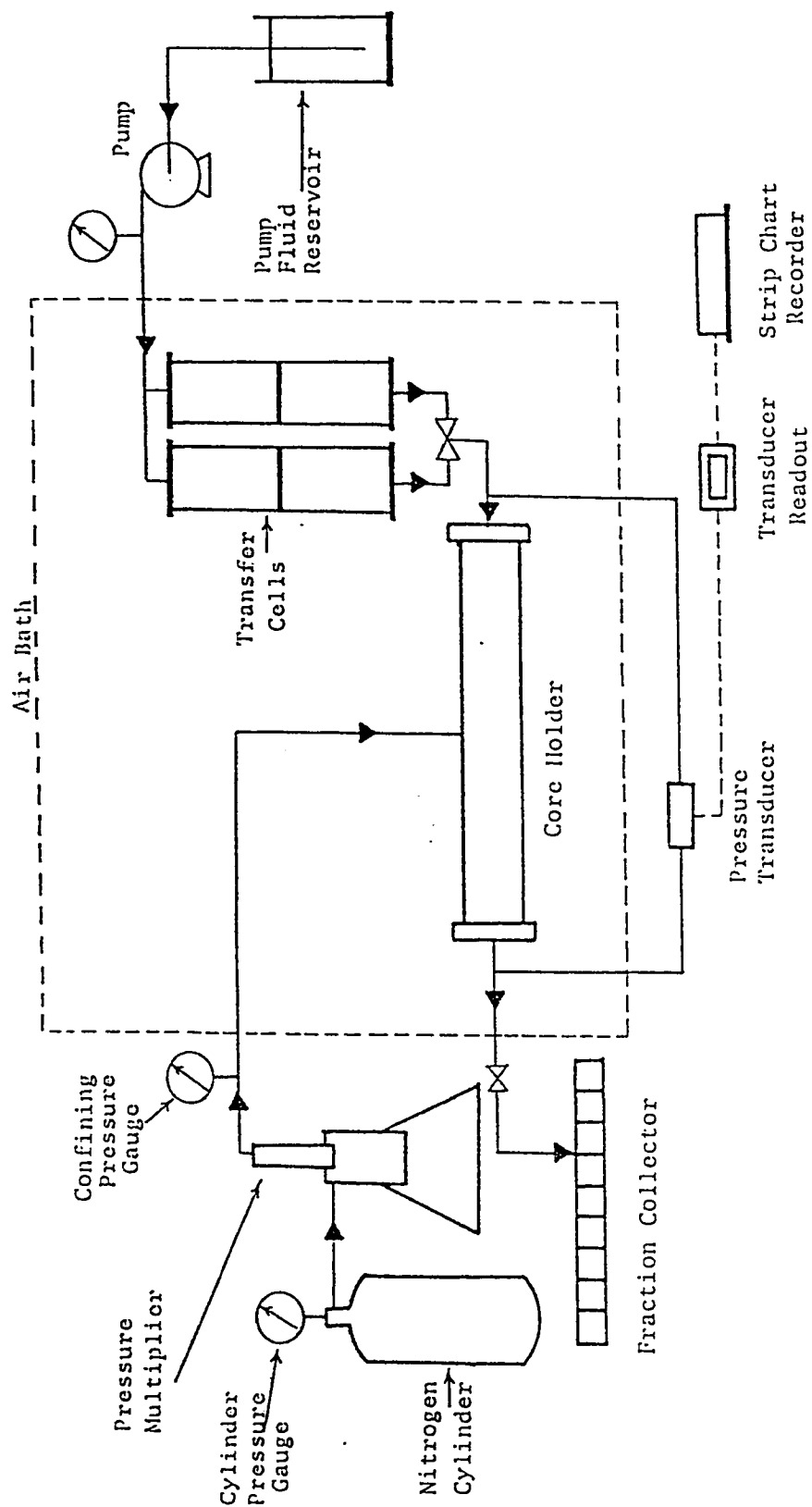


Figure 4.5: Schematic Diagram of Permeability Measurements Set-Up.

- 1- About 1.0 pore volume of brine was injected through the core to obtain a complete saturation.
- 2- The absolute permeability to brine (1% KCL) was determined at room temperature by measuring the pressure differential across the core at different flow rates.
- 3- The desired temperature was adjusted and the system was heated for about 10 hours for temperature equilibration.
- 4- Steps (1) and (2) were repeated at higher temperatures to investigate the effect of temperature on absolute permeability.
- 5- After measuring the absolute permeability the core was flooded with the oleic phase to irreducible water saturation until no more water came out. The fluid saturations were determined by material balance calculations on the water.
- 6- Consequently, water injection was started. At the same time, differential pressure was recorded continuously and the effluents were collected in graduated tubes. The flood continued until about 4 to 5 pore volumes of brine were injected.

4.3.5 Core Cleaning

After the completion of each experiment, the composite cores were taken out of the core holder and placed in the Dean Stark Distillation Unit to determine water saturation. Those cores were then placed in a Soxhlet Unit to clean them with toluene for several days. Next, the cores were cleaned with isopropyl alcohol for three days to restore the wettability.

Chapter V

FLUID AND ROCK CHARACTERISTICS

In this chapter, the effects of temperature on fluid densities, viscosities, interfacial tension of tar-solvent mixtures against brine, relative permeability to oil and water are examined. Furthermore, some physical properties, solubility tests, and rheology of tar-solvent mixtures are determined.

Knowledge of the physical properties of the fluids is required in most EOR processes and, especially thermal characteristics of the oil-solvent system, since these characteristics have a direct effect on recovery mechanisms. Also, they are important in the interpretation of the results to enhance the understanding of the behavior of tar-mat using hot water and solvent flooding.

5.1 SOLUBILITY TESTS

Many investigations show that most heavy oils and tars contain components which are insoluble in most hydrocarbon-type solvents. These are asphaltene, resins, and metals. The insoluble content varies from one crude to another and depends upon the origin of the crude (Mitchel, D.L. et al., 1973).

It has been shown that the solubility of asphaltene in most hydrocarbon-type solvents is different. When tar mixes with a solvent in which the asphaltene are not soluble the asphaltene may precipitate and cause pore plugging during the displacement process leading to a decrease in matrix permeability. Therefore, solubility tests were conducted to select the appropriate solvents to be used in tar displacement processes. The solubility testing method (Mckay, J.F., et al., 1981) used for this study is as follows: Ten grams of tar were agitated in 150 ml of solvent at room temperature for 10 minutes. The solution was left unagitated for 1 hour and then agitated again for 10 minutes and left unagitated for 15 hours. The insolubles were filtered using Whatman No.1 filter paper and washed with 20 ml of solvent, dried, and weighed. The solubility test results are reported in Table 5.1.

According to these results, reformat (from Ras Tannura refinery) was selected as an appropriate solvent for this study. Moreover, in order to investigate the effect of different types of solvent on oil recovery and to compare different solvents, naphtha was used as a second solvent in this study.

Table 5.1: Solubility Test Results

Solvent	Insolubles (weight % of tar)
n-Pentane	40.0
n-Hexane	22.1
n-Heptane	20.2
Toluene	6.5
Xylene	6.1
Kerosene	18.3
Naphtha (analytical grade)	3.0
Reformate (Riyadh refinery)	4.5
Reformate (Ras Tannura refinery)	4.7

The reformat and naphtha used in this study have the following specifications:

Reformat	Naphtha
Density @ 20 °C 0.777 g/cc	Density @ 20 °C 0.866 g/cc
Boiling range (95%) 50 - 184 °C	Boiling range (95%) 150 - 184 °C

The compositions of solvents and kerosene are shown in Table 5.2. On the other hand, physical properties, elemental analysis and hydrocarbon groups of tar are listed in Table 5.3. The pour point was determined per ASTM D-97. The ASTM D-92 open cup was used for flash point. Amounts of carbon, hydrogen, nitrogen, and sulfur were determined using a Carlo Erba 1106 analyzer. The hydrocarbon group separation and quantification were carried out with a high performance liquid chromatograph (HPLC) manufactured by Waters.

Table 5.2: Composition of Solvents.

Solvent	Components (weight %)			
	Paraffins	Naphthenes	Olefins	Aromatics
Naphtha (analytical grade)	3.8	0.2	0.4	95.6
Reformate (Riyadh refinery)	37.8	1.4	1.1	59.7
Reformate (Ras Tannura)	34.7	0.6	2.3	62.4
Kerosene	46.5	30.0	—	23.5

Table 5.3: Properties of Tar.

Test	Result
Pour point ($^{\circ}\text{F}$)	50
Flash point ($^{\circ}\text{F}$)	160
BS & W (% vol)	Trace
Sulphur (% weight)	3.25
Carbon content(% C)	81.8
Hydrogen content (% H)	11.8
Carbon/Hydrogen ratio (C/H ratio)	4/7
Nitrogen content (% N)	0.253
Asphaltenes (% weight)	25.8
Aromatics (% weight)	32.37
Resins (% weight)	9.06
Saturates (% weight)	32.77

5.2 DENSITY OF FLUIDS AND TAR-SOLVENT MIXTURES

Densities of the fluids vs. temperature were measured over the range of 20 °C to 120 °C using a 50 cc pycnometer immersed in a temperature-controlled oil bath. Densities of some samples were also measured directly with a hydrometer. Both methods (pycnometer and hydrometer) gave very close results.

Tables 5.4 summarizes the density results for tar, reformat, naphtha, kerosene, and brine at different temperatures while the density results for tar-reformat, tar-naphtha, and tar-kerosene mixtures are shown in Tables A-1, A-2, and A-3 (Appendix-A), respectively. Figures 5.1 through 5.4 show the plot of density vs. temperature for the pure fluids and tar/solvent mixtures. It is clear that the density varies linearly with temperature according to:

$$\rho = a - bT \quad (5.1)$$

where:

ρ = density (g/cc).

T = temperature (°C).

a, b = constants.

Table 5.4: Density Results of Tar, Reformate, Naphtha, Kerosene,
and Brine at Different Temperatures.

Temperature	Density (g/cc)				
(° C)	Tar	Reformate	Naphtha	Kerosene	Brine
20	0.922	0.777	0.866	0.787	1.007
40	0.912	0.765	0.854	0.775	0.997
60	0.900	0.750	0.843	0.764	0.985
80	0.887	0.736	0.831	0.752	0.973
100	0.875	0.721	0.819	0.740	0.961
120	0.860	0.707	0.808	0.728	0.947

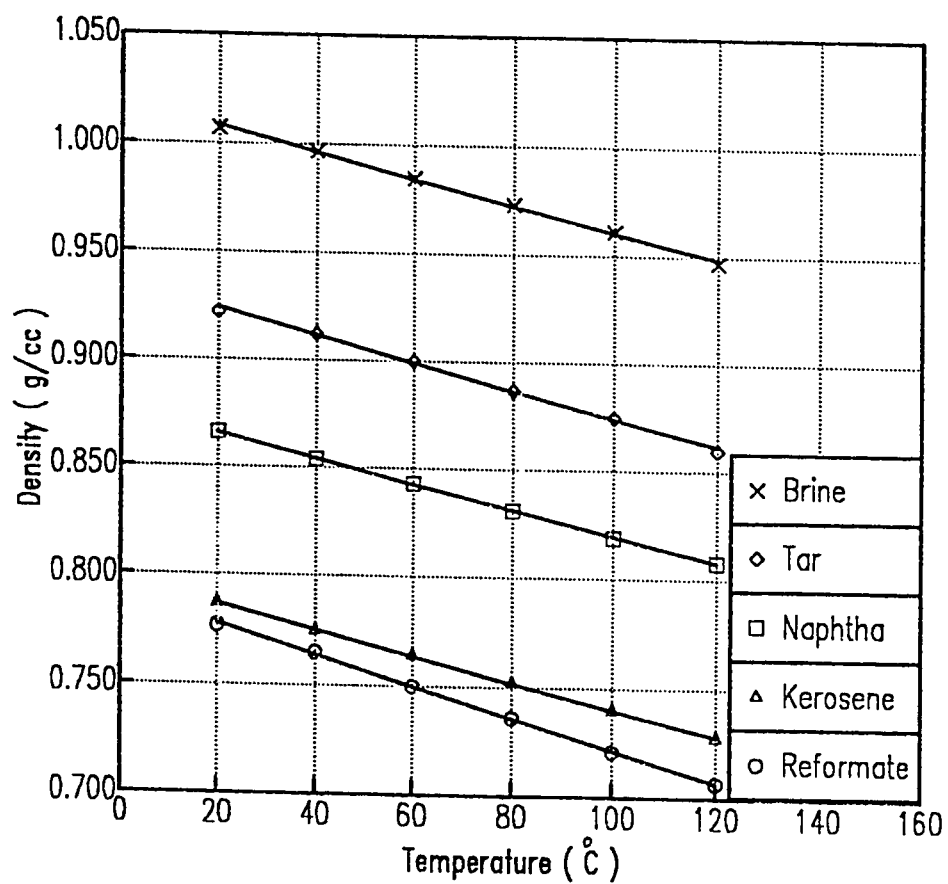


Figure 5.1: Density vs. temperature for brine, tar naphtha, kerosene and reformate.

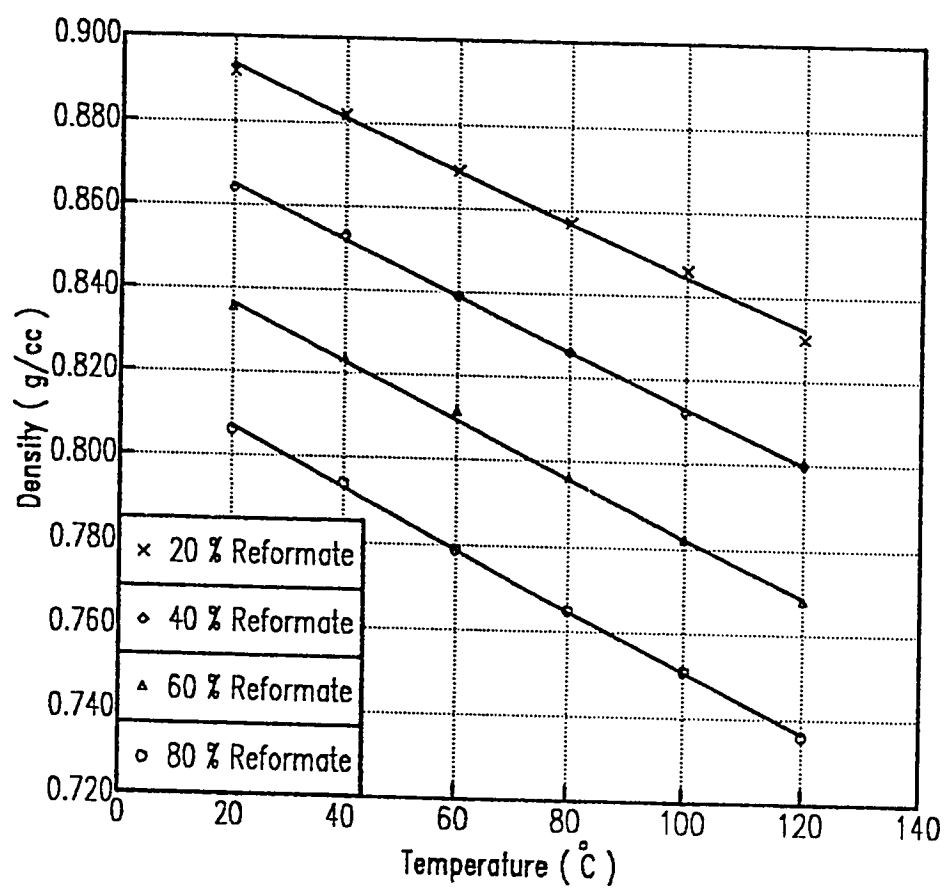


Figure 5.2: Density vs. temperature for tar/reformate mixtures.

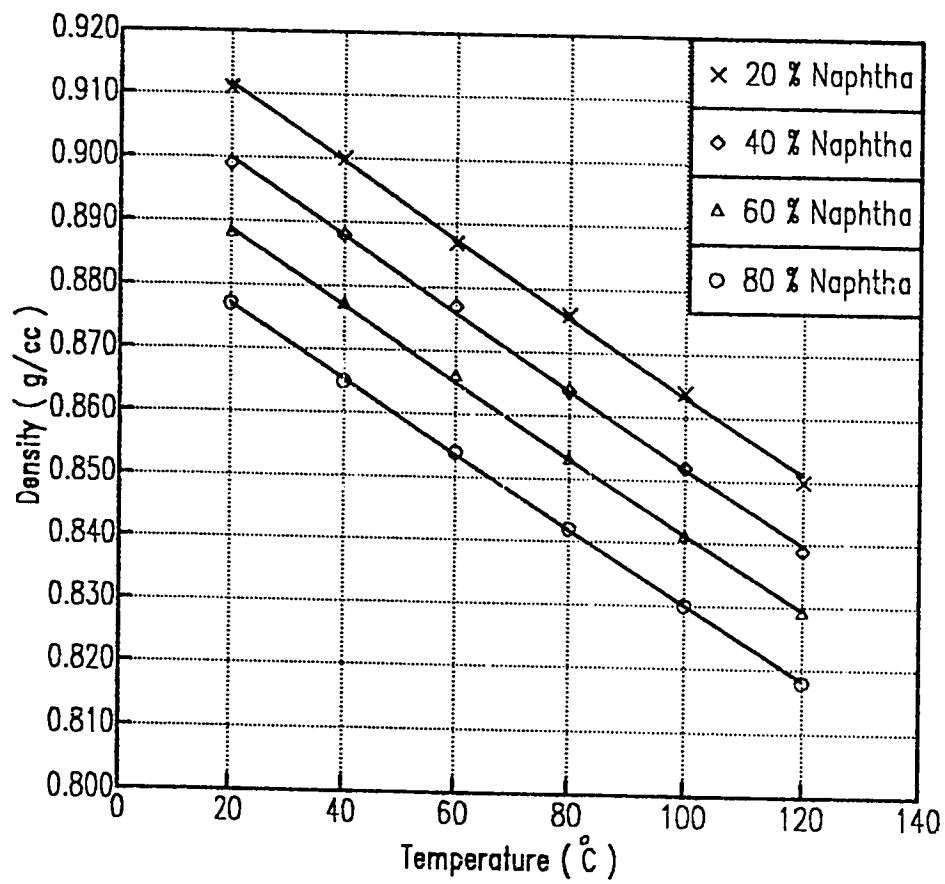


Figure 5.3: Density vs. temperature for tar/naphtha mixtures.

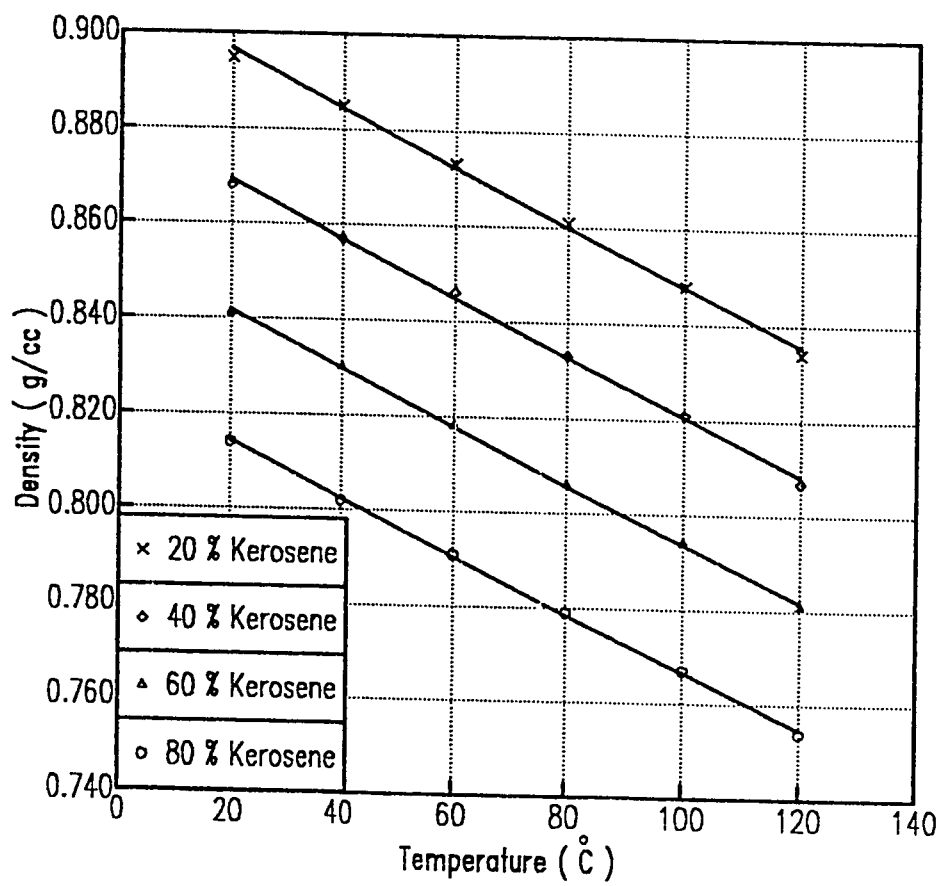


Figure 5.4: Density vs. temperature for tar/kerosene mixtures.

The slope was found to be almost constant for all tar, solvents, brine, and tar-solvent mixtures. Hence, a mean slope was taken to estimate the density variations with temperature. The following equation was used to estimate the density of the fluid at any temperature greater than room temperature:

$$\rho = a - 5.85 \times 10^{-4}(T - T_r) \quad (5.2)$$

where:

T_r = reference temperature ($^{\circ}\text{C}$).

a = density of the fluid at T_r .

T = temperature ($^{\circ}\text{C}$).

Figures A-1, A-2, and A-3 (Appendix-A) show the plot of tar-solvent mixture densities vs. concentration of solvent at different temperatures. At each temperature, the density of tar-solvent mixtures showing a linear variation with solvent concentration. Each straight line can be extrapolated to zero solvent concentration to find the density of the tar at that particular temperature. Hence, at any temperature, the density of tar-solvent mixtures follows an equation of this type:

$$\rho_m = X_s (\rho_s - \rho_t) + \rho_t \quad (5.3)$$

where:

ρ_m = density of the mixture (g/cc) .

ρ_t = density of tar (g/cc) .

ρ_s = density of solvent (g/cc) .

X_s = volume fraction of solvent .

Since equations 5.2 and 5.3 describe the variation of density with temperature and percentage of solvent, respectively, the density of any tar-solvent mixture can be estimated from the tar and solvent densities at any given temperature. The errors involved in estimating the density of any tar-solvent mixture using equation 5.3 are less than 0.3 % (see Appendix-A, Tables A-4, A-5, and A-6).

5.3 RHEOLOGICAL PROPERTIES OF TAR AND TAR-SOLVENT MIXTURES

An important factor to be considered when developing EOR recovery techniques for mobilizing the heavy oil in tar-mat reservoirs is the high viscosity of the tar itself. An efficient method of production in such reservoirs requires heat input in the form of hot-fluid injection and use of the smallest possible slug of solvent at the lowest possible cost. It is, therefore, important to study the effect of temperature and concentration of solvent on the viscosity of a tar-solvent mixtures.

A Plate-cone type, Contraves Low Shear 30 viscometer which is equipped with a HAAKE M circulated temperature oil bath was used to measure the viscosity. This instrument is particularly suited for rheological measurements at atmospheric pressure and varying temperatures. A continuous scan of velocities (shear rate) serves to ascertain whether or not the fluid is Newtonian. Viscosity measurements were carried out in the range from room temperature (20°C) to about 120°C.

Table 5.5 summarizes the results of shear stress and shear rate for tar which are also plotted in Figures 5.5 and 5.6. These figures show that for all temperatures the shear stress is directly proportional to the shear rate thus revealing the Newtonian behavior of the tar used in this study. This behavior is described by the equation:

$$\tau = \mu \gamma \quad (5.4)$$

Table 5.5: Shear Stress vs. Shear Rate for Tar at Different Temperatures.

Shear Rate (1/s)	Shear Stress, Dyne/cm ²					
	20 °C	40 °C	60 °C	80 °C	100 °C	120 °C
0.0297	3.03					
0.0404	4.11	0.42				
0.0549	5.67	0.57				
0.0746	7.77	0.78				
0.1015	10.56	1.05				
0.1379	14.34	1.41				
0.1874	19.44	1.89				
0.255	26.25	2.55	0.48			
0.346		3.45	0.63			
0.471		4.74	0.84			
0.639		6.39	1.14			
0.870		8.73	1.53			
1.182		11.82	2.05	0.62		
1.607		16.14	2.76	0.84		
2.190			3.72	1.14		
2.970			5.02	1.53		
4.040			6.83	2.07	0.93	0.45
5.490			9.21	2.79	1.23	0.60
7.460			12.54	3.78	1.68	0.81
10.150			16.95	5.16	2.28	1.11
13.790				6.99	3.12	1.53
18.740				9.48	4.23	2.07
25.500				12.84	5.73	2.79
34.600				17.46	7.80	3.81
47.100					10.56	5.22
63.900					14.40	7.02
87.000						9.57

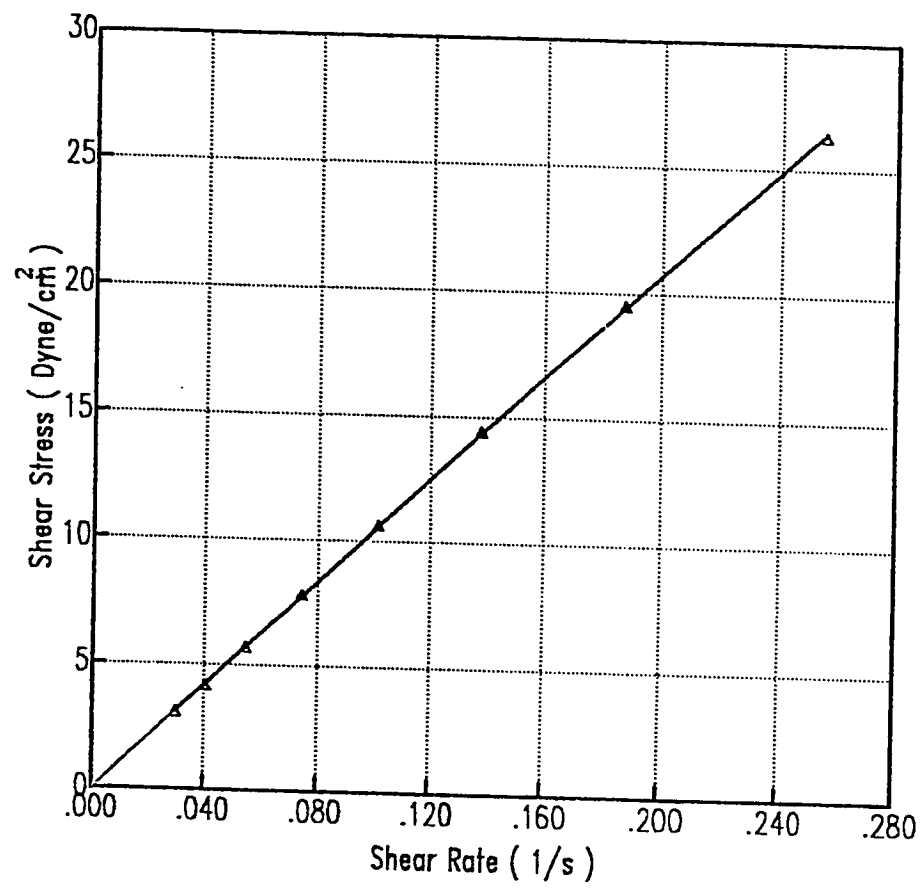


Figure 5.5: Shear stress vs. shear rate for tar at room temperature.

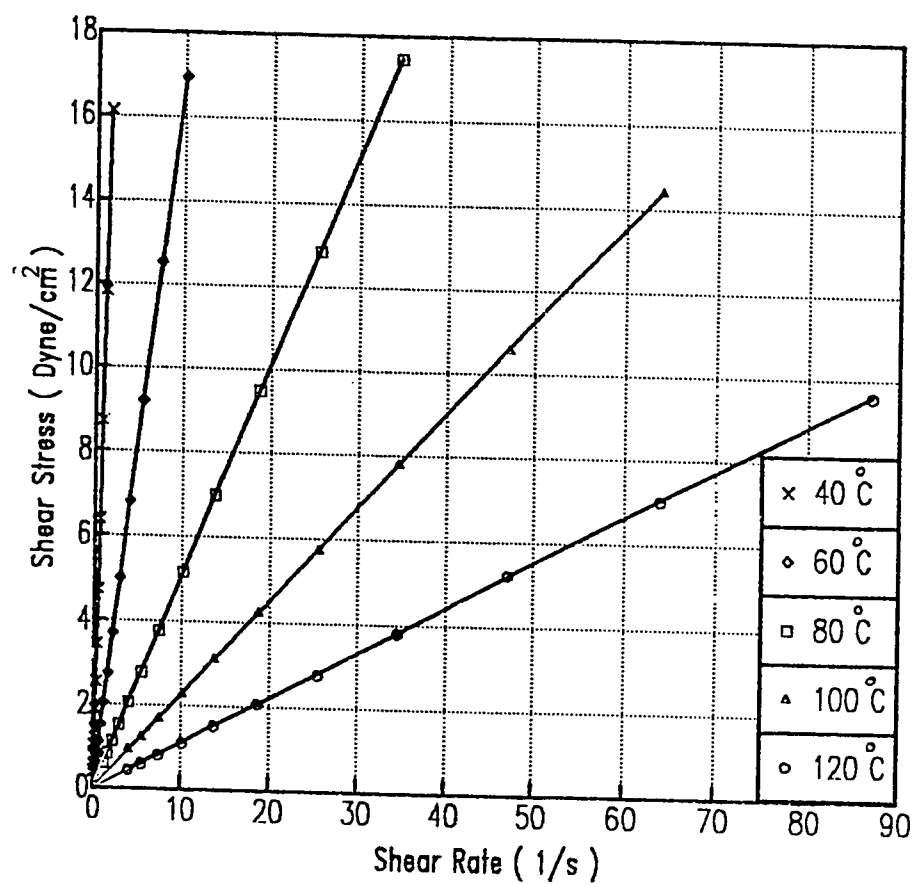


Figure 5.6: Shear stress vs. shear rate for tar at different temperature.

where:

τ = shear stress (dyne/cm²).

μ = dynamic viscosity (poises).

γ = shear rate (1/s).

To further assess the Newtonian behavior of tar, the data of Figures 5.5 and 5.6 are plotted on log-log coordinates as shown in Figure 5.7. It is clear from Figure 5.7 that the slope of all the $\log \tau$ vs. $\log \gamma$ lines is equal to 1; hence there is no doubt about the Newtonian behavior of the tar. Furthermore, the logarithmic plot of viscosity vs. shear rate shown in Figure 5.8 definitely establishes that this tar is Newtonian.

The rheological measurements were also carried out for tar-solvent mixtures. Figures 5.9, 5.10, and 5.11 show the plots of shear stress vs. shear rate for 60% tar-40% reformat, 60% tar-40% naphtha, and 40% tar-60% kerosene mixtures, respectively. The plots show a linear variation of τ vs. γ without yield values. Therefore, the tar-solvent mixtures also behave as Newtonian fluids. The shear stress-shear rate data for these tar-solvent mixtures are listed in Tables A-7, A-8, and A-9 (Appendix-A).

The kinematic viscosity, ν , of a fluid can be calculated from the dynamic viscosity and density using the relationship:

$$\nu = \frac{\mu}{\rho} \quad (5.5)$$

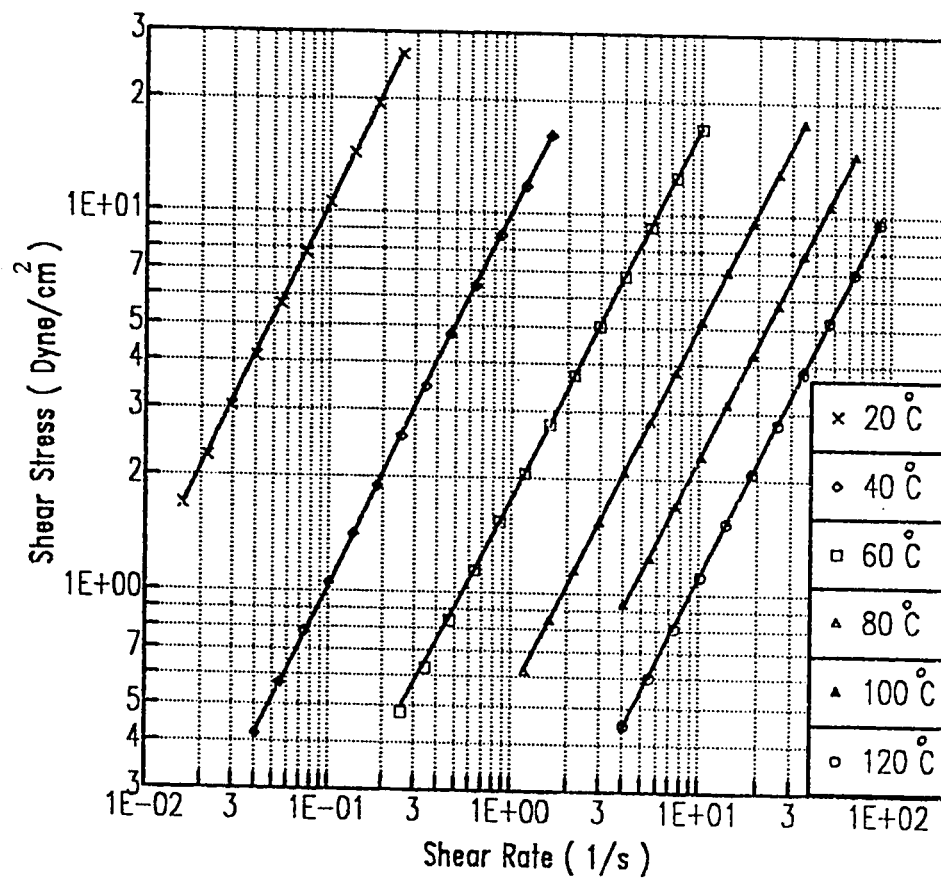


Figure 5.7: Logarithmic plot of shear stress vs. shear rate for tar.

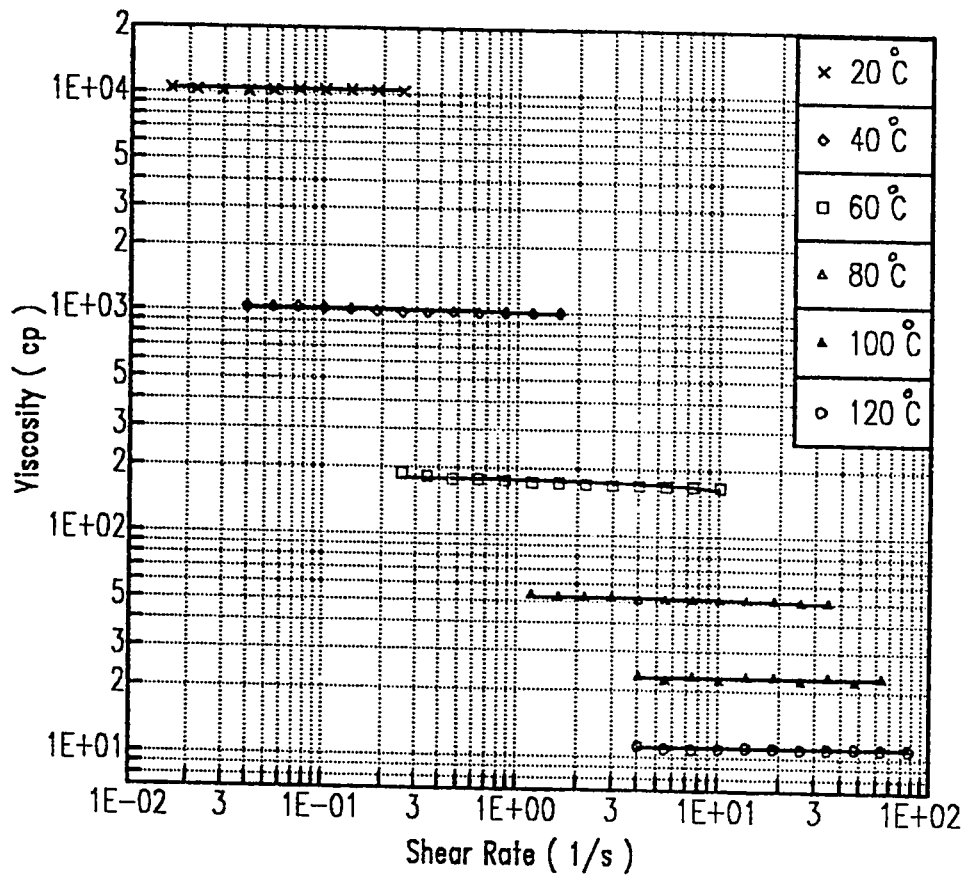


Figure 5.8: Absolute viscosity vs. shear rate for tar at different temperatures.

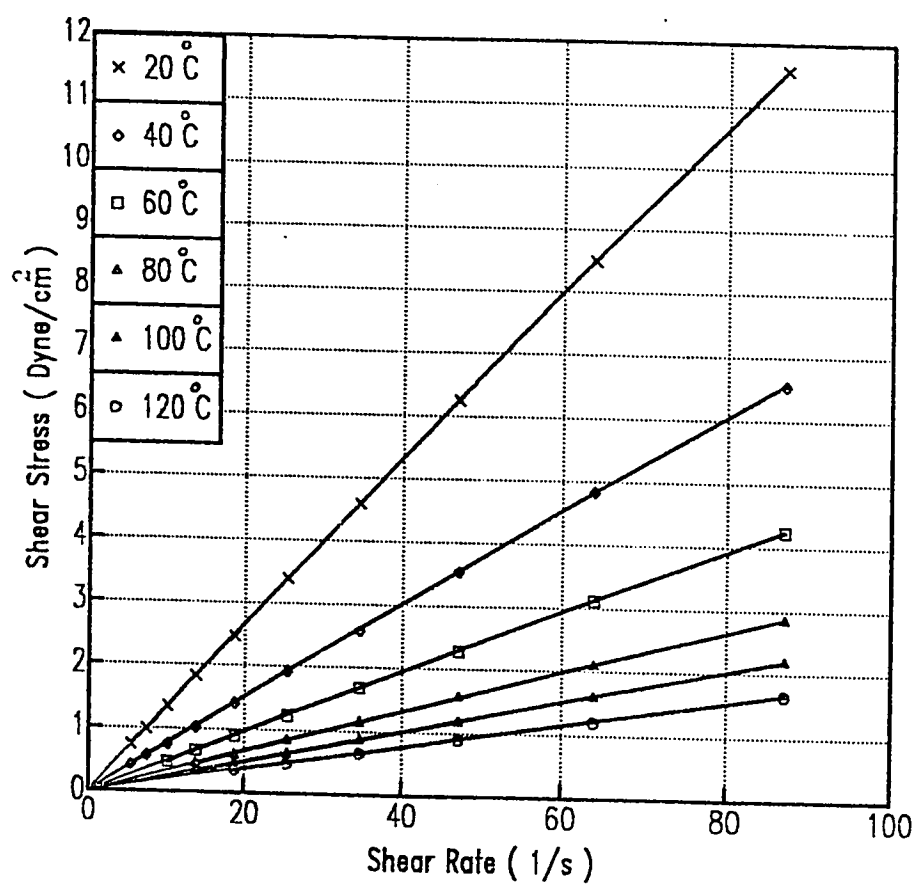


Figure 5.9: Shear stress vs. shear rate for 40% reformat/60% tar mixture.

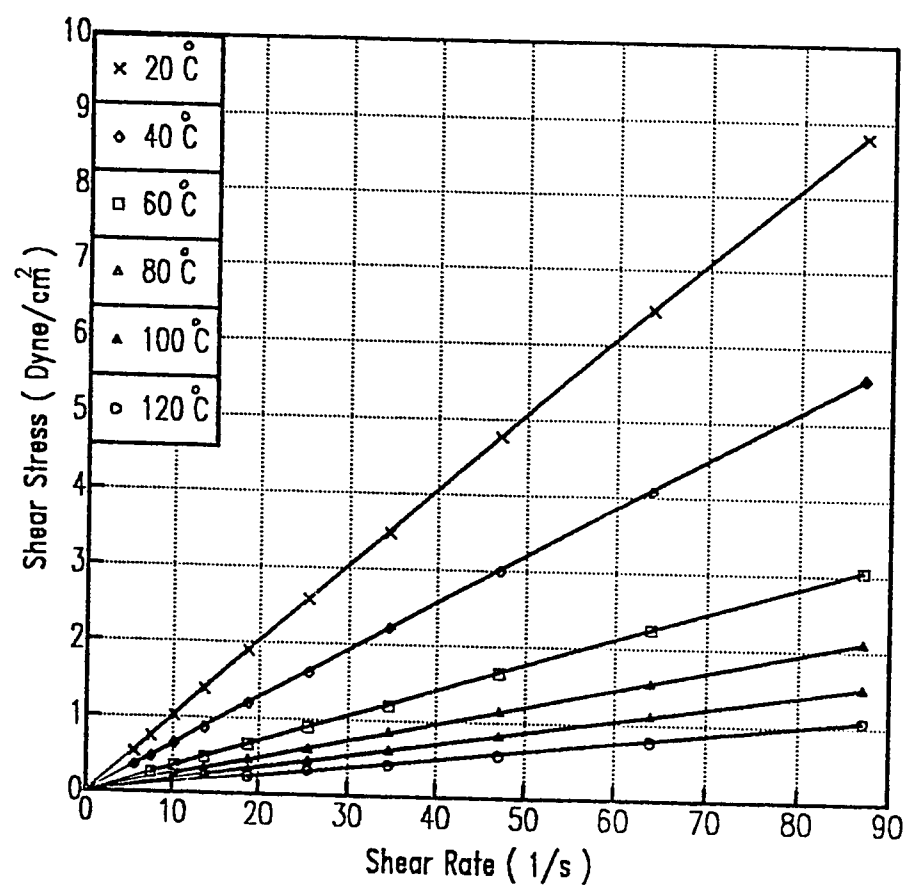


Figure 5.10: Shear stress vs. shear rate for 40% naphtha/60% tar mixture.

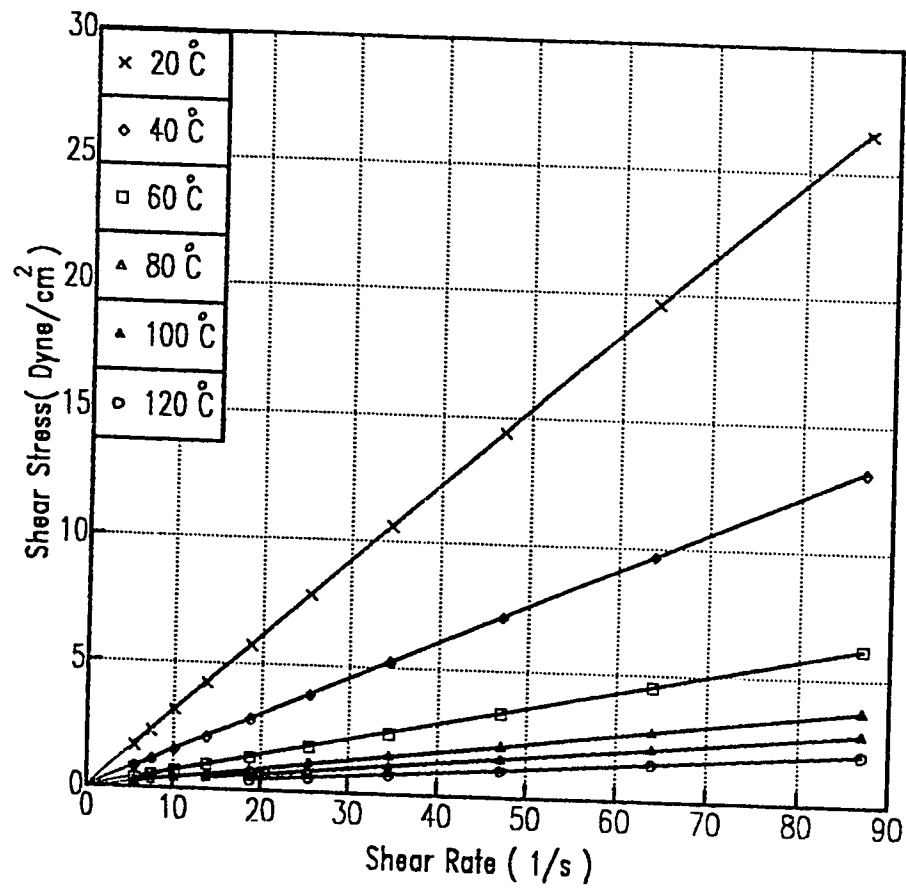


Figure 5.11: Shear stress vs. shear rate for 40% kerosene/60% tar mixture.

where:

ν = *kinematic viscosity (cSt).*

μ = *dynamic viscosity (cp).*

ρ = *density (g/cc).*

Table 5.6 summarizes the dynamic and kinematic viscosities of tar at different temperatures. According to ASTM D341, a general relationship between kinematic viscosity and temperature can be expressed as:

$$\log (\log Z) = A - B \log T \quad (5.6)$$

where:

$$Z = \nu + 0.7 + C - D + E - F + G - H ,$$

A and B are constants.

and C to H are exponentials of ν , on the natural base, to be added according to the viscosity range used. As shown in Figure 5.12, $Z = \nu + 0.7$ turned out to be sufficient for the tar of this study.

Therefore, equation 5.6 can be simplified to:

$$\log [\log(\nu + 0.7)] = A - B \log T$$

and kinematic viscosity of tar can be estimated from the following equation:

$$\log [\log(\nu + 0.7)] = 11.267 - 4.334 \log(T + 273) \quad (5.7)$$

Table 5.6: Dynamic and Kinematic Viscosity of Tar at
Different Temperatures.

Temperature ($^{\circ}\text{C}$)	Dynamic Viscosity (cp)	Density (g/cc)	Kinematic Viscosity (cSt)
20	10,332	0.922	11,206
40	1,015	0.912	1112
60	174	0.900	193
80	51	0.887	57
100	23	0.875	26
120	11	0.860	13

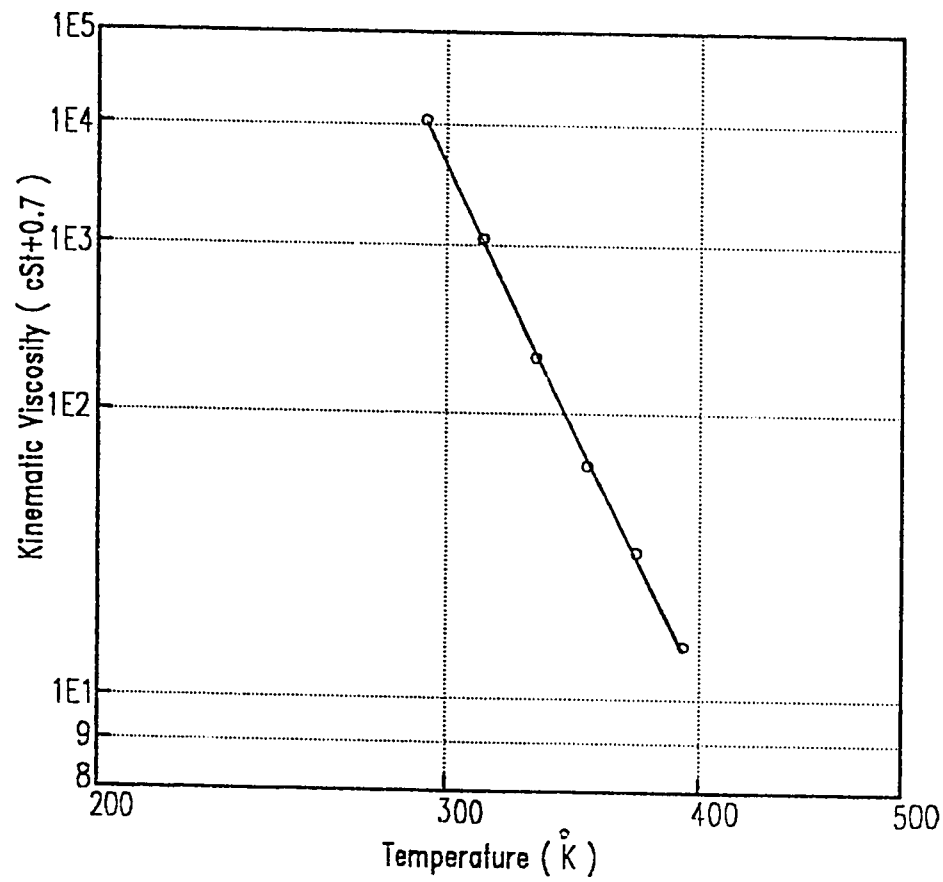


Figure 5.12: Kinematic viscosity vs. temperature for tar.

where:

$$T = \text{temperature } (^{\circ}\text{C}).$$

The absolute errors involved using this prediction are less than 8.7% with an average of 4% as shown in Table 5.7.

The dynamic viscosities of tar, reformat, naphtha, kerosene, and brine are listed in Table 5.8 while viscosity results of tar-solvent mixtures are listed in Tables A-10, A-11, and A-12 (Appendix-A). Figures 5.13 and 5.14 show the effect of temperature on viscosity of tar, solvents, and brine; while Figures 5.15, 5.16, and 5.17 show the effect of temperature on viscosity of tar-reformat, tar-naphtha, and tar-kerosene mixtures, respectively. These figures show that the viscosity of the fluid decreases dramatically as the temperature increases, and the viscosity of a tar-solvent mixture decreases as the solvent concentration increases.

Table 5.7: Measured and Estimated Kinematic Viscosity of
Tar at Different Temperatures.

Temperature ($^{\circ}\text{C}$)	Measured Viscosity (cSt)	Estimated Viscosity (cSt)	Error %
20	11,206	10,690	4.6
40	1,112	1,062	4.5
60	193	206	-6.4
80	57	62	-8.7
100	26	26	0.0
120	13	13	0.0

Table 5.8: Dynamic Viscosities of Tar, Reformate, Kerosene, Naphtha, and Brine at Different Temperatures.

Temperature (° C)	Viscosity (cp)				
	Tar	Reformate	Naphtha	Kerosene	Brine
20	10,332	0.52	0.79	1.39	1.04
40	1,015	0.47	0.65	1.07	0.78
60	174	0.42	0.48	0.82	0.63
80	51	0.39	0.40	0.66	0.56
100	23	0.37	0.35	0.57	0.54
120	11	0.35	0.30	0.52	0.50

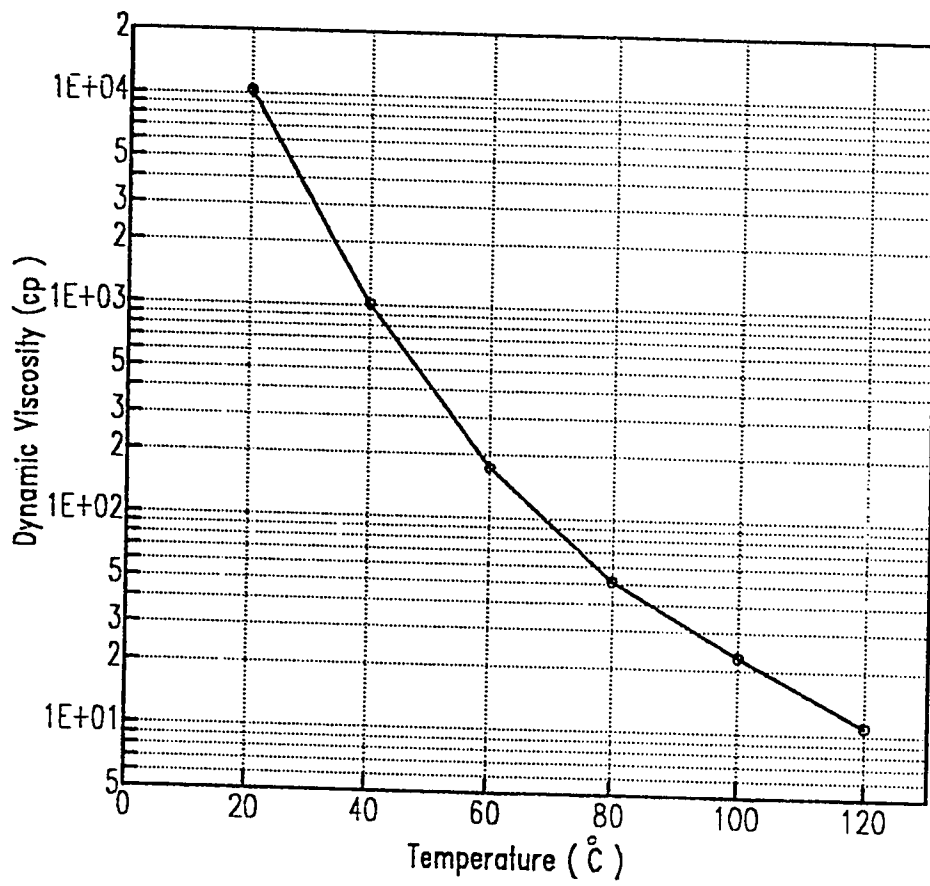


Figure 5.13: Dynamic viscosity vs. temperature for tar.

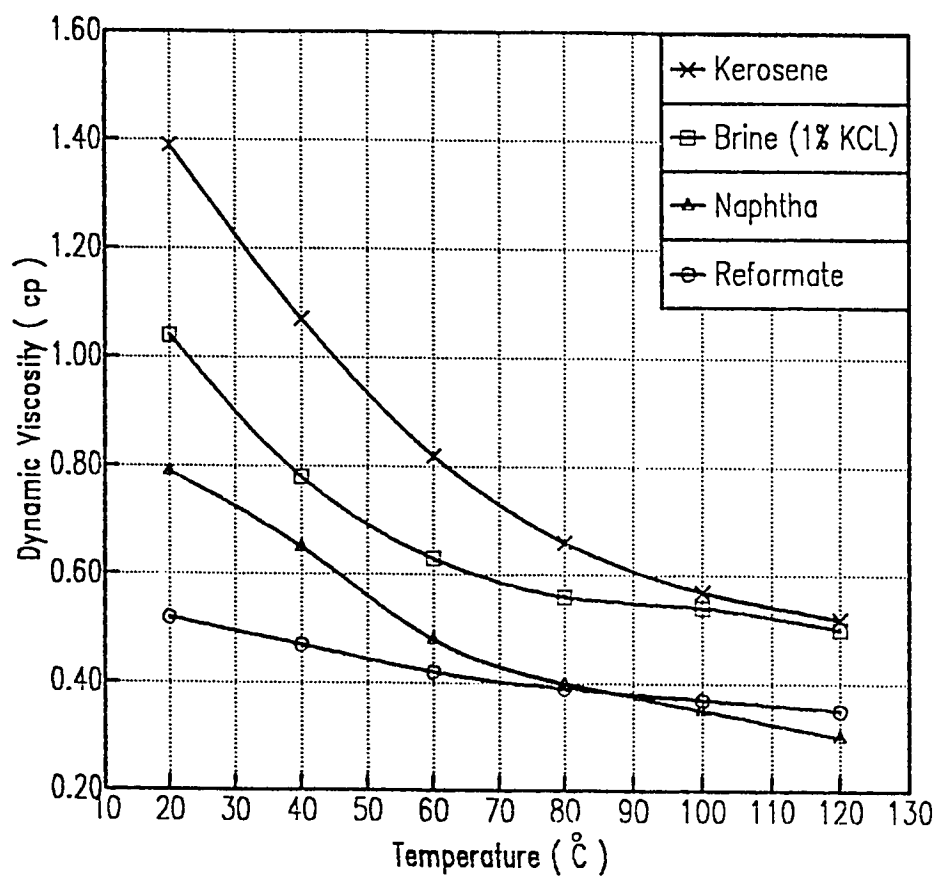


Figure 5.14: Dynamic viscosity vs. temperature for reformate, naphtha, kerosene, and brine.

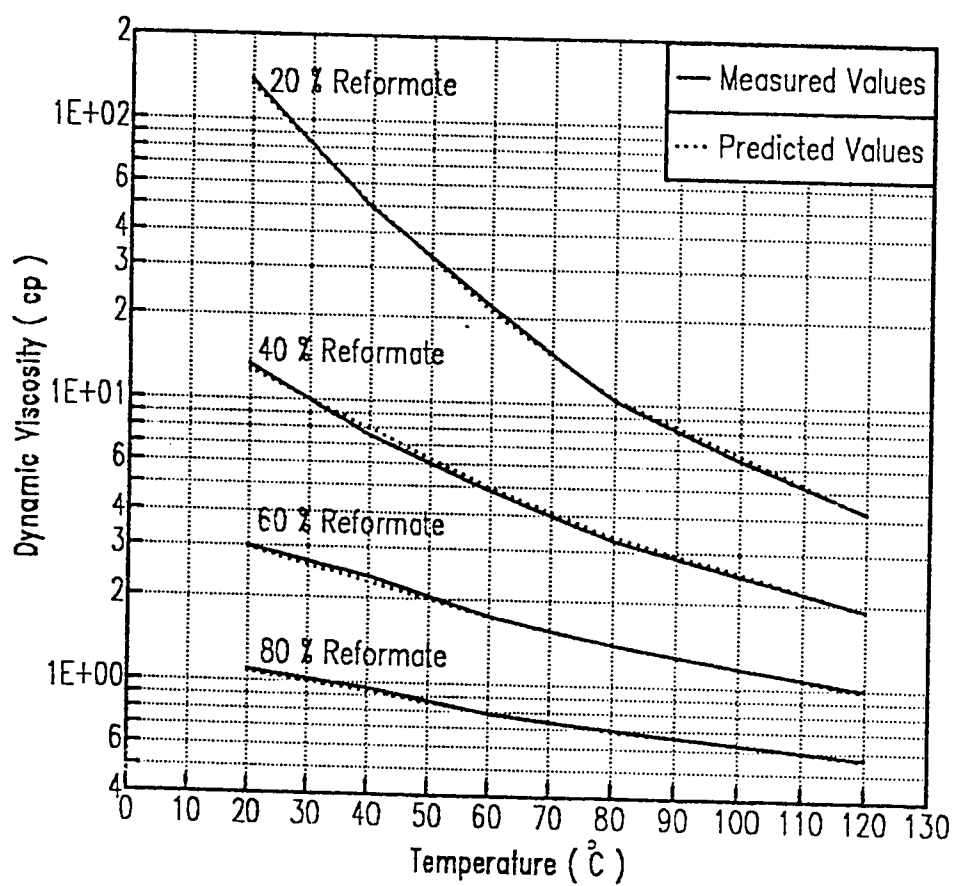


Figure 5.15: Dynamic Viscosity vs. temperature for tar/reformate mixtures.

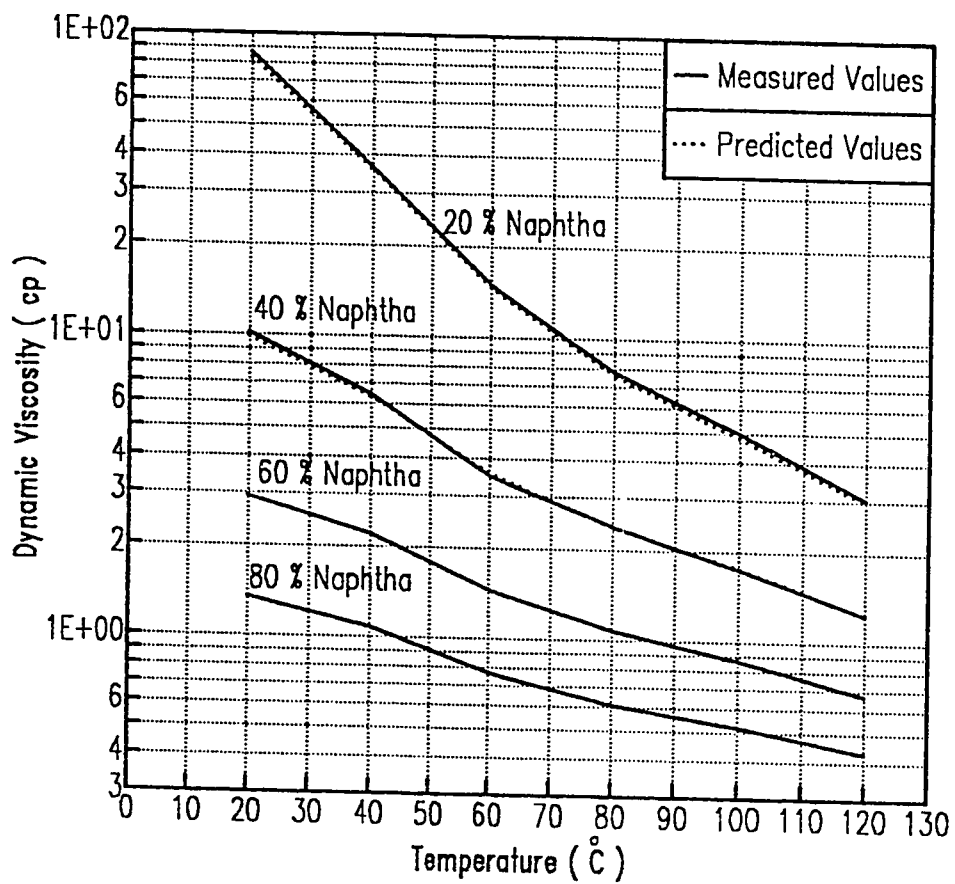


Figure 5.16: Dynamic viscosity vs. temperature for tar/naphtha mixtures.

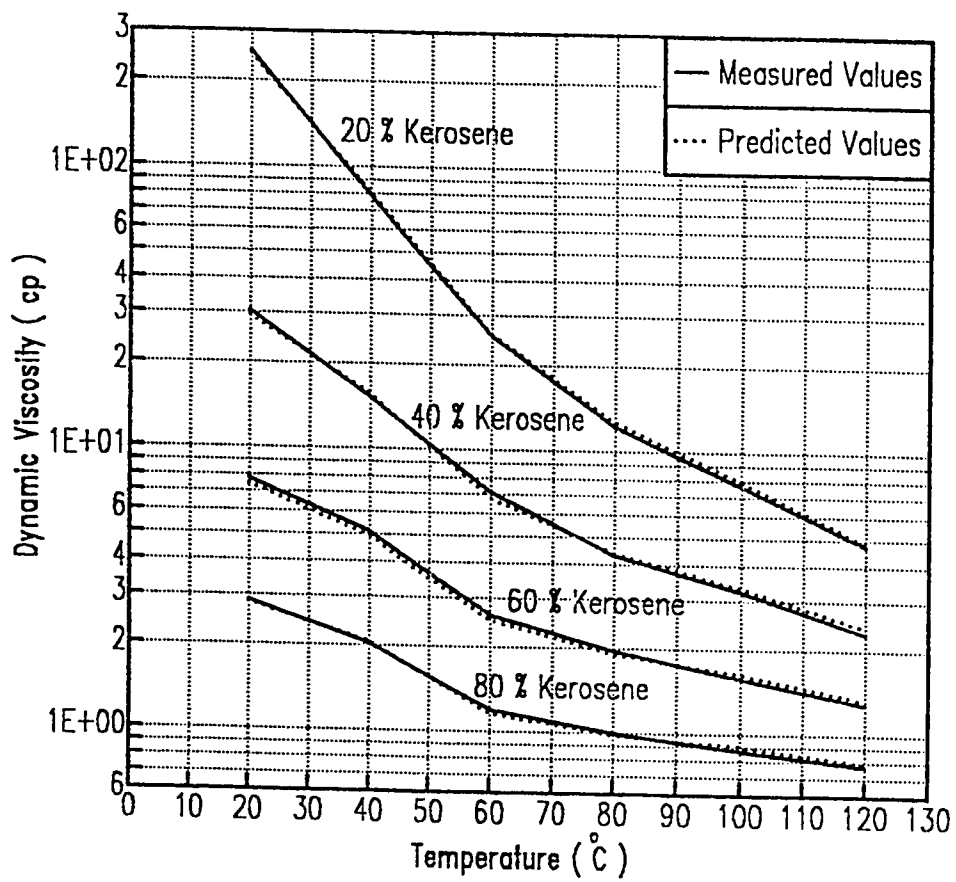


Figure 5.17: Dynamic viscosity vs. temperature for tar/kerosene mixtures.

Since the addition of a solvent to tar reduces tar viscosity, it is important to estimate the viscosity of tar-solvent mixtures at any given temperature and concentration. A number of attempts have been made to predict viscosities of different heavy oil or tar-solvent mixtures. Shu (1984) developed a generalized correlation for predicting the viscosities of heavy oils and light petroleum solvent mixtures. This correlation involves four equations:

$$\ln \mu = X_A \ln \mu_A + X_B \ln \mu_B \quad (5.8)$$

$$X_A = \frac{\alpha V_A}{\alpha V_A + V_B} \quad (5.9)$$

$$X_B = 1 - X_A \quad (5.10)$$

$$\alpha = \frac{17.04 (\Delta\rho^{0.5237}) (\rho_A^{3.2745}) (\rho_B^{1.6316})}{\ln(\mu_A/\mu_B)} \quad (5.11)$$

where:

$$\Delta\rho = \rho_A - \rho_B$$

For convenience, it is preferred to designate A as the more viscous component (tar or heavy oil) and B as the less viscous one (solvent). X_A and X_B are compositional parameters, but not mole fraction, since they depend on α which depends on the viscosities and densities. V_A and V_B are volume frac-

tions.

To see how well the Shu correlation predicts the viscosities of the tar-solvent mixtures, the measured viscosity and density of tar and solvents at different temperatures were used to calculate values of α , X_A , and X_B for volume fractions and, then, the predicted viscosities of tar-solvent mixtures were calculated using equation 5.9. Tables 5.9, 5.10, and 5.11 summarize the Shu correlation parameters and give the measured and predicted viscosities for tar-reformate, tar-naphtha, and tar-kerosene mixtures, respectively. Comparisons of the measured and predicted viscosities for different tar-solvent mixtures show that the absolute errors involved in this prediction are less than 6 % with an average of 4%. The predicted viscosities of tar-reformate, tar-naphtha, and tar-kerosene mixtures are also plotted in Figures 5.15, 5.16, and 5.17, respectively. It can be seen that the predictions are quite good.

Plots of kinematic viscosity vs. temperature for tar-reformate, tar-naphtha, and tar-kerosene mixtures are shown in Figures A-4, A-5, and A-6 (Appendix-A), respectively. They show a straight line relationship and follow equation 5.6.

From the previous discussion and investigations of rheological properties of tar and tar-solvent mixtures, it can be fairly stated that both tar and tar-solvent mixtures can be considered as Newtonian fluids. The behavior and rheological properties of the tar-solvent mixtures used in this study are consistent with the behavior and properties of similar tars documented in the literature. The present results compare nicely, for example, with Athabasca

Table 5.9: Measured and Predicted Dynamic Viscosities of Tar/Reformate Mixtures at Different Temperatures Using Shu Correlation.

Temperature (° C)	VB %	α	XA	XB	Measured Viscosity cp	Predicted Viscosity cp	Error %
20	20	0.318	0.560	0.440	138.0	132.6	3.9
	40		0.323	0.677	13.31	12.71	4.4
	60		0.175	0.825	3.00	2.94	2.0
	80		0.074	0.926	1.10	1.08	1.8
40	20	0.388	0.608	0.392	49.00	50.22	-2.5
	40		0.368	0.632	7.52	7.94	-5.6
	60		0.206	0.794	2.38	2.28	4.2
	80		0.089	0.911	0.96	0.93	3.1
60	20	0.464	0.650	0.350	22.00	21.07	4.2
	40		0.410	0.590	4.84	4.98	-2.9
	60		0.236	0.764	1.75	1.74	0.6
	80		0.104	0.896	0.79	0.79	0.0
80	20	0.532	0.680	0.320	10.30	10.74	-4.3
	40		0.440	0.560	3.27	3.39	-3.7
	60		0.260	0.740	1.40	1.40	0.6
	80		0.120	0.880	0.70	0.69	1.4
100	20	0.587	0.700	0.300	6.40	6.70	-4.7
	40		0.470	0.530	2.50	2.56	-2.4
	60		0.280	0.720	1.18	1.18	0.0
	80		0.130	0.870	0.63	0.63	0.0
120	20	0.641	0.720	0.280	4.20	4.18	0.5
	40		0.490	0.510	1.91	1.90	0.5
	60		0.300	0.700	1.00	0.98	2.0
	80		0.140	0.860	0.57	0.56	1.8

Table 5.10: Measured and Predicted Dynamic Viscosities of Tar/Naphtha Mixtures at Different Temperatures Using Shu Correlation.

Temperature (° C)	VB %	α	XA	XB	Measured Viscosity cp	Predicted Viscosity cp	Error %
20	20	0.240	0.490	0.510	86.31	82.69	4.2
	40		0.265	0.735	10.17	9.77	3.3
	60		0.140	0.860	2.93	2.93	0.0
	80		0.060	0.940	1.35	1.35	0.0
40	20	0.300	0.540	0.460	36.20	35.52	1.9
	40		0.310	0.690	6.42	6.31	1.7
	60		0.170	0.830	2.20	2.20	0.0
	80		0.070	0.930	1.08	1.08	0.0
60	20	0.350	0.580	0.420	14.92	14.67	1.7
	40		0.340	0.660	3.50	3.59	-2.6
	60		0.190	0.810	1.45	1.45	0.0
	80		0.080	0.920	0.77	0.77	0.0
80	20	0.390	0.610	0.390	7.77	7.63	1.8
	40		0.370	0.630	2.39	2.38	0.4
	60		0.210	0.790	1.08	1.08	0.0
	80		0.090	0.910	0.61	0.61	0.0
100	20	0.420	0.630	0.370	5.00	4.82	3.6
	40		0.390	0.610	1.74	1.76	-1.1
	60		0.220	0.780	0.87	0.87	0.0
	80		0.090	0.910	0.52	0.52	0.0
120	20	0.431	0.630	0.370	3.02	2.95	2.3
	40		0.390	0.610	1.24	1.24	0.0
	60		0.220	0.780	0.67	0.67	0.0
	80		0.100	0.900	0.43	0.43	0.0

Table 5.11: Measured and Predicted Dynamic Viscosities of Tar/Kerosene Mixtures at Different Temperatures Using Shu Correlation.

Temperature (° C)	VB %	α	XA	XB	Measured Viscosity cp	Predicted Viscosity cp	Error %
20	20	0.347	0.580	0.420	255.50	247.75	3.0
	40		0.340	0.660	30.60	29.45	3.8
	60		0.190	0.810	7.77	7.43	4.4
	80		0.080	0.920	2.88	2.83	1.8
40	20	0.428	0.630	0.370	78.20	81.14	-3.8
	40		0.390	0.610	15.10	15.63	-3.5
	60		0.220	0.780	5.10	4.90	3.9
	80		0.100	0.900	2.04	2.08	-1.9
60	20	0.487	0.660	0.340	25.32	25.83	-2.0
	40		0.420	0.580	7.10	6.75	4.9
	60		0.240	0.760	2.60	2.50	3.9
	80		0.110	0.890	1.20	1.16	3.3
80	20	0.561	0.690	0.310	12.24	12.70	-3.8
	40		0.460	0.540	4.30	4.40	-2.3
	60		0.270	0.730	1.96	1.91	-2.5
	80		0.120	0.880	1.00	0.98	2.0
100	20	0.629	0.720	0.280	7.63	7.91	-3.7
	40		0.490	0.510	3.23	3.34	-3.4
	60		0.300	0.700	1.58	1.64	-3.8
	80		0.140	0.860	0.87	0.90	-3.4
120	20	0.694	0.740	0.260	4.74	4.85	-2.3
	40		0.510	0.490	2.30	2.42	-5.2
	60		0.320	0.680	1.28	1.33	-3.9
	80		0.150	0.850	0.77	0.79	-2.6

bitumen mixed with naphtha and other solvents which also display Newtonian behavior (Schramm, L. L., 1988).

5.4 INTERFACIAL TENSION OF TAR AND TAR-SOLVENT MIXTURES AGAINST BRINE

The interfacial tension between tar, or heavy oil, and injected brine plays an important role in the displacement efficiency. The interaction between tar and hot water depends on temperature and the composition of both oleic and aqueous phases. Increasing the formation temperature is the most significant factor in mobilizing the tar or heavy oil. However, the addition of solvent to injected hot water is expected to improve the displacement efficiency and thus enhance oil recovery by reducing IFT between tar and brine.

In this study, the effect of temperature on IFT between tar and brine as well as between tar-solvent mixtures and brine is investigated. Interfacial tension is determined by measuring the force necessary to detach a planar ring of platinum wire from the surface of the liquid of higher surface tension, that is upward from the water-tar interface (ASTM D971-82). The procedure for IFT measurement is as follows:

- (1) The first step is cleaning the ring with naphtha and heating to glowing by holding this ring above a Bunsen burner. Also, the sample container is cleaned with chromic acid, boiled out for a prolonged period of time in distilled water, and then flamed out with a Bunsen burner.

- (2) The second step is adjusting the tensiometer scale to zero. The sample container is then filled halfway with the heavy phase (1% KCL brine) and the perfectly cleaned ring is submerged in this phase. Next, the light phase (tar or tar-solvent mixture) is added carefully on top of the heavy phase.
- (3) The third step is allowing the tar-brine interface to age for 30 seconds, then the container is lowered slowly until the pointer of zero-point swings into the negative range and the servomotor starts. The apparatus stops after a short period, and the measured value can be read on the digital display. For higher temperatures, the fluids and ring are left for 20 minutes for temperature equilibration.

The measured interfacial tension is corrected by an empirically determined factor which depends upon the force applied, the density of both tar and brine, and the dimensions of the ring according to the following equation:

$$\sigma = \sigma^* \times F \quad (5.12)$$

where:

σ = corrected value of IFT (mN/m).

σ^* = measured IFT value (mN/m).

F = correction factor.

Using the diameter ratio, R/r , specified by the manufacturer for the ring used, the measured IFT value should be corrected by the equation of Zuidema and Waters (1941):

$$F = 0.725 + \left[\frac{1.452\sigma^*}{L_b^2(D-d)} + 0.04535 - \frac{1.679}{R/r} \right]^{1/2} \quad (5.13)$$

where:

D = density of the brine (g/cc).

d = density of tar or tar/solvent mixture (g/cc).

σ^* = measured interfacial tension (mN/m).

L_b = wetted length (119.95 mm).

R/r = diameter ratio (51.6).

According to the ring specifications, equation 5.13 becomes

$$F = 0.725 + \left[\frac{1.01 \times 10^{-4} \sigma^*}{(D-d)} + 0.0128 \right]^{1/2} \quad (5.14)$$

The correction factor F should be multiplied by 1.07 before it is applied to the measured value. So, the corrected IFT value will be calculated from the following equation:

$$\sigma = \sigma^* \times F \times 1.07 \quad (5.15)$$

Distilled water was used to check the equipment. At 22 °C , the IFT between distilled water and air was measured as 72.3 mN/m which indicates a good calibration and working conditions of the K10 Digital Tensiometer.

Figure 5.18 shows the IFT/temperature relationship for tar-brine, reformat-brine, naphtha-brine, and kerosene-brine systems. These results show a decrease in IFT with temperature in the range of 22 °C to 85 °C . The decrease of IFT values at higher temperature can be attributed to the weakening of intermolecular forces at the oil-brine interface. In addition, Figure 5.18 shows that kerosene-brine, reformat-brine, and naphtha-brine IFT values are higher than tar-brine IFT values. The IFT results are, also, listed in Table 5.12.

IFT measurements at different temperatures were also carried out for different tar-solvent mixtures and brine. Figures 5.19, 5.20, and 5.21 show plots of IFT results vs. temperature for tar-reformat, tar-naphtha, and tar-kerosene mixtures over the temperature range of 22 °C to 85 °C , respectively. These results show a general trend of increase in IFT with increase in percent of solvent. This trend is expected since tar has the least IFT with brine at any temperature.

Also, it can be mentioned that IFT values increase as the density difference between oleic phase and aqueous phase increases. For instance a mixture of 20% reformat and 80% tar which has a density difference of 0.106 g/cc will have an IFT of 17.60 mN/m at 22 °C .while a mixture of 80% reformat and 20% tar which has a density difference of 0.192 g/cc will have an IFT of 20.5 mN/m at the same temperature. The same trend can be observed

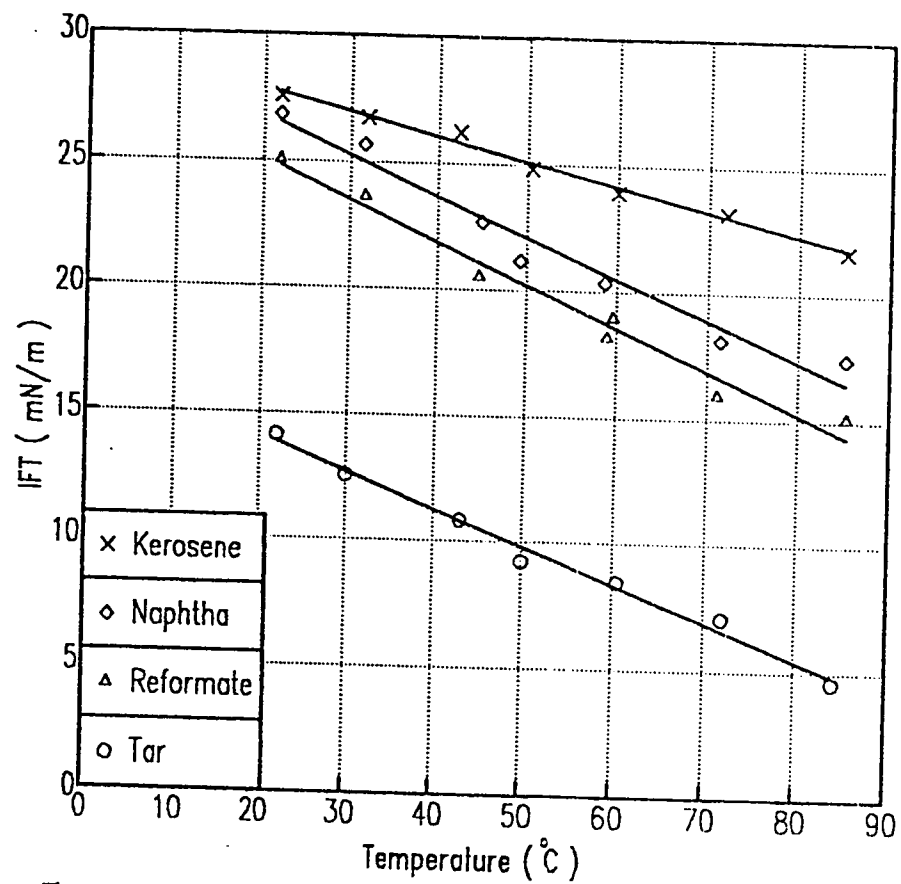


Figure 5.18: Interfacial tension vs. temperature for tar/brine, reformate /brine, naphtha/brine, and kerosene/brine.

Table 5.12: Interfacial Tensions of Tar, Reformate, Naphtha, and Kerosene Against Brine at Different Temperatures.

Tar		Reformate		Naphtha		Kerosene	
Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)
22.0	14.13	22.0	25.03	22.0	26.85	22.0	27.57
30.0	12.58	31.7	23.64	31.6	25.68	31.9	26.75
43.0	10.85	44.7	20.51	45.0	22.69	42.4	26.24
50.0	9.25	49.6	18.96	49.3	21.17	50.5	24.85
60.5	8.46	59.0	18.18	58.7	20.35	60.0	23.96
72.0	7.1	71.1	15.97	71.4	18.14	72.0	23.17
84.2	4.61	85.3	15.11	85.2	17.45	85.2	21.70

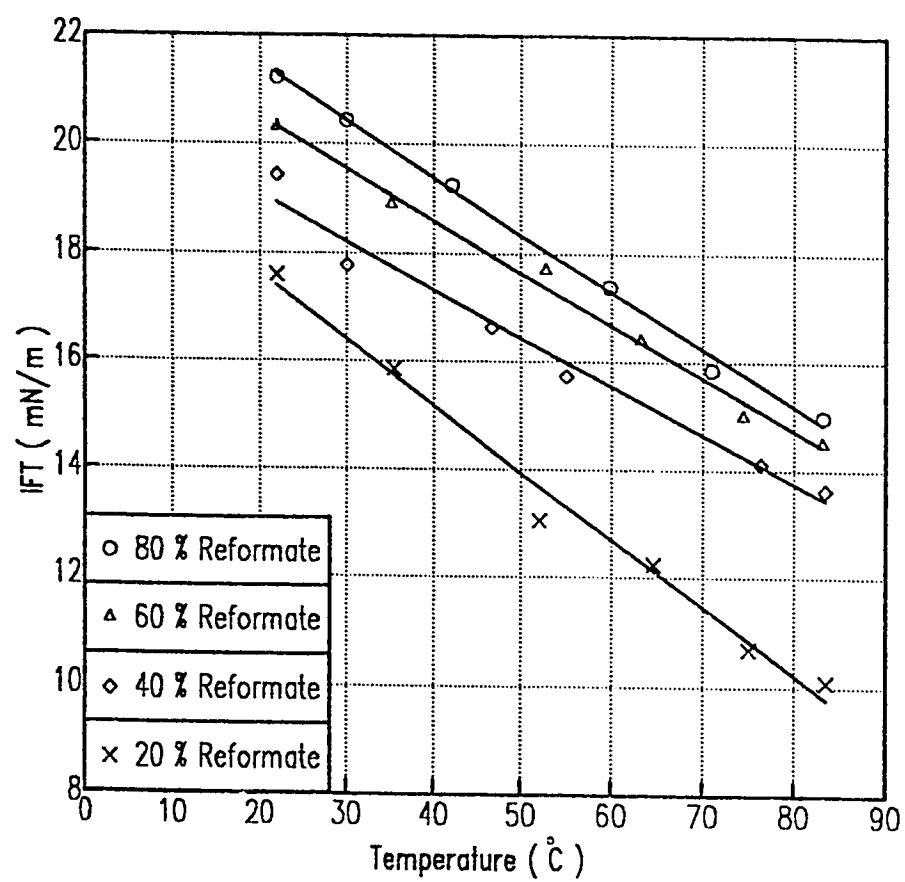


Figure 5.19: Interfacial tension vs. temperature for tar/reformate mixtures.

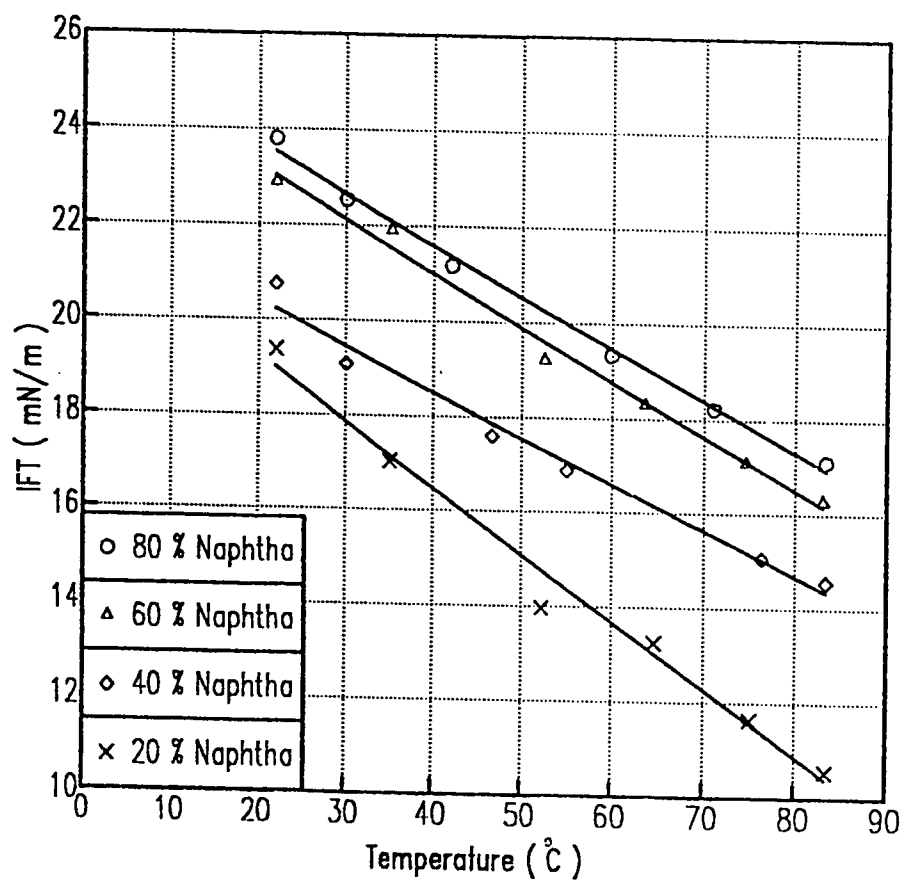


Figure 5.20: Interfacial tension vs. temperature for tar/naphtha mixtures.

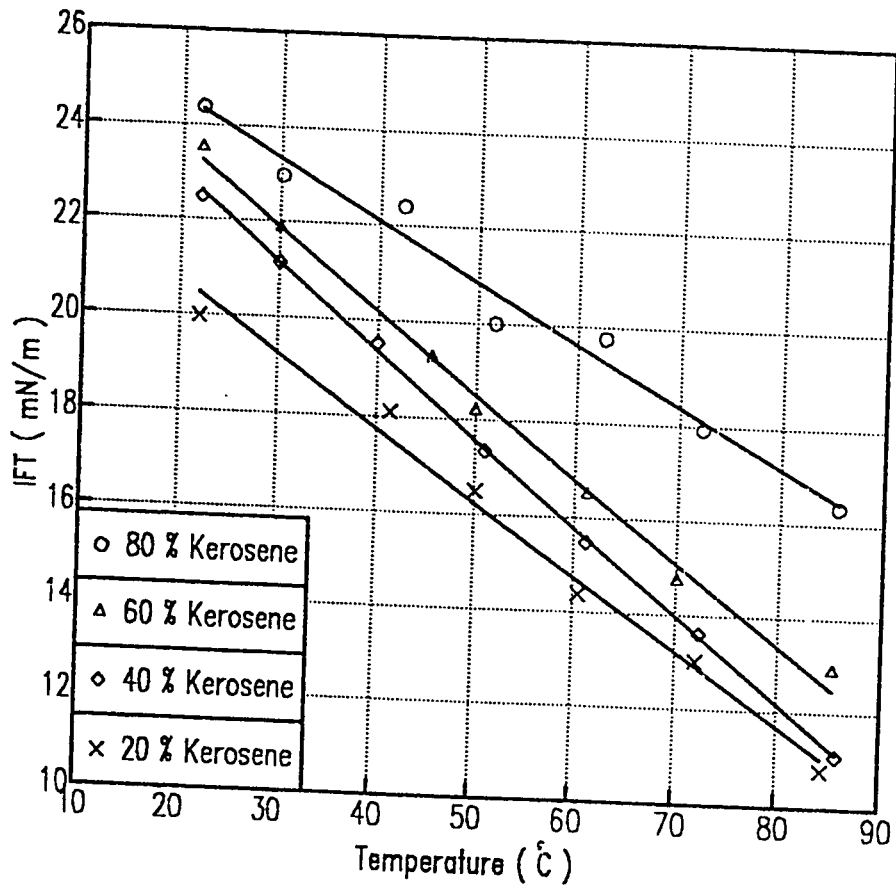


Figure 5.21: Interfacial tension vs. temperature for tar/kerosene mixtures.

for the other tar-solvent mixtures studied at different temperatures. Tables A-14, A-15, and A-16 (Appendix-A) summarize the IFT results for tar-reformate, tar-naphtha, and tar-kerosene mixtures, respectively.

It should be noted that the trend of IFT vs. temperature for tar, solvent, tar-solvent mixtures and brine observed in this study is consistent and in agreement with other IFT results available in the literature. For example, Bowman (1967) studied the effect of temperature on the properties of Athabasca tar sands and found a decrease in IFT values with an increase in temperature up to 90 °C for bitumen-water system. In another study carried out by Flock and Gibeau (1986) on the effect of temperature on the interfacial tension of heavy crude oils, they pointed to a decrease in IFT with an increase in temperature over the range from room temperature to 160 °C.

It can be stated that the most important factors affecting IFT of tar-solvent mixtures are temperature and concentration of solvent. So, a nonlinear regression analysis was performed on the data plotted on Figures 5.19, 5.20, and 5.21 to correlate IFT results of tar-reformate, tar-naphtha, and tar-kerosene mixtures, respectively, with temperature and solvent concentration. The following relations were obtained for prediction of IFT values of the previous mixtures:

$$\sigma_{(T_R)} = 18.0282 - 0.1031 T + 0.07393 C_R \quad (5.16)$$

$$\sigma_{(T_N)} = 18.9387 - 0.11218 T + 0.0972 C_N \quad (5.17)$$

$$\sigma_{(T\ K)} = 22.569 - 0.15496\ T + 0.06534\ C_K \quad (5.18)$$

where:

$\sigma_{(T\ R)}$ = *predicted IFT of tar-reformate mixture, (mN/m).*

$\sigma_{(T\ N)}$ = *predicted IFT of tar-naphtha mixture, (mN/m).*

$\sigma_{(T\ K)}$ = *predicted IFT of tar-kerosene mixture, (mN/m).*

C_R = *reformate concentration, (percent).*

C_N = *naphtha concentration, (percent).*

C_K = *kerosene concentration, (percent).*

The absolute errors involved in relations 5.16 through 5.18 are less than 10.15% with an average of 3.8% as shown in Tables A-13 through A-15 (Appendix-A).

5.5 EFFECT OF TEMPERATURE ON RELATIVE PERMEABILITY

One of the most important petrophysical parameters that describes multi-phase flow through porous media is the relative permeability. In many cases, relative permeability curves obtained at room temperature are used to predict fluid flow at reservoir temperature. This practice can lead to inaccurate forecasts of oil recovery. So, many researchers (Davidson, L.B., 1969, Mungan, 1973, Weinbrandt and Ramey, 1975, Miller and Ramey, 1983) have investigated the temperature effects on relative permeabilities. Although their experimental results are quite contradictory, they all found that raising the temperature changes relative permeability curves.

In this study, four experiments were carried out to study the effect of temperature on relative permeability in order to have a better understanding of recovery mechanisms involved in thermal-miscible displacement. A mixture of 40% solvent (reformate)-60% tar was used as the oleic phase. The assumption here is that during the course of displacement the tar in the cores is completely mixed with the solvent slug. The aqueous phase was represented by 1% KCL. The experiments were conducted on fired Berea sandstone cores of 2.54 cm in diameter and about 10 cm in length according to the procedures described in chapter IV (section 4.3.4). The confining pressure was 2000 psi and flow rate was 1 cc/min for the four runs.

5.5.1 Effect of Temperature on Absolute Permeability

Before relative permeability runs were performed on the Berea cores, absolute permeability to water at 100 % water saturation was measured at room temperature and at elevated temperatures. Figure 5.22 shows absolute permeability versus temperature with the individual points identified by the run number. The straight line fit indicates the trend of the data. It is clearly observed that, within the range of temperatures studied, there is a considerable decrease in the absolute permeability of Berea sandstone cores as the temperature increases. Weinbrandt and Ramey (1975) indicated a significant decrease in the absolute permeability at higher temperatures that is in agreement with this study. This decrease in absolute permeability at elevated temperature may be attributed to the expansion of rock grains which causes changes in pore geometry and closure of some tight openings.

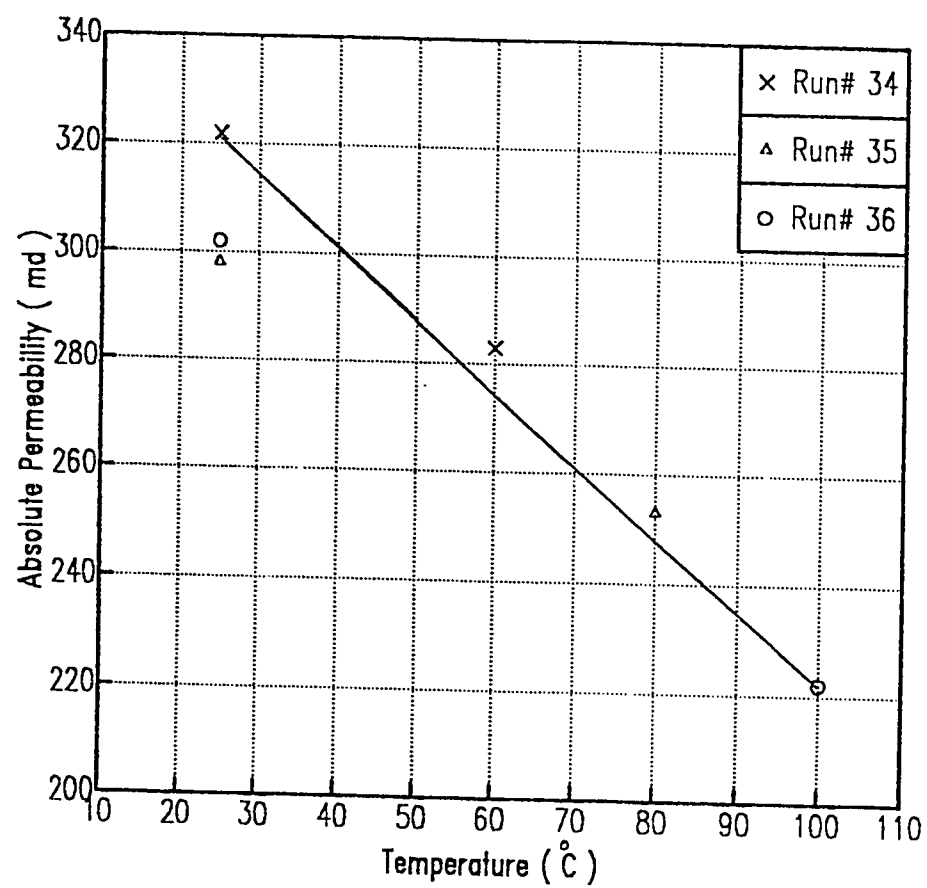


Figure 5.22: Effect of temperature on absolute permeability of Berea sandstone ($Q = 1$ cc/min).

5.5.2 Effect of Temperature on Oil and Water Relative Permeability

Unsteady-state imbibition relative permeabilities were determined using the Johnson-Bossler-Naumann method (1959). A fortran program written by Kose (1987) which employed a third degree polynomial fit to the experimental data was used to calculate the individual relative permeabilities. Four experiments: Runs# 33, 34, 35, and 36 were conducted at a temperature of 25, 60, 80, and 100 °C , respectively. Raw data used in relative permeability calculations for these runs are presented in Tables A-16 through A-19 (Appendix-A).

The relative permeability curves for Runs# 33 through 36 are shown in Figures 5.23 through 5.26 while water saturation, fraction flow of water, K_{ro} and K_{rw} results are presented in Tables A-20 through A-23 (Appendix-A). All sets of relative permeability curves for the four runs are shown in Figure 5.27.

Figure 5.27 indicates that for any given water saturation, relative permeability to oleic phase increases with increasing temperature while the increase in relative permeability to water is not significant. This may be attributed to the decrease of the interfacial tension at higher temperatures. Also, Figure 5.27 indicates that the increase in temperature shifted the curve of relative permeability to oil (K_{ro}) in the direction of increasing water saturation but the curve's shape is not changed significantly. The crossover point (at which $K_{ro} = K_{rw}$) shifts toward a higher water saturation with increasing temperature. This indicates an increase in water-wetness of the Berea

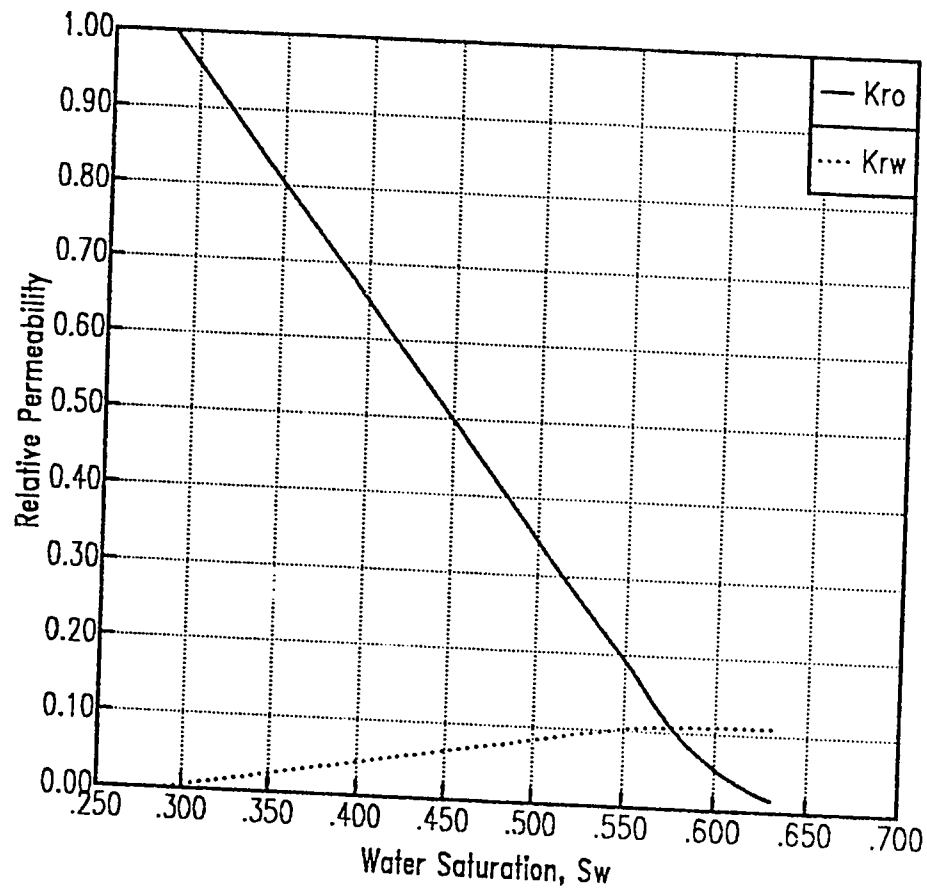


Figure 5.23: Relative permeability of 40% reformat-60% tar mixture/brine at 25 °C.

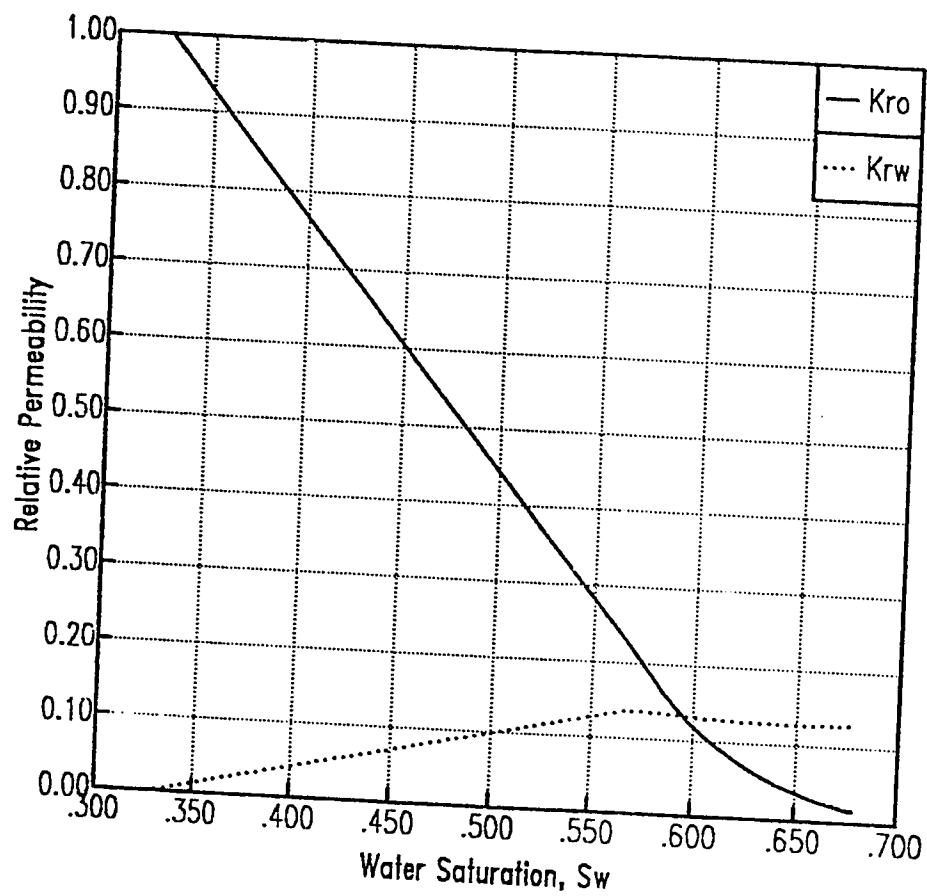


Figure 5.24: Relative permeability of 40% reformat-60% tar mixture/brine at 60 °C.

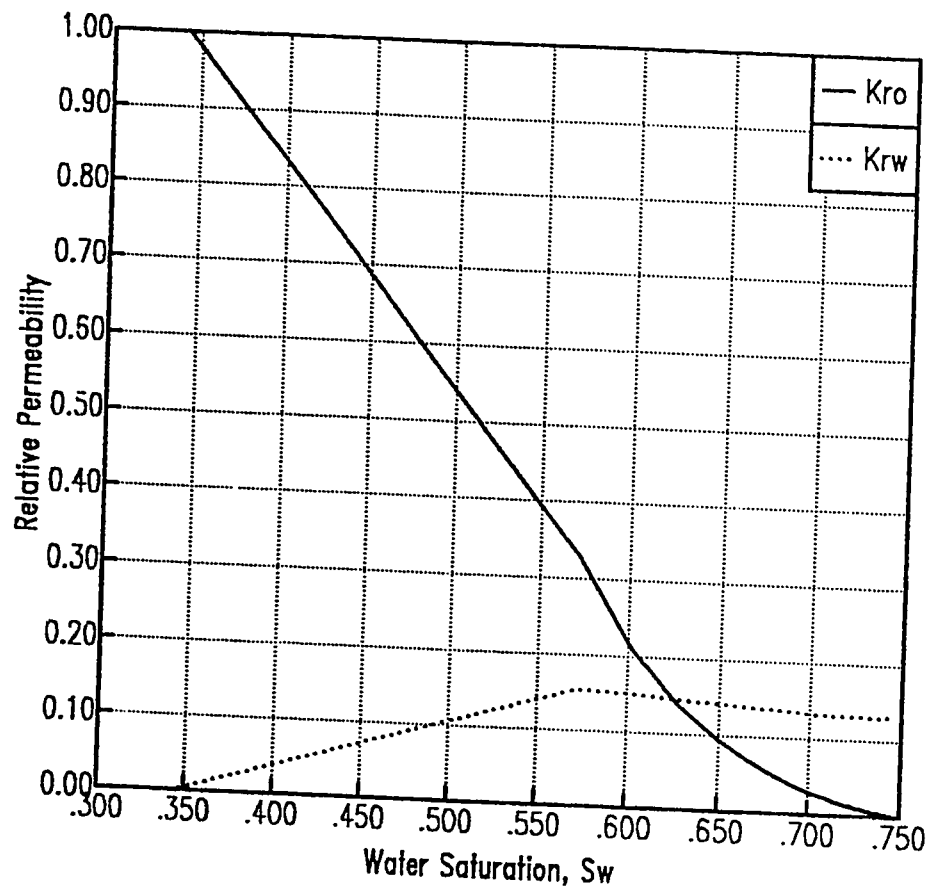


Figure 5.25: Relative permeability of 40% reformat-60% tar mixture/brine at 80 °C.

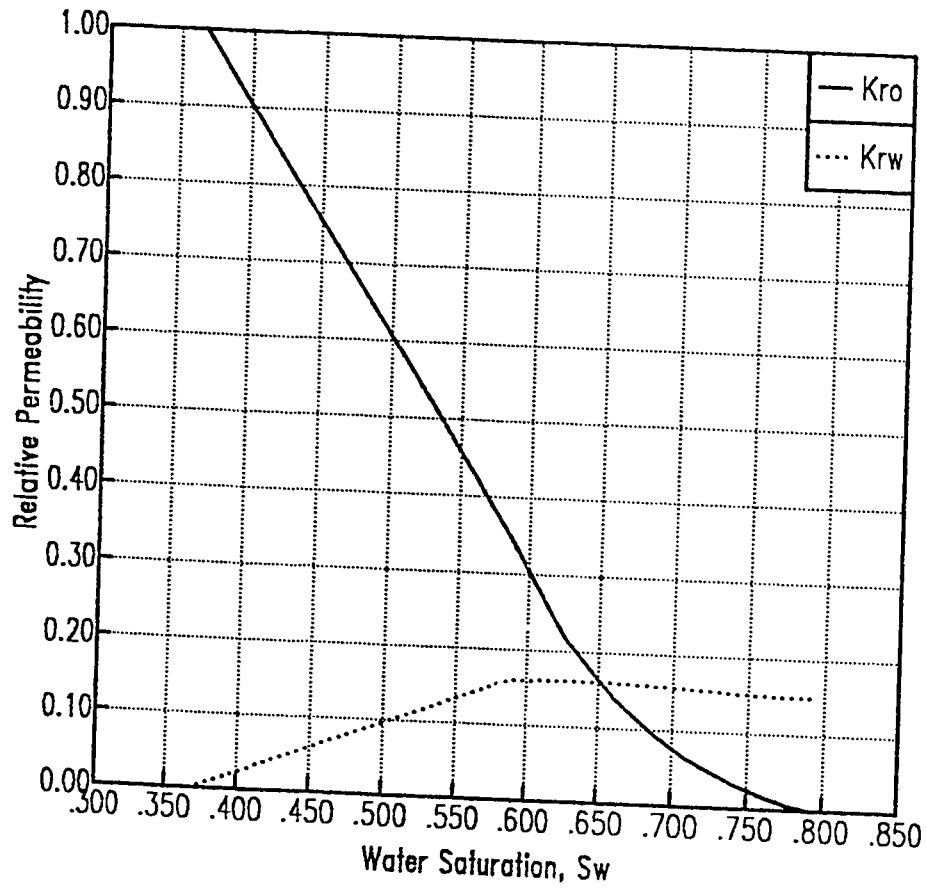


Figure 5.26: Relative permeability of 40% reformat-60% tar mixture/brine at 100 °C.

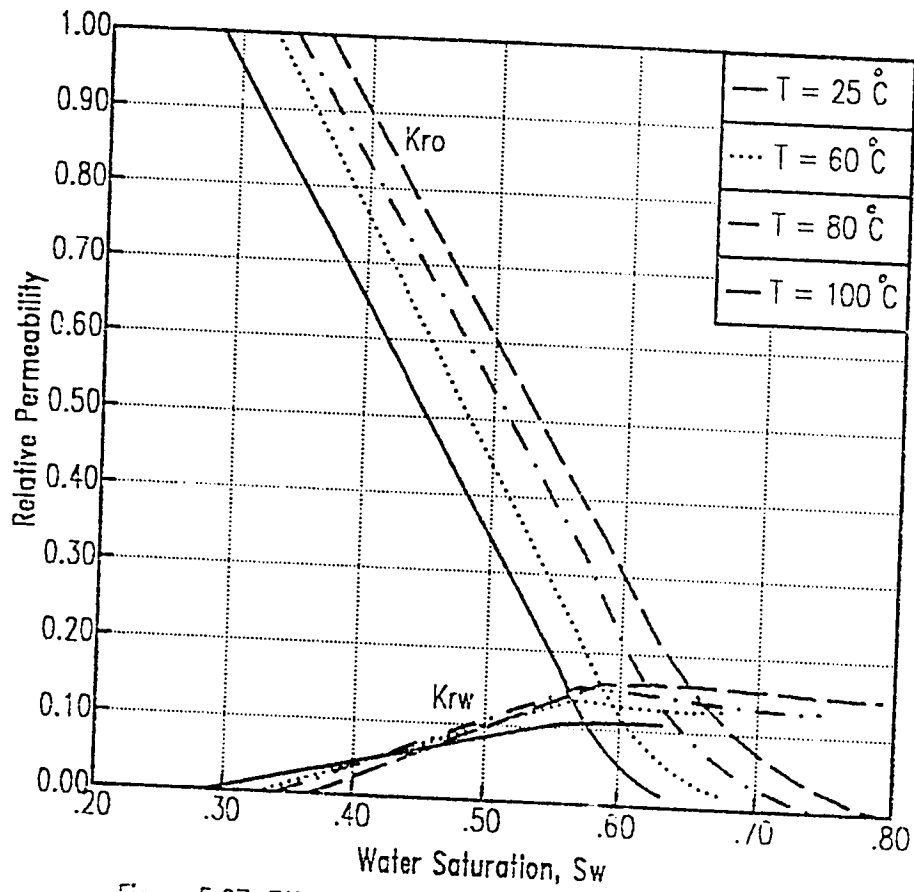


Figure 5.27: Effect of temperature on relative permeability of 40% reformat-60% tar mixture/brine.

cores. Similar behavior for sandstone cores has been reported by Nakornthap and Evans (1986). However, the K_{rw} curves showed no such shift with temperature, rather they rotated in a counter clockwise manner leading to a decrease in K_{rw} below 45% Sw and increase above 45% Sw.

Water/oil relative permeability ratio, $\frac{K_{rw}}{K_{ro}}$, and water fraction flow curves at different temperatures are shown in Figures 5.28 and 5.29, respectively. For a given water saturation, $\frac{K_{rw}}{K_{ro}}$ decreases with increasing temperature. $\frac{K_{rw}}{K_{ro}}$ shifts toward higher water saturations with increasing temperature reflecting an increase of water-wetness of sandstone cores. This behavior is similar to the behavior observed by Edmondson (1965) which showed a decrease in the $\frac{K_{rw}}{K_{ro}}$ ratio with temperature increase.

Figure 5.29 shows a decrease in fraction of water with temperature increase for any given water saturation. The temperature increase shifted the fraction flow curve in the direction of increasing water saturation indicating an increase in water-wetness of the cores. Table 5.13 summarizes the unsteady-state end point data of relative permeability runs conducted at different temperatures. The results of this table show that irreducible water saturation, S_{wir} , increased from 28.6 % at 25 °C to 36.7 % at 100 °C. This may be due to the decrease of capillary forces between oleic and aqueous phases

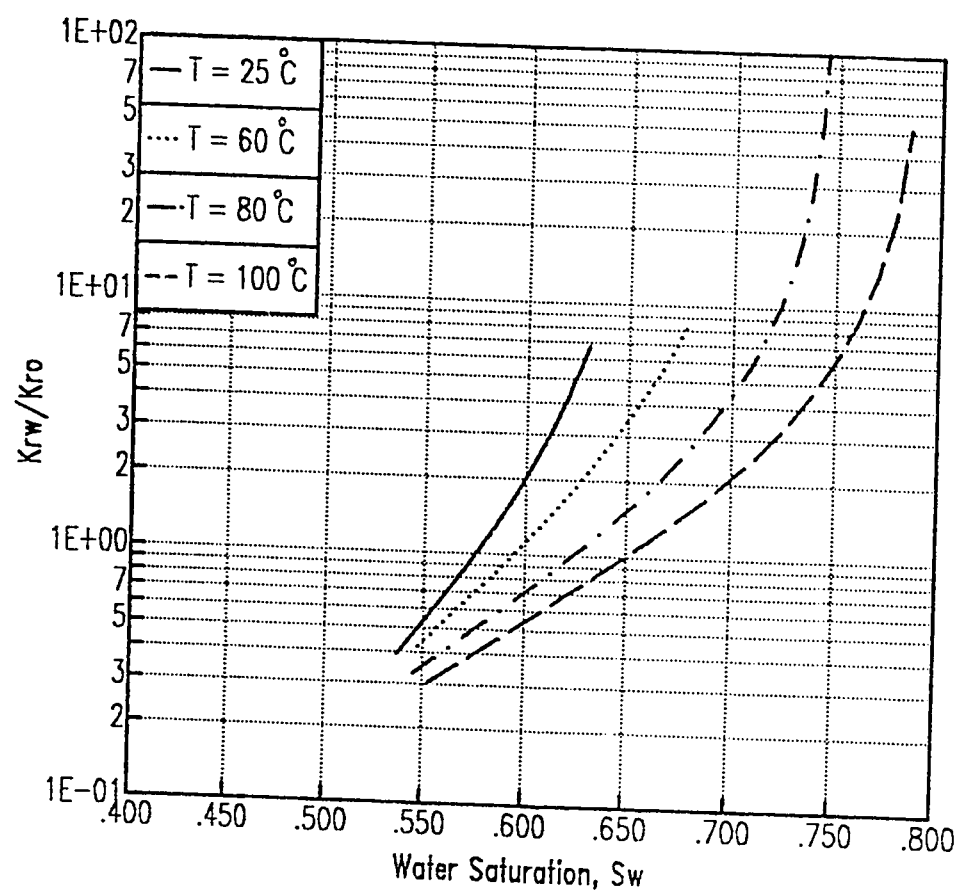


Figure 5.28: Water/oil relative permeability ratios at elevated temperatures.

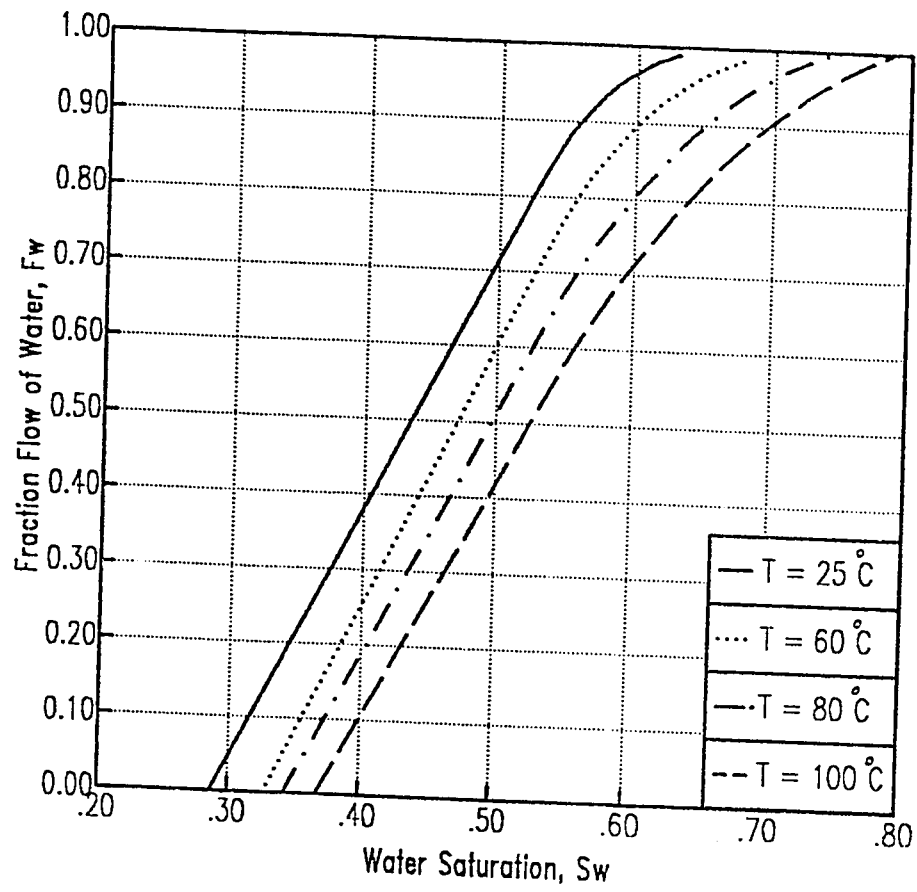


Figure 5.29: Water fraction flow curves at elevated temperatures.

as a result of reducing the IFT forces at higher temperatures (see Figure 5.19). Also, the decrease of viscosity ratio, $\frac{\mu_o}{\mu_w}$, at higher temperatures is another factor which may cause an increase of irreducible water saturation S_{wir} . On the other hand, the residual oil saturation, S_{or} , decreased from 37 % at 25 °C to 21 % at 100 °C. This could be due to a decrease in the interfacial tension with increasing temperature.

Table 5.13: Unsteady-State End Point Data of Relative Permeability Experiments.

Run #	T °C	Swi %	Sor %
33	25	28.6	37.0
34	60	32.7	32.0
35	80	34.3	25.0
36	100	36.7	21.0

Chapter VI

RESULTS AND DISCUSSION

In this study, all displacement experiments were conducted on one- foot Berea sandstone composite cores as described in chapter IV. The tar viscosity was about 10,000 cp and the ratio of oil zone to tar zone thickness was always kept at 2:1. Both of these zones had no initial water saturation.

In this chapter, the results are discussed with regard to the effect of hot-water-driven hydrocarbon solvent injection on oil recovery from tarmat reservoirs. Specifically, the effect of solvent slug size, type of solvent, injection rate, and mode of injection on the recovery were investigated as related to recovery mechanisms.

It is instructive to define various terms used in the following discussion. These are:

OZPV = oil zone pore volume, cc.

TZPV = tar zone pore volume, cc

SPV = total solvent injected, cc.

THPV = total hydrocarbon pore volume, cc.

= OZPV + TZPV

$Np_{(b.t)}$ = hydrocarbon produced at breakthrough, cc.

N_p = total hydrocarbon produced at 4 pore volumes of water injected, cc.

$$R_{(b.t)} = \text{hydrocarbon recovery at breakthrough, (\% THPV).}$$

$$= \frac{N_p(b.t)}{(THPV)} \times 100$$

$$R_t = \text{total hydrocarbon recovery, (\% THPV).}$$

$$= \frac{N_p}{(THPV)} \times 100$$

$$R_n = \text{net hydrocarbon recovery, (\% THPV).}$$

$$= \frac{N_p - SPV}{(THPV)} \times 100$$

ΔR = incremental recovery, percent.

$$\Delta R = \frac{R_n (\text{with solvent}) - R_n (\text{without solvent})}{R_n (\text{without solvent})}$$

$P_{(b.t)}$ = pressure at breakthrough, psi.

$T_{(b.t)}$ = temperature at breakthrough, °C.

$t_{(b.t)}$ = time of breakthrough, min.

r = recovery ratio.

$$r = \frac{R_n (\text{with solvent}) - R_n (\text{without solvent})}{\text{solvent slug size, (percent of THPV)}}$$

The incremental recovery indicates the gain in the hydrocarbon recovery as a result of the injection of hydrocarbon solvent in conjunction with hot water. Raw and computed results as well as production histories of all flood-

ing runs are presented in the tables of Appendix-B.

6.1 EFFECT OF TEMPERATURE ON RECOVERY

To study the effect of temperature on the hydrocarbon recovery of tarmat reservoirs, a cold-water injection experiment (Run # 1) and another hot-water flooding (Run # 2) were conducted with no solvent injection. Table 6.1 lists the composite-core data and recovery results for both runs.

6.1.1 Cold-Water Flooding

Figure 6.1 shows a plot of recovery versus the volume of water injected (measured in terms of total hydrocarbon pore volumes) for a cold water experiment (Run# 1). It is observed from Figure 6.1 that the recovery increased up to water breakthrough and no additional recovery was observed after that. The total hydrocarbon recovery, R_t , was about 40 %.

The results shown in Table B-1 (Appendix-B) indicate that pressure needs time to build up due to accumulation and a very slow advance of water through the tar zone. Hence, no oil production was observed during the initial period of injection because of extremely low tar mobility and very small displacement of tar. The cold-water injection run resulted in relatively low hydrocarbon recovery values. This was attributed to an extra high viscosity ratio involved and a highly unfavorable mobility ratio during displacement of tar by cold water.

Table 6.1: Experimental Data and Results for Studies of the Effect
of Temperature on Recovery.

Run #	OZPV	TZPV	THPV	Np(b.t)	R(b.t) %	Np	Rt %	t(b.t) min	P(b.t) psi	T(b.t) °C
1	19.98	9.96	29.94	12.0	40.09	12.0	40.09	22	640	20
2	22.59	11.47	34.06	16.9	49.62	17.0	49.91	26	1080	86

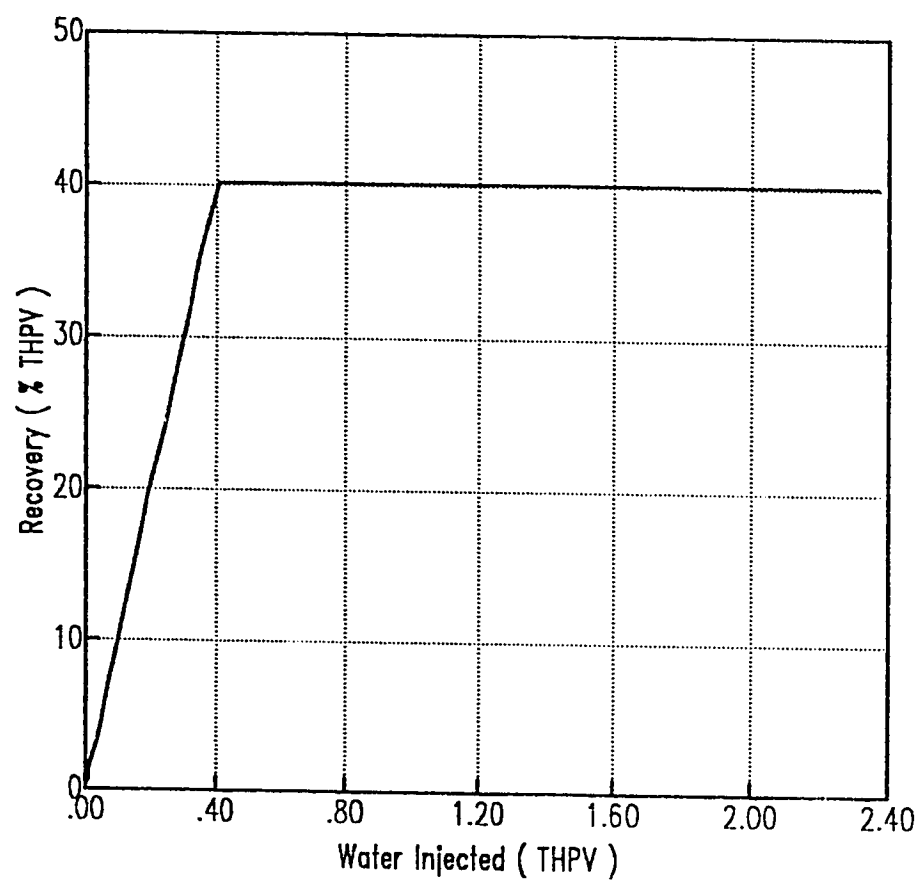


Figure 6.1: Recovery vs. water injected for Run# 1 (cold water displacing tar, no solvent, $Q = 1$ cc/min).

6.1.2 Hot-Water Flooding

The hydrocarbon recovery results for the hot-water injection experiment (Run # 2) showed a similar trend to the cold-water experiment (Run # 1) as seen in Figure 6.2. Comparison of Figures 6.1 and 6.2 shows an increase in breakthrough recovery, $R_{(b.t)}$ (49.62 %) and total recovery, R_t (49.91 %) over the cold-water injection Run# 1.

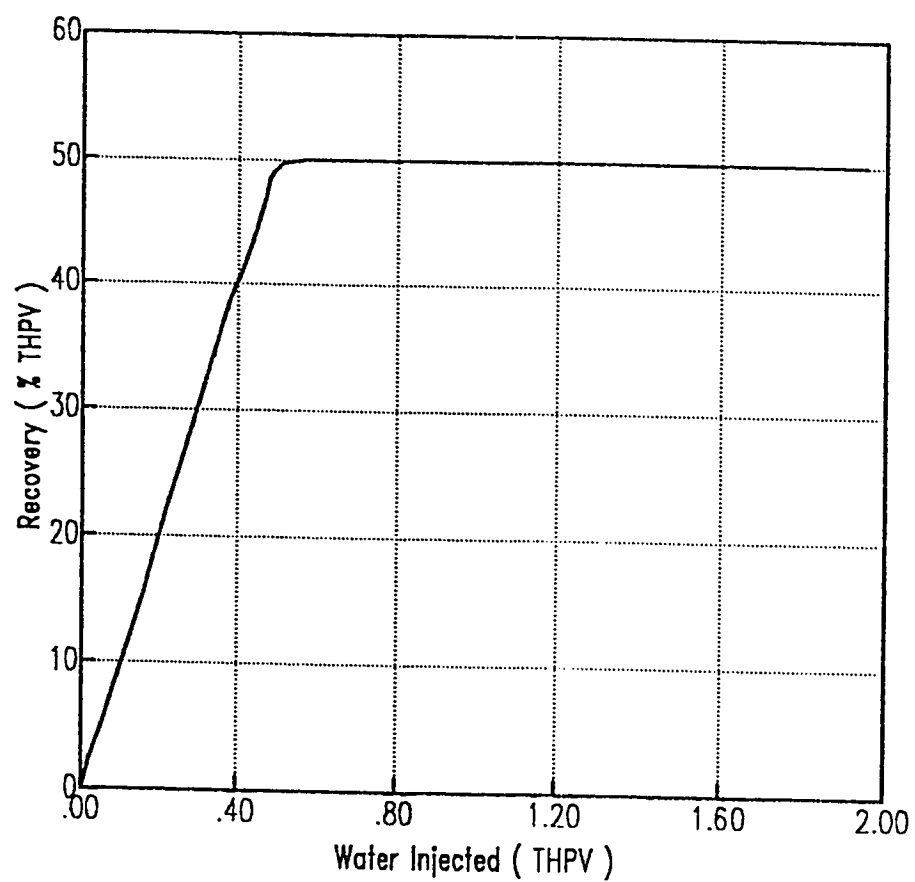


Figure 6.2: Recovery vs. water injected for Run# 2 (hot water displacing tar, no solvent, $Q = 1$ cc/min).

6.2 EFFECT OF SOLVENT SLUG SIZE ON RECOVERY

The simultaneous use of thermal and miscible displacement methods can be effective because of the combined effect on the mobility ratio and the interfacial tension. In this study, different solvent slug sizes driven by hot water were applied to investigate the effect of solvent slug size on the recovery.

Table 6.2 summarizes the experimental data and results for runs conducted to study the effect of solvent slug size on recovery. In Appendix-B, Tables B-3 through B-8 list the results of production histories of the recoveries in addition to the inlet pressure and temperature for Runs# 3 through 7 and Run# 19, respectively.

Figure 6.3 shows the plot of net recovery (% THPV) versus solvent (reformate) slug size (% THPV). From Table 6.2 and Figure 6.3, it can be seen that the net hydrocarbon recovery, R_n , increased as the solvent (reformate) slug size increases up to 10 % THPV. Beyond that, the net hydrocarbon recovery tends to decrease.

Therefore, there is an optimum solvent (reformate) slug size which maximizes the hydrocarbon recovery. The results presented in Table 6.2 indicate that the maximum net hydrocarbon recovery, R_n , was about 52.51 % (THPV) and obtained at an optimum solvent (reformate) slug size of 9.45 % (THPV). After that, the recovery seems to decrease for larger solvent slug sizes. A similar trend is observed when naphtha was used as a solvent. This will be discussed later in the investigation of the effect of type of solvent.

Table 6.2: Experimental Data and Results for Studies of the Effect of Solvent (Reformate) Slug Size on Recovery.

Run #	OZPV	TZPV	SPV	THPV	Np(b.t)	R(b.t)	Np	Rn	Rt	Slug	R	r	t(b.t)	P(b.t)	T(b.t)
	cc	cc	cc	cc	cc	%	cc	(THPV)	%	Size	%		min	psi	C
3	21.71	11.16	1.92	32.87	16.4	49.89	18.8	51.53	57.20	5.84	2.9	0.25	24	350	82
4	22.35	10.67	3.12	33.02	17.65	53.54	20.46	52.51	61.96	9.45	5.3	0.28	27	670	116
5	22.65	11.41	4.45	34.06	18.20	53.44	21.28	49.40	62.48	13.07	-1.0	-0.04	27	770	102
6	22.32	10.93	5.16	33.25	18.00	54.14	20.57	46.35	61.68	15.52	-7.1	-0.23	20	840	113
7	21.24	10.50	6.16	31.70	16.80	52.93	18.95	40.28	59.70	19.40	-19	-0.50	18	740	88
19	22.17	10.96	11.0	33.13	20.52	61.94	23.40	37.63	70.63	33.26	-25	-0.40	33	1320	98

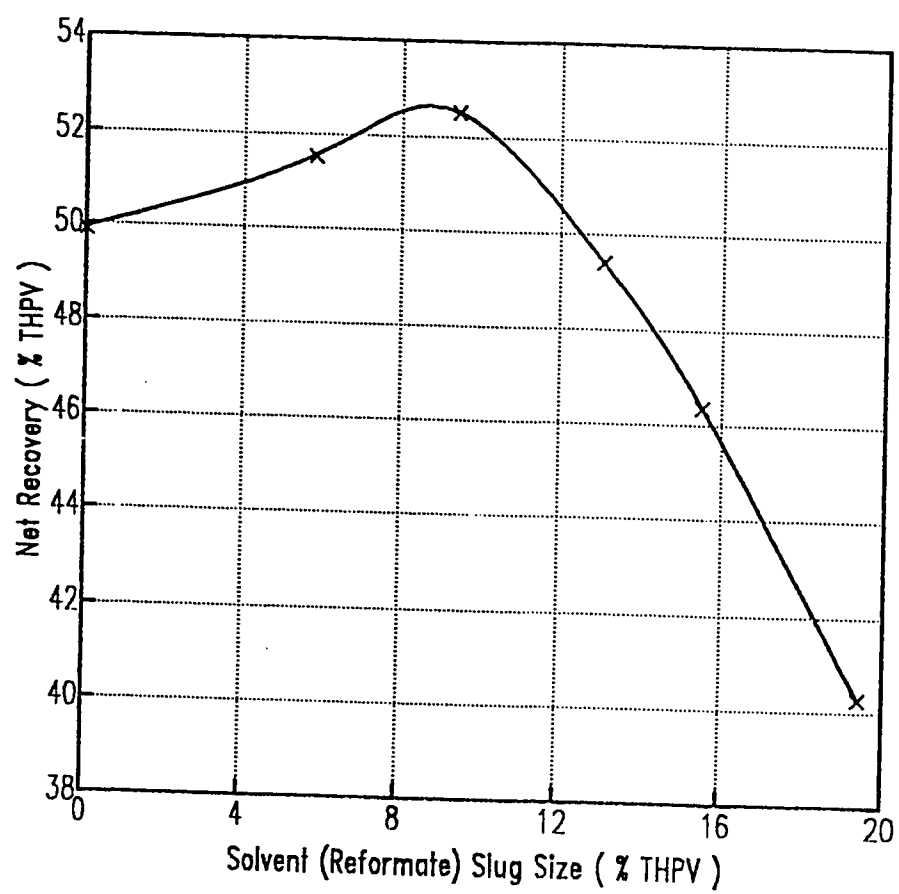


Figure 6.3: Net recovery vs. solvent (reformate) slug size.

Two interesting findings are obtained from the results presented in Table 6.2. The first one is that the ultimate hydrocarbon recovery was higher than breakthrough recovery. This may be due to the production of small batches of a mixture of oil, tar, and solvent after breakthrough. Such behavior is different from the one obtained by applying cold or hot-water flooding which indicates little or no oil production after water breakthrough. The second finding is that the breakthrough time was prolonged as solvent slug size increases up to the optimum slug size. For larger slug sizes, breakthrough times become shorter. However, for very large slug sizes (33 %THPV) which is not economical, the breakthrough time increased again.

Figure 6.4 shows a typical history of hydrocarbon recovery, R_t , versus the volume of water injected, Q_{iw} , as obtained for Run# 4. These results indicate that the THPV's injected at breakthrough recovery vary over a very small range with an average of 0.54; while, the THPV's in the case of cold-water flooding were about 0.41 and for hot-water flooding were 0.51. Thus, comparisons of results show that the THPV's injected at breakthrough recovery using solvent slugs driven by hot water are higher than those obtained from cold or hot-water flooding. This reflects an enhancement in the tar mobility and recovery.

It can be stated that the injection of a solvent slug prior to hot water flooding leads to an increase in the hydrocarbon recovery when compared to cold-water or hot-water flooding alone. This can be attributed to the combined effects of temperature and mixing of solvent with tar and oil. The

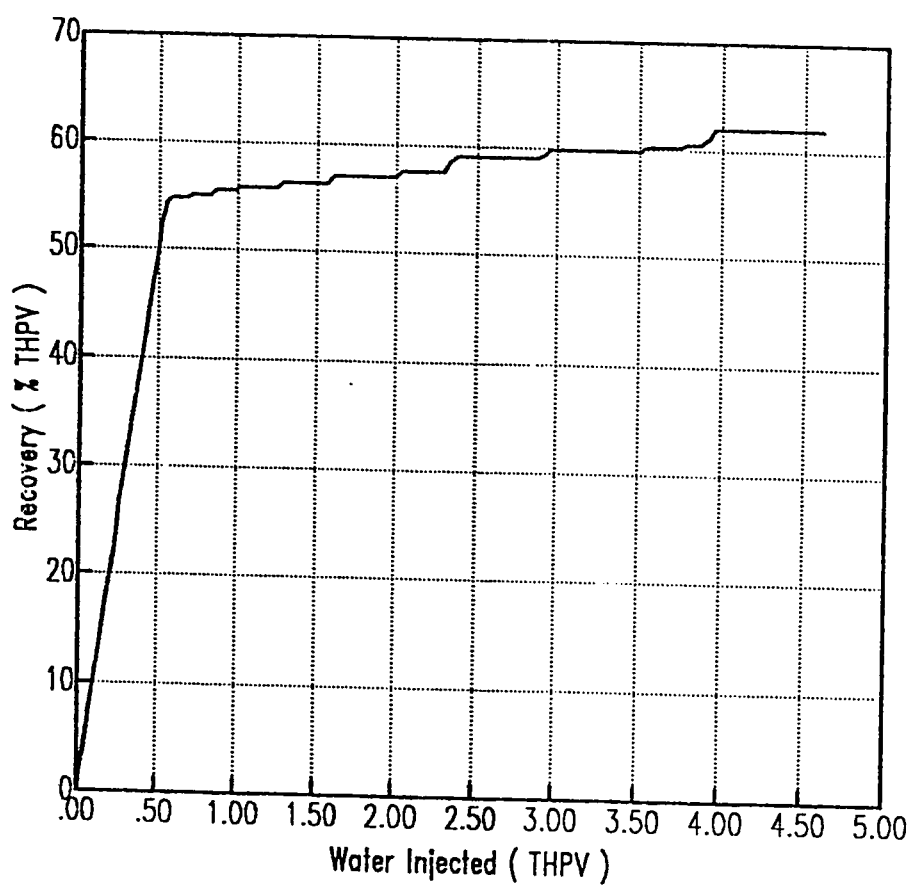


Figure 6.4: Recovery vs. water injected for Run# 4 (hot water with reformate slug = 9.45 % THPV, $Q = 1$ cc/min).

hydrocarbon recovery increases as the solvent slug size increases up to an optimum slug size for which the recovery is maximum.

6.3 EFFECT OF TYPE OF SOLVENT ON RECOVERY

To investigate the effect of type of solvent on hydrocarbon recovery, different naphtha slug sizes driven by hot water were injected. Table 6.3 summarizes the experimental data and results for Runs# 20 through 24 which have different naphtha slug sizes. Figure 6.5 shows a plot of net hydrocarbon recovery, R_n (% THPV), versus solvent (Naphtha) slug size (% THPV).

Both Table 6.3 and Figure 6.5 indicate an increase in recovery as the solvent slug size increases up to an optimum slug size. In this case, the optimum slug size was about 11% (THPV). It is quite clear that beyond the optimum slug size the recovery decreases. Also, Table 6.3 shows that breakthrough time is prolonged as solvent slug size increases up to the optimum value. The ultimate hydrocarbon recovery is higher than breakthrough recovery. This result is similar to the one observed with reformate.

The net hydrocarbon recovery is a little higher in the case of reformate when compared to naphtha. Beyond the optimum slug value the situation is reversed. The difference in recovery obtained by using a reformate slug and a naphtha slug is not so high. This may be due to a small difference in the viscosities of reformate (0.52 cp) and naphtha (0.79 cp). (see Table 5.8).

Table 6.3: Experimental Data and Results for Studies of the Effect of Solvent (Naphtha) Slug on Recovery.

Run #	OZPV	TZPV	SPV	THPV	Np(b.t)	R(b.t)	Np	Rn	Rt	Slug	R	r	t(b.t)	P(b.t)	T(b.t)
	cc	cc	cc	cc	cc	%	cc	%	%	Size	%		min	psi	°C
20	22.07	11.34	1.74	33.41	16.28	48.73	18.52	50.22	55.43	5.21	0.62	0.06	23	315	99
21	22.25	11.51	3.69	33.76	17.80	52.73	21.20	51.87	62.80	10.93	3.93	0.18	27	238	122
22	22.24	11.71	4.75	33.95	16.57	48.81	21.16	48.34	62.33	13.99	-2.2	-0.08	27	512	98
23	21.60	10.82	6.53	32.42	17.72	54.66	20.86	44.20	64.34	20.14	-11	-0.28	26	64	127
24	21.63	10.85	8.04	32.48	17.35	53.42	21.72	42.12	66.87	24.75	-15	-0.31	24	62	126

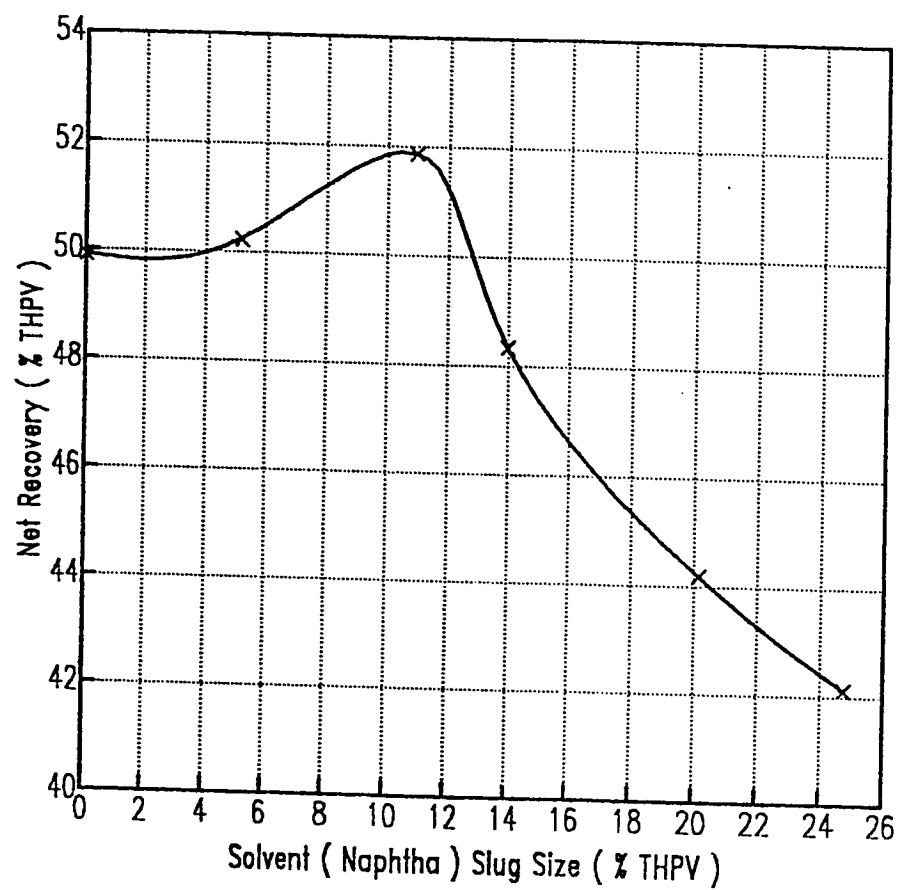


Figure 6.5: Net recovery vs. solvent (naphtha) slug size.

A typical plot of the history of hydrocarbon recovery versus the volume of brine injected, Q_{iw} , for Run# 21 is shown in Figure 6.6. In this run, the optimum slug size of naphtha was used. The results presented in Appendix-B (Tables B-9 through B-13) indicate that THPV's injected at breakthrough vary over a small range (0.51 - 0.57) with an average of 0.54 which is higher than the one observed with cold-water flooding (0.41) or hot-water flooding (0.51). This is an indication of enhancement of tar mobility.

The previous discussion and observations show that both reformate and naphtha slugs driven by hot water result in an increase in hydrocarbon recoveries as the solvent slug size increases up to a certain value. For each solvent there is an optimum slug size. Away from the optimum slug size, the hydrocarbon recovery will decrease. The small difference in recoveries for both solvents is due to the slight difference in the viscosities. Indeed, the reformate which has a slightly lower viscosity than naphtha, produces a higher recovery.

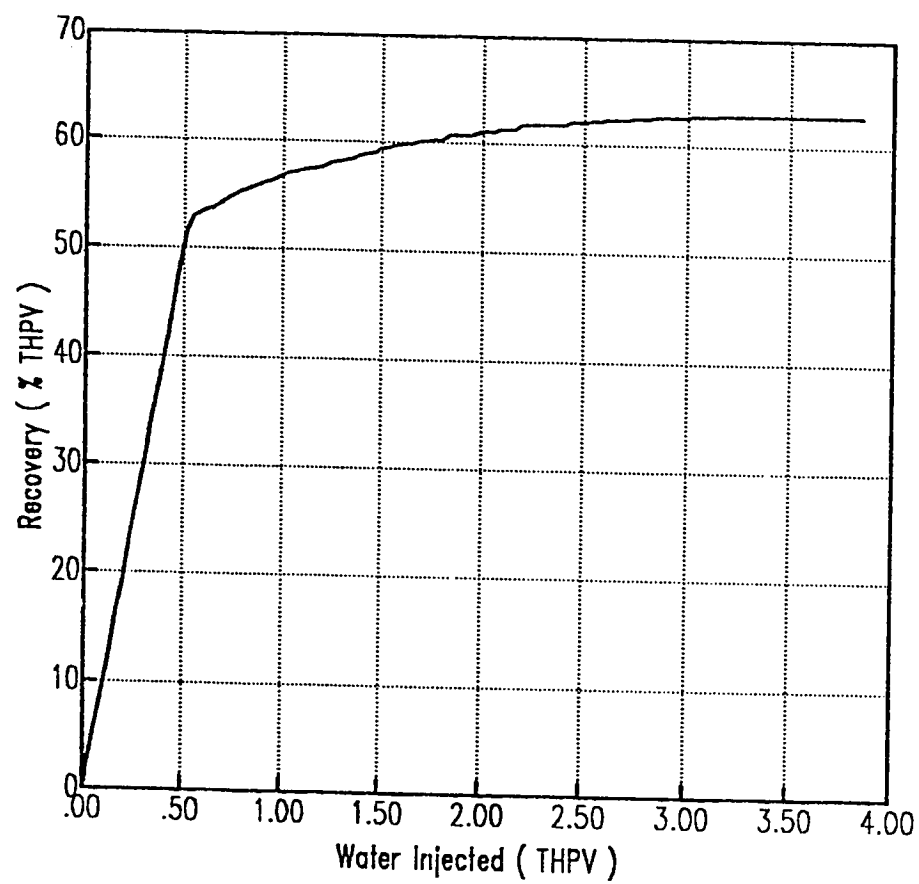


Figure 6.6: Recovery vs. water Injected for Run# 21 (hot water with naphtha slug = 10.93 % THPV, $Q = 1$ cc/min).

6.4 EFFECT OF SOLVENT SLUG SIZE ON RECOVERY RATIO

The recovery ratio (r) is defined as the difference in the net recoveries between those obtained from hot water and solvent flooding runs and that obtained from hot-water flooding only divided by the solvent slug size (% THPV). It reflects the effectiveness of the solvent in producing a higher recovery and can be considered as an economic index. The results presented in Tables 6.2 and 6.3 show that the recovery ratio (r) increases as the solvent slug size increases up to optimum. For solvent slug sizes larger than the optimum, the recovery ratio decreases. From an economic point of view, it is better to use the small slug size (optimum) which maximizes the recovery. A recovery ratio greater than zero indicates a gain over the solvent slug injected. The incremental hydrocarbon recovery (ΔR) indicate similar trend as the recovery ratio as shown in Tables 6.2 and 6.3. However, the recovery ratio and incremental recovery are higher in the case of reformate than naphtha.

6.5 EFFECT OF INJECTION RATE ON RECOVERY

The injection rate plays an important role in the movement of fluids through the porous medium during any displacement process. Therefore, a different series of cold and hot-water floods were conducted using a composite core arrangement to study the effect of injection rate on hydrocarbon recovery as discussed below.

6.5.1 Cold-Water Displacing Oil (Kerosene), No Tar Zone

The first series of displacement runs involved cold water displacing oil (kerosene) with no tar zone present. Three runs: Runs# 16, 17, and 18 were conducted at 1, 2, and 4 cc/min. respectively. Table 6.4 summarizes the experimental data and recovery results while Figure 6.7 shows recovery versus water injected for these runs.

The results indicate a decrease in total oil recovery as the injection rate increases. The total recoveries for Runs# 16, 17, and 18 were 74.08, 68.46, and 66.93 % (OZPV), respectively. The recoveries are quite high because of close values of brine viscosity (1.04 cp), and oil viscosity (1.39 cp). Hence, the mobility ratio is less unfavorable compared to highly unfavorable mobility ratio between brine and tar (Run# 1). In this case, it can be stated that the displacement is quite stable. Also, it is observed that at higher injection rates (2 and 4 cc/min) the breakthrough recovery occurs earlier than at the lower rate (1 cc/min).

Table 6.4: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
(Cold Water Flooding, No Tar Zone).

Run #	Injection Rate cc/min	OZPV cc	Np(b.t) cc	R(b.t) % OZPV	Np cc	Oil Recovery %(OZPV)	t(b.t) min	P(b.t) psi	T(b.t) °C
16	1	20.41	14.33	70.21	15.12	74.08	18	6	22
17	2	20.04	12.87	64.22	13.72	68.46	11	14	22
18	4	20.53	13.35	65.03	13.74	66.93	9	30	24

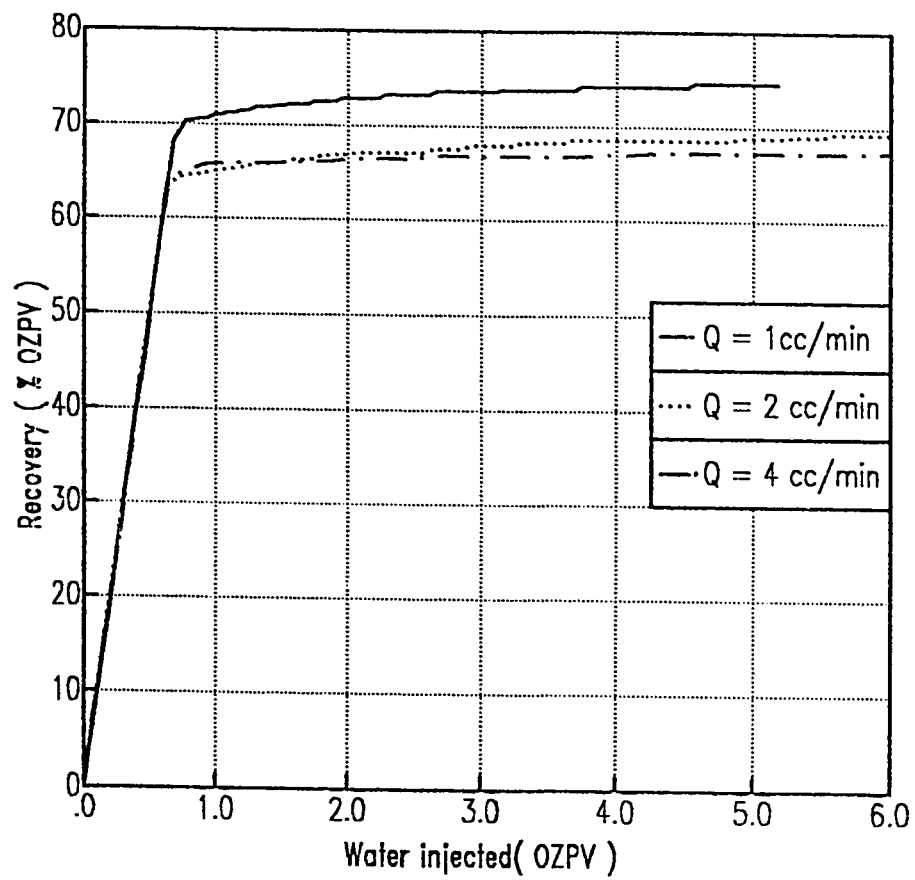


Figure 6.7: Effect of injection rate on recovery (cold-water flooding, no tar zone).

6.5.2 Hot-Water Displacing Oil (Kerosene), No Tar Zone

In the second series of displacement runs, hot water was injected at different rates to displace oil. Three hot-water flooding runs: Runs# 13, 14, and 15 were carried out at 1, 2, and 4 cc/min, respectively. Table 6.5 lists the experimental data and results and Figure 6.8 shows the recovery versus water injected (OZPV) for these runs. A similar trend of decreasing recovery with an increase in injection rate is observed.

Comparison of Figures 6.7 and 6.8 indicates that the recoveries of cold-water runs are higher than those of hot-water runs. Water breakthrough occurs earlier in the case of hot-water flooding than cold-water runs. This is because the viscosity of the injected hot-water is lower than that of cold-water. Thus, the mobility ratio between oil ahead of the displacement front and injected hot-water is less favorable than the mobility ratio in the case of cold-water flooding.

Moreover, it is clearly shown that as the injection rate increases the pressure drop across the cores increases in both cold and hot-water flooding runs with no tar zones (Tables 6.4 and 6.5). This may be due to the less effect of temperature on the viscosity of kerosene in the oil zone.

Table 6.5: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
(Hot Water Flooding, No Tar Zone).

Run #	Injection Rate cc/min	OZPV cc	Np(b.t) cc	R(b.t) % OZPV	Np cc	Oil Recovery %(OZPV)	t(b.t) min	P(b.t) psi	T(b.t) C
13	1	20.12	12.11	60.19	13.34	67.30	13	6	102
14	2	19.39	11.10	57.25	12.84	66.22	10	24	108
15	4	20.10	11.20	55.72	12.58	62.59	6	28	104

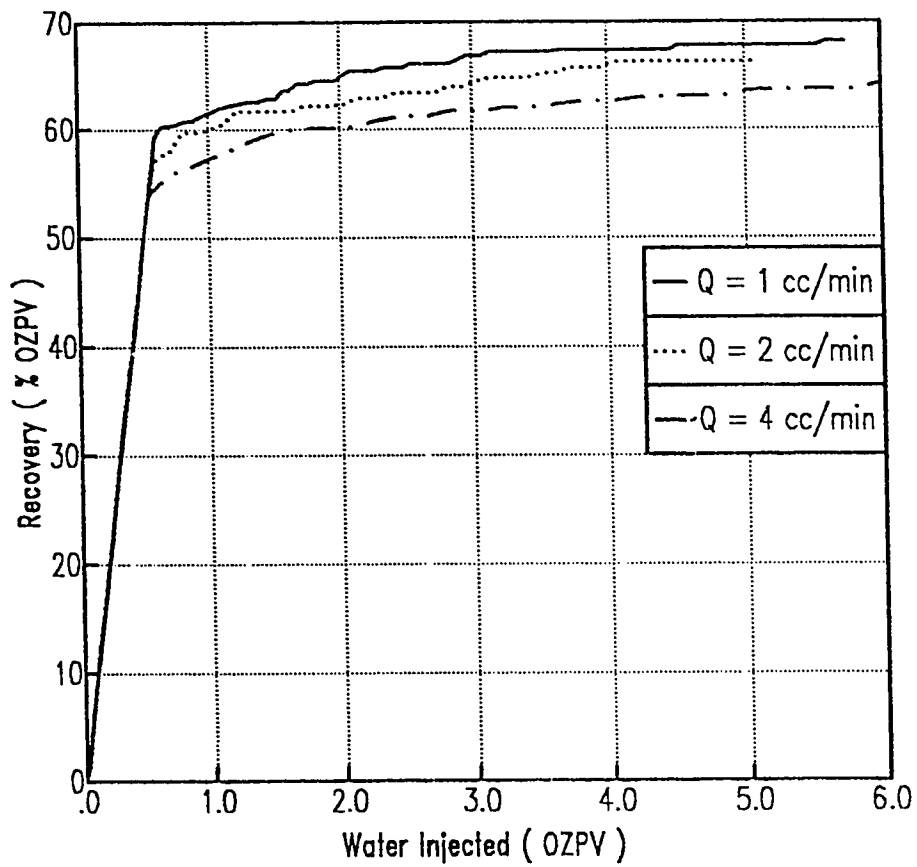


Figure 6.8: Effect of injection rate on recovery (hot-water flooding, no tar zone).

6.5.3 Hot-Water Displacing Tar and Oil, No Solvent

The third series of displacement runs were conducted to study the effect of injection rate on hydrocarbon recovery using hot water to displace tar and oil. Three runs: Runs# 2, 11, and 12 were carried out at injection rates of 1, 2, and 4 cc/min, respectively. Table 6.6 lists the experimental data and results of these runs. A Plot of the hydrocarbon recoveries of Runs# 2, 11, and 12 versus volume of water injected (THPV) is shown in Figure 6.9.

Table 6.6 and Figure 6.9 indicate a decrease in hydrocarbon recovery as the injection rate increases. For example, the total hydrocarbon recoveries, (% THPV), of Runs# 2, 11, and 12 which were carried out at injection rates of 1, 2, and 4 cc/min in order were 49.91, 47.57, and 44.3 %, respectively. Moreover, water breakthrough occurs earlier at higher injection rates than at lower rates.

Comparison of Tables 6.5 and 6.6 shows that the hydrocarbon recoveries (% OZPV) are higher in the case of runs using hot-water to displace tar and oil than runs using hot water to displace oil only.

Table 6.6: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
(Hot-Water Displacing Tar and Oil).

Run #	Injection Rate cc/min	OZPV cc	TZPV cc	THPV cc	Np(h.t) %	R (h.t) %	Np cc	THPV cc	Oil Recovery %(OZPV)	Rt %	t(b.t) min	P(b.t) psi	T(b.t) °C
2	1	22.59	11.47	34.06	16.9	49.62	17.00	75.30	49.91	26	1080	86	
11	2	22.23	11.13	33.36	14.4	43.17	15.87	71.39	47.57	14	1070	84	
12	4	22.03	10.77	32.8	11.8	35.98	14.53	65.96	44.30	7	470	100	

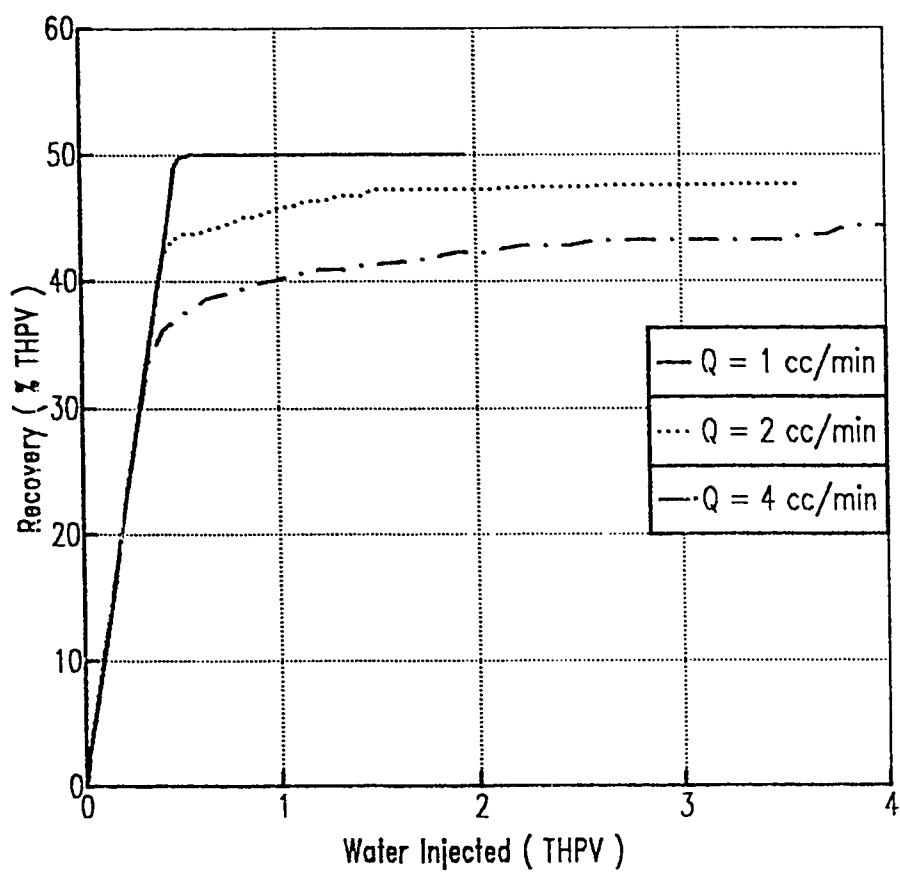


Figure 6.9: Effect of injection rate on recovery (hot water displacing tar and oil, no solvent).

6.5.4 Hot-Water Driven Solvent slug to Displace Tar and Oil (Mode I)

In the fourth displacement series, the hot-water-driven solvent (reformat) slug was used to displace tar and oil. Table 6.7 lists data and results for Runs# 5, 8, 9, and 10 conducted at 1, 2, 4, and 6 cc/min, respectively. Figure 6.10 shows the effect of injection rate on the hydrocarbon recovery (% THPV).

These results show a decrease in the total hydrocarbon recoveries as the injection rate increases. For example, the total hydrocarbon recovery was 62.48 %(THPV) for Run# 5 which was conducted at 1 cc/min; while in Run# 10, the injection rate was 6 cc/min resulting in a considerably lower value of 51.43 % (THPV).

It can be stated that a lower injection rate would reduce viscous fingering and water channeling, thus increasing the period of miscibility and hydrocarbon recoveries. Hence, the total hydrocarbon recoveries are higher in the case of runs using solvent slug and hot water than that obtained from runs using hot water only (Tables 6.6 and 6.7).

Table 6.7: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
(Hot Water Driven Solvent Slug).

Run #	Injection Rate cc/min	OZPV cc	TZPV cc	SPV cc	THPV cc	Np(b.t) cc	R (b.t) %	Np cc	Rt (THPV) min	t(b.t) min	P(b.t) psi	T(b.t) °C
5	1	22.65	11.41	4.45	34.06	18.2	53.44	21.28	62.48	27	770	102
8	2	18.29	10.39	4.13	28.68	13.7	47.77	16.32	56.90	16	1100	93
9	4	19.22	10.19	4.07	29.41	13.0	44.20	16.09	54.71	9	480	114
10	6	18.67	9.74	3.90	28.41	12.9	45.41	14.61	51.43	7	250	102

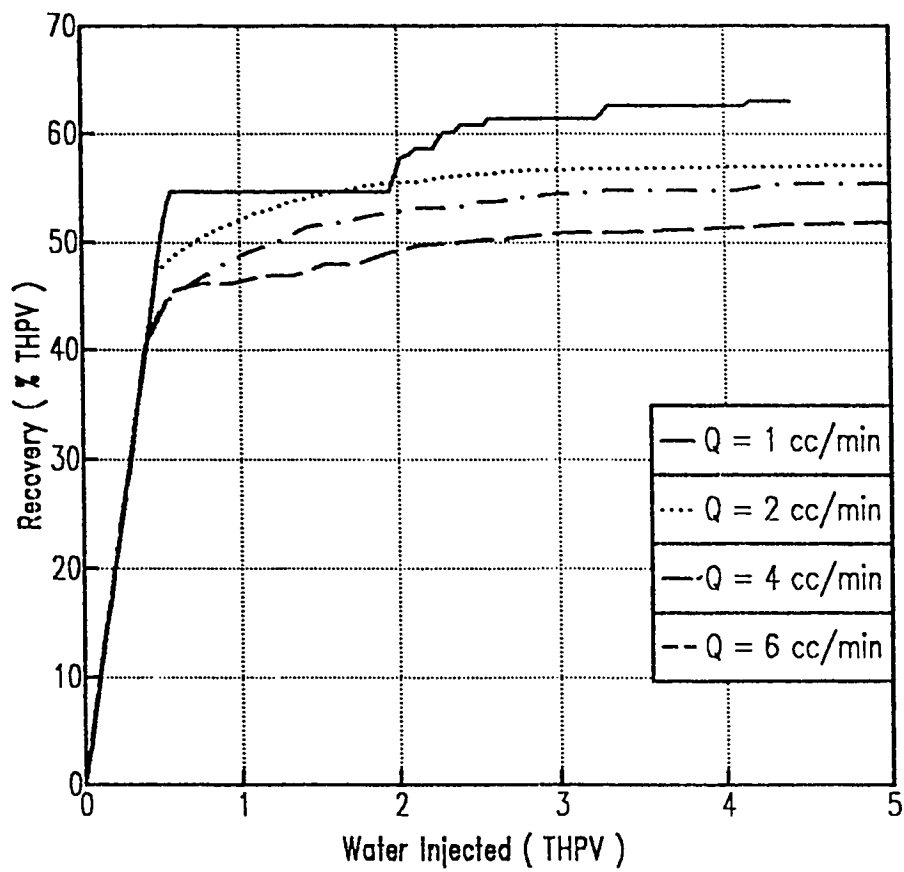


Figure 6.10: Effect of injection rate on recovery (hot-water-driven reformat slugs).

6.6 EFFECT OF INJECTION MODE ON RECOVERY

In some applications of miscible displacement, solvent and hot water are injected in small alternating slugs rather than in sequence. Therefore, three different injection modes involving both reformate and naphtha slugs driven by hot water were examined. These injection modes are described below.

(A) Mode I

In this mode, the optimum solvent slug size is injected first followed by continuous hot-water flooding (Figure 6.11. a).

(B) Mode II

In this mode, the optimum solvent slug is divided into two equal portions. The two portions are separated by a slug of hot-water (50 %TZPV) and the second portion is driven by continuous hot-water flooding (Figure 6.11, b). It is believed that this amount of hot-water slug (50 % TZPV) is sufficient to separate the two small solvent slugs.

(C) Mode III

The optimum solvent slug is divided into four equal portions. Each portion is followed by a slug of hot-water (25 %TZPV) and the last portion is driven continuous hot-water flooding (Figure 6.11, c).

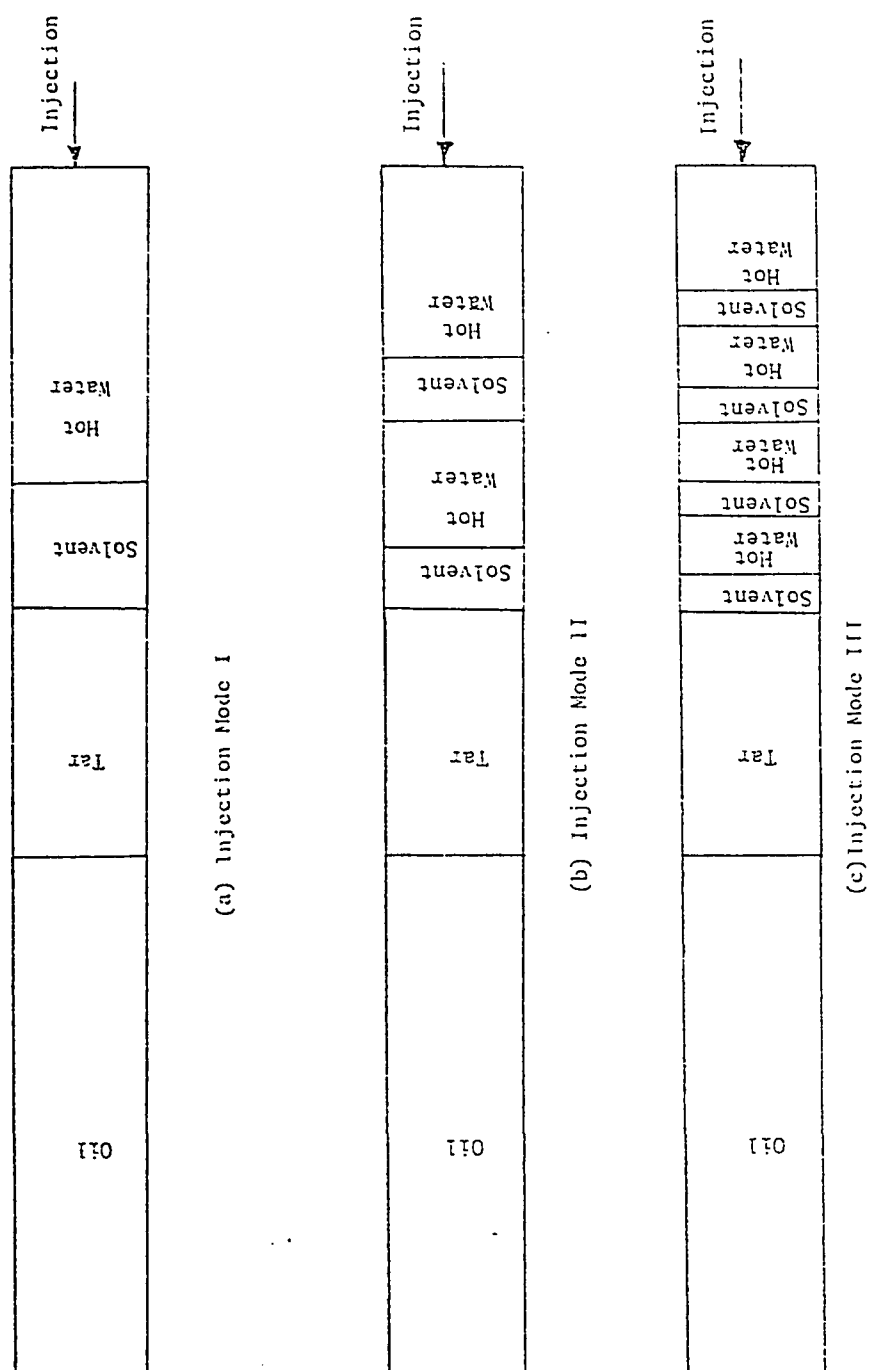


Figure 6.11: Different injection modes.

6.6.1 Effect of Injection Mode on Recovery Using Reformate

Three displacement runs: Runs# 5, 25, and 27 were conducted at an injection rate of 1 cc/min using the optimum slug of reformate and following injection modes I, II, and III, respectively. The experimental data and results of these runs are listed in Table 6.8. Figures 6.12 shows the change of hydrocarbon recovery versus the volume of water injected for the three injection modes.

These results show that mode III gave the highest recovery, both net and total, and mode I gave the lowest. The pressure at breakthrough was the lowest in mode III and the highest in mode I. Therefore, it can be concluded that the more portions the solvent slug is divided into, the higher the recovery will be. The total hydrocarbon recovery (%THPV) for modes I, II, and III was 62.48, 65.26, and 67.75 %, respectively; while the net recovery (% THPV) was 49.40, 51.89, and 53.97 %, respectively. The results of Table 6.8 show that the pressure at breakthrough is less in the case of injection mode II (157 psi) and mode III (34 psi) than in mode I (770 psi).

Table 6.8: Experimental Data and Results for Studies of the Effect of Injection Mode on Recovery
Using Reformate.

Run #	Injection Mode	OZPV	TZPV	SPV	THPV	Np(b.t)	R (b.t) %	Np	Rn %	Rt (THPV)	t(b.t) min	P(b.t) psi	T(b.t) °C
5	I	22.65	11.41	4.45	34.06	18.20	53.44	21.28	49.40	62.48	27	770	102
25	II	23.25	11.90	4.70	35.15	18.47	52.55	22.94	51.89	65.26	27	157	109
27	III	22.26	11.85	4.70	34.11	18.53	54.32	23.11	53.97	67.75	26	34	117

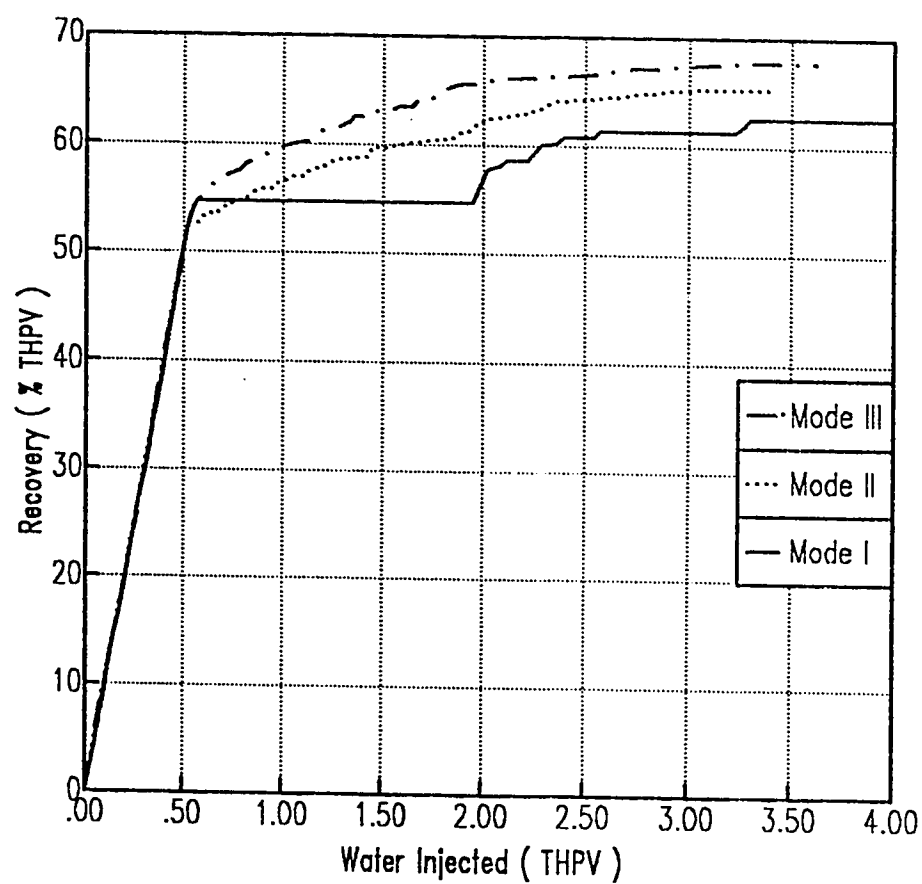


Figure 6.12: Recovery vs. water injected for different injection modes (reformate solvent, $Q=1$ cc/min).

6.6.2 Effect of Injection Mode on Recovery Using Naphtha

Three more runs: Runs# 22, 26, and 28 were conducted at 1 cc/min using the optimum slug of naphtha following injection modes I, II, and III, respectively. The experimental data and results are presented in Table 6.9. Figure 6.13 shows the effect of injection mode on hydrocarbon recovery. The related data and results of these runs are shown in Appendix-B.

It can be seen from the results of Table 6.9 and Figure 6.13 that both injection mode II and III gave higher total recoveries, Rt, (64.53 and 65.76 % THPV, respectively) than injection mode I which gave a total recovery of 62.33 % (THPV). This behavior is in agreement with recovery results obtained using reformat. Hence, the injection of alternating small slugs of solvent and hot water (modes II and III) gave better recoveries than the injection of one slug continuously (mode I).

It is interesting to note that, except for mode I, the recovery with reformat is always higher than the recovery with naphtha. This may be explained by the fact that tar-reformat mixtures always have a slightly higher viscosity than similar mixtures of tar-naphtha. Thus, the mobility ratio between tar-reformat mixtures, and tar is more favorable than the mobility ratio between tar-naphtha mixtures and tar.

Table 6.9: Experimental Data and Results for Studies of the Effect of Injection Mode on Recovery
Using Naphtha.

Run #	Injection Mode	OZPV	TZPV	SPV	THPV	Np(b.t)	R (b.t) %	Np	Rn %	Rt (THPV)	t(b.t) min	P(b.t) psi	T(b.t) °C
22	I	22.24	11.71	4.75	33.95	16.57	48.81	21.16	48.34	62.33	27	512	98
26	II	21.71	11.64	4.70	33.35	19.00	56.97	21.52	50.43	64.53	32	352	93
28	III	23.03	11.72	4.70	34.75	18.75	53.96	22.85	52.23	65.76	24	40	130

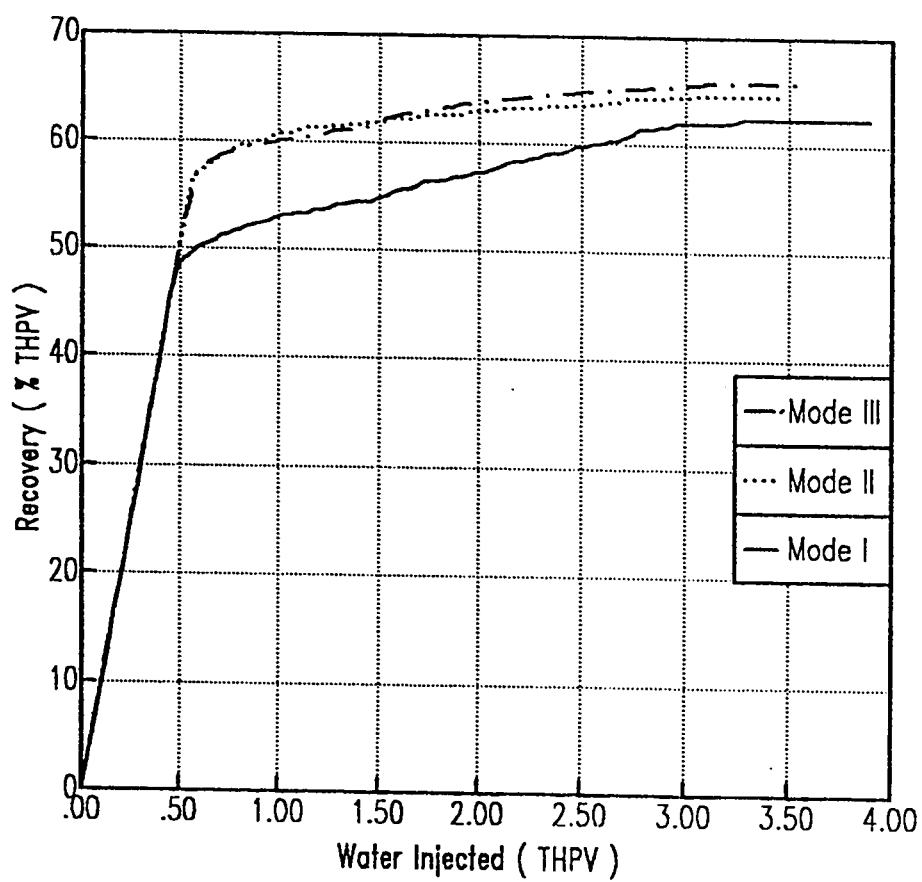


Figure 6.13: Recovery vs. water injected for different injection modes (naphtha solvent, $Q = 1$ cc/min).

6.6.3 Effect of Injection Rate on Recovery Applying Different injection Modes

It is beneficial to study the effect of injection rate on hydrocarbon recovery for the three injection modes described earlier. Runs involving mode I and using reformat were discussed in section 6.5.4 and their results are presented in Table 6.7 and Figure 6.10.

6.6.3.1 Effect of Injection Rate on Recovery Applying Mode II

Three runs: Runs# 25, 29 and 30 employing mode II were conducted at an injection rate of 1, 2, and 4 cc/min, respectively. Table 6.10 summarizes the data and results for these runs while Figure 6.14 shows the hydrocarbon recoveries, R_t , versus the volume of water injected. The complete data and results of these runs are presented in Appendix-B.

The results show a decrease in both total and net hydrocarbon recoveries at higher injection rates. Total hydrocarbon recovery, R_t , for Runs# 25, 29, and 30 conducted at 1, 2, and 4 cc/min in sequence were 65.26, 62.18, and 61.02 % (THPV), respectively. Similar results were obtained for net hydrocarbon recoveries. This behavior is similar to that observed for mode I. Also, both time and pressure at breakthrough decrease at higher injection rates.

Table 6.10: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
Applying mode II (Reformate slugs).

Run #	Injection Rate cc/min	OZPV cc	TZPV cc	SPV cc	THPV cc	Np(b.t) cc	R (b.t) THPV %	Np cc	Rn (THPV) %	Rt (THPV) %	t(b.t) min	P(b.t) psi	T(b.t) °C
25	1	23.25	11.90	4.70	35.15	18.47	52.55	22.94	51.89	65.26	27	157	109
29	2	23.66	11.82	4.70	35.48	16.13	45.46	22.06	48.93	62.18	13	164	98
30	4	23.65	10.93	4.70	34.58	15.98	46.21	21.10	47.43	61.02	8	106	100

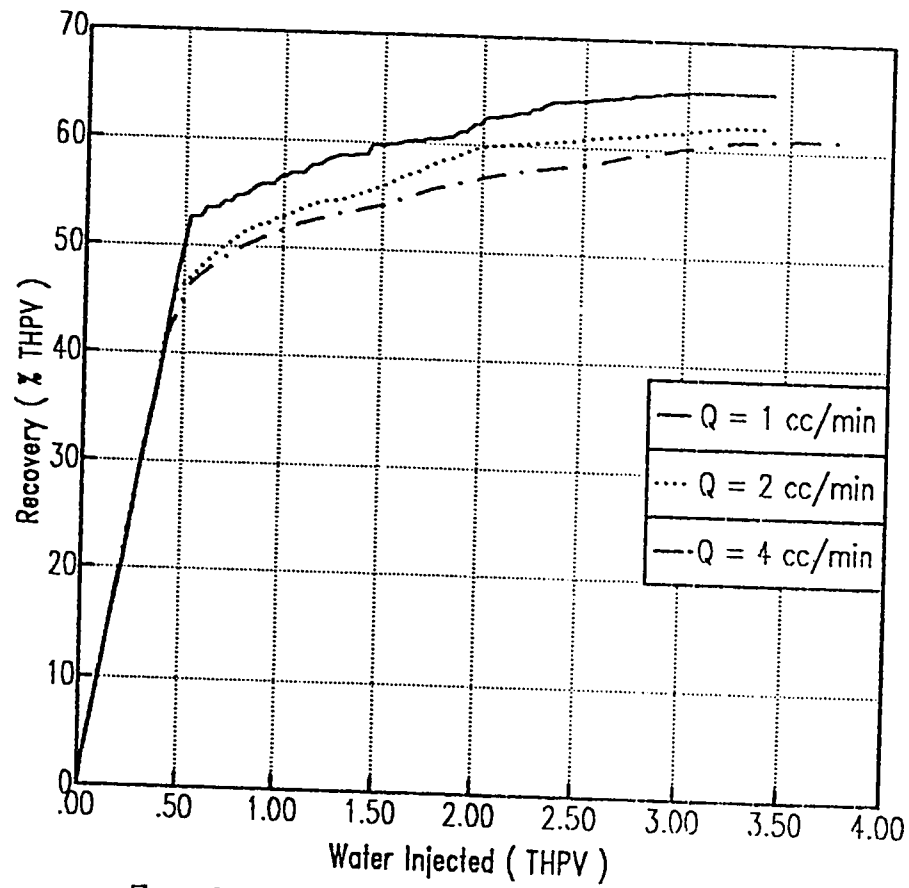


Figure 6.14: Effect of injection rate on recovery applying injection mode II (reformate solvent).

6.6.3.2 Effect of Injection Rate on Recovery Applying Mode III

Three runs: Runs# 27, 31, and 32 employing mode III were conducted at 1, 2, and 4 cc/min, respectively. The experimental data and results for these runs are listed in Table 6.11 while Figure 6.15 shows the hydrocarbon recoveries versus volume of water injected. Raw data and computed results are presented in Appendix-B.

These results indicate a decrease in breakthrough time, total and net hydrocarbon recoveries as injection rate increases. This behavior is similar to that observed with modes I and II.

Comparison of the results listed in Tables 6.7, 6.10, and 6.11 indicates that higher recoveries were obtained with modes II and III relative to mode I at any given injection rate. Figure 6.16 demonstrates this trend. The comparison also leads us to believe that dividing the solvent slug into smaller portions improves the recovery and provides for a trade off if a higher injection rate is desired.

Table 6.11: Experimental Data and Results for Studies of the Effect of Injection Rate on Recovery
Applying mode III (Reformate slugs).

Run #	Injection Rate cc/min	OZPV cc	TZPV cc	SPV cc	THPV cc	Np(b.t) cc	R (b.t) %	Np cc	Rn %	Rt %	t(b.t) min	P(b.t) psi	T(b.t) °C
27	1	22.26	11.85	4.70	34.11	18.53	54.32	23.11	53.97	67.75	26	34	117
31	2	22.64	10.92	4.70	33.56	17.53	52.23	21.67	50.57	64.57	13	88	108
32	4	22.88	10.94	4.70	33.82	17.51	51.77	21.34	49.19	63.10	8	79	103

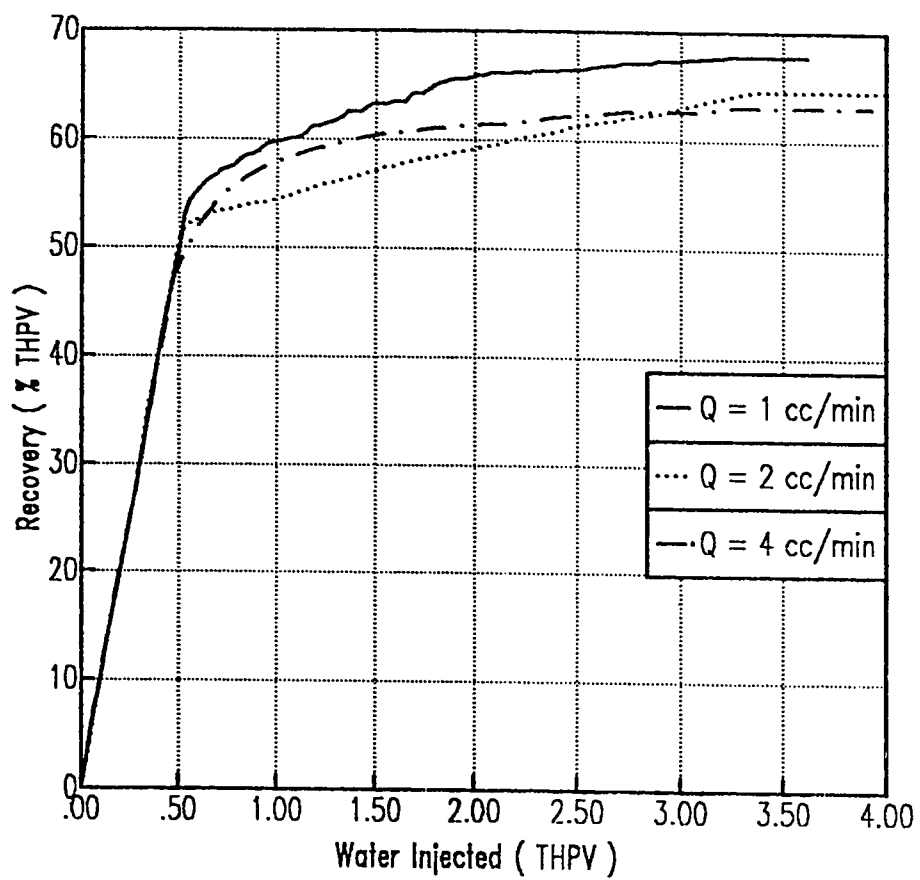


Figure 6.15: Effect of injection rate on recovery applying injection mode III (reformate solvent).

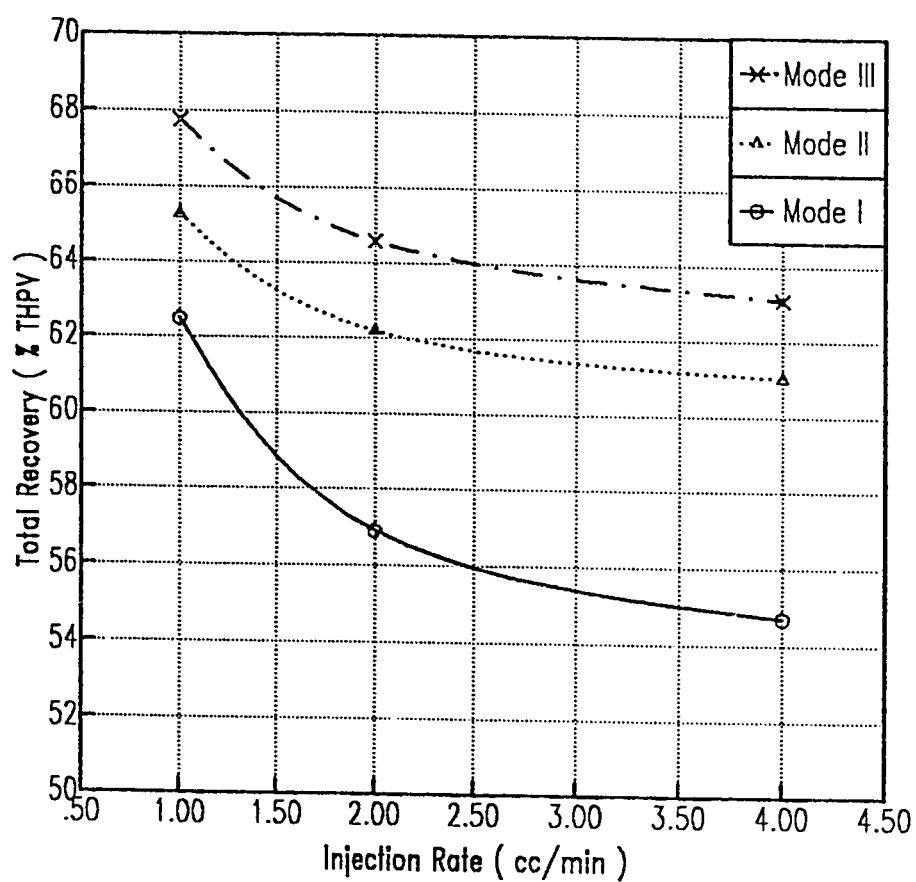


Figure 6.16: Effect of injection rate on total recovery applying various injection modes (reformate solvent).

6.7 PRESSURE BEHAVIOR

In the following section, the pressure behavior response to various parameters such as solvent slug size, type of solvent, injection rate,etc. will be examined.

6.7.1 Pressure Behavior in Cold and Hot-Water Flooding

Figure 6.17 shows the variation of the inlet pressure versus the volume of water injected for cold-water Run# 1. The volume of water is based on the total hydrocarbon pore volume (THPV). The production outlet is always held at atmospheric pressure, thus the inlet pressure was equal to the differential pressure across the composite core. Figure 6.17 shows a sharp build up in pressure right after the commencement of injection. The pressure reached a peak then declined gently to a level which was maintained, more or less, at constant value till the end of the run.

The time of the first oil production in Run# 1 was about 9 minutes. At this time, it is believed that the system have been pressurized enough that the tar starts moving into the oil zone. Hence, oil production starts at a slow rate before water breakthrough of the tar layer. After the pressure reaches the peak shortly before tar breakdown, the production rate increases slightly due to decompression of the tar zone and starts to decrease gradually until a steady-state level is reached.

The highly adverse mobility ratio between tar and brine leads to initiation of water fingers at the water-tar interface. The unstable nature of the displace-

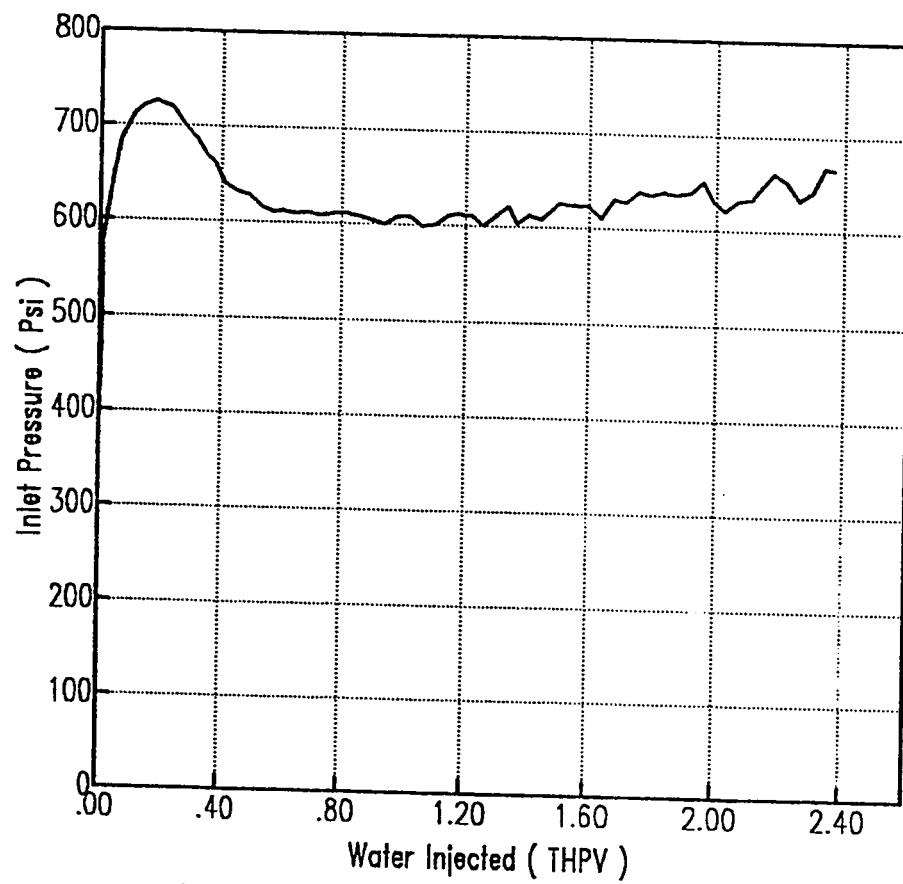


Figure 6.17: Variation of the inlet pressure with water injected for Run# 1, $Q = 1$ cc/min.

ment causes these fingers to propagate and grow through the tar zone. It is believed to be the phase associated with pressure build up. Once the water breaks through the tar zone, it is expected that there is no significant growth in the size of fingers due to high viscosity of the tar.

The inlet pressure and temperature versus the volume of water injected for the hot-water run, Run# 2 are shown in Figure 6.18. The pressure starts increasing immediately after commencement of injection, but with more time required (25 minutes) to reach the peak than in the case of cold-water Run# 1 (16 minutes). The water injected to achieve the peak pressure required for tar breakdown in hot-water Run# 2 was about 0.49 (THPV); while for cold-water, Run# 1, it was about 0.19 (THPV). It is observed from Figure 6.18 that after pressure reaches the peak value, it begins to decline gradually with large fluctuations which correspond to synchronized fluctuations in the inlet temperature. The dashed line in Figure 6.18 represents the smoothed trend of pressure behavior if the inlet temperature was kept at constant value.

It is believed that the heat carried by hot water reduces the tar viscosity and leads to movement of tar into the oil zone for a longer distance than in the case of cold-water flooding. The instability between tar and hot water causes fingering and channeling of hot water in the tar layer, but in this case the fingers may have a significant growth in their size due to heat conducted. This was confirmed by visual inspection of the composite core after the flood where movement of tar into the oil zone was larger than in the case of cold-water run.

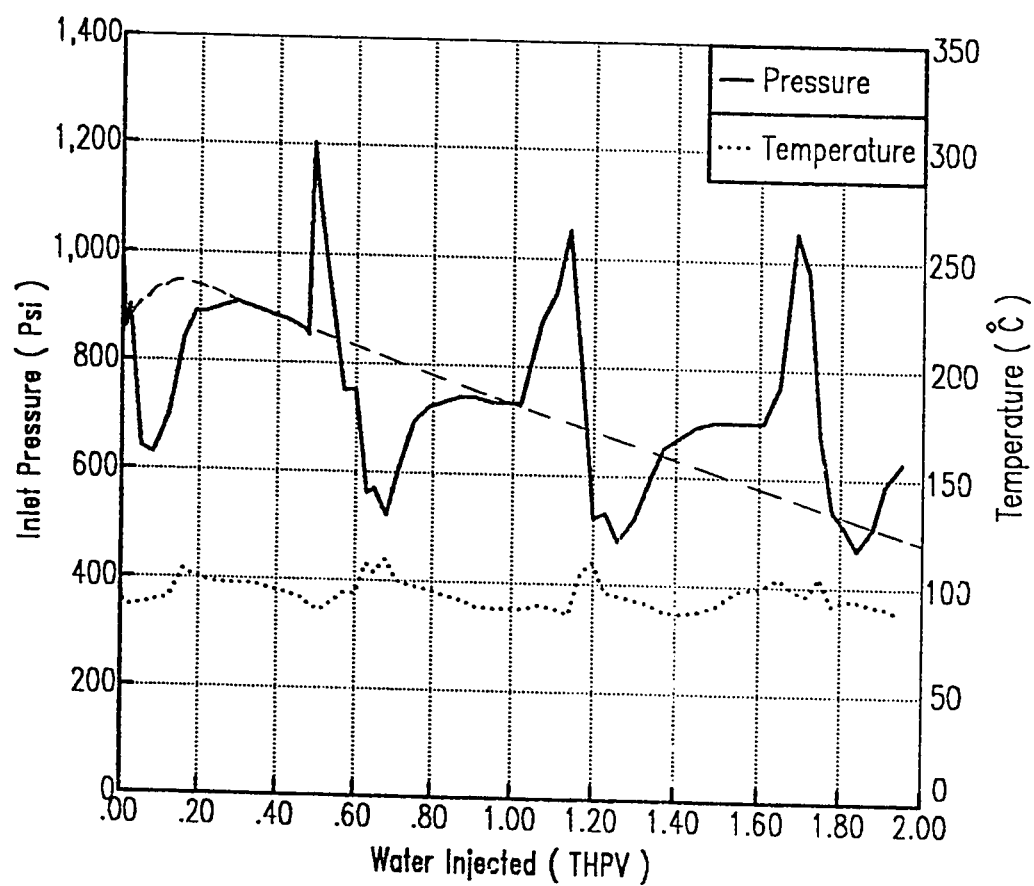


Figure 6.18: Inlet pressure and temperature vs. water injected for Run# 2, $Q = 1$ cc/min.

6.7.2 Pressure Behavior of Runs Investigating the Effect of Solvent Slug Size on Recovery (Mode I)

In Runs# 3, 4, 5, 6, 7, and 19, a solvent (reformate) slug size of 5.84, 9.45, 13.07, 15.52, 19.40, and 33.26 %(THPV) ,respectively, was used. Typical variations of inlet pressure and temperature versus the volume of water injected (THPV) for these runs are shown in Figure 6.19 (Run# 5). Similar graphs for Runs# 3, 4, 6, 7, and 19 are shown in Appendix-C. These figures show a rapid build up in pressure after starting the injection due to high resistance of the tar layer. After the injected fluids breakthrough the tar layer, the pressure declines sharply. However, with continuous hot-water injection, the pressure starts increasing gradually due to encroachment of tar and tar/solvent mixture into the oil zone which may cause reduction of permeability in this zone. These figures show fluctuation of pressure drop with variation of temperature.

Another group of runs: Runs# 20 through 24 were carried out using another solvent (naphtha) with slug sizes of 5.21, 10.93, 13.99, 20.14, and 24.75 %(THPV), respectively. Figure 6.20 shows a typical pressure drop versus water injected for these runs (Run# 20). Similar graphs for Runs# 21 through 24 are shown in Appendix-C.

It is clear that for both naphtha and reformate, the pressure and temperature histories for a typical displacement run are similar but with different peak pressure levels (Table 6.12).

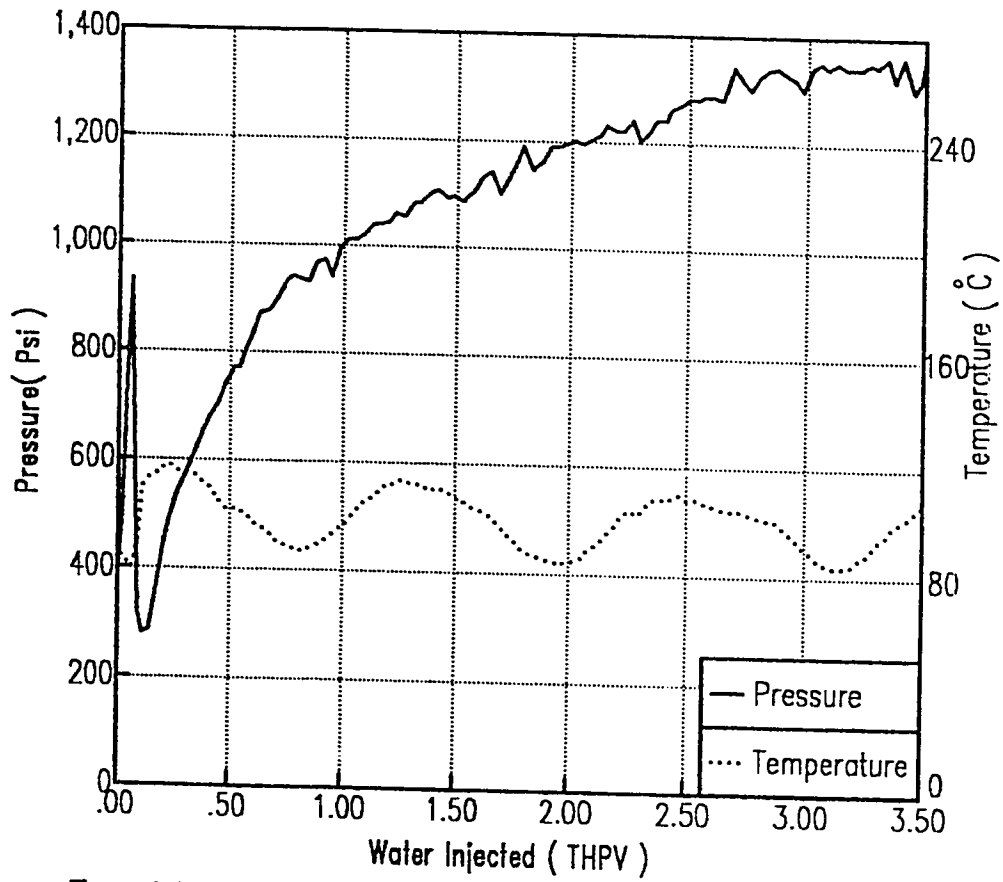


Figure 6.19: Inlet pressure and temperature vs. water injected for Run# 5 (hot-water-driven reformate slug, $Q = 1$ cc/min).

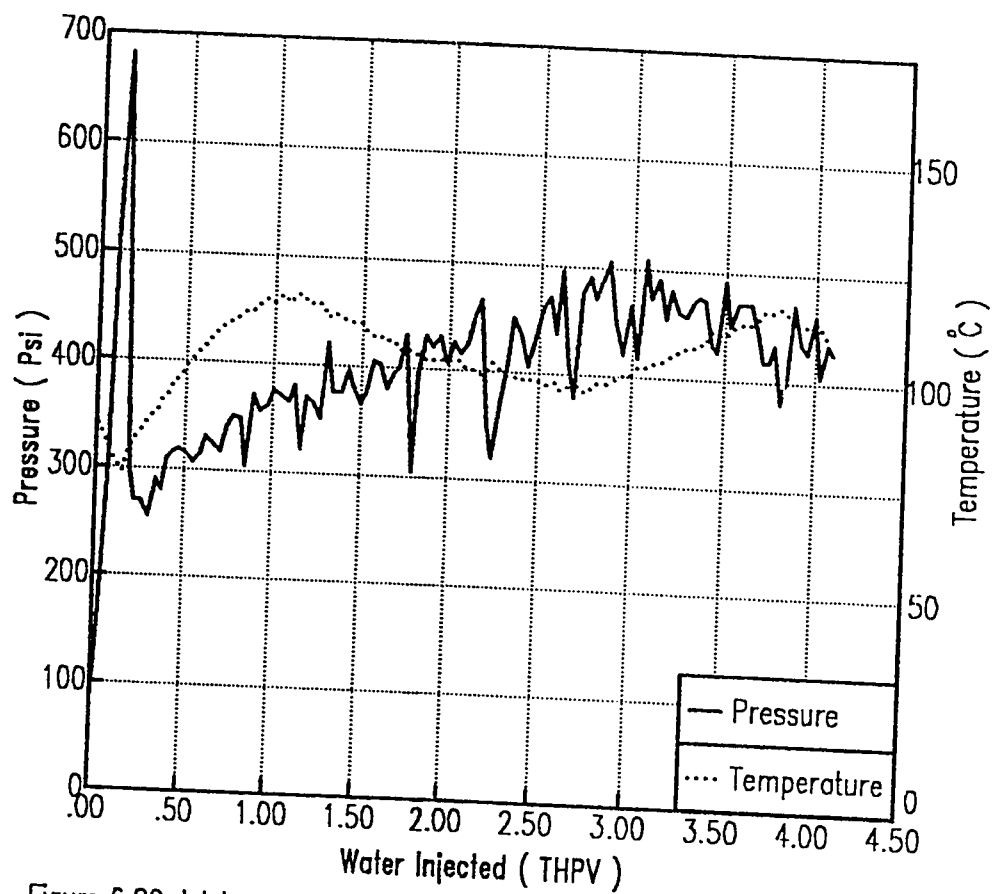


Figure 6.20: Inlet pressure and temperature vs. water injected for Run# 20 (hot-water-driven naphtha slug, $Q = 1$ cc/min).

Table 6.12: Peak Pressure for Runs Investigating the Effect of Solvent Slug Size on Recovery.

Run #	Solvent	Slug Size %(THPV)	Peak Pressure Psi	Time of Peak Pressure min
3	Reformate	5.84	595	9
4	Reformate	9.45	285	11
5	Reformate	13.07	930	12
6	Reformate	15.52	790	4
7	Reformate	19.40	750	11
19	Reformate	33.26	1620	33
20	Naphtha	5.21	680	13
21	Naphtha	10.93	415	11
22	Naphtha	13.99	800	13
23	Naphtha	20.14	212	11
24	Naphtha	24.75	375	13

6.7.3 Pressure Behavior of Runs Investigating the Effect of Injection Rate on Recovery of Tarmat Reservoirs

Two groups of displacement runs were conducted to study the effect of injection rate on recovery for tarmat reservoirs. In the first group, only hot-water was injected at different rates to displace tar and oil. Three runs: Runs# 2, 11, and 12 were conducted at injection rates of 1, 2, and 4 cc/min, respectively. Figures 6.18, 6.21, and 6.22 show the variation of pressure drop and inlet temperature for Runs# 2, 11, and 12, respectively. These figures and the results given in Table 6.13 show that as the injection rate increases the peak pressure values at which the tar layer breaks down decreases. This may be attributed to the large amount of heat carried by hot-water flow at high rates and reduction of tar viscosity in addition to a decrease in interfacial tension between tar and hot brine. Moreover, the time required for pressure to reach its peak value as well as the time of first oil production decrease as the injection rate increases.

In the second group, hot-water-driven optimum solvent (reformate) slug size was used to displace tar and oil. Runs# 5, 8, 9, and 10 were conducted at injection rates of 1, 2, 4, and 6 cc/min, respectively. Figures C-10 through C-12 (Appendix-C) show the pressure drop variation and inlet temperature versus the volume of water injected (THPV) for Runs# 8 through 10. These figures in addition to Figure 6.19 and Table 6.13 indicate a similar trend of decreasing the time of peak pressure and oil production time as the injection rate increases. Hence, the variation of pressure drop in the second displace-

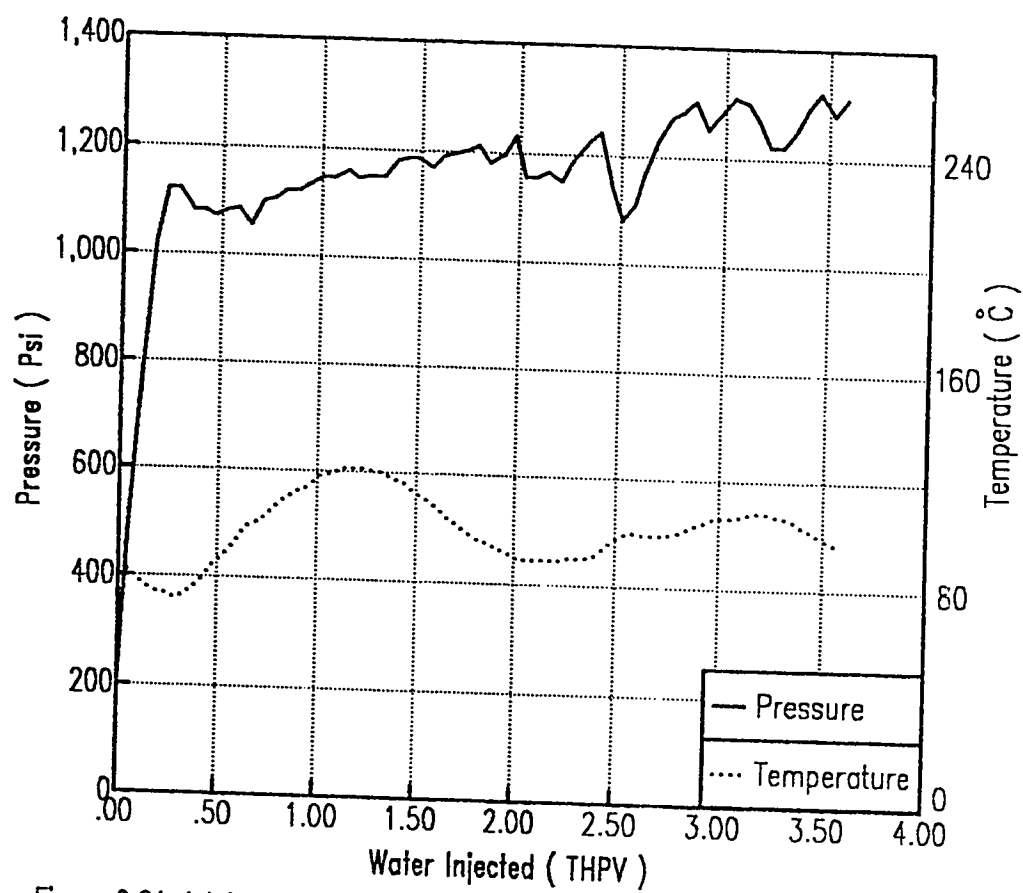


Figure 6.21: Inlet pressure and temperature vs. water injected for Run#11 (hot water displacing tar and oil, no solvent, $Q=2$ cc/min).

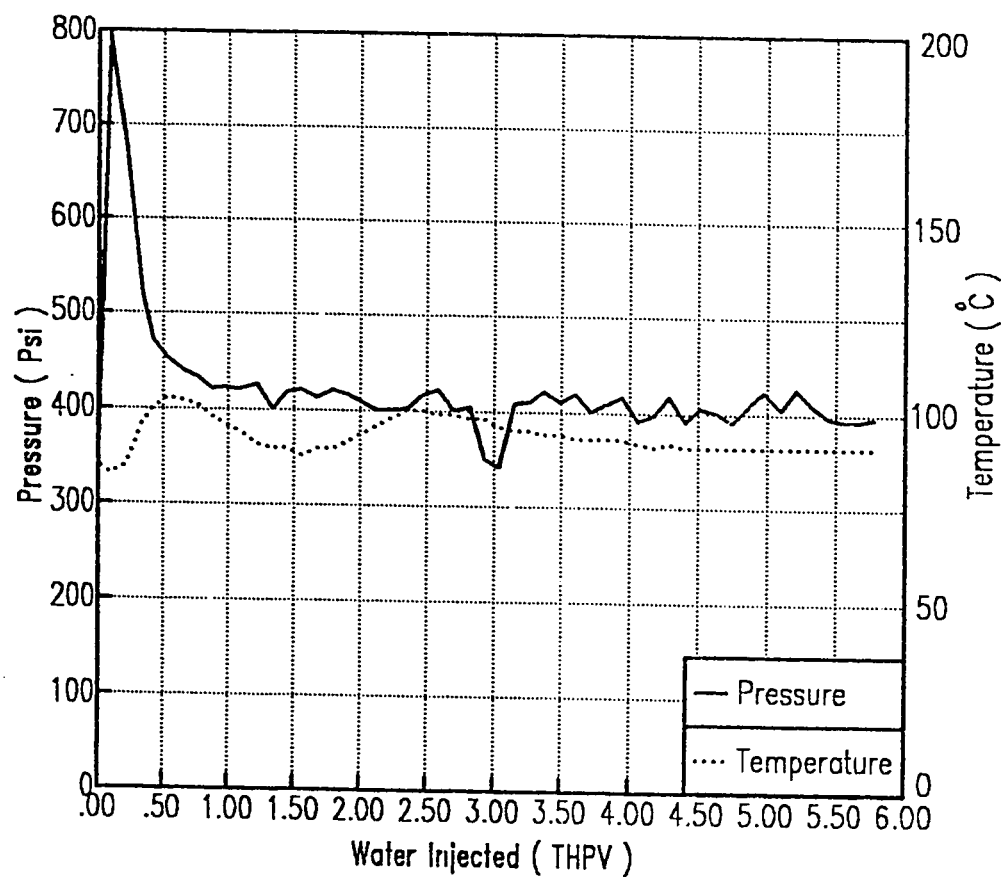


Figure 6.22: Inlet pressure and temperature vs. water injected for Run# 12 (hot water displacing tar and oil, no solvent, $Q=4$ cc/min).

Table 6.13: Peak Pressure for Runs Investigating the Effect of
Injection Rate on Recovery.

Run #	Injection Rate cc/min	Solvent	Peak Pressure Psi	Time of Peak Pressure min	Time of Oil Production min
2	1	_____	1200	25	9
11	2	_____	1120	11	7
12	4	_____	795	4	4
5	1	Reformate	930	12	10
8	2	Reformate	1200	23	7
9	4	Reformate	480	9	4
10	6	Reformate	340	12	3

ment group is similar to that obtained in the first group. However, the Peak pressure of Run# 8 which was conducted at 2 cc/min is 1200 psi. It shows an opposite trend of pressure drop behavior with injection rate. This may be attributed to high viscous forces which outweigh the effect of heat transferred by hot water flowing at 2 cc/min.

values of peak pressure and steady-state pressure when using a solvent slug driven by hot water are less than those values obtained when using hot water only.

6.7.4 Pressure Behavior of Runs Investigating the Effect of Injection Mode on Recovery

As mentioned earlier in section 6.6, three runs (Runs# 5, 25, and 27) using reformat plus three runs (Runs# 22, 26, and 28) using naphtha were conducted to study the effect of injection mode on recovery.

Figure 6.19, 6.23, and 6.24 show the graphs of pressure drop and inlet temperature variation versus the volume of water injected (THPV) for Runs# 5, 25, and 27, respectively. These figures and the results presented in Table 6.14 show that both injection modes II and III result in much lower levels of peak and steady-state pressure than mode I. For example, the peak pressure for Runs# 5, 25, and 27 were 930, 275, and 210 psi, respectively. This indicates that both injection mode II and III were desirable as far as brine injectivity is concerned.

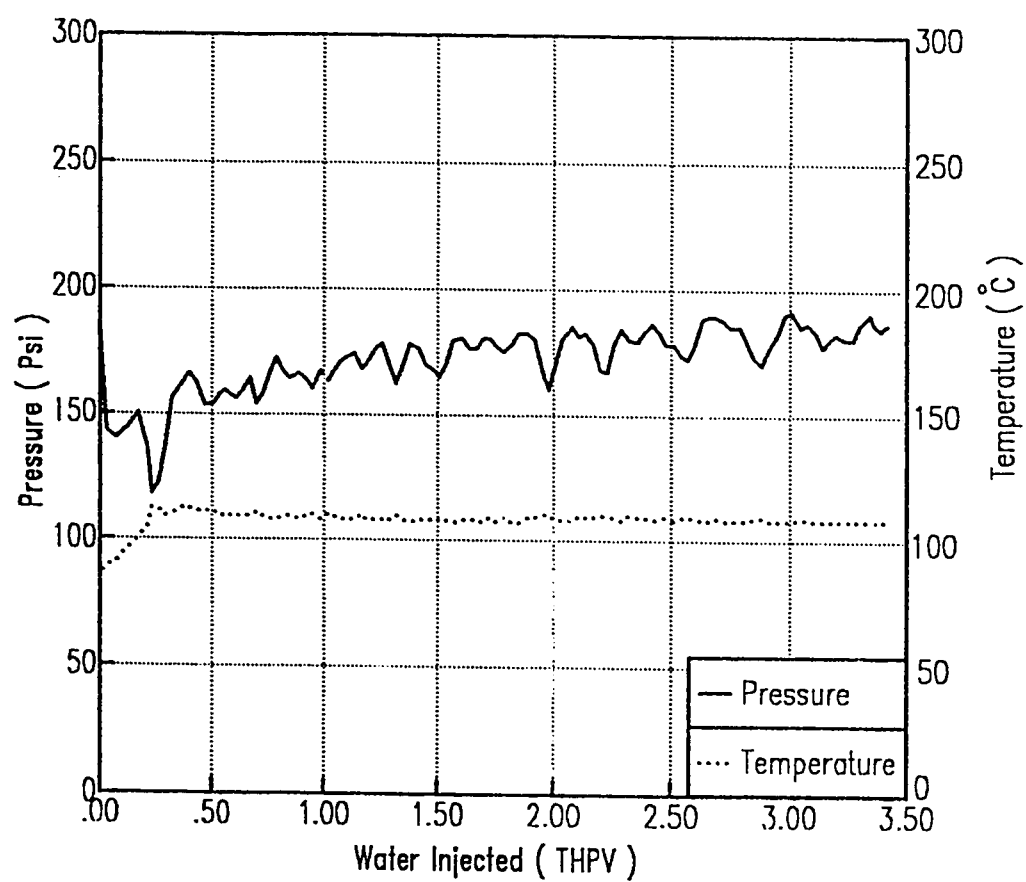


Figure 6.23: Inlet pressure and temperature vs. water injected for Run# 25(mode II, $Q = 2$ cc/min).

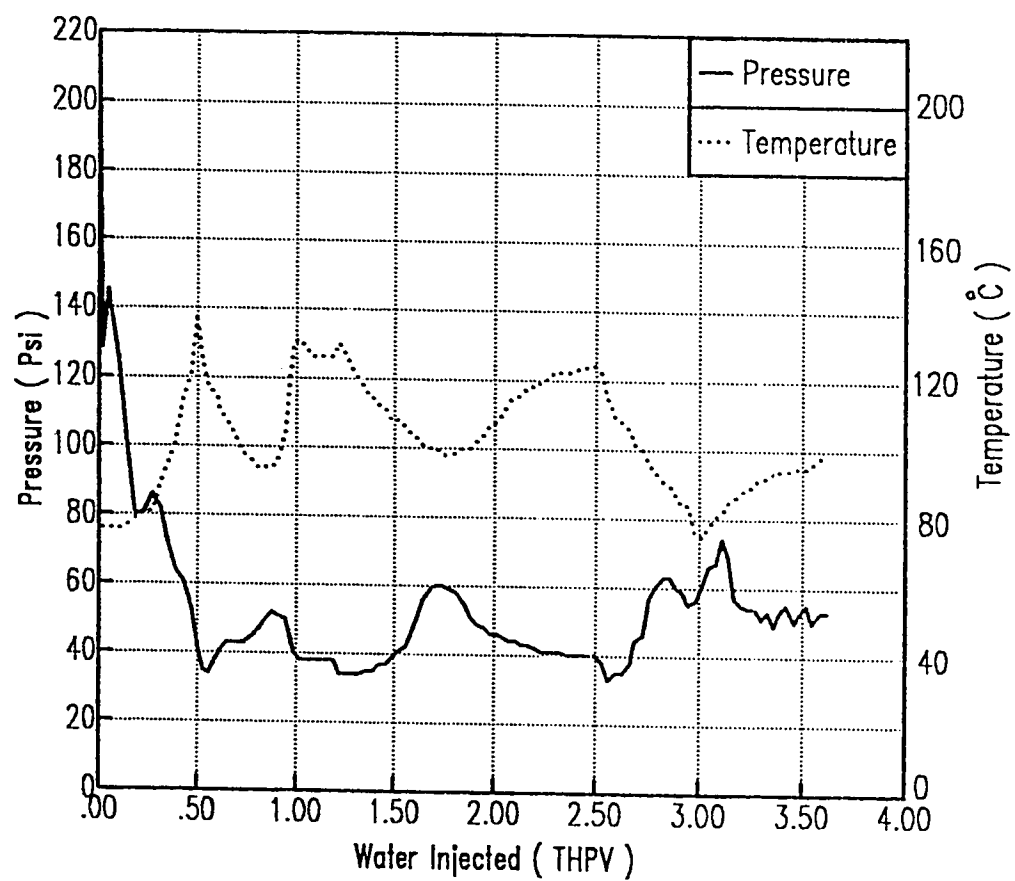


Figure 6.24: Inlet pressure and temperature vs. water injected for Run# 27 (reformate solvent, mode III, $Q = 1$ cc/min).

Table 6.14: Peak Pressure for Runs Investigating the Effect of
Injection Mode on Recovery.

Run #	Injection Mode	Solvent	Peak Pressure Psi	Time of Peak Pressure min
5	I	Reformate	930	12
25	II	Reformate	275	11
27	III	Reformate	210	11
22	I	Naphtha	800	13
26	II	Naphtha	770	14
28	III	Naphtha	395	4

For the naphtha runs, Tables 6.14 and Figures C-7, C-13, and C-14 (Appendix-C) indicate similar behavior of decreasing peak and steady-state pressure levels in the case of modes II, and III compared to mode I. Moreover, it is clear that while the 'steady-state' pressure was climbing for mode I, it stabilized for mode II, and was actually declining for mode III.

6.7.5 Effect of Injection Rate and Mode on the Pressure Behavior

Three displacement-run groups were conducted to study the effect of injection rate on recovery for different injection modes. In the first group, Runs# 5, 8, 9, and 10 were conducted at injection rates of 1, 2, 4, and 6 cc/min, respectively. All these runs represent injection mode I. The behavior of the pressure drops of these runs was discussed earlier in section 6.7.3.

In the second group, Runs# 25, 29, and 30 were carried out at injection rates of 1, 2, and 4 cc/min, respectively. These runs represent injection mode II. Figures 6.23, 6.25, and 6.26 show graphs of pressure drops and inlet temperature variations versus the volume of water injected (THPV) for Runs# 25, 29, and 30, respectively. These figures and results listed in Table 6.15 indicate that at higher injection rates, the peak pressure values increases. The required time for pressure to building up to the peak value and the breakthrough time are less in the case of higher injection rates than lower rates.

In the third group, Runs# 27, 31, and 32 were conducted at injection rates of 1, 2, and 4 cc/min, respectively. These runs represent injection mode III.

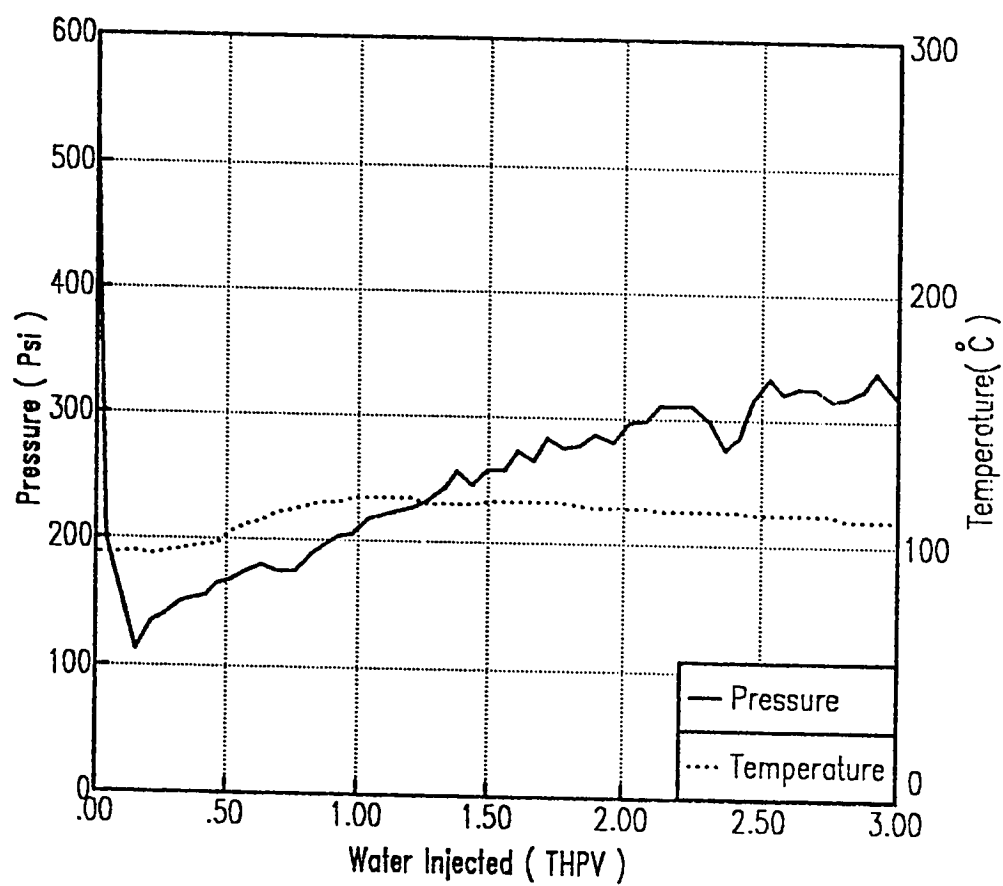


Figure 6.25: Inlet pressure and temperature vs. water injected for Run# 29 (reformate solvent, mode II, $Q = 2$ cc/min).

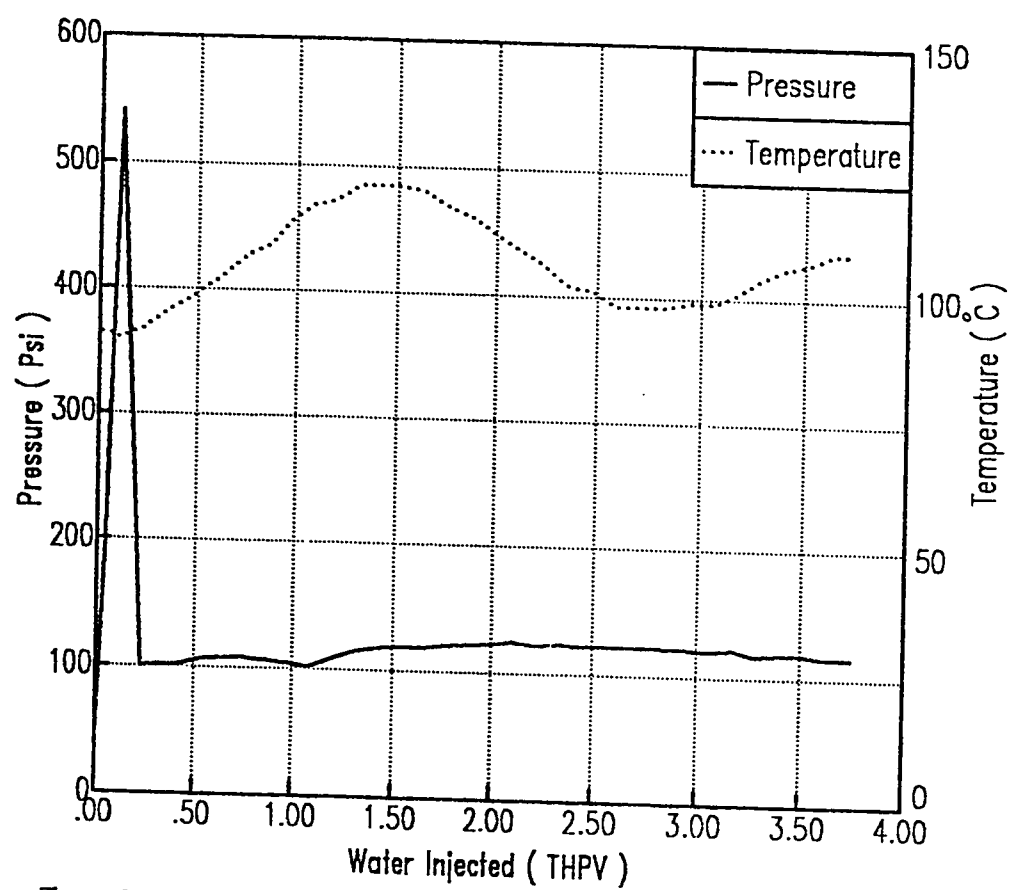


Figure 6.26: Inlet pressure and temperature vs. water injected for Run# 30 (reformate solvent, mode II, $Q = 4$ cc/min).

Table 6.15: Peak Pressure for Runs Investigating the Effect of
Injection Rate and Mode on Recovery.

Run #	Injection Rate cc/min	Injection Mode	Peak Pressure Psi	Time of Peak Pressure min
25	1	II	275	11
29	2	II	530	5
30	4	II	540	4
27	1	III	210	11
31	2	III	245	8
32	4	III	635	4

Figures 6.24, 6.27, and 6.28 show the pressure drops and inlet temperature variations for These runs. These figures and results listed in Table 6.15 indicate a similar trend of pressure behavior as in the case of injection mode II but with different peak pressure values. Also, the steady-state pressure level for modes II and III is more stable (Figures 6.27 and 6.28) than that for mode I (Figure 6.24).

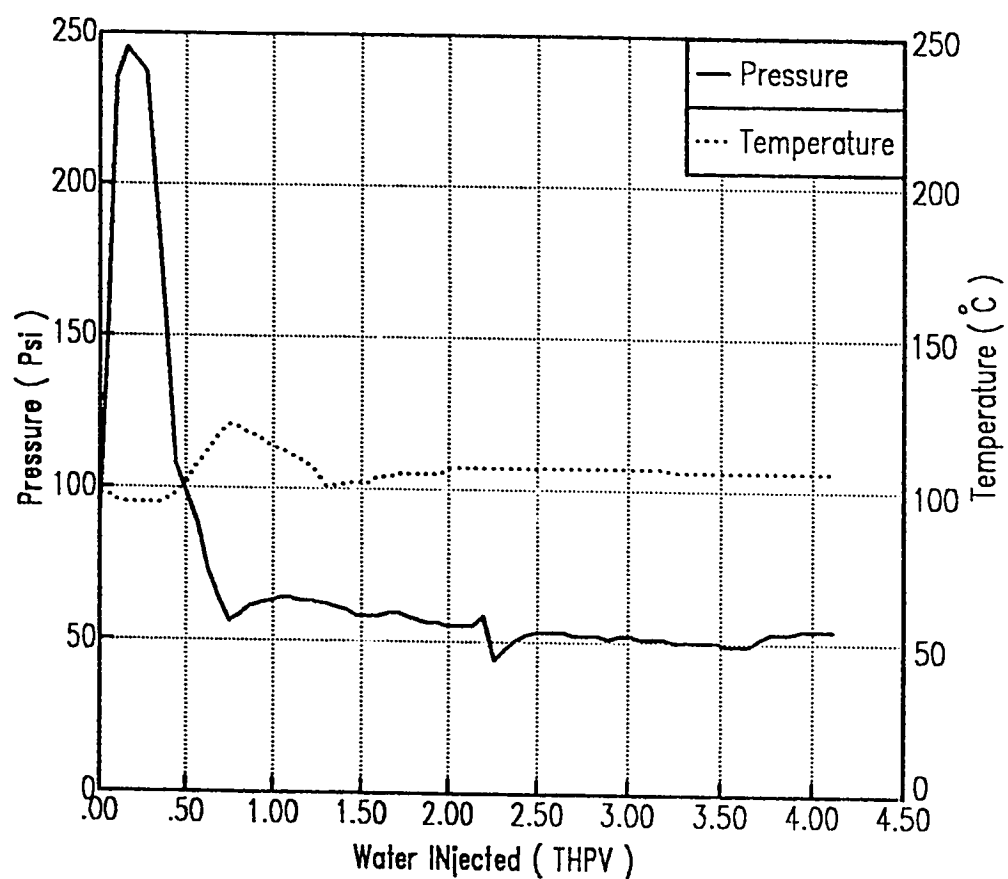


Figure 6.27: Inlet pressure and temperature vs. water injected for Run# 31 (reformate solvent, mode III, $Q = 2$ cc/min).

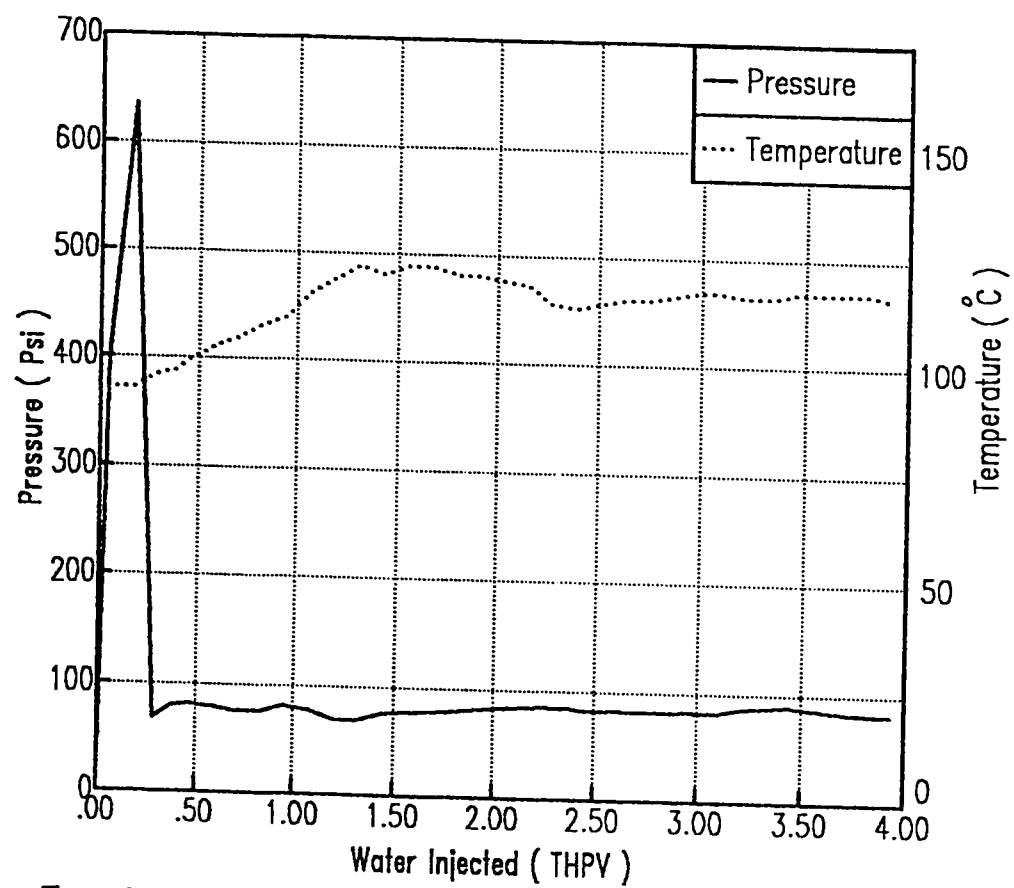


Figure 6.28: Inlet pressure and temperature vs. water injected for Run# 32 (reformate solvent, mode III, $Q = 4$ cc/min).

6.7.6 Pressure Behavior of Runs Investigating the Effect of Injection Rate on Oil Recovery (No Tar Zone)

To investigate the pressure behavior when a tar layer is absent, Runs# 13, 14, and 15 were conducted at injection rates of 1, 2, and 4 cc/min, respectively, using hot-water flooding. Figures 6.29 through 6.31 show pressure variations versus the volume of water injected (THPV) for these runs. These figures show completely different pressure behaviors than those obtained with runs having a tar layer. They indicate a rapid increase in inlet pressure up to a steady-state pressure level with no pressure peak. The pressure gradient values are much less than those encountered with tar runs. Moreover, at higher injection rates the inlet pressure increases. This behavior is opposite to the one obtained with tar runs at higher injection rates. This may be attributed to the larger decrease in tar viscosity than oil viscosity as a result of heat transferred by hot water flow at higher rates. Hence, the resistance of tar will be reduced quickly because tar is more viscous than oil.

The addition of a solvent slug to hot-water flooding reduces the pressure drop across the composite cores more than in the case of using cold or hot-water flooding only. Such a reduction in the pressure drop may be attributed to reduction of tar viscosity by the combined miscible and thermal effects. Furthermore, both injection modes II and III result in a lower pressure drop than mode I at low injection rates and hence the injectivity and recovery were improved. Higher injection rates result in lower pressure drop due to the large amounts of heat introduced by the brine.

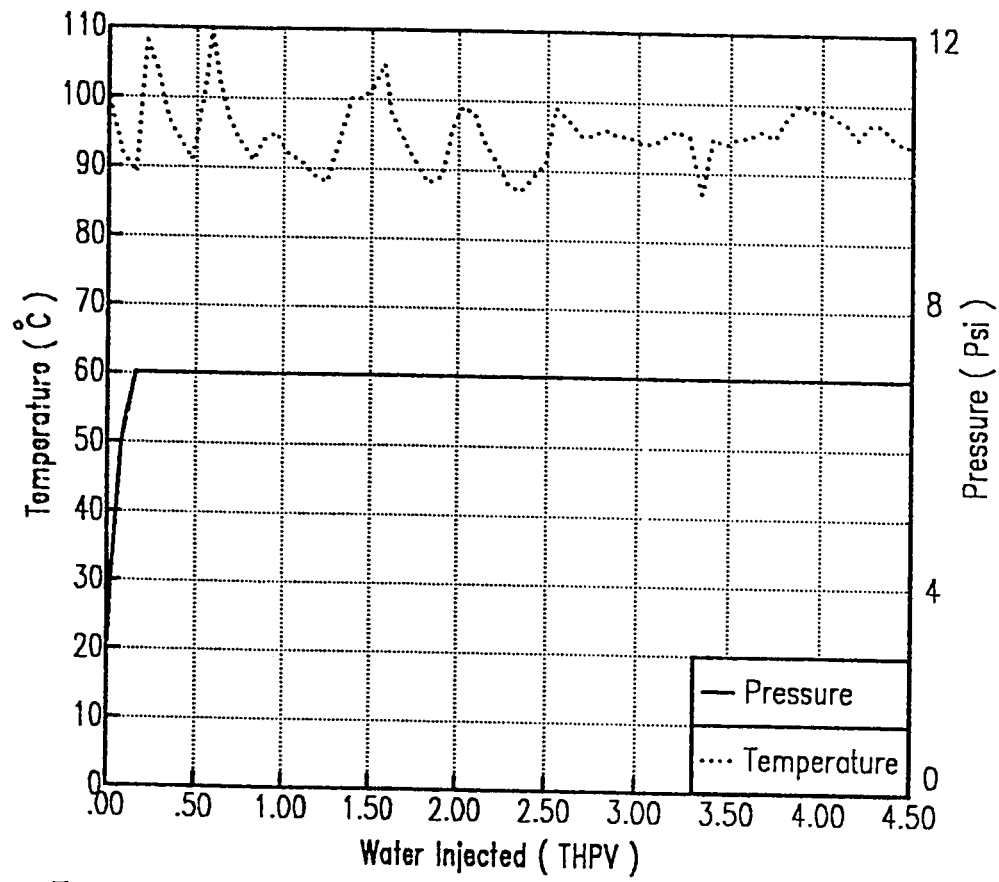


Figure 6.29: Inlet pressure and temperature vs. water injected for Run# 13 (hot water displacing oil, no tar, $Q = 1 \text{ cc/min}$).

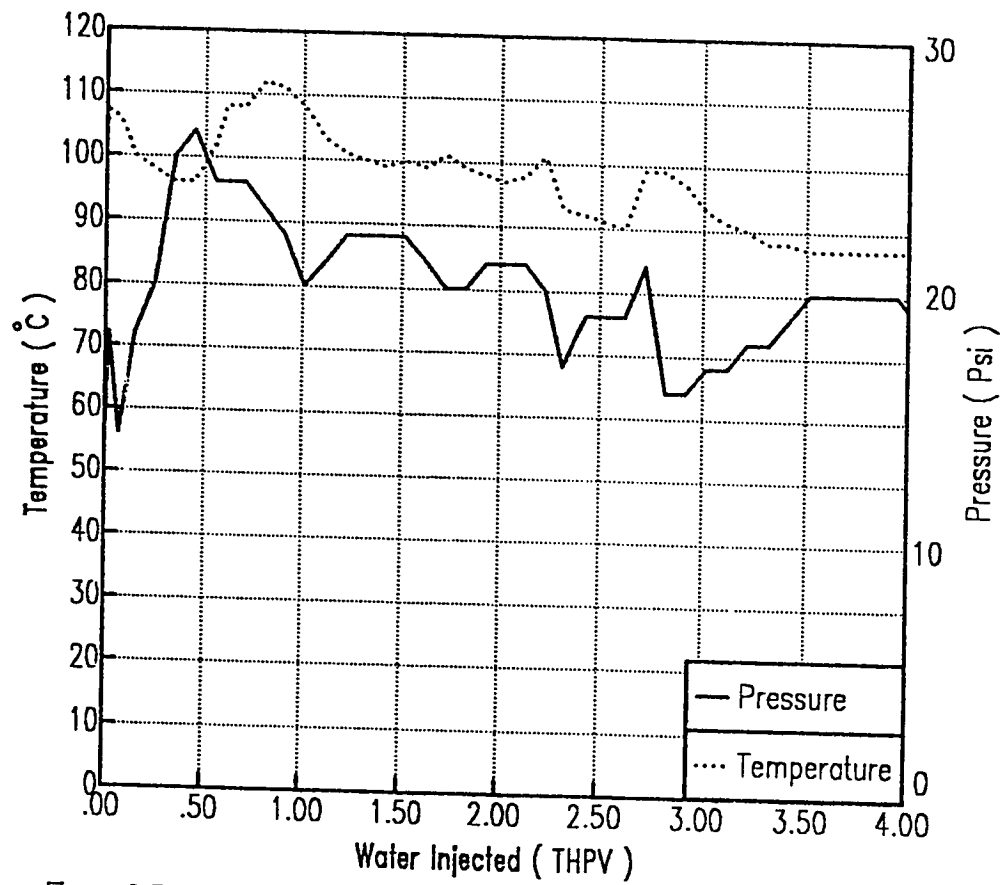


Figure 6.30: Inlet pressure and temperature vs. water injected for Run# 14 (hot water displacing oil, no tar zone, $Q = 2$ cc/min).

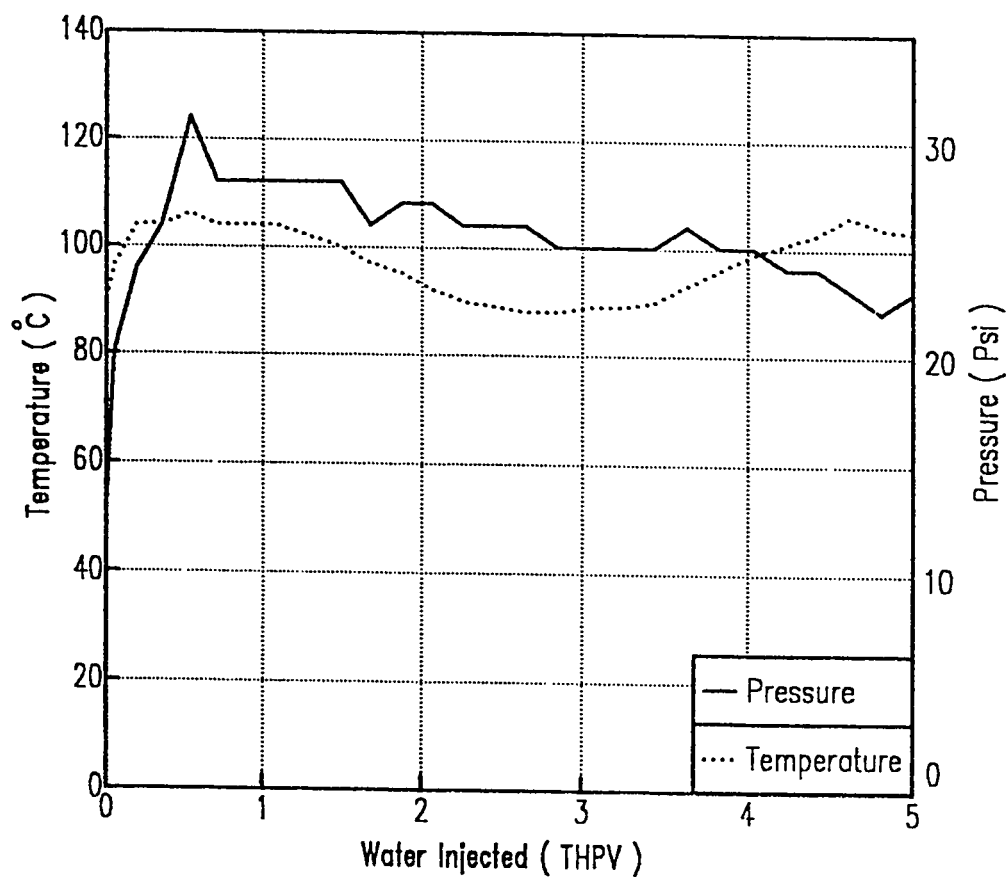


Figure 6.31: Inlet pressure and temperature vs. water injected for Run# 15 (hot water displacing oil, no tar zone, $Q = 4$ cc/min).

6.8 AVERAGE WATER SATURATION

Table 6.16 lists the average water saturation for both oil and tar zones at the end of each flooding run. These saturations were determined by extraction of the composite cores that make up each zone. Moreover, the average water saturation in the oil zone was computed by material balance to compare it with the value obtained from extraction. Table D-1 (Appendix-D) provides the water saturation data of tar and oil zones for all runs. The material balance equation used to calculate the average water saturation in the oil zone for runs having tar and oil zones (Runs# 1, 2, 11, and 12) without injection of solvent is:

$$\bar{S}_{wo} = \frac{N_p - \bar{S}_{wt} \times TZPV}{OZPV} \times 100 \quad (6.1)$$

where:

\bar{S}_{wo} = average oil zone water saturation, percent

$OZPV$ = oil zone pore volume, cc

$TZPV$ = tar zone pore volume, cc

N_p = cumulative oil produced, cc

\bar{S}_{wt} = average tar zone water saturation, percent

Since both oil and tar are miscible, so it is implied in equation 6.1 that oil is completely displaced by tar. For other displacement runs: Runs# 3 through 10 and 19 through 32 in which solvent (reformate or naphtha) slugs were injected and driven by hot water, the following material balance equation was used to calculate the average water saturation in the oil zone:

$$\bar{S}_{wo} = \frac{N_p - \bar{S}_{wt} \times TZPV - SPV}{OZPV} \times 100 \quad (6.2)$$

where:

SPV = volume of solvent injected, cc

In this equation, it is assumed that solvent slug is completely produced. For Runs# 13 through 18 conducted to study the effect of injection rate on recovery in the absence of tar layer, the average water saturation of oil zones was determined by extraction method and material balance for comparison purpose.

Table 6.16: Average Water Saturations by Extraction and MBE Method of Oil and Tar Zones for All Flooding Runs.

Run #	Injection Rate cc/min	Sw % (By Extraction)		Sw % (By MBE)	Solvent
		Tar Zone	Oil Zone	Oil Zone	
1	1	9.04	53.02	55.60	_____
2	1	15.70	63.75	67.30	_____
3	1	25.10	61.24	64.80	Reformate
4	1	23.40	61.48	66.41	Reformate
5	1	24.50	59.05	62.62	Reformate
6	1	22.90	55.15	57.83	Reformate
7	1	25.70	45.54	47.51	Reformate
8	2	23.10	50.34	53.26	Reformate
9	4	25.50	47.34	50.06	Reformate
10	6	23.60	46.05	47.73	Reformate
11	2	20.66	56.70	60.73	_____
12	4	18.57	54.93	58.69	_____
13	1	_____	64.60	68.09	_____
14	2	_____	61.30	66.22	_____
15	4	_____	60.62	64.18	_____
16	1	_____	70.70	74.47	_____

Table 6.16: Continued.

Run #	Injection Rate cc/min	Sw % (By Extraction)		Sw % By NBE	Solvent
		Tar Zone	Oil Zone	Oil Zone	
17	2	_____	65.70	69.86	_____
18	4	_____	63.15	67.27	_____
19	1	27.37	40.76	42.31	Reformate
20	1	30.86	55.71	60.17	Naphtha
21	1	22.60	59.74	67.00	Naphtha
22	1	21.35	59.32	62.54	Naphtha
23	1	22.20	52.34	55.22	Naphtha
24	1	23.96	48.57	51.23	Naphtha
25	1	25.60	64.27	65.35	Reformate
26	1	27.50	62.25	62.73	Naphtha
27	1	23.60	66.20	70.14	Reformate
28	1	26.50	63.80	65.32	Naphtha
29	2	22.80	60.67	61.98	Reformate
30	4	25.30	55.01	57.65	Reformate
31	2	24.50	59.05	63.14	Reformate
32	4	26.10	56.30	60.25	Reformate

Table 6.16 shows that the average water saturation in the oil zone computed by material balance equation is always higher than that obtained by extraction method. This could be the result of water evaporation during storage of the cores. Also, it is observed in all runs which have both tar and oil zones that there is a gradual increase in the average water saturation of oil zones toward the production outlet. This saturation distribution is opposite to what is usually expected in regular water flooding tests which exhibit gradual decrease in water saturation toward the outlet. The average water saturation results of displacement Runs# 13 through 18 (Appendix-D) in which water displaced oil directly (no tar zone) confirm the decrease of water saturation in the direction of water flow since the average water saturations in the downstream cores are always less than those of cores at the injection inlet.

The results presented in Table 6.16 and Appendix-D indicate no specific water saturation trend with the variation of the solvent slug size, type of solvent, or injection modes. Comparison of water saturation results of cold-water Run# 1 and hot-water Run# 2 shows higher water saturation, in both oil and tar zones, in the case of hot-water flooding than cold-water flooding.

In hot-water displacement runs, \bar{S}_{wt} was always higher when a solvent slug was present. This may be attributed to the thinning up of tar with solvent thus causing the tar to be more displaceable. It is clearly observed that average water saturation in the oil zone decreases as the injection rate increases as a result of viscous fingering and channeling phenomena.

Chapter VII

ANALYSIS AND MODELING

7.1 INTRODUCTION

It appears from what has been seen in the previous chapters that the complexity of the flow in tarmat systems, comes from the interaction of the following three phenomena:

- the flow in a complex system constituted by the juxtaposition of a highly viscous tar layer with other fluids of normal viscosity.
- the effect of temperature in such a system.
- and the effect of solvent.

Most enhanced oil recovery processes are based on the displacement of one fluid by another. If the displacing fluid is less viscous than the displaced one, viscous fingering develops. Thus, viscous fingering phenomenon is expected to be the most common feature occurring in any EOR method for tar displacement. This is the case when the fluid is injected within or below the tar zone.

In this chapter, a model which describes the behavior of tarmat reservoirs in response to various EOR methods is proposed. The model will describe first the behavior of a tarmat reservoir when cold-water flooding is

applied. It will be expanded after to account for the effects of temperature, solvent slug size, injection mode, and injection rate.

7.2 COLD-WATER FLOODING

Cold-water flooding is the most common and well-established technique for oil recovery. Therefore, it was tested as a basic recovery technique for tar-saturated reservoirs. In this case, the driving fluid is more mobile than the driven fluid (tar). Right after the beginning of injection, water attempts to invade the tar zone. Due to the extremely large tar viscosity, the pressure at the inlet builds up rapidly with no significant flow of tar-or-oil achieved. During this very early stage, the bulk of the water injected serves to compress the tar only.

The highly adverse mobility ratio between tar and brine leads to initiation of water fingers at the tar-water interface. The unstable nature of the displacement causes these fingers to propagate and grow through the tar zone (Perkins, et al., 1969, and Vossoughi, et al., 1982). Although several models have been proposed to describe viscous fingering during immiscible displacement in porous media, (Perkins and Johnston, 1969, Peter and Flock, 1981), no model has gained acceptance as a tool for displacement performance when viscous fingering occurs. Thus, the displacement front cannot be stabilized as required by Buckley & Leverett model at extremely high mobility ratios.

It is expected that the growth of water fingers through the tar zone coincides with the initial period of pressure build up in the tar zone. The fingers developed in the tar zone are relatively larger in size in the vicinity of the water-tar interface and their size gradually decreases toward the tar-oil interface. Thus, a gradual decrease in the water saturation in the tar zone is expected towards the producing end. Such a saturation profile was observed by many investigators (Van Meurs, 1957, and Peters and Flock, 1981). Then, once the water breaks through the tar zone, there is no significant growth in the size of fingers due to the high viscosity of tar (Abu-Khamsin, et al., 1993). Consequently, the pressure declines gradually until it reaches a steady-state level. However, it is expected that the pressure (steady state) will remain at a relatively higher level due to restricted movement of water through narrow paths developed by water fingers.

When water breaks through the tar zone, water fingers enter the oil zone and tend to disperse as they move through the core and deteriorate into a zone of graded saturation. This may be attributed to the capillary forces which may oppose the development of these fingers and dampen their propagation in a strong water wet porous medium (Berea sandstone). Such behavior will result in increasing water saturation in the direction of flow. A similar behavior was also observed by Perkin and Johnston, 1969. However, this saturation distribution is contrary to what is usually observed in a regular water-oil displacement test, i.e., saturation decreases in the direction of flow.

Once water breaks through the oil zone, the injected water will be confined to the areas contacted by the original viscous fingers and thereby prevented from invading new areas of the core. Figure 7.1 shows the expected patterns of fingers distribution in a farmat reservoir model applying cold-water flooding.

The viscous fingering and channeling phenomena will result in decreasing the macroscopic displacement efficiency. This is due to high oil saturations remaining in the the regions bypassed by the displacing brine. This will lead to a relatively low hydrocarbon recovery. The trapped oil in the area bypassed by the water fingers will not be produced even when large amount of water is injected. This is due to the capillary forces and strong water wetness of Berea sandstone which oppose the drainage of water.

The displacement results of cold-water flooding (Run# 1), presented in Table 6.1, conform to the proposed model. Figure 6.1 and Table 6.1 show a relatively low hydrocarbon recovery (40 % THPV) as a result of viscous fingers and channeling.

Figure 6.17 shows the pressure behavior during cold-water flooding. This figure indicates a build up in pressure during the first period of injection. Then, the pressure declines gradually after water breaks through the tar zone. Also, the steady-state pressure level is maintained at high value. Furthermore, the results presented in Tables 6.16 and D-1 (Appendix-D) indicate a water saturation increase in the oil zone in the direction of flow as described by the model.

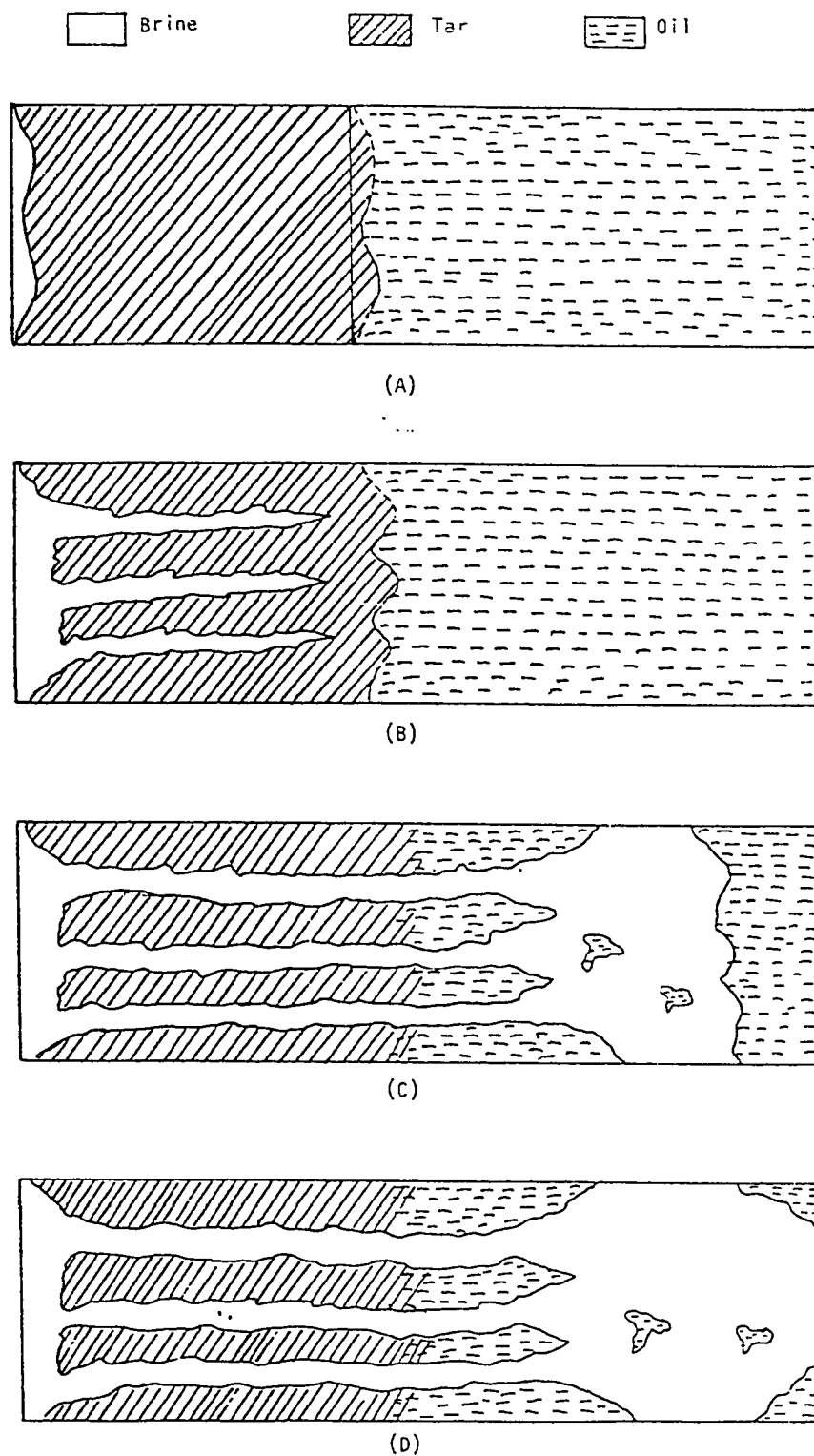


Figure 7.1: Distribution of fingering patterns in a tar-mat reservoir model using cold-water flooding.

7.3 HOT-WATER FLOODING

When hot-water flooding is applied to the farmat model, viscous fingering and heat input become the most important factors affecting the behavior of the system. The minute the hot water injection starts, the tar interface contacted by hot water will be heated up as a result of heat transfer. Thus, the tar viscosity in a small interval at the inlet will be reduced. Yet, the bulk of the tar will be too viscous to move and the inlet pressure builds up in a fashion similar to cold-water flooding. Also, viscous fingers are initiated at the inlet to the tar zone.

Before initiation of the fingers at low injection rate, the heat loss is important and the temperature does not depart from the initial temperature. Thus at the tips of the water fingers, the tar mobility is that of the unheated tar. It is obvious that the water in the smallest fingers will be cooled more rapidly than that in the larger fingers. The longer fingers will continue to push against the cold tar while the smallest fingers will expand against the reduced resistance of the heated tar alongside. Therefore, the fingers may undergo significant growth in size. In essence, the bulk water saturation in the tar zone will be larger compared to cold water displacement.

When hot water enters the oil zone, the viscous fingers will begin dispersing into a small set of channels which will form a graded saturation zone that leads to a quite stable displacement (Perkins, et al . 1969). Moreover, continuous injection of hot water reduces both tar and oil viscosities and hence the displacement efficiency and recovery are enhanced. After water breaks

through the oil zone, oil production is mainly due to the growth in the flow direction of the fingers already formed.

The recovery improvement from a tar-mat reservoir due to hot-water flooding over cold-water flooding can be attributed to the following effects of temperature:

- 1- Tar and oil mobilities are improved as a result of reduction of their viscosities at higher temperature. Referring to Table 5.8 and Figures 5.13 and 5.14, it can be stated that both tar and oil viscosities decrease as the temperature increases. Tar viscosity is reduced faster than that of oil at higher temperature as shown in Table 5.8. Thus, decreasing the oleic phase viscosity would affect the mobility ratio defined as $M = \frac{K_{rw} \mu_c}{K_{ro} \mu_w}$. Generally, the tar and oil viscosities are reduced faster than water viscosity as the temperature increases (Table 5.8). Hence, the reduction in viscosity ratios will result in enhancing the mobility ratio between tar and brine as well as between oil and brine. Consequently, it increases oil displacement efficiency and recovery.
- 2- The increase in temperature causes a decrease in the interfacial tension between tar and brine as well as between oil (kerosene) and brine as illustrated in Table 5.12 and Figure 5.18. Such a decrease in IFT will reduce the effect of capillary forces which results in decreasing the residual oil saturation.

- 3- The fingers size and density increase as the temperature increases due to the tar and oil viscosity decrease. This will result in increasing the swept area and hence enhancing the recovery. In addition, more oil will be displaced as a result of tar movement into the oil zone.
- 4- Finally, the temperature has a favorable effect on relative permeabilities to oil and water. Referring to section 5.5, it can be stated that the temperature increase shifted the relative permeability curves in the direction of increasing water wetness. Also, the irreducible water saturation increased from 28.6 % at 25 °C to 36.7 % at 100 °C. This may be attributed to the decrease in IFT between oleic phase and aqueous phase which is equivalent to a decrease in capillary forces at high temperatures.

The high viscosity ratio between tar and hot water always leads to unstable displacement and viscous fingering; and more so at higher injection rates. In the case of higher injection rates, viscous fingers will propagate faster through the tar zone and hence lead to earlier water breakthrough. Consequently, this will result in lower recovery. On the other hand, the large amount of heat carried by a high injection rate will reduce both viscosities of tar and oil and decreases the resistance to flow. Hence, the pressure drop is expected to decrease at higher rates.

Indeed, visual observation of the invaded oil cores by tar, at the end of hot-water flooding (Run# 2) confirms the assumption of tar movement into oil

zone for a longer distance (4.5 cm) than similar movement obtained from cold-water flooding (2.8 cm). Also, the water saturation value of the far core for hot-water flooding was higher (14.74 %) than the value obtained for cold-water flooding (9.04 %). This supports the thinking that the tar was moved for a longer distance in the oil zone and the increase in size of viscous fingers. Moreover, the residual oil saturation of oil zone in hot-water flooding was about 36.25 % while similar saturation in the case of cold-water flooding was 46.98 %.

The pressure behavior shown in Figure 6.18 indicates a continuous decrease of pressure gradient with continuous hot water injection due to a decrease of resistance to flow. Such behavior is different from that obtained from cold-water flooding (Figure 6.17) which indicates a steady-state pressure drop with continuous water injection. Moreover, Table 6.13 in addition to Figures 6.18, 6.21 and 6.22 indicate a decrease in both peak pressure (at which hot water breaks through the far zone) and breakthrough pressure as the injection rate increases. This is due to more heat conducted at higher rates.

The hydrocarbon recovery in the case of hot-water flooding was higher (49.91 % THPV) than in the case of cold-water flooding (40 % THPV) as a result of the effect of temperature. Furthermore, Table 6.6 indicates a decrease in hydrocarbon recovery as the injection rate increases due to faster propagation of fingers and earlier water breakthrough as described earlier.

7.4 HOT-WATER-DRIVEN SOLVENT SLUG

Different solvents (reformat and naphtha) slug sizes driven by hot water were applied to a tar-mat model. In this case, viscous fingers, heat input and mixing represent the most important factors affecting the behavior of the tar-mat reservoir. The solvent slug was injected as one portion and driven by continuous hot-water flooding (mode I). As the injection starts, the solvent slug mixes with tar and results in a reduction of tar viscosity at the interface. Simultaneously, the pressure starts to build up due to high tar resistance and movement of fluids through small pores.

The large difference between solvent and tar viscosities leads to a highly unfavorable mobility ratio. As a result, the solvent front becomes unstable and numerous fingers of solvent will develop and penetrate into the tar layer in an irregular fashion. At the foremost edge of the fingers there is considerable mixing between tar and solvent resulting in a positive viscosity gradient along the length of the solvent finger with the viscosity of the mixture at the tips of the fingers of the same order as the tar viscosity. The developing of a viscosity gradient may dampen further growth of a finger. However, there is a possibility of developing smaller fingers from points along the length of the finger where the viscosity difference is large. The initiation of such solvent fingers in the tar zone leads to considerable mixing of tar and solvent at the microscopic and macroscopic scales.

Therefore, it is expected that mixing of the solvent slug injected prior to hot-water flooding leads to the development of a transition zone of graded

viscosity. Effectively, this zone acts as a viscosity buffer between hot water and tar. The presence of such a transition zone is desirable in displacement at unfavorable mobility ratios (Sancevic, 1961, Slobod and Thomas, 1963). The length of the transition zone is naturally dependent on the amount of solvent injected.

The driving hot water will flow preferentially through the fingers developed by solvent in the tar zone. The viscosity of tar in the regions contacted by hot water will be further reduced due to heat transfer. Thus, the size of fingers will increase as a result of heat conduction and mixing.

With small solvent slugs, it is expected that the driving hot water will penetrate the transition zone at several locations and fingers through the rest of the original tar zone. Hence, hot water will break through the graded viscosity zone and tar zone while the tar-solvent mixture still exists somewhere inside the tar zone as shown in Figure 7.2. Once water and solvent break through the tar zone, the pressure declines gradually. Consequently, water and solvent fingers will disperse and break down into small dendritic fingers which result in quite stable displacement. Some tar mixed with solvent and heated by hot water will move into the oil zone.

The smaller the solvent slug, the shorter the transition zone and the more chance for the water to be in contact with oil rapidly, and consequently, the recovery will be lower.

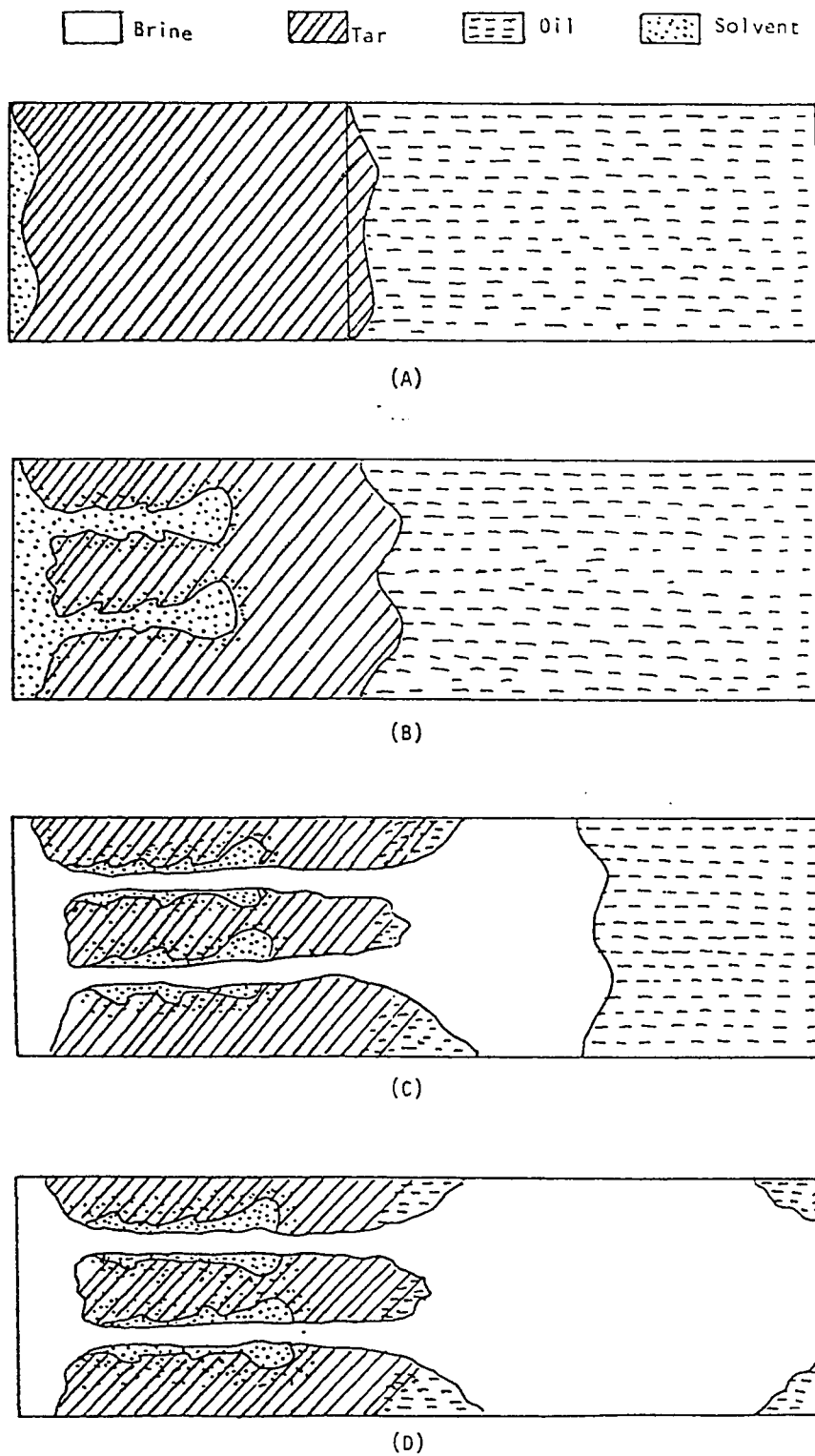


Figure 7.2: Distribution of fingering patterns in a tarmat reservoir model using small or medium solvent slug driven by hot water.

On the other hand, a larger solvent slug will cause more dilution of the tar contacted by solvent. This will lead to more encroachment of tar-solvent mixture into the oil zone and trapping of some oil inside the pores. Thus, using a large solvent slug will result in more mixing and formation of longer zone with high viscosity. Accordingly, the hot water will penetrate this long zone in the form of frontal displacement at highly unfavorable mobility ratio. Consequently, the diluted mixture driven by hot water will break through the oil zone and leave large area where lower hydrocarbon recovery is expected (Figure 7.3).

It should be stated that deposition of some heavy components (asphaltene and resins) will occur in some pores of the tar zone and in few pores of the oil zone contaminated with tar. Such deposition may cause plugging of some pores and trapping of oil inside especially when large solvent slug sizes are used. The contamination of oil zone by tar and spreading of tar over a large distance will increase the resistance to flow. Thus, when the fluids break through the tar zone the pressure gradient declines gradually, but starts to increase again due to contamination of oil zone by tar and plugging of some pores with asphaltene. Also, a pressure surge and fluctuation is expected due to the change of tar composition as a result of mixing and fluctuation of temperature. The experiments for different slug size in presence of hot water discussed in chapter VI show that for intermediary slug sizes, the recovery is higher than both small and large slug sizes.

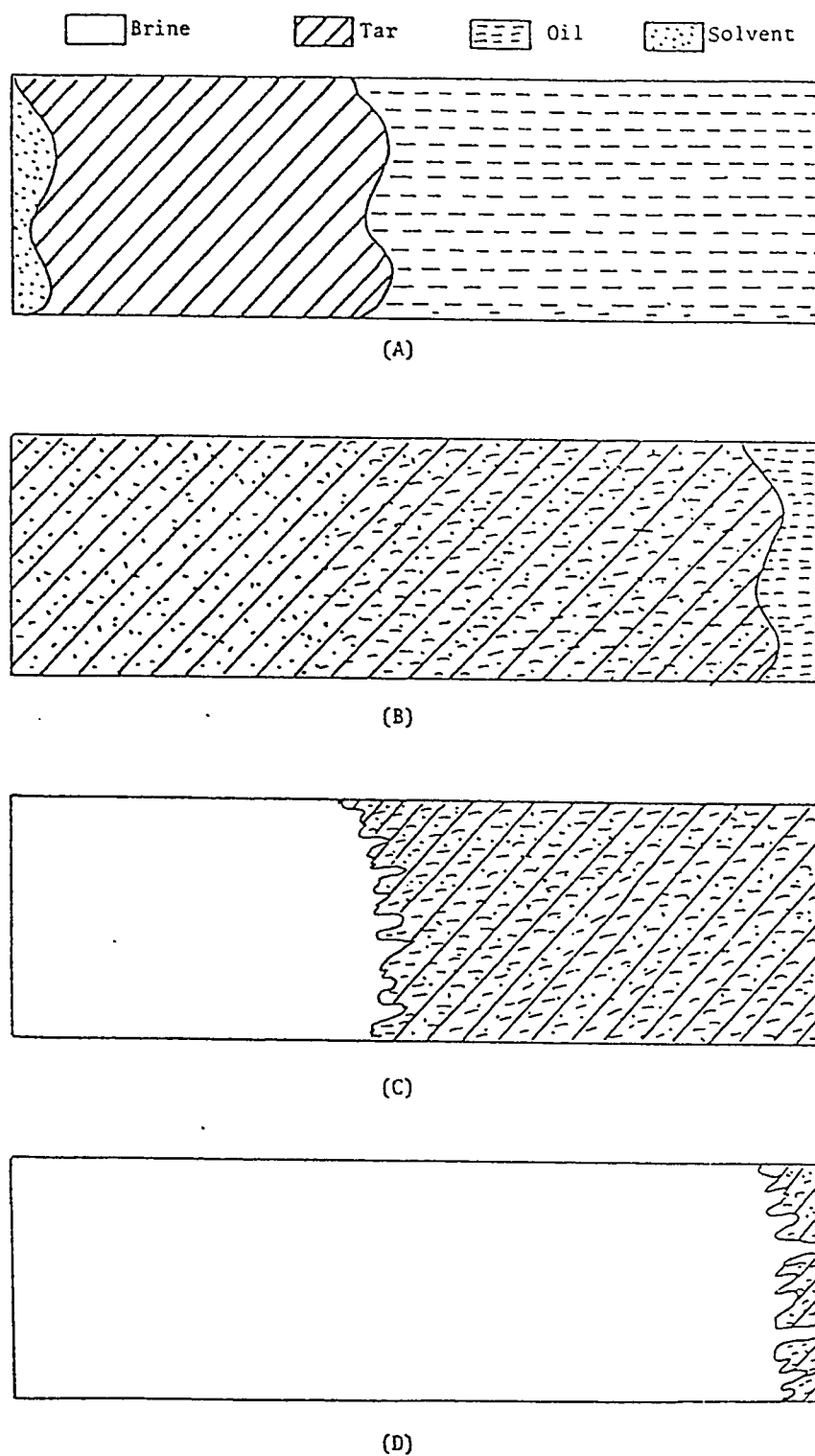


Figure 7.3: Distribution of fingering patterns in a tarmat reservoir model using large solvent slug driven by hot water.

The existence of an optimum solvent-slug size for which the recovery is maximum when solvent is combined with hot water to displace oil in a tar-mat system may be due to the following mechanisms:

(1) Mixing of fluids

Referring to Tables A-10, A-11, and A-12, (Appendix-A), and Figures 5.15, 5.16, and 5.17, it can be stated that as the fraction of solvent increases in a mixture of tar and solvent, the mixture viscosity decreases substantially. For example, when mixing tar with 10% reformat, the viscosity of tar was reduced by 90%. Thus, mixing takes place in the pores due to a large difference between solvent (reformat or naphtha) and tar viscosity. Furthermore, more mixing between solvent and tar tends to occur due to the presence of flow channels of varying size with frequent junctures between channels in a porous medium. This mixing phenomena will result in the creation of a viscosity transition zone ahead of the hot-water flow and hence will enhance the mobility ratio.

Many investigators discussed the mechanisms contributing to the mixing of miscible fluids (Blackwell, R.J., et.al., 1959, Habermann, B., 1960, and Stalkup, F.I., 1984). They stated that the degree of mixing between highly viscous oil and solvent results from interplay between the mechanisms of molecular diffusion and convective dispersion. Molecular diffusion is a result of random thermal motion of molecules which leads to more mixing in the direction of flow. Convective dispersion results from flow paths caused by rock inhomogeneities and permeability heterogeneities.

(2) Temperature Effects

The effect of temperature on oil recovery in tar-mat reservoirs is very important. The combined effects of temperature were discussed earlier in section 1.3.

At higher injection rates, the injected solvent and hot water will break through earlier than at lower rate. This will lead to lower recovery due to high oil saturation in the regions bypassed by viscous fingers. At the same time, more heat will be conducted at higher rates. This will result in a considerable reduction of tar viscosity and hence a decrease in the resistance to flow. Consequently, the pressure gradient levels become lower than similar ones at lower rate.

Actually, the results listed in Tables 6.2 and 6.3 show that the hydrocarbon recovery was higher for medium (optimum) slug and lower for small or large slug sizes. In addition, water breakthrough occurs earlier in the case of large slug sizes than small or medium sizes. Visual observation indicates that water breaks through the oil zone before the production of tar-solvent mixture for small or medium solvent slug sizes. On the other hand, a breakthrough of tar-solvent mixture was observed before production of water when large solvent slug sizes were used. These results and observations confirm the idea proposed by the model for large and small or medium slugs. Table 6.7 and Figure 6.10 indicate that the hydrocarbon recovery decreases as the injection rate increases due to faster propagation of fingers and earlier breakthrough.

Figures 6.19 and 6.20 show a typical pressure behavior when hot water was used to drive reformat and naphtha slugs respectively. These figures indicate a build up in pressure immediately after starting injection until the pressure reaches the peak value. Then, after water breaks through the tar zone, the pressure declines gradually. After that, the pressure starts to increase again as described by the model due to contamination of oil zone by tar and plugging of some pores as a result of asphaltene deposition. Moreover, the pressure surge and fluctuation are clearly shown. This is due to the change of tar composition through the composite core and fluctuation of the inlet temperature. The results listed in Table 6.13 confirm the decrease of peak pressure values as the injection rate increases. Table 6.16 indicates that water saturation in the tar zones in the case of runs using solvent slugs driven by hot water were higher than similar saturation obtained from runs where only hot or cold water were used. This supports the assumption that fingers width increases for runs using solvent slug driven by hot water due to mixing and heat effects.

The alternating injection of small slugs of solvent and hot water was tested. In this case, the solvent was divided into two equal portions (mode II), or four portions, (mode III), and separated by slugs of hot water. It is believed that such alternating injection reduces the fingering in miscible displacement. The first small solvent slug will result in creating a graded viscosity zone between tar and hot-water slug. Thus the mobility ratio between hot-water slug and tar is improved. Then, the second small solvent slug has the ability to invade new areas of the tar zone bypassed by viscous fingers of the first

slug. Consequently, another graded viscosity zone will be formed by a second solvent slug.

Therefore, the mobility ratios are improved as a result of a formation of successive transition zones. Furthermore, the hot-water slugs between solvent slugs will reduce the tar viscosity for the next solvent slugs which result in improving the miscibility. Thus, the less viscous fingers initiated in these modes (II and III) will delay the deterioration of the mixing zone and hence the width of fingers will increase more than in the case of mode I. This will result in improving the displacement efficiency and recovery.

It should be mentioned that the recovery with reformat is always higher than the recovery with naphtha. This may be due to the fact that the viscosity and density of reformat are lower than those of naphtha. Also, the compositions of each one of this solvent itself may have an effect on recovery.

It is expected that the pressure gradient level will be less and more stable in the case of alternating injection of small slugs of solvent and hot water than mode I. This may be due to dispersion of water fingers and a dissipation into small dendritic fingers when they enter the oil zone. Moreover, the formation of successive graded viscosity zones may support the pressure stabilization. Also, less contamination of oil zone by tar will enhance the stabilization of pressure gradient.

Tables 6.8 and 6.9 indicate that hydrocarbon recovery using reformat and naphtha are higher for modes II and III than similar ones obtained from

mode I. This confirms the enhancement of displacement efficiency for runs conducted with alternating injection of small slugs of solvent and hot water. Moreover, water saturation of far zones, for runs conducted with modes II and III, are higher than similar ones obtained from runs conducted with mode I. Hence, this is an indication of an increase of fingers size as a result of mixing and heat effects. On the other hand, higher injection rates cause earlier breakthrough and hence a decrease in hydrocarbon recovery. Tables 6.10 and 6.11 confirm the decrease of recovery at higher injection rates.

Figures 6.24 and C.14 (Appendix-C) are typical examples of pressure behavior applying mode III for reformat and naphtha respectively. These figures indicate quite stabilized pressure levels especially after hot water breaks through the far zone as described by the model.

To investigate the pressure behavior in the absence of a far zone, conventional hot and cold-water flooding runs were conducted. After starting injection, a rapid increase in the pressure gradient level with no pressure peak occurred. According to the model, the pressure gradient values are expected to be much less than those encountered with far zone. The pressure gradient trend is expected to decrease with continuous hot or cold water injection due to a decreasing resistance to flow. Since the mobility ratio between oil ahead of the displacement front and hot or cold water is much better than a similar one in the case of the presence of a tar layer, small viscous fingers, if initiated, will dampen out before travelling very far. The dampening mechanism is believed to occur due to movement of two phases in a

direction transverse to the direction of gross flow (Perkins, 1969). Thus, the displacement will be quite stable leading to a higher recovery.

At higher injection rates, the pressure gradient levels are expected to increase as dictated by Darcy's law. This behavior is contrary to the pressure behavior for runs with a tar layer in which the pressure gradient value levels decrease at higher rates. This is due to the fact that the tar viscosity is reduced faster than the light oil viscosity. Thus, at higher injection rates, large amounts of heat will be introduced into the tar zone and hence the resistance to flow will be reduced sharply and results in a lower pressure drop.

Figures 6.29 through 6.31 indicate the pressure behavior of runs conducted in the absence of tar zone. These figures show a rapid increase in the pressure gradient until it reaches steady-state level without a peak. Also, they show a decrease in pressure drop with continuous water injection due to a decreasing resistance to flow. Moreover, Tables 6.4 and 6.5 indicate that the pressure drop increases as the injection rate increases as stated by Darcy's law.

The previous results and discussion reveal that viscous fingering phenomenon is the most common feature in any EOR method for tar displacement. The fingers size and density are larger in the case of hot-water flooding than cold-water flooding. This leads to improvement in recovery. Furthermore, the fingers size will increase more when the optimum solvent slug is injected ahead of hot water due to mixing and heat conduction. Thus, higher

recovery is expected as a result of using solvent and hot-water flooding. In addition, the severity of fingers is reduced in the case of alternating injection of small slugs of solvent and hot water due to improvement in mobility ratios. This will result in enhancing the displacement efficiency and recovery over the case of injection of solvent slug as one portion driven by hot water. At higher injection rates, viscous fingers will propagate faster and lead to earlier breakthrough. Consequently, this will result in lower recovery.

Chapter VIII

SUMMARY, CONCLUSIONS, AND RECOMMENDATIONS

8.1 SUMMARY

The objective of this research was to investigate the hydrocarbon recovery from taromat reservoirs using hot water and solvent flooding. Displacement runs were conducted on one-foot long Berea sandstone composite cores. The average porosity and permeability of the cores were 23 % and 300 millidarcy. The tar and oil viscosities were 10,000 and 1.39 cp, respectively, at room temperature. The aqueous phase used was analytical grade water with 1 % KCL.

The first phase of the investigation involved the determination of the most suitable solvents for dissolving tar. Hence, solubility tests were conducted on many solvents to select the appropriate ones. Reformate and naphtha were found to be the most suitable solvents because they gave the lowest percentage of precipitated residue. Consequently, studies were made on the variations of viscosity and density with temperature and percentage of added solvents to tar for the determination of the rheology of tar and its mixtures. From the test results, the Newtonian behavior of the used tar and its mixtures became evident. The tar viscosity reduces dramatically as temperature and/

or solvent concentration increases. Additionally, the effect of temperature on the interfacial tension between tar and brine as well as between tar/solvent mixtures and brine was investigated. It was found that IFT between tar or tar-solvent mixtures or oil and brine decreases as the temperature increases.

The second phase of this work, was directed at studying the effect of temperature on relative permeability. The oleic phase consisted of 40 % reformat/60 % tar mixture while the aqueous phase was represented by water with 1 % KCL. The results showed that the relative permeability to oil increased as the temperature increased at any given saturation. The water-oil relative permeability ratio decreased and shifted toward a higher water saturation at a higher temperature. The change in relative permeability to water was not significant. Moreover, the residual oil saturation decreased while irreducible water saturation increased at higher temperature.

The third phase of the study involved an investigation of the effect of solvent slug size, type of solvent, and injection rate on hydrocarbon recovery. The observed fluid production histories were used for evaluating the proposed recovery mechanisms. It was found that solvent slug(s) injected ahead of hot water flooding improved hydrocarbon recovery as compared to a straight hot water flooding. The solvent, in view of the prevailing adverse mobility ratio, mixes with tar and helps to lower its viscosity leading to an improvement in the mobility ratio, and hence an improvement in the displacement efficiency. For each solvent studied, there was an optimum slug size which maximized the recovery. The hydrocarbon recovery was also found to

vary with injection rate. A higher injection rate caused a decrease in the recovery.

Different displacement modes were tested to investigate their effect on recovery. In the first injection mode, the solvent slug was injected as one portion ahead of hot water flooding. In the second mode, solvent slug was divided into two equal portions and separated by a slug of hot water (50 % of tar zone pore volume) and then followed by continuous hot water flooding. In the third mode, the slug was split into four equal portions and each portion was separated from the other by a slug of hot water (25 % tar zone pore volume) and then continuous hot water flooding. All slugs were of the optimum size. The results showed that injection of small alternating slugs of solvent and hot water (modes II and III) gave higher recoveries than injecting the slug as one portion (mode I).

8.2 CONCLUSIONS

The following conclusions have been made:

1. The oil recovery with hot-water flooding is substantially larger than that with cold-water flooding.
2. Reformate and naphtha are suitable solvents for tar dissolution and dispersion.
3. The injection of solvent slug(s) followed by hot-water flooding disperses the tar layer and establishes communication between oil zone and water zone.

4. Higher hydrocarbon recoveries are obtained with combined hot water and solvent flooding than with hot water alone.
5. For each type of solvent, there is an optimum slug size which maximizes the hydrocarbon recovery. Larger and smaller solvent slugs are less effective than the optimum slug.
6. Displacement results show that although the oil recovery from hot-water flooding is lower than cold-water flooding in the absence of tar, the gain in recovery from hot-water flooding is substantial in the presence of tarmat.
7. Hydrocarbon recovery increases as the injection rate decreases for all displacement schemes. In general, higher recoveries are obtained from the combined injection of solvent slugs and hot water than with injection of hot water alone.
8. The injection of small alternating slugs of solvent and hot water results in higher recovery than the injection of solvent slug as one portion followed by hot-water flooding.
9. The displacement pressure gradient decreases as the injection rate is increased in hot-water flooding.
10. Peak pressure required for tarmat breakdown using solvent slug(s) and hot-water flooding is less than that required when flooding with cold water.
11. Both injection modes II and III result in a lower pressure gradient than mode I at low injection rates.

12. Water and oil relative permeabilities were obtained experimentally at elevated temperatures. The results show that as the temperature increases, the irreducible water saturation increases, the residual oil saturation decreases, and the relative permeability to oil increases at any given saturation. Moreover, the water/oil relative permeability ratio decreases and shifts toward higher water saturation. The change in relative permeability to water is not significant.

8.3 RECOMMENDATIONS

The following recommendations are suggested for further research work to be conducted on tar mat reservoirs applying thermal-miscible method.

1. Investigation of recovery from tar mat reservoirs using radial flow model of consolidated rock matrix of limestone or sandstone (4 or 6 inches in diameter).
2. Studying the effect of viscosity of natural tar in addition to tar thickness on the recovery using radial flow model.
3. Analysis of the effluent productions to determine the percentage of components in the effluent (oil, tar, solvent, and possibly water).
4. Investigation of recovery under reservoir conditions of temperature and pressure.
5. Feasibility study of employing thermal-miscible technique.

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Appendix A
Physical Properties of Fluids and Rock
and Relative Permeability Results

Table A.1: Densities of Tar/Reformate Mixtures at Different Temperatures.

Temperature	Density (g/cc)			
(°C)	20 % Reformate	40 % Reformate	60 % Reformate	80 % Reformate
20	0.892	0.864	0.835	0.806
40	0.882	0.853	0.823	0.794
60	0.869	0.839	0.811	0.779
80	0.857	0.826	0.796	0.765
100	0.846	0.812	0.782	0.751
120	0.830	0.800	0.768	0.736

Table A.2: Densities of Tar/Naphtha Mixtures at Different Temperatures.

Temperature (° C)	Density (g/cc)			
	20 % Naphtha	40 % Naphtha	60 % Naphtha	80 % Naphtha
20	0.911	0.899	0.888	0.877
40	0.900	0.888	0.877	0.865
60	0.887	0.877	0.866	0.854
80	0.876	0.864	0.853	0.842
100	0.864	0.852	0.841	0.830
120	0.850	0.839	0.829	0.818

Table A.3: Densities of Tar/Kerosene Mixtures at Different Temperatures.

Temperature (° C)	Density (g/cc)			
	20 % Kerosene	40 % Kerosene	60 % Kerosene	80 % Kerosene
20	0.895	0.868	0.841	0.814
40	0.885	0.857	0.830	0.802
60	0.873	0.846	0.818	0.791
80	0.861	0.833	0.806	0.779
100	0.848	0.821	0.794	0.767
120	0.834	0.807	0.781	0.754

Table A.4: Measured and Predicted Densities of Tar/Reformate Mixtures at Different Temperatures.

Temperature	Density (g/cc)							
(° C)	20 % Reformate		40 % Reformate		60 % Reformate		80 % Reformate	
	Meas.	Pred. Error %	Meas.	Pred. Error %	Meas.	Pred. Error %	Meas.	Pred. Error %
20	0.892	0.893 -0.1	0.864	0.864 0.0	0.835	0.835 0.00	0.806	0.806 0.00
40	0.882	0.883 -0.1	0.853	0.853 0.0	0.823	0.824 -0.10	0.794	0.794 0.00
60	0.869	0.870 -0.1	0.839	0.840 -0.1	0.811	0.810 0.12	0.779	0.780 -0.13
80	0.857	0.857 0.0	0.826	0.827 -0.1	0.796	0.796 0.00	0.765	0.766 -0.10
100	0.846	0.844 0.2	0.812	0.813 -0.1	0.782	0.783 -0.10	0.751	0.752 -0.10
120	0.830	0.830 0.0	0.800	0.799 0.13	0.768	0.768 0.00	0.736	0.738 -0.27

Table A.5: Measured and Predicted Densities of Tar/Naphtha Mixtures at Different Temperatures.

Temperature	Density (g/cc)											
(° C)	20 % Naphtha			40 % Naphtha			60 % Naphtha			80 % Naphtha		
	Meas.	Pred.	Error	Meas.	Pred.	Error	Meas.	Pred.	Error	Meas.	Pred.	Error
	%			%			%			%		
20	0.911	0.911	0.00	0.899	0.899	0.00	0.888	0.884	0.47	0.877	0.877	0.00
40	0.900	0.900	0.00	0.888	0.889	-0.10	0.877	0.877	0.00	0.865	0.866	-0.12
60	0.887	0.889	-0.23	0.877	0.877	0.00	0.866	0.866	0.00	0.854	0.854	0.00
80	0.876	0.876	0.00	0.864	0.865	0.00	0.853	0.853	0.00	0.842	0.842	0.00
100	0.864	0.864	0.00	0.852	0.853	-0.12	0.841	0.841	0.00	0.830	0.830	0.00
120	0.850	0.850	0.00	0.839	0.839	0.00	0.829	0.829	0.00	0.818	0.818	0.00

Table A.7: Shear Stress vs. Shear Rate for 40 % Reformate/60 % Tar
Mixture at Different Temperatures.

Shear Rate (1/s)	Shear Stress, Dyne/cm ²					
	20 °C	40 °C	60 °C	80 °C	100 °C	120 °C
5.49	0.75	0.42				
7.46	0.99	0.57				
10.15	1.35	0.75	0.48			
13.79	1.83	1.02	0.66	0.45	0.33	
18.74	2.46	1.41	0.90	0.60	0.48	0.36
25.50	3.39	1.92	1.23	0.84	0.63	0.48
34.60	4.59	2.58	1.68	1.14	0.87	0.66
47.10	6.24	3.54	2.28	1.56	1.17	0.90
63.90	8.49	4.80	3.12	2.09	1.59	1.20
87.00	11.58	6.54	4.25	2.85	2.19	1.65

Table A.8: Shear Stress vs. Shear Rate for 40 % Naphtha/60 % Tar

Mixture at Different Temperatures.

Shear Rate (1/s)	Shear Stress, Dyne/cm ²					
	20 °C	40 °C	60 °C	80 °C	100 °C	120 °C
5.49	0.54	0.36				
7.46	0.75	0.48	0.27			
10.15	1.02	0.66	0.36	0.24		
13.79	1.38	0.87	0.48	0.53	0.24	
18.74	1.89	1.20	0.66	0.45	0.33	0.24
25.50	2.58	1.62	0.90	0.60	0.45	0.33
34.90	3.48	2.22	1.20	0.84	0.60	0.42
47.10	4.77	3.00	1.65	1.14	0.81	0.57
63.90	6.45	4.08	2.25	1.53	1.11	0.78
87.00	8.79	5.58	3.05	2.10	1.50	1.08

Table A.9: Shear Stress vs. Shear Rate for 40 % Kerosene/60 % Tar
Mixture at Different Temperatures.

Shear Rate (1/s)	Shear Stress, Dyne/cm ²					
	20 °C	40 °C	60 °C	80 °C	100 °C	120 °C
5.49	1.68	0.84	0.39	0.24		
7.46	2.28	1.14	0.54	0.30		
10.15	3.12	1.53	0.72	0.42		
13.79	4.21	2.07	0.99	0.60	0.45	
18.74	5.73	2.82	1.32	0.81	0.60	0.42
25.50	7.78	3.84	1.80	1.10	0.81	0.57
34.90	10.59	5.22	2.40	1.50	1.11	0.78
47.10	14.40	7.11	3.34	2.00	1.50	1.08
63.90	19.60	9.66	4.53	2.70	2.04	1.47
87.00	26.53	13.14	6.18	3.70	2.79	2.00

Table A.10: Dynamic and Kinematic Viscosities of Tar/Reformat Mixtures
at Different Temperatures.

Temperature (° C)	Viscosity					
	20 % Reformat		40 % Reformat		60 % Reformat	
	cp	cSt	cp	cSt	cp	cSt
20	138.0	154.70	13.30	15.39	3.00	3.60
40	49.0	55.60	7.52	8.80	2.38	2.89
60	22.0	25.30	4.84	5.80	1.75	2.16
80	10.3	12.00	3.27	3.90	1.40	1.76
100	6.4	7.60	2.50	3.10	1.18	1.51
120	4.2	5.06	1.91	2.40	1.00	1.30
					0.57	0.77
					0.63	0.84
					0.70	0.92
					0.79	1.01
					0.96	1.21
					1.10	1.36

Table A.11: Dynamic and Kinematic Viscosities of Tar/Naphtha Mixtures
at Different Temperatures.

Temperature (° C)	Viscosity					
	20 % Naphtha		40 % Naphtha		60 % Naphtha	
	cp	cSt	cp	cSt	cp	cSt
20	86.31	94.74	10.10	11.23	2.93	3.30
40	36.20	40.22	6.42	7.23	2.20	2.51
60	14.92	16.82	3.50	3.99	1.45	1.67
80	7.77	8.87	2.39	2.76	1.08	1.27
100	5.00	5.79	1.74	2.04	0.87	1.03
120	3.02	3.55	1.24	1.48	0.67	0.81
					1.35	1.54
					1.08	1.25
					0.77	0.90
					0.61	0.72
					0.52	0.63
					0.43	0.53

Table A.12: Dynamic and Kinematic Viscosities of Tar/Kerosene Mixtures
at Different Temperatures.

Temperature (° C)	Viscosity					
	20 % Kerosene		40 % Kerosene		60 % Kerosene	
	cp	cSt	cp	cSt	cp	cSt
20	255.50	285.00	30.60	35.25	7.77	9.24
40	78.20	88.36	15.10	17.62	5.10	6.14
60	25.32	29.00	7.10	8.39	2.60	3.18
80	12.24	14.22	4.30	5.16	1.96	2.43
100	7.63	8.99	3.23	3.93	1.58	1.99
120	4.74	5.68	2.30	2.85	1.28	1.64
					2.88	3.54
					2.04	2.54
					1.20	1.52
					1.00	1.28
					0.87	1.13
					0.77	1.02

Table A.13: Interfacial Tensions of Tar/Reformate Mixtures Against
Brine at Different Temperatures.

20 % Reformate		40 % Reformate		60 % Reformate		80 % Reformate	
Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)
22.0	17.60	22.0	19.44	22.0	20.30	22.0	21.23
35.0	15.85	30.1	17.78	35.1	18.90	30.0	20.44
52.1	13.05	46.7	16.64	52.8	17.70	42.1	19.25
64.6	12.25	55.1	15.73	63.2	16.42	59.8	17.39
75.0	10.69	76.3	14.12	74.4	15.06	71.0	15.85
83.5	10.10	83.4	13.63	83.1	14.58	83.2	14.98

Table A.14: Interfacial Tensions of Tar/Naphtha Mixtures Against Brine at Different Temperatures.

20 % Naphtha		40 % Naphtha		60 % Naphtha		80 % Naphtha	
Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)
22.0	19.37	22.0	20.76	22.0	22.89	22.0	23.79
35.2	17.04	30.1	19.02	35.3	21.92	30.1	22.53
52.3	13.96	46.7	17.61	52.6	19.22	42.1	21.17
64.7	13.25	55.1	16.89	63.6	18.30	59.9	19.33
75.1	11.65	76.3	15.06	74.6	17.09	71.1	18.22
83.4	10.57	83.4	14.56	83.1	16.29	83.4	17.12

Table A.15: Interfacial Tensions of Tar/Kerosene Mixtures Against

Brine at Different Temperatures.

20 % Kerosene		40 % Kerosene		60 % Kerosene		80 % Kerosene	
Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)	Temperature (° C)	IFT (mN/m)
22.0	20.19	22.0	22.46	22.0	23.23	22.0	23.94
41.4	18.19	30.1	21.01	30.2	21.51	30.2	22.55
50.1	16.56	40.0	19.38	45.5	18.91	42.4	21.44
60.5	14.44	51.0	17.27	50.0	17.92	51.8	19.67
72.0	13.05	61.2	15.39	61.2	16.35	62.7	19.17
84.4	10.89	72.3	13.52	70.1	14.50	72.3	17.51
		85.8	11.10	85.3	12.76	85.6	15.96

Table A.16: Experimental Data for Run# 33.

$U_w=0.975$ cp $U_o=12.8$ cp DPI=72 psi
 $QWI=72$ cc/hr $Swc=0.286$ VP= 10.648 cc
 $T=25$ °C

WI	Np	DP	QW
cc	cc	psi	cc/hr
3.39	3.24	74	68
4.34	3.34	68	65
5.27	3.44	67.5	63
6.19	3.54	66.5	60
7.21	3.59	66.5	60
8.23	3.64	66	60
9.26	3.68	66	60
10.30	3.72	66	60
11.35	3.75	66	60
12.4	3.78	66	60
13.46	3.80	66	60
14.49	3.82	66	60
15.53	3.84	66	60
16.59	3.86	66	60
17.66	3.87	66	60
18.66	3.87	66	60

Table A.17: Experimental Data for Run# 34.

$U_w=0.63$ cp $U_o=4.84$ cp DPI=18 psi
 $Q_{WI}=70$ cc/hr $S_{wc}=0.327$ VP= 11.42 cc
 $T=60$ °C

WI	Np	DP	QW
cc	cc	psi	cc/hr
3.40	3.26	14.4	68
4.20	3.41	14.4	63
5.10	3.57	14.3	61
6.00	3.69	14.1	60
7.00	3.77	13.9	60
8.02	3.84	13.8	60
9.03	3.90	13.6	60
10.03	3.95	13.3	60
11.05	3.99	13.1	60
12.05	4.03	13.0	60
13.06	4.07	12.9	60
14.07	4.12	12.8	60
15.07	4.13	12.7	60
16.09	4.16	12.6	60
17.10	4.18	12.4	60
18.10	4.20	12.3	60
19.1	4.2	12.1	60

Table A.18: Experimental Data for Run# 35.

$U_w=0.56$ cp $U_o=3.27$ cp DPI=15.8 psi
 $Q_{WI}=66$ cc/hr $Swc=0.343$ VP= 11.12 cc
 $T=80$ °C

WI	Np	DP	QW
cc	cc	psi	cc/hr
3.51	3.38	15.8	70
4.11	3.68	16.3	62
5.01	3.88	16.6	60
6.01	4.08	16.7	60
7.02	4.15	16.6	60
8.03	4.21	16.4	60
9.05	4.26	16.3	60
10.06	4.31	16.0	60
11.06	4.35	15.9	60
12.06	4.39	15.8	60
13.07	4.43	15.7	60
14.07	4.45	15.6	60
15.07	4.47	15.4	60
16.09	4.49	15.4	60
17.09	4.51	15.3	60
18.09	4.52	15.2	60
19.09	4.52	15.1	60

Table A.19: Experimental Data for Run# 36.

$U_w=0.54$ cp $U_o=2.50$ cp DPI=32.5 psi
 $Q_w=72$ cc/hr $S_{wc}=0.367$ VP= 10.897 cc
 $T=100$ °C

WI	Np	DP	QW
cc	cc	psi	cc/hr
3.52	3.40	33.5	70
4.13	3.80	35.0	62
5.03	4.00	35.0	60
6.03	4.20	35.0	60
7.04	4.30	34.5	60
8.06	4.40	34.5	60
9.06	4.45	34.5	60
10.07	4.48	34.0	60
11.09	4.52	34.0	60
12.10	4.56	34.0	60
13.10	4.59	33.0	60
14.10	4.60	33.0	60
15.11	4.61	33.0	60
16.13	4.62	32.5	60
17.14	4.63	32.5	60
18.14	4.64	32.0	60

Table A.20: Water/Oil Relative Permeability Data
for Run# 33, T=25 °C.

Sw	Kro	Krw	Fw	Krw/Kro
0.2860	1.0000	0.0000	0.0000	
0.5370	0.2588	0.1008	0.8364	0.3894
0.5539	0.1805	0.1045	0.8837	0.5786
0.5665	0.1353	0.1063	0.9116	0.7856
0.5763	0.1061	0.1074	0.9300	1.0117
0.5852	0.0839	0.1080	0.9441	1.2877
0.5925	0.0682	0.1084	0.9543	1.5909
0.5988	0.0564	0.1087	0.9620	1.9260
0.6042	0.0474	0.1089	0.9679	2.2952
0.6090	0.0403	0.1089	0.9726	2.7010
0.6132	0.0347	0.1090	0.9763	3.1422
0.6169	0.0301	0.1090	0.9794	3.6257
0.6202	0.0264	0.1091	0.9819	4.1347
0.6231	0.0233	0.1091	0.9840	4.6908
0.6259	0.0206	0.1091	0.9858	5.3045
0.6284	0.0183	0.1091	0.9874	5.9759
0.6306	0.0164	0.1091	0.9887	6.6546

Table A.21: Water/Oil Relative Permeability Data
for Run# 34, T=60 °C.

Sw	Kro	Krw	Fw	Krw/Kro
0.3270	1.0000	0.0000	0.0000	
0.5477	0.3299	0.1392	0.7642	0.4219
0.5679	0.2257	0.1374	0.8238	0.6087
0.5854	0.1603	0.1349	0.8661	0.8416
0.5993	0.1208	0.1327	0.8941	1.0986
0.6118	0.0926	0.1308	0.9156	1.4127
0.6223	0.0733	0.1295	0.9313	1.7652
0.6311	0.0599	0.1285	0.9428	2.1473
0.6386	0.0500	0.1279	0.9516	2.5595
0.6452	0.0423	0.1276	0.9586	3.0166
0.6510	0.0364	0.1275	0.9642	3.5026
0.6561	0.0316	0.1276	0.9687	4.0341
0.6607	0.0277	0.1278	0.9725	4.6089
0.6648	0.0245	0.1282	0.9757	5.2239
0.6687	0.0218	0.1286	0.9784	5.9015
0.6721	0.0195	0.1291	0.9807	6.6264
0.6752	0.0175	0.1297	0.9827	7.4014
0.6781	0.0158	0.1304	0.9844	8.2381

Table A.22: Water/Oil Relative Permeability Data
for Run# 35, $T=80^{\circ}\text{C}$.

Sw	Kro	Krw	Fw	Krw/Kro
0.3430	1.0000	0.0000	0.0000	
0.5457	0.4729	0.1549	0.6567	0.3276
0.5719	0.3287	0.1550	0.7335	0.4715
0.6026	0.2090	0.1515	0.8089	0.7251
0.6286	0.1376	0.1469	0.8618	1.0682
0.6492	0.0957	0.1429	0.8971	1.4935
0.6658	0.0692	0.1396	0.9217	2.0168
0.6796	0.0513	0.1370	0.9398	2.6716
0.6910	0.0388	0.1350	0.9531	3.4829
0.7007	0.0297	0.1336	0.9633	4.5004
0.7091	0.0228	0.1325	0.9714	5.8129
0.7164	0.0174	0.1317	0.9779	7.5710
0.7228	0.0132	0.1312	0.9831	9.9642
0.7284	0.0098	0.1309	0.9874	13.4192
0.7335	0.0069	0.1308	0.9910	18.9283
0.7379	0.0046	0.1308	0.9940	28.4491
0.7419	0.0027	0.1310	0.9965	49.2846
0.7455	0.0010	0.1313	0.9987	129.7938

Table A.23: Water/Oil Relative Permeability Data
for Run# 36, T=100 °C.

Sw	Kro	Krw	Fw	Krw/Kro
0.3670	1.0000	0.0000	0.0000	
0.5527	0.5060	0.1514	0.5807	0.2992
0.5874	0.3471	0.1594	0.6802	0.4593
0.6271	0.2174	0.1621	0.7754	0.7456
0.6606	0.1400	0.1609	0.8418	1.1492
0.6869	0.0947	0.1586	0.8858	1.6755
0.7081	0.0659	0.1563	0.9165	2.3717
0.7251	0.0470	0.1544	0.9383	3.2824
0.7394	0.0336	0.1528	0.9546	4.5442
0.7516	0.0238	0.1515	0.9672	6.3756
0.7620	0.0164	0.1506	0.9769	9.1547
0.7708	0.0109	0.1499	0.9846	13.7964
0.7784	0.0065	0.1495	0.9907	23.0998
0.7852	0.0029	0.1493	0.9958	51.1341

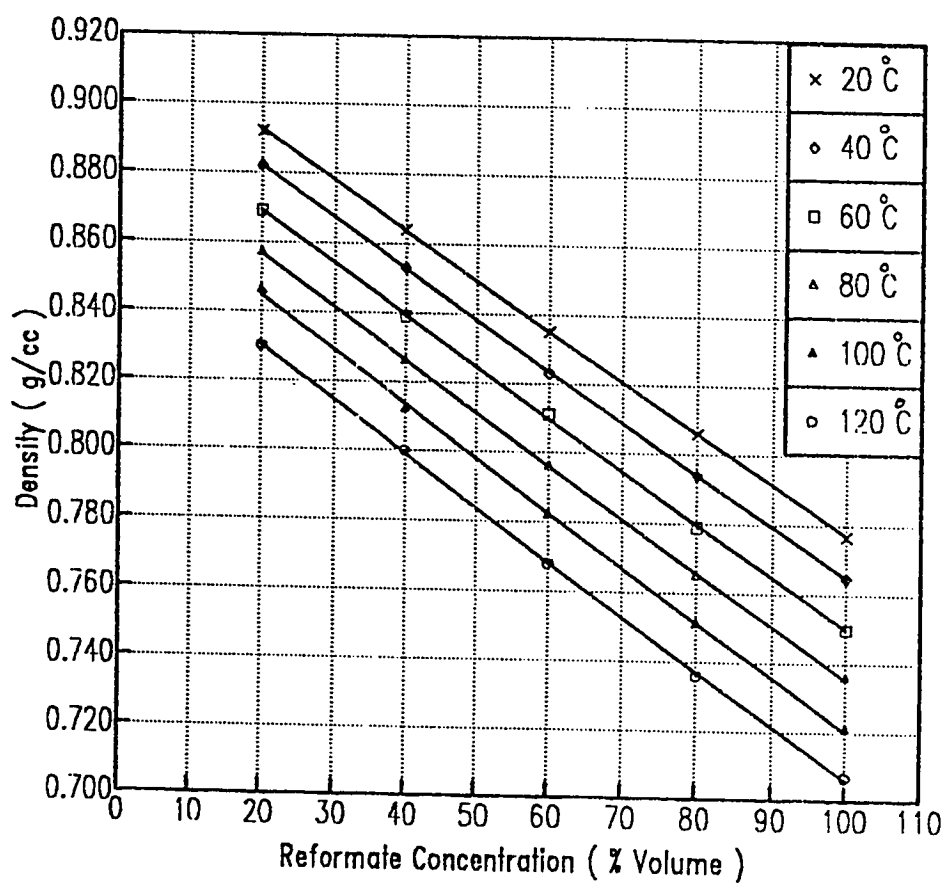


Figure A.1: Tar/reformate mixture density vs. reformate concentration at different temperatures.

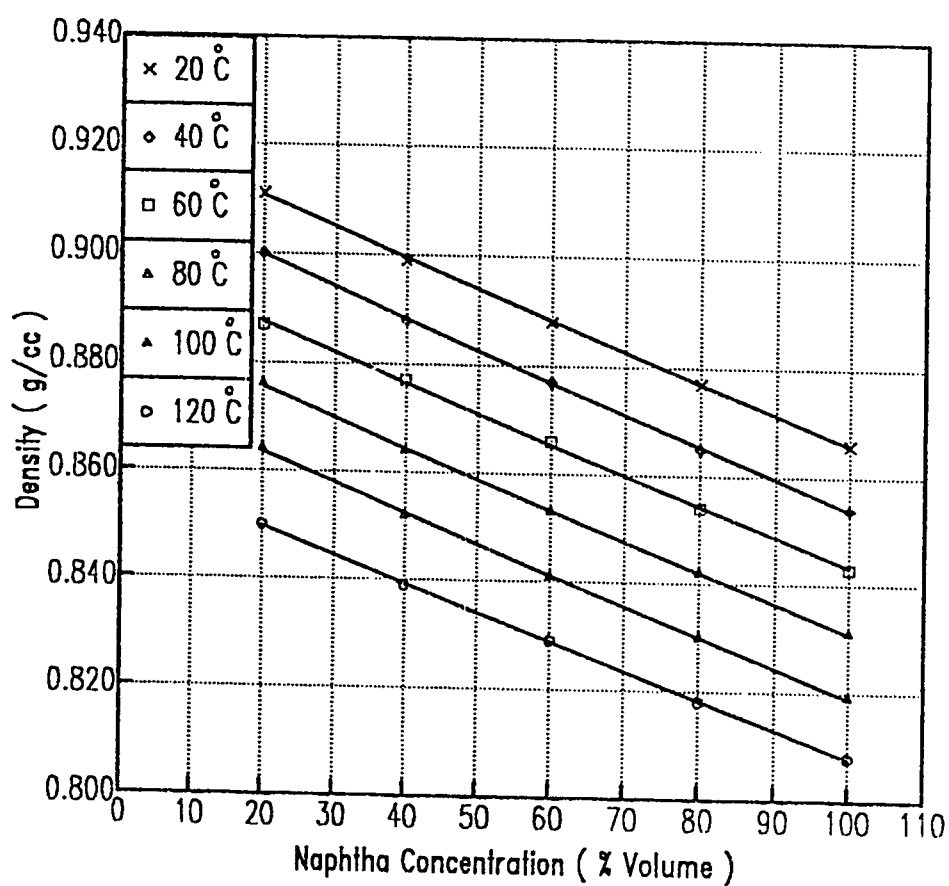


Figure A.2: Tar/naphtha mixture density vs. naphtha concentration at different temperatures.

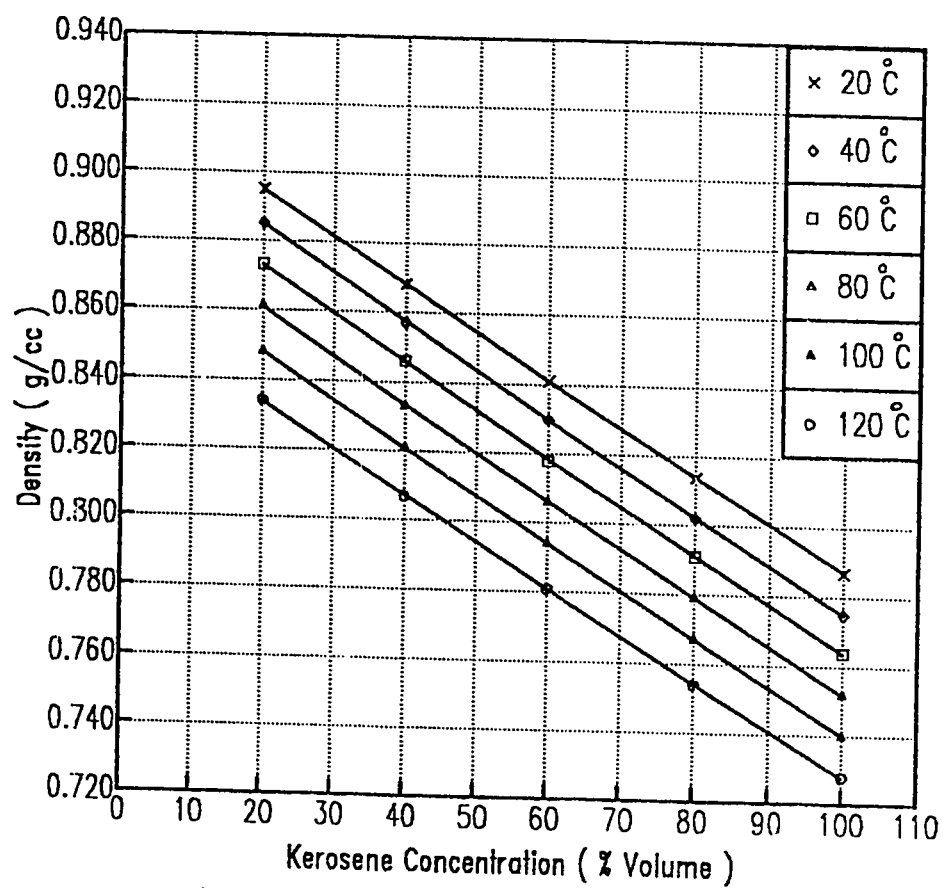


Figure A.3: Tar/kerosene mixture density vs. kerosene concentration at different temperatures.

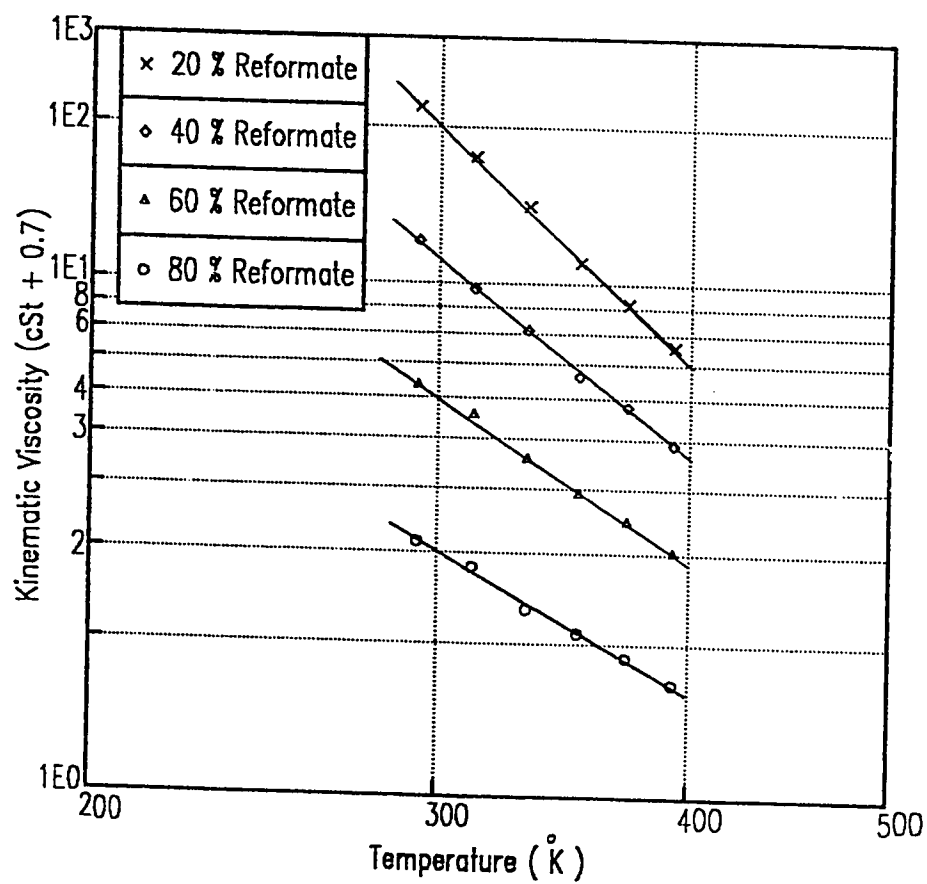


Figure A.4: Kinematic viscosity vs. temperature for tar/reformate mixtures.

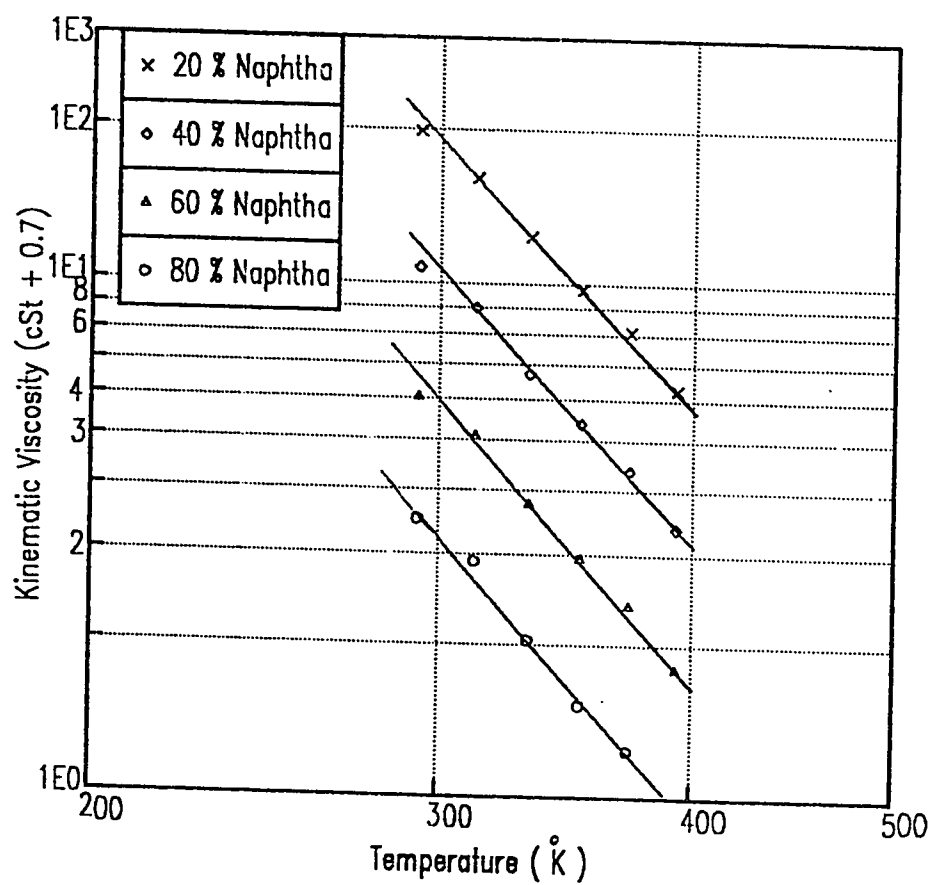


Figure A.5: Kinematic viscosity vs. temperature for tar/naphtha mixtures.

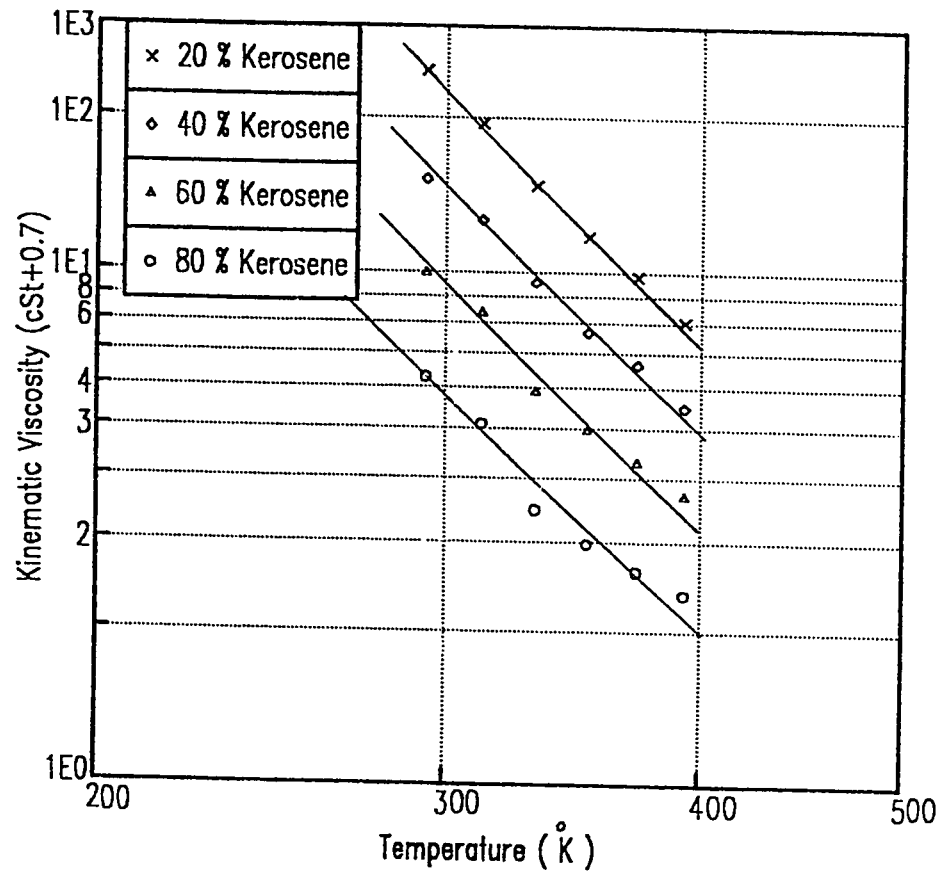


Figure A.6: Kinematic viscosity vs. temperature for tar/kerosene mixtures.

Appendix B

Experimental Data and Results for Flood Runs

In this appendix, the experimental data and results are presented. The abbreviations used in the tables are as follows:

N_p = cumulative hydrocarbon produced, cc

W_p = cumulative water produced, cc

W_i = cumulative water injected, cc

$$= (N_p + W_p). \text{ cc}$$

THPV = total hydrocarbon pore volume, cc

Q_{iw} = water injected in total hydrocarbon pore volumes

$$= \frac{W_i}{THPV}$$

F_w = water cut

$$= \frac{\Delta W_p}{\Delta W_p + \Delta N_p}$$

R_t = cumulative hydrocarbon recovery, %(THPV)

$$= \frac{N_p}{THPV} \times 100$$

P = Inlet pressure, psi

T = Inlet temperature, °C

Table B.1 : Raw and Computed Results for Run # 1
(Cold Water With Tar, No Solvent, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	14	20
2	0.00	0.00	0.00	0.00	0.00	0.00	19	20
3	0.00	0.00	0.00	0.00	0.00	0.00	25	20
4	0.00	0.00	0.00	0.00	0.00	0.00	31	20
5	0.00	0.00	0.00	0.00	0.00	0.00	42	20
6	0.00	0.00	0.00	0.00	0.00	0.00	73	20
7	0.00	0.00	0.00	0.00	0.00	0.00	128	20
8	0.00	0.00	0.00	0.00	0.00	0.00	225	20
9	0.10	0.00	0.10	0.00	0.00	0.33	375	20
10	0.20	0.00	0.20	0.01	0.00	0.67	510	20
11	0.40	0.00	0.40	0.01	0.00	1.34	575	20
12	1.10	0.00	1.10	0.04	0.00	3.67	640	20
13	2.10	0.00	2.10	0.07	0.00	7.01	685	20
14	3.30	0.00	3.30	0.11	0.00	11.02	710	20
15	4.50	0.00	4.50	0.15	0.00	15.03	720	20
16	5.80	0.00	5.80	0.19	0.00	19.37	725	20
17	7.10	0.00	7.10	0.24	0.00	23.72	718	20
18	8.30	0.00	8.30	0.28	0.00	27.73	700	20
19	9.50	0.00	9.50	0.32	0.00	31.73	685	20
20	10.50	0.00	10.50	0.35	0.00	35.07	670	20
21	11.30	0.00	11.30	0.38	0.00	37.75	660	20
22	12.00	0.40	12.40	0.41	0.36	40.09	640	20
23	12.00	1.50	13.50	0.45	1.00	40.09	632	20
24	12.00	2.70	14.70	0.49	1.00	40.09	628	20
25	12.00	4.10	16.10	0.54	1.00	40.09	615	20
26	12.00	5.30	17.30	0.58	1.00	40.09	610	20
27	12.00	6.40	18.40	0.61	1.00	40.09	612	20
28	12.00	7.60	19.60	0.65	1.00	40.09	609	20
29	12.00	9.00	21.00	0.70	1.00	40.09	610	20
30	12.00	10.20	22.20	0.74	1.00	40.09	608	20
31	12.00	11.40	23.40	0.78	1.00	40.09	610	20
32	12.00	12.60	24.60	0.82	1.00	40.09	610	20
33	12.00	13.80	25.80	0.86	1.00	40.09	608	20
34	12.00	15.00	27.00	0.90	1.00	40.09	604	20
35	12.00	16.20	28.20	0.94	1.00	40.09	600	20
36	12.00	17.40	29.40	0.98	1.00	40.09	608	20
37	12.00	18.50	30.50	1.02	1.00	40.09	608	20
38	12.00	19.60	31.60	1.06	1.00	40.09	598	20
39	12.00	20.80	32.80	1.10	1.00	40.09	600	20
40	12.00	22.00	34.00	1.14	1.00	40.09	609	20

Table B.1 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	12.00	23.20	35.20	1.18	1.00	40.09	612	20
42	12.00	24.40	36.40	1.22	1.00	40.09	610	20
43	12.00	25.70	37.70	1.26	1.00	40.09	600	20
44	12.00	26.90	38.90	1.30	1.00	40.09	610	20
45	12.00	28.00	40.00	1.34	1.00	40.09	620	20
46	12.00	29.10	41.10	1.37	1.00	40.09	602	20
47	12.00	30.30	42.30	1.41	1.00	40.09	612	20
48	12.00	31.50	43.50	1.45	1.00	40.09	608	20
49	12.00	33.30	45.30	1.51	1.00	40.09	625	20
50	12.00	34.60	46.60	1.56	1.00	40.09	623	20
51	12.00	35.90	47.90	1.60	1.00	40.09	622	20
52	12.00	37.10	49.10	1.64	1.00	40.09	610	20
53	12.00	38.30	50.30	1.68	1.00	40.09	630	20
55	12.00	39.50	51.50	1.72	1.00	40.09	627	20
56	12.00	40.70	52.70	1.76	1.00	40.09	638	20
57	12.00	42.00	54.00	1.80	1.00	40.09	635	20
58	12.00	43.20	55.20	1.84	1.00	40.09	638	20
59	12.00	44.40	56.40	1.88	1.00	40.09	636	20
60	12.00	45.60	57.60	1.92	1.00	40.09	638	20
61	12.00	46.60	58.60	1.96	1.00	40.09	650	20
62	12.00	47.70	59.70	1.99	1.00	40.09	630	20
63	12.00	48.70	60.70	2.03	1.00	40.09	620	20
64	12.00	49.90	61.90	2.07	1.00	40.09	630	20
65	12.00	51.10	63.10	2.11	1.00	40.09	632	20
66	12.00	52.30	64.30	2.15	1.00	40.09	648	20
67	12.00	53.40	65.40	2.18	1.00	40.09	660	20
68	12.00	54.50	66.50	2.22	1.00	40.09	652	20
69	12.00	55.70	67.70	2.26	1.00	40.09	632	20
70	12.00	56.90	68.90	2.30	1.00	40.09	640	20
71	12.00	58.00	70.00	2.34	1.00	40.09	667	20
72	12.00	59.00	71.00	2.37	1.00	40.09	665	20

Table B.2 : Raw and Computed Results for Run # 2
(Hot Water With Tar, No Solvent, Q=1 cc/min).

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Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	$^{\circ}\text{C}$
1	0.00	0.00	0.00	0.00	0.00	0.00	21	92
2	0.00	0.00	0.00	0.00	0.00	0.00	270	89
3	0.00	0.00	0.00	0.00	0.00	0.00	340	90
4	0.00	0.00	0.00	0.00	0.00	0.00	470	88
5	0.00	0.00	0.00	0.00	0.00	0.00	630	92
6	0.00	0.00	0.00	0.00	0.00	0.00	700	93
7	0.00	0.00	0.00	0.00	0.00	0.00	890	90
8	0.00	0.00	0.00	0.00	0.00	0.00	1010	89
9	0.30	0.00	0.30	0.01	0.00	0.88	860	89
10	0.80	0.00	0.80	0.02	0.00	2.35	900	87
11	1.70	0.00	1.70	0.05	0.00	4.99	640	88
12	2.70	0.00	2.70	0.08	0.00	7.93	630	89
13	4.00	0.00	4.00	0.12	0.00	11.74	700	91
14	5.30	0.00	5.30	0.16	0.00	15.56	840	104
15	6.50	0.00	6.50	0.19	0.00	19.09	890	101
16	7.60	0.00	7.60	0.22	0.00	22.31	890	99
17	8.90	0.00	8.90	0.26	0.00	26.13	900	98
18	10.30	0.00	10.30	0.30	0.00	30.24	910	98
19	11.70	0.00	11.70	0.34	0.00	34.35	900	98
20	13.10	0.00	13.10	0.38	0.00	38.46	890	96
21	14.20	0.00	14.20	0.42	0.00	41.69	880	94
22	15.20	0.00	15.20	0.45	0.00	44.63	870	93
23	16.00	0.00	16.00	0.47	0.00	46.98	860	91
24	16.50	0.00	16.50	0.48	0.00	48.45	850	89
25	16.70	0.00	16.70	0.49	0.00	49.03	1200	88
26	16.90	0.50	17.40	0.51	0.71	49.62	1080	86
27	17.00	2.30	19.30	0.57	0.95	49.91	750	94
28	17.00	3.30	20.30	0.60	1.00	49.91	750	94
29	17.00	4.30	21.30	0.63	1.00	49.91	560	108
30	17.00	5.10	22.10	0.65	1.00	49.91	570	104
31	17.00	6.10	23.10	0.68	1.00	49.91	520	110
32	17.00	7.20	24.20	0.71	1.00	49.91	600	100
33	17.00	8.40	25.40	0.75	1.00	49.91	690	98
34	17.00	9.80	26.80	0.79	1.00	49.91	720	96
35	17.00	11.10	28.10	0.83	1.00	49.91	730	94
36	17.00	12.50	29.50	0.87	1.00	49.91	740	92
37	17.00	13.90	30.90	0.91	1.00	49.91	740	89
38	17.00	15.70	32.70	0.96	1.00	49.91	730	88
39	17.00	17.70	34.70	1.02	1.00	49.91	730	88
40	17.00	19.50	36.50	1.07	1.00	49.91	880	90

Table B.2 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	17.00	20.80	37.80	1.11	1.00	49.91	940	88
42	17.00	21.80	38.80	1.14	1.00	49.91	1050	86
43	17.00	22.80	39.80	1.17	1.00	49.91	800	105
44	17.00	23.80	40.80	1.20	1.00	49.91	520	110
45	17.00	24.80	41.80	1.23	1.00	49.91	530	96
46	17.00	26.00	43.00	1.26	1.00	49.91	480	95
47	17.00	27.20	44.20	1.30	1.00	49.91	520	93
48	17.00	28.50	45.50	1.34	1.00	49.91	600	91
49	17.00	29.70	46.70	1.37	1.00	49.91	650	88
50	17.00	31.00	48.00	1.41	1.00	49.91	670	87
51	17.00	32.40	49.40	1.45	1.00	49.91	690	88
52	17.00	33.80	50.80	1.49	1.00	49.91	700	90
53	17.00	35.80	52.80	1.55	1.00	49.91	700	98
55	17.00	37.80	54.80	1.61	1.00	49.91	700	100
56	17.00	39.30	56.30	1.65	1.00	49.91	770	104
57	17.00	40.50	57.50	1.69	1.00	49.91	1050	98
58	17.00	41.50	58.50	1.72	1.00	49.91	980	96
59	17.00	42.50	59.50	1.75	1.00	49.91	680	105
60	17.00	43.50	60.50	1.78	1.00	49.91	540	92
61	17.00	44.60	61.60	1.81	1.00	49.91	510	94
62	17.00	45.60	62.60	1.84	1.00	49.91	470	94
63	17.00	46.90	63.90	1.88	1.00	49.91	510	92
64	17.00	48.10	65.10	1.91	1.00	49.91	590	91
65	17.00	49.50	66.50	1.95	1.00	49.91	630	88

Table B.3 : Raw and Computed Results for Run# 3

(Hot Water With Solvent Slug=5.84 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	7	79
2	0.00	0.00	0.00	0.00	0.00	0.00	10	108
3	0.00	0.00	0.00	0.00	0.00	0.00	44	101
4	0.00	0.00	0.00	0.00	0.00	0.00	74	146
5	0.00	0.00	0.00	0.00	0.00	0.00	93	160
6	0.00	0.00	0.00	0.00	0.00	0.00	101	144
7	0.00	0.00	0.00	0.00	0.00	0.00	126	134
8	0.00	0.00	0.00	0.00	0.00	0.00	470	131
9	0.00	0.00	0.00	0.00	0.00	0.00	595	126
10	0.60	0.00	0.60	0.02	0.00	1.83	430	125
11	1.40	0.00	1.40	0.04	0.00	4.26	370	122
12	2.20	0.00	2.20	0.07	0.00	6.69	350	118
13	3.30	0.00	3.30	0.10	0.00	10.04	340	116
14	4.50	0.00	4.50	0.14	0.00	13.69	338	112
15	5.80	0.00	5.80	0.18	0.00	17.65	338	108
16	7.10	0.00	7.10	0.22	0.00	21.60	340	106
17	8.30	0.00	8.30	0.25	0.00	25.25	340	103
18	9.60	0.00	9.60	0.29	0.00	29.21	340	98
19	10.90	0.00	10.90	0.33	0.00	33.16	338	96
20	12.30	0.00	12.30	0.37	0.00	37.42	540	94
21	13.70	0.00	13.70	0.42	0.00	41.68	330	91
22	14.90	0.00	14.90	0.45	0.00	45.33	330	88
23	16.10	0.00	16.10	0.49	0.00	48.98	330	85
24	16.40	1.00	17.40	0.53	0.77	49.89	350	82
25	16.40	2.40	18.80	0.57	1.00	49.89	352	80
26	16.40	3.80	20.20	0.61	1.00	49.89	450	77
27	16.40	5.40	21.80	0.66	1.00	49.89	430	78
28	16.40	7.00	23.40	0.71	1.00	49.89	365	82
29	16.40	8.50	24.90	0.76	1.00	49.89	285	122
30	16.70	9.70	26.40	0.80	0.80	50.81	220	131
31	17.10	10.70	27.80	0.85	0.71	52.02	230	126
32	17.10	11.60	28.70	0.87	1.00	52.02	315	124
33	17.10	12.90	30.00	0.91	1.00	52.02	350	124
34	17.30	14.20	31.50	0.96	0.87	52.63	350	124
35	17.30	15.40	32.70	0.99	1.00	52.63	350	121
36	17.30	16.50	33.80	1.03	1.00	52.63	345	118
37	17.30	17.70	35.00	1.06	1.00	52.63	348	116
38	17.30	18.90	36.20	1.10	1.00	52.63	350	114
39	17.30	20.20	37.50	1.14	1.00	52.63	351	112
40	17.30	21.30	38.60	1.17	1.00	52.63	355	109

Table B.3 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	17.30	22.50	39.80	1.21	1.00	52.63	355	97
42	17.30	23.70	41.00	1.25	1.00	52.63	360	94
43	17.30	25.00	42.30	1.29	1.00	52.63	363	92
44	17.30	26.10	43.40	1.32	1.00	52.63	362	88
45	17.30	27.20	44.50	1.35	1.00	52.63	380	86
46	17.30	28.40	45.70	1.39	1.00	52.63	380	84
47	17.30	29.50	46.80	1.42	1.00	52.63	382	81
48	17.30	30.80	48.10	1.46	1.00	52.63	400	81
49	17.30	31.90	49.20	1.50	1.00	52.63	400	83
50	17.50	33.00	50.50	1.54	0.85	53.24	400	84
51	17.50	34.20	51.70	1.57	1.00	53.24	382	86
52	17.50	35.40	52.90	1.61	1.00	53.24	440	90
53	17.50	36.60	54.10	1.65	1.00	53.24	410	90
54	17.50	37.90	55.40	1.69	1.00	53.24	400	95
55	17.50	39.20	56.70	1.72	1.00	53.24	300	106
56	17.50	40.60	58.10	1.77	1.00	53.24	250	117
57	17.50	42.00	59.50	1.81	1.00	53.24	270	114
58	17.50	43.30	60.80	1.85	1.00	53.24	380	116
59	17.50	44.60	62.10	1.89	1.00	53.24	370	120
60	17.50	46.00	63.50	1.93	1.00	53.24	370	119
61	17.50	47.30	64.80	1.97	1.00	53.24	378	118
62	17.50	48.50	66.00	2.01	1.00	53.24	375	116
63	17.50	49.70	67.20	2.04	1.00	53.24	370	114
64	17.50	51.00	68.50	2.08	1.00	53.24	370	111
65	17.50	52.40	69.90	2.13	1.00	53.24	375	109
66	17.50	53.60	71.10	2.16	1.00	53.24	380	106
67	17.70	54.90	72.60	2.21	0.87	53.85	385	104
68	17.70	56.30	74.00	2.25	1.00	53.85	390	101
69	18.00	57.40	75.40	2.29	0.79	54.76	380	98
70	18.00	58.60	76.60	2.33	1.00	54.76	390	97
71	18.00	59.80	77.80	2.37	1.00	54.76	388	94
72	18.00	61.10	79.10	2.41	1.00	54.76	382	90
73	18.00	62.50	80.50	2.45	1.00	54.76	380	88
74	18.00	63.90	81.90	2.49	1.00	54.76	400	87
75	18.00	65.20	83.20	2.53	1.00	54.76	400	84
76	18.00	66.40	84.40	2.57	1.00	54.76	412	83
77	18.00	67.60	85.60	2.60	1.00	54.76	408	82
78	18.00	68.80	86.80	2.64	1.00	54.76	400	80
79	18.00	69.90	87.90	2.67	1.00	54.76	425	80
80	18.00	71.10	89.10	2.71	1.00	54.76	440	80

Table B.3 : Continued.

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Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	18.20	72.20	90.40	2.75	0.85	55.37	420	81
82	18.35	73.40	91.75	2.79	0.89	55.83	440	83
83	18.35	74.70	93.05	2.83	1.00	55.83	440	86
84	18.35	76.00	94.35	2.87	1.00	55.83	460	90
85	18.35	77.30	95.65	2.91	1.00	55.83	390	96
86	18.35	78.50	96.85	2.95	1.00	55.83	300	102
87	18.35	79.60	97.95	2.98	1.00	55.83	270	103
88	18.35	80.80	99.15	3.02	1.00	55.83	380	106
89	18.35	82.00	100.35	3.05	1.00	55.83	415	110
90	18.35	83.30	101.65	3.09	1.00	55.83	410	113
91	18.35	84.40	102.75	3.13	1.00	55.83	410	113
92	18.35	85.50	103.85	3.16	1.00	55.83	410	113
93	18.60	86.60	105.20	3.20	0.81	56.59	418	111
94	18.80	87.80	106.60	3.24	0.86	57.20	425	109
95	18.80	89.10	107.90	3.28	1.00	57.20	423	106
96	18.80	90.40	109.20	3.32	1.00	57.20	415	105
97	18.80	91.60	110.40	3.36	1.00	57.20	412	103
98	18.80	92.90	111.70	3.40	1.00	57.20	408	103
99	18.80	94.10	112.90	3.43	1.00	57.20	408	100
100	18.80	95.30	114.10	3.47	1.00	57.20	405	87

Table B.4 : Raw and Computed Results for Run# 4

(hot eater with solvent slug=9.45 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	12	110
2	0.00	0.00	0.00	0.00	0.00	0.00	16	122
3	0.00	0.00	0.00	0.00	0.00	0.00	15	129
4	0.00	0.00	0.00	0.00	0.00	0.00	17	123
5	0.00	0.00	0.00	0.00	0.00	0.00	19	122
6	0.00	0.00	0.00	0.00	0.00	0.00	18	114
7	0.00	0.00	0.00	0.00	0.00	0.00	21	108
8	0.00	0.00	0.00	0.00	0.00	0.00	39	104
9	0.00	0.00	0.00	0.00	0.00	0.00	100	101
10	0.40	0.00	0.40	0.01	0.00	1.21	148	97
11	1.00	0.00	1.00	0.03	0.00	3.03	285	94
12	1.60	0.00	1.60	0.05	0.00	4.85	270	91
13	2.40	0.00	2.40	0.07	0.00	7.27	290	88
14	3.40	0.00	3.40	0.10	0.00	10.30	315	88
15	4.50	0.00	4.50	0.14	0.00	13.63	358	88
16	5.40	0.00	5.40	0.16	0.00	16.35	385	92
17	6.25	0.00	6.25	0.19	0.00	18.93	365	96
18	7.45	0.00	7.45	0.23	0.00	22.56	452	97
19	8.75	0.00	8.75	0.26	0.00	26.50	498	107
20	10.05	0.00	10.05	0.30	0.00	30.44	540	111
21	11.35	0.00	11.35	0.34	0.00	34.37	565	115
22	12.55	0.00	12.55	0.38	0.00	38.01	585	118
23	13.85	0.00	13.85	0.42	0.00	41.94	602	119
24	15.15	0.00	15.15	0.46	0.00	45.88	628	119
25	16.35	0.00	16.35	0.50	0.00	49.52	640	119
26	17.25	0.00	17.25	0.52	0.00	52.24	650	117
27	17.65	0.20	17.85	0.54	0.33	53.45	670	116
28	17.85	0.40	18.25	0.55	0.50	54.06	672	113
29	17.95	0.70	18.65	0.56	0.75	54.36	675	111
30	18.05	1.80	19.85	0.60	0.92	54.66	693	108
31	18.05	3.10	21.15	0.64	1.00	54.66	710	105
32	18.05	4.40	22.45	0.68	1.00	54.66	728	102
33	18.15	5.50	23.65	0.72	0.92	54.97	732	99
34	18.15	6.80	24.95	0.76	1.00	54.97	725	96
35	18.15	8.10	26.25	0.79	1.00	54.97	750	92
36	18.15	9.40	27.55	0.83	1.00	54.97	755	89
37	18.30	10.50	28.80	0.87	0.88	55.42	765	86
38	18.30	11.80	30.10	0.91	1.00	55.42	760	84
39	18.30	13.00	31.30	0.95	1.00	55.42	763	82
40	18.30	14.40	32.70	0.99	1.00	55.42	772	81

Table B.4 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	18.40	15.40	33.80	1.02	0.91	55.72	800	82
42	18.40	16.90	35.30	1.07	1.00	55.72	800	84
43	18.40	18.10	36.50	1.11	1.00	55.72	790	87
44	18.40	19.20	37.60	1.14	1.00	55.72	810	91
45	18.40	20.40	38.80	1.18	1.00	55.72	840	95
46	18.40	21.70	40.10	1.21	1.00	55.72	770	102
47	18.40	22.90	41.30	1.25	1.00	55.72	785	104
48	18.55	24.00	42.55	1.29	0.88	56.18	810	108
49	18.55	25.20	43.75	1.32	1.00	56.18	840	111
50	18.55	26.60	45.15	1.37	1.00	56.18	832	116
51	18.55	27.90	46.45	1.41	1.00	56.18	840	120
52	18.55	29.20	47.75	1.45	1.00	56.18	852	121
53	18.55	30.60	49.15	1.49	1.00	56.18	862	122
54	18.55	31.90	50.45	1.53	1.00	56.18	850	124
55	18.55	33.40	51.95	1.57	1.00	56.18	860	123
56	18.80	34.30	53.10	1.61	0.78	56.94	860	122
57	18.80	35.70	54.50	1.65	1.00	56.94	860	120
58	18.80	36.80	55.60	1.68	1.00	56.94	860	117
69	18.80	38.20	57.00	1.73	1.00	56.94	840	116
60	18.80	39.40	58.20	1.76	1.00	56.94	885	112
61	18.80	40.80	59.60	1.80	1.00	56.94	860	109
62	18.80	42.20	61.00	1.85	1.00	56.94	890	105
63	18.80	43.40	62.20	1.88	1.00	56.94	855	102
64	18.80	44.80	63.60	1.93	1.00	56.94	885	98
65	18.80	45.90	64.70	1.96	1.00	56.94	890	95
66	18.80	47.30	66.10	2.00	1.00	56.94	870	92
67	18.98	48.40	67.38	2.04	0.86	57.48	890	91
68	18.98	49.70	68.68	2.08	1.00	57.48	890	90
69	18.98	51.10	70.08	2.12	1.00	57.48	915	88
70	18.98	52.40	71.38	2.16	1.00	57.48	918	88
71	18.98	53.80	72.78	2.20	1.00	57.48	910	88
72	18.98	55.10	74.08	2.24	1.00	57.48	922	88
73	18.98	56.50	75.48	2.29	1.00	57.48	925	90
74	19.28	57.80	77.08	2.33	0.81	58.39	930	91
75	19.48	59.00	78.48	2.38	0.86	58.99	950	91
76	19.48	60.40	79.88	2.42	1.00	58.99	945	92
77	19.48	61.70	81.18	2.46	1.00	58.99	935	94
78	19.48	63.20	82.68	2.50	1.00	58.99	925	95
79	19.48	64.50	83.98	2.54	1.00	58.99	930	97
80	19.48	65.70	85.18	2.58	1.00	58.99	905	99

Table B.4 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	19.48	67.00	86.48	2.62	1.00	58.99	890	100
82	19.48	68.20	87.68	2.66	1.00	58.99	892	102
83	19.48	69.50	88.98	2.69	1.00	58.99	870	104
84	19.48	70.90	90.38	2.74	1.00	58.99	860	104
85	19.48	72.10	91.58	2.77	1.00	58.99	885	105
86	19.48	73.40	92.88	2.81	1.00	58.99	902	104
87	19.48	74.80	94.28	2.86	1.00	58.99	930	104
88	19.48	76.10	95.58	2.89	1.00	58.99	940	102
89	19.57	77.20	96.77	2.93	0.92	59.27	930	101
90	19.74	78.00	97.74	2.96	0.82	59.78	950	100
91	19.74	79.40	99.14	3.00	1.00	59.78	952	98
92	19.74	80.80	100.54	3.04	1.00	59.78	950	98
93	19.74	82.30	102.04	3.09	1.00	59.78	975	97
94	19.74	83.60	103.34	3.13	1.00	59.78	968	97
95	19.74	84.70	104.44	3.16	1.00	59.78	980	97
96	19.74	85.90	105.64	3.20	1.00	59.78	995	97
97	19.74	87.10	106.84	3.24	1.00	59.78	930	98
98	19.74	88.40	108.14	3.27	1.00	59.78	940	98
99	19.74	89.60	109.34	3.31	1.00	59.78	930	100
100	19.74	90.90	110.64	3.35	1.00	59.78	980	100
101	19.74	92.20	111.94	3.39	1.00	59.78	1000	100
102	19.74	93.70	113.44	3.44	1.00	59.78	990	100
103	19.74	94.90	114.64	3.47	1.00	59.78	980	101
104	19.74	96.00	115.74	3.51	1.00	59.78	976	101
105	19.84	97.20	117.04	3.54	0.92	60.08	1010	100
106	19.86	98.50	118.36	3.58	0.98	60.15	1000	100
107	19.86	99.70	119.56	3.62	1.00	60.15	1000	98
108	19.86	101.20	121.06	3.67	1.00	60.15	1000	98
109	19.86	102.50	122.36	3.71	1.00	60.15	980	97
110	19.86	103.80	123.66	3.75	1.00	60.15	1000	96
111	19.96	105.30	125.26	3.79	0.94	60.45	995	96
112	19.96	106.50	126.46	3.83	1.00	60.45	990	94
113	19.96	107.90	127.86	3.87	1.00	60.45	1010	93
114	20.16	109.20	129.36	3.92	0.87	61.05	1015	92
115	20.46	110.30	130.76	3.96	0.79	61.96	990	92
116	20.46	111.60	132.06	4.00	1.00	61.96	990	92
117	20.46	112.80	133.26	4.04	1.00	61.96	995	92
118	20.46	114.30	134.76	4.08	1.00	61.96	1030	90
119	20.46	115.60	136.06	4.12	1.00	61.96	990	91
120	20.46	116.80	137.26	4.16	1.00	61.96	1000	91

Table B.4 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
121	20.46	118.00	138.46	4.19	1.00	61.96	980	92
122	20.46	119.20	139.66	4.23	1.00	61.96	1020	92
123	20.46	120.50	140.96	4.27	1.00	61.96	1030	92
124	20.46	122.00	142.46	4.31	1.00	61.96	1040	92
125	20.46	123.20	143.66	4.35	1.00	61.96	1020	94
126	20.46	123.50	143.96	4.36	1.00	61.96	1005	95
127	20.46	124.90	145.36	4.40	1.00	61.96	1020	97
128	20.46	126.30	146.76	4.44	1.00	61.96	1020	98
129	20.46	127.50	147.96	4.48	1.00	61.96	1050	98
130	20.46	128.60	149.06	4.51	1.00	61.96	1050	99
131	20.46	129.70	150.16	4.55	1.00	61.96	1040	100
132	20.46	130.80	151.26	4.58	1.00	61.96	1020	102
133	20.46	131.80	152.26	4.61	1.00	61.96	1040	102

Table 8.5 : Raw and Computed Results for Run# 5
(hot water with solvent slug=13.07 %THPV, Q=1 cc/min).

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Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	5	103
2	0.00	0.00	0.00	0.00	0.00	0.00	7	96
3	0.00	0.00	0.00	0.00	0.00	0.00	14	93
4	0.00	0.00	0.00	0.00	0.00	0.00	14	102
5	0.00	0.00	0.00	0.00	0.00	0.00	21	97
6	0.00	0.00	0.00	0.00	0.00	0.00	30	94
7	0.00	0.00	0.00	0.00	0.00	0.00	87	92
8	0.00	0.00	0.00	0.00	0.00	0.00	200	90
9	0.00	0.00	0.00	0.00	0.00	0.00	400	87
10	0.60	0.00	0.60	0.02	0.00	1.76	500	84
11	1.20	0.00	1.20	0.04	0.00	3.52	740	82
12	1.90	0.00	1.90	0.06	0.00	5.58	930	80
13	2.90	0.00	2.90	0.09	0.00	8.51	320	90
14	3.90	0.00	3.90	0.11	0.00	11.45	280	110
15	4.90	0.00	4.90	0.14	0.00	14.39	285	113
16	6.00	0.00	6.00	0.18	0.00	17.62	385	115
17	7.10	0.00	7.10	0.21	0.00	20.85	455	117
18	8.20	0.00	8.20	0.24	0.00	24.08	500	118
19	9.30	0.00	9.30	0.27	0.00	27.30	540	116
20	10.40	0.00	10.40	0.31	0.00	30.53	580	115
21	11.60	0.00	11.60	0.34	0.00	34.06	610	115
22	12.80	0.00	12.80	0.38	0.00	37.58	650	112
23	13.90	0.00	13.90	0.41	0.00	40.81	680	110
24	15.20	0.00	15.20	0.45	0.00	44.63	705	105
25	16.50	0.00	16.50	0.48	0.00	48.44	740	102
26	17.70	0.00	17.70	0.52	0.00	51.97	770	102
27	18.20	0.10	18.30	0.54	0.17	53.44	770	102
28	18.60	0.70	19.30	0.57	0.60	54.61	805	100
29	18.60	1.80	20.40	0.60	1.00	54.61	835	98
30	18.60	3.00	21.60	0.63	1.00	54.61	870	96
31	18.60	4.30	22.90	0.67	1.00	54.61	875	94
32	18.60	5.50	24.10	0.71	1.00	54.61	900	90
33	18.60	6.90	25.50	0.75	1.00	54.61	930	89
34	18.60	8.10	26.70	0.78	1.00	54.61	940	88
35	18.60	9.40	28.00	0.82	1.00	54.61	935	87
36	18.60	10.50	29.10	0.85	1.00	54.61	930	88
37	18.60	11.50	30.10	0.88	1.00	54.61	965	89
38	18.60	12.70	31.30	0.92	1.00	54.61	970	91
39	18.60	13.80	32.40	0.95	1.00	54.61	940	93
40	18.60	15.00	33.60	0.99	1.00	54.61	995	96

Table B.5 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	18.60	16.20	34.80	1.02	1.00	54.61	1010	98
42	18.60	17.40	36.00	1.06	1.00	54.61	1010	102
43	18.60	18.60	37.20	1.09	1.00	54.61	1018	105
44	18.60	19.90	38.50	1.13	1.00	54.61	1038	107
45	18.60	21.10	39.70	1.17	1.00	54.61	1040	110
46	18.60	22.20	40.80	1.20	1.00	54.61	1042	112
47	18.60	23.40	42.00	1.23	1.00	54.61	1060	112
48	18.60	24.60	43.20	1.27	1.00	54.61	1055	114
49	18.60	26.00	44.60	1.31	1.00	54.61	1080	112
50	18.60	27.20	45.80	1.34	1.00	54.61	1080	112
51	18.60	28.60	47.20	1.39	1.00	54.61	1100	110
52	18.60	29.80	48.40	1.42	1.00	54.61	1105	111
53	18.60	31.00	49.60	1.46	1.00	54.61	1090	110
54	18.60	32.30	50.90	1.49	1.00	54.61	1095	108
55	18.60	33.60	52.20	1.53	1.00	54.61	1085	106
56	18.60	33.80	52.40	1.54	1.00	54.61	1090	106
57	18.60	35.00	53.60	1.57	1.00	54.61	1100	104
58	18.60	36.20	54.80	1.61	1.00	54.61	1130	103
59	18.60	37.70	56.30	1.65	1.00	54.61	1140	101
60	18.60	38.90	57.50	1.69	1.00	54.61	1100	98
61	18.60	40.10	58.70	1.72	1.00	54.61	1125	95
62	18.60	41.30	59.90	1.76	1.00	54.61	1160	92
63	18.60	42.50	61.10	1.79	1.00	54.61	1190	89
64	18.60	43.90	62.50	1.83	1.00	54.61	1145	87
65	18.60	45.20	63.80	1.87	1.00	54.61	1160	86
66	18.60	46.50	65.10	1.91	1.00	54.61	1190	85
67	18.60	47.70	66.30	1.95	1.00	54.61	1190	84
68	19.60	49.10	68.70	2.02	0.58	57.55	1200	85
69	19.70	50.10	69.80	2.05	0.91	57.84	1195	86
70	19.75	51.20	70.95	2.08	0.96	57.99	1200	89
71	19.95	52.40	72.35	2.12	0.86	58.57	1210	91
72	19.95	53.40	73.35	2.15	1.00	58.57	1230	94
73	19.95	54.60	74.55	2.19	1.00	58.57	1220	98
74	19.95	55.70	75.65	2.22	1.00	58.57	1220	102
75	20.25	56.60	76.85	2.26	0.75	59.45	1240	104
76	20.45	57.60	78.05	2.29	0.83	60.04	1200	102
77	20.45	58.80	79.25	2.33	1.00	60.04	1220	106
78	20.48	59.90	80.38	2.36	0.97	60.13	1240	108
79	20.68	60.90	81.58	2.40	0.83	60.72	1240	108
80	20.68	61.90	82.58	2.42	1.00	60.72	1260	108

Table B.5 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	20.68	63.30	83.98	2.47	1.00	60.72	1270	110
82	20.68	64.50	85.18	2.50	1.00	60.72	1280	108
83	20.68	65.70	86.38	2.54	1.00	60.72	1280	108
84	20.88	66.70	87.58	2.57	0.83	61.30	1285	107
85	20.88	67.90	88.78	2.61	1.00	61.30	1285	106
86	20.88	69.20	90.08	2.64	1.00	61.30	1280	105
87	20.88	70.60	91.48	2.69	1.00	61.30	1340	104
88	20.88	72.00	92.88	2.73	1.00	61.30	1315	104
89	20.88	73.10	93.98	2.76	1.00	61.30	1300	103
90	20.88	74.30	95.18	2.79	1.00	61.30	1320	102
91	20.88	75.60	96.48	2.83	1.00	61.30	1335	101
92	20.88	76.90	97.78	2.87	1.00	61.30	1340	101
93	20.88	78.20	99.08	2.91	1.00	61.30	1330	98
94	20.88	79.60	100.48	2.95	1.00	61.30	1320	95
95	20.88	80.70	101.58	2.98	1.00	61.30	1300	92
96	20.88	82.10	102.98	3.02	1.00	61.30	1340	89
97	20.88	83.20	104.08	3.06	1.00	61.30	1350	86
98	20.88	84.50	105.38	3.09	1.00	61.30	1340	85
99	20.88	85.80	106.68	3.13	1.00	61.30	1350	84
100	20.88	87.00	107.88	3.17	1.00	61.30	1340	84
101	20.88	88.30	109.18	3.21	1.00	61.30	1340	85
102	20.88	89.30	110.18	3.23	1.00	61.30	1340	87
103	21.08	90.30	111.38	3.27	0.83	61.89	1350	89
104	21.28	91.20	112.48	3.30	0.82	62.48	1345	93
105	21.28	92.40	113.68	3.34	1.00	62.48	1360	95
106	21.28	93.60	114.88	3.37	1.00	62.48	1320	99
107	21.28	94.90	116.18	3.41	1.00	62.48	1360	101
108	21.28	96.10	117.38	3.45	1.00	62.48	1300	103
109	21.28	97.10	118.38	3.48	1.00	62.48	1320	106
110	21.28	98.30	119.58	3.51	1.00	62.48	1385	108
111	21.28	99.30	120.58	3.54	1.00	62.48	1415	110
112	21.28	100.50	121.78	3.58	1.00	62.48	1390	112
113	21.28	101.70	122.98	3.61	1.00	62.48	1390	114
114	21.28	102.90	124.18	3.65	1.00	62.48	1420	114
115	21.28	104.10	125.38	3.68	1.00	62.48	1400	114
116	21.28	105.70	126.98	3.73	1.00	62.48	1380	112
117	21.28	106.90	128.18	3.76	1.00	62.48	1400	110
118	21.28	108.00	129.28	3.80	1.00	62.48	1360	108
119	21.28	109.30	130.58	3.83	1.00	62.48	1380	106
120	21.28	110.60	131.88	3.87	1.00	62.48	1370	105

Table B.5 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
121	21.28	112.00	133.28	3.91	1.00	62.48	1405	105
122	21.28	113.40	134.68	3.95	1.00	62.48	1440	103
123	21.28	114.60	135.88	3.99	1.00	62.48	1460	102
124	21.28	115.70	136.98	4.02	1.00	62.48	1380	100
125	21.28	116.90	138.18	4.06	1.00	62.48	1385	97
126	21.28	118.00	139.28	4.09	1.00	62.48	1420	97
127	21.28	119.20	140.48	4.12	1.00	62.48	1430	94
128	21.43	120.40	141.83	4.16	0.89	62.92	1460	91
129	21.43	121.60	143.03	4.20	1.00	62.92	1480	86
130	21.43	122.70	144.13	4.23	1.00	62.92	1400	85
131	21.43	123.70	145.13	4.26	1.00	62.92	1500	84
132	21.43	124.90	146.33	4.30	1.00	62.92	1480	83
133	21.43	126.10	147.53	4.33	1.00	62.92	1470	83
134	21.43	127.30	148.73	4.37	1.00	62.92	1485	84
135	21.43	128.50	149.93	4.40	1.00	62.92	1380	86

Table B.6 : Raw and Computed Results for Run# 6

(hot water with solvent slug=15.52 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	75	101
2	0.00	0.00	0.00	0.00	0.00	0.00	220	100
3	0.00	0.00	0.00	0.00	0.00	0.00	565	96
4	0.00	0.00	0.00	0.00	0.00	0.00	790	93
5	0.00	0.00	0.00	0.00	0.00	0.00	440	90
6	0.20	0.00	0.20	0.01	0.00	0.60	375	88
7	0.80	0.00	0.80	0.02	0.00	2.41	425	86
8	1.80	0.00	1.80	0.05	0.00	5.41	535	78
9	3.10	0.00	3.10	0.09	0.00	9.32	545	91
10	4.50	0.00	4.50	0.14	0.00	13.53	585	90
11	5.90	0.00	5.90	0.18	0.00	17.74	600	90
12	7.30	0.00	7.30	0.22	0.00	21.95	640	91
13	8.60	0.00	8.60	0.26	0.00	25.86	660	100
14	10.10	0.00	10.10	0.30	0.00	30.38	690	104
15	11.60	0.00	11.60	0.35	0.00	34.89	725	110
16	13.10	0.00	13.10	0.39	0.00	39.40	755	114
17	14.50	0.00	14.50	0.44	0.00	43.61	780	116
18	16.00	0.00	16.00	0.48	0.00	48.12	780	117
19	17.10	0.00	17.10	0.51	0.00	51.43	805	115
20	18.00	0.50	18.50	0.56	0.36	54.14	840	113
21	18.00	1.60	19.60	0.59	1.00	54.14	860	112
22	18.25	2.30	20.55	0.62	0.74	54.89	885	110
23	18.65	3.00	21.65	0.65	0.64	56.09	915	108
24	18.65	4.10	22.75	0.68	1.00	56.09	930	106
25	18.75	5.10	23.85	0.72	0.91	56.39	965	104
26	18.77	6.30	25.07	0.75	0.98	56.45	985	101
27	18.87	7.40	26.27	0.79	0.92	56.75	990	90
28	18.87	8.60	27.47	0.83	1.00	56.75	1000	86
29	19.07	9.70	28.77	0.87	0.85	57.35	1020	87
30	19.17	10.80	29.97	0.90	0.92	57.65	1040	87
31	19.32	11.80	31.12	0.94	0.87	58.11	1050	89
32	19.32	13.00	32.32	0.97	1.00	58.11	1060	92
33	19.32	14.30	33.62	1.01	1.00	58.11	1070	96
34	19.32	15.50	34.82	1.05	1.00	58.11	1080	99
35	19.32	16.70	36.02	1.08	1.00	58.11	1100	103
36	19.32	17.90	37.22	1.12	1.00	58.11	1100	106
37	19.32	19.10	38.42	1.16	1.00	58.11	1105	108
38	19.32	20.40	39.72	1.19	1.00	58.11	1125	110
39	19.32	21.60	40.92	1.23	1.00	58.11	1140	108
40	19.32	22.90	42.22	1.27	1.00	58.11	1160	108

Table B.6 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	19.32	24.10	43.42	1.31	1.00	58.11	1180	106
42	19.32	25.30	44.62	1.34	1.00	58.11	1180	106
43	19.32	26.50	45.82	1.38	1.00	58.11	1180	104
44	19.32	27.70	47.02	1.41	1.00	58.11	1210	102
45	19.32	28.80	48.12	1.45	1.00	58.11	1220	101
46	19.32	30.00	49.32	1.48	1.00	58.11	1225	99
47	19.52	31.00	50.52	1.52	0.83	58.71	1210	96
48	19.82	31.80	51.62	1.55	0.73	59.61	1210	94
49	19.92	32.80	52.72	1.59	0.91	59.91	1230	90
50	19.92	34.00	53.92	1.62	1.00	59.91	1220	84
51	19.92	35.10	55.02	1.65	1.00	59.91	1220	86
52	19.92	36.20	56.12	1.69	1.00	59.91	1250	90
53	19.92	37.30	57.22	1.72	1.00	59.91	1265	102
54	19.92	38.40	58.32	1.75	1.00	59.91	1280	104
55	19.92	39.70	59.62	1.79	1.00	59.91	1300	104
56	19.92	40.90	60.82	1.83	1.00	59.91	1300	107
57	19.92	42.20	62.12	1.87	1.00	59.91	1300	109
58	19.92	43.30	63.22	1.90	1.00	59.91	1260	110
69	19.92	44.40	64.32	1.93	1.00	59.91	1280	108
60	19.92	45.60	65.52	1.97	1.00	59.91	1310	106
61	19.92	46.80	66.72	2.01	1.00	59.91	1320	104
62	20.02	48.00	68.02	2.05	0.92	60.21	1340	104
63	20.27	48.70	68.97	2.07	0.74	60.96	1315	102
64	20.27	50.00	70.27	2.11	1.00	60.96	1310	102
65	20.27	51.10	71.37	2.15	1.00	60.96	1340	99
66	20.27	52.40	72.67	2.19	1.00	60.96	1350	96
67	20.27	53.70	73.97	2.22	1.00	60.96	1360	92
68	20.27	55.00	75.27	2.26	1.00	60.96	1390	89
69	20.27	56.30	76.57	2.30	1.00	60.96	1390	87
70	20.27	57.60	77.87	2.34	1.00	60.96	1395	85
71	20.27	58.80	79.07	2.38	1.00	60.96	1415	82
72	20.27	60.00	80.27	2.41	1.00	60.96	1400	84
73	20.27	61.30	81.57	2.45	1.00	60.96	1400	86
74	20.27	62.30	82.57	2.48	1.00	60.96	1400	88
75	20.27	63.50	83.77	2.52	1.00	60.96	1405	89
76	20.27	64.60	84.87	2.55	1.00	60.96	1400	90
77	20.27	65.70	85.97	2.59	1.00	60.96	1400	92
78	20.47	66.80	87.27	2.62	0.85	61.56	1430	95
79	20.47	68.00	88.47	2.66	1.00	61.56	1420	96
80	20.47	69.00	89.47	2.69	1.00	61.56	1440	99

Table B.6 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	20.47	70.20	90.67	2.73	1.00	61.56	1440	100
82	20.47	71.20	91.67	2.76	1.00	61.56	1400	102
83	20.47	72.50	92.97	2.80	1.00	61.56	1440	105
84	20.47	73.70	94.17	2.83	1.00	61.56	1470	107
85	20.47	74.70	95.17	2.86	1.00	61.56	1440	106
86	20.47	75.80	96.27	2.90	1.00	61.56	1460	106
87	20.47	77.00	97.47	2.93	1.00	61.56	1460	108
88	20.47	78.30	98.77	2.97	1.00	61.56	1465	105
89	20.47	79.70	100.17	3.01	1.00	61.56	1485	102
90	20.47	81.00	101.47	3.05	1.00	61.56	1490	100
91	20.47	82.10	102.57	3.08	1.00	61.56	1500	99
92	20.47	83.10	103.57	3.11	1.00	61.56	1460	100
93	20.47	84.30	104.77	3.15	1.00	61.56	1460	101
94	20.47	85.40	105.87	3.18	1.00	61.56	1440	100
95	20.57	86.30	106.87	3.21	0.90	61.86	1460	99
96	20.57	87.40	107.97	3.25	1.00	61.86	1480	96
97	20.57	88.60	109.17	3.28	1.00	61.86	1490	94
98	20.57	89.70	110.27	3.32	1.00	61.86	1490	93

Table B.7 : Raw and Computed Results for Run# 7

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(hot water with solvent slug=19.4 % THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	9	100
2	0.00	0.00	0.00	0.00	0.00	0.00	9	102
3	0.00	0.00	0.00	0.00	0.00	0.00	8	104
4	0.00	0.00	0.00	0.00	0.00	0.00	12	106
5	0.50	0.00	0.50	0.02	0.00	1.58	19	107
6	1.60	0.00	1.60	0.05	0.00	5.04	43	108
7	2.80	0.00	2.80	0.09	0.00	8.82	100	101
8	4.10	0.00	4.10	0.13	0.00	12.92	240	98
9	5.40	0.00	5.40	0.17	0.00	17.01	435	93
10	6.70	0.00	6.70	0.21	0.00	21.11	570	91
11	7.90	0.00	7.90	0.25	0.00	24.89	750	89
12	9.20	0.00	9.20	0.29	0.00	28.99	730	86
13	10.60	0.00	10.60	0.33	0.00	33.40	690	84
14	11.90	0.00	11.90	0.37	0.00	37.49	700	81
15	13.30	0.00	13.30	0.42	0.00	41.90	680	79
16	14.60	0.00	14.60	0.46	0.00	46.00	615	81
17	15.90	0.00	15.90	0.50	0.00	50.09	690	83
18	16.80	0.20	17.00	0.54	0.18	52.93	740	88
19	17.20	1.10	18.30	0.58	0.69	54.19	760	95
20	17.40	2.20	19.60	0.62	0.85	54.82	785	99
21	17.45	3.40	20.85	0.66	0.96	54.98	800	104
22	17.45	4.70	22.15	0.70	1.00	54.98	805	108
23	17.45	6.00	23.45	0.74	1.00	54.98	810	116
24	17.45	7.30	24.75	0.78	1.00	54.98	830	117
25	17.45	8.60	26.05	0.82	1.00	54.98	850	119
26	17.45	10.00	27.45	0.86	1.00	54.98	855	120
27	17.75	11.00	28.75	0.91	0.77	55.92	860	118
28	17.75	12.50	30.25	0.95	1.00	55.92	860	118
29	17.75	14.00	31.75	1.00	1.00	55.92	890	116
30	17.75	15.40	33.15	1.04	1.00	55.92	890	116
31	17.75	16.90	34.65	1.09	1.00	55.92	905	115
32	17.75	18.20	35.95	1.13	1.00	55.92	890	113
33	17.95	19.30	37.25	1.17	0.85	56.55	910	110
34	18.35	20.00	38.35	1.21	0.64	57.81	915	105
35	18.45	21.00	39.45	1.24	0.91	58.13	935	104
36	18.45	22.20	40.65	1.28	1.00	58.13	940	102
37	18.45	23.40	41.85	1.32	1.00	58.13	930	98
38	18.45	24.70	43.15	1.36	1.00	58.13	930	96
39	18.45	25.80	44.25	1.39	1.00	58.13	930	92
40	18.45	27.20	45.65	1.44	1.00	58.13	960	89

Table B.7 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Re	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	18.45	28.40	46.85	1.48	1.00	58.13	915	87
42	18.45	29.70	48.15	1.52	1.00	58.13	935	86
43	18.45	31.00	49.45	1.56	1.00	58.13	935	86
44	18.45	32.30	50.75	1.60	1.00	58.13	970	86
45	18.45	33.60	52.05	1.64	1.00	58.13	960	88
46	18.45	34.90	53.35	1.68	1.00	58.13	970	89
47	18.45	36.10	54.55	1.72	1.00	58.13	970	92
48	18.45	37.40	55.85	1.76	1.00	58.13	980	94
49	18.45	38.70	57.15	1.80	1.00	58.13	995	97
50	18.55	39.80	58.35	1.84	0.92	58.44	1005	99
51	18.65	41.00	59.65	1.88	0.92	58.76	1000	102
52	18.65	42.30	60.95	1.92	1.00	58.76	1000	106
53	18.65	43.60	62.25	1.96	1.00	58.76	1000	106
54	18.65	44.80	63.45	2.00	1.00	58.76	1015	107
55	18.65	45.90	64.55	2.03	1.00	58.76	1015	105
56	18.65	47.10	65.75	2.07	1.00	58.76	1025	104
57	18.65	48.40	67.05	2.11	1.00	58.76	1035	102
58	18.65	49.70	68.35	2.15	1.00	58.76	1035	102
59	18.65	50.90	69.55	2.19	1.00	58.76	1025	99
60	18.65	52.10	70.75	2.23	1.00	58.76	1020	97
61	18.65	53.30	71.95	2.27	1.00	58.76	1035	95
62	18.65	54.60	73.25	2.31	1.00	58.76	1035	93
63	18.70	55.80	74.50	2.35	0.96	58.92	1065	91
64	18.75	56.90	75.65	2.38	0.96	59.07	1045	89
65	18.75	58.10	76.85	2.42	1.00	59.07	1035	88
66	18.75	59.30	78.05	2.46	1.00	59.07	1040	87
67	18.75	60.50	79.25	2.50	1.00	59.07	1035	88
68	18.75	61.70	80.45	2.53	1.00	59.07	1045	89
69	18.75	62.90	81.65	2.57	1.00	59.07	1050	91
70	18.75	64.30	83.05	2.62	1.00	59.07	1055	93
71	18.75	65.70	84.45	2.66	1.00	59.07	1055	97
72	18.75	66.70	85.45	2.69	1.00	59.07	1060	101
73	18.75	67.70	86.45	2.72	1.00	59.07	1060	104
74	18.75	68.80	87.55	2.76	1.00	59.07	1040	108
75	18.75	70.30	89.05	2.81	1.00	59.07	1050	110
76	18.75	71.50	90.25	2.84	1.00	59.07	1060	114
77	18.75	72.70	91.45	2.88	1.00	59.07	1080	114
78	18.95	73.80	92.75	2.92	0.85	59.70	1080	118
79	18.95	74.90	93.85	2.96	1.00	59.70	1090	116
80	18.95	76.20	95.15	3.00	1.00	59.70	1040	114

Table 8.7 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	18.95	77.50	96.45	3.04	1.00	59.70	1010	110
82	18.95	78.80	97.75	3.08	1.00	59.70	1050	108
83	18.95	79.80	98.75	3.11	1.00	59.70	1060	105
84	18.95	81.10	100.05	3.15	1.00	59.70	1110	103
85	18.95	82.40	101.35	3.19	1.00	59.70	1050	102
86	18.95	83.80	102.75	3.24	1.00	59.70	1080	100
87	18.95	85.00	103.95	3.28	1.00	59.70	1100	97
88	18.95	86.30	105.25	3.32	1.00	59.70	1120	94
89	18.95	87.50	106.45	3.35	1.00	59.70	1080	92
90	18.95	89.10	108.05	3.40	1.00	59.70	1070	89
91	18.95	90.20	109.15	3.44	1.00	59.70	1100	87
92	18.95	91.30	110.25	3.47	1.00	59.70	1115	86
93	18.95	92.30	111.25	3.51	1.00	59.70	1100	86
94	18.95	93.80	112.75	3.55	1.00	59.70	1115	86
95	18.95	95.10	114.05	3.59	1.00	59.70	1100	88
96	18.95	96.30	115.25	3.63	1.00	59.70	1070	90
97	18.95	97.40	116.35	3.67	1.00	59.70	1040	93
98	18.95	98.80	117.75	3.71	1.00	59.70	1080	95
99	18.95	100.00	118.95	3.75	1.00	59.70	1090	98
100	18.95	101.30	120.25	3.79	1.00	59.70	1080	102

Table B.8 : Raw and Computed Results for Run#19

(hot water with solvent slug=33.26 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	3	101
2	0.00	0.00	0.00	0.00	0.00	0.00	4	102
3	0.00	0.00	0.00	0.00	0.00	0.00	4	102
4	0.00	0.00	0.00	0.00	0.00	0.00	4	102
5	0.00	0.00	0.00	0.00	0.00	0.00	12	105
6	0.00	0.00	0.00	0.00	0.00	0.00	13	115
7	0.00	0.00	0.00	0.00	0.00	0.00	17	118
8	0.00	0.00	0.00	0.00	0.00	0.00	18	120
9	0.00	0.00	0.00	0.00	0.00	0.00	21	120
10	0.00	0.00	0.00	0.00	0.00	0.00	28	120
11	0.00	0.00	0.00	0.00	0.00	0.00	33	111
12	0.00	0.00	0.00	0.00	0.00	0.00	52	107
13	1.20	0.00	1.20	0.04	0.00	3.62	83	104
14	2.20	0.00	2.20	0.07	0.00	6.64	119	100
15	3.10	0.00	3.10	0.09	0.00	9.36	156	96
16	4.20	0.00	4.20	0.13	0.00	12.68	275	92
17	5.30	0.00	5.30	0.16	0.00	16.00	460	89
18	6.30	0.00	6.30	0.19	0.00	19.02	655	85
19	7.28	0.00	7.28	0.22	0.00	21.97	850	82
20	8.28	0.00	8.28	0.25	0.00	24.99	1020	80
21	9.18	0.00	9.18	0.28	0.00	27.71	1190	77
22	10.18	0.00	10.18	0.31	0.00	30.73	1340	74
23	11.08	0.00	11.08	0.33	0.00	33.44	1500	72
24	12.24	0.00	12.24	0.37	0.00	36.95	1620	70
25	13.24	0.00	13.24	0.40	0.00	39.96	1360	70
26	14.19	0.00	14.19	0.43	0.00	42.83	1120	80
27	15.19	0.00	15.19	0.46	0.00	45.85	1015	89
28	16.19	0.00	16.19	0.49	0.00	48.87	1025	92
29	17.16	0.00	17.16	0.52	0.00	51.80	1060	95
30	18.16	0.00	18.16	0.55	0.00	54.81	1140	96
31	19.06	0.00	19.06	0.58	0.00	57.53	1230	96
32	19.87	0.00	19.87	0.60	0.00	59.98	1280	96
33	20.52	0.35	20.87	0.63	0.35	61.94	1320	98
34	20.72	1.25	21.97	0.66	0.82	62.54	1380	98
35	20.76	2.15	22.91	0.69	0.96	62.66	1400	98
36	20.81	3.07	23.88	0.72	0.95	62.81	1440	99
37	20.87	3.97	24.84	0.75	0.94	62.99	1480	99
38	20.95	4.77	25.72	0.78	0.91	63.24	1520	100
39	21.09	5.67	26.76	0.81	0.87	63.66	1530	102
40	21.17	6.57	27.74	0.84	0.92	63.90	1540	103

Table B.8 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	21.24	7.77	29.01	0.88	0.94	64.11	1550	104
42	21.41	8.87	30.28	0.91	0.87	64.62	1555	106
43	21.41	9.87	31.28	0.94	1.00	64.62	1555	107
44	21.50	10.87	32.37	0.98	0.92	64.90	1585	108
45	21.50	11.87	33.37	1.01	1.00	64.90	1580	110
46	21.66	12.77	34.43	1.04	0.85	65.38	1520	112
47	21.66	13.87	35.53	1.07	1.00	65.38	1540	112
48	21.71	15.17	36.88	1.11	0.96	65.53	1550	114
49	21.85	16.02	37.87	1.14	0.86	65.95	1540	115
50	21.85	17.22	39.07	1.18	1.00	65.95	1470	117
51	21.85	18.42	40.27	1.22	1.00	65.95	1480	118
52	22.07	19.52	41.59	1.26	0.83	66.62	1530	116
53	22.07	20.72	42.79	1.29	1.00	66.62	1590	114
54	22.11	22.02	44.13	1.33	0.97	66.74	1660	113
55	22.14	23.22	45.36	1.37	0.98	66.83	1685	111
56	22.17	24.12	46.29	1.40	0.97	66.92	1675	113
57	22.17	25.32	47.49	1.43	1.00	66.92	1660	114
58	22.17	26.42	48.59	1.47	1.00	66.92	1595	116
69	22.19	27.42	49.61	1.50	0.98	66.98	1650	115
60	22.21	28.62	50.83	1.53	0.98	67.04	1650	114
61	22.21	29.82	52.03	1.57	1.00	67.04	1675	113
62	22.21	30.82	53.03	1.60	1.00	67.04	1695	113
63	22.21	32.02	54.23	1.64	1.00	67.04	1700	114
64	22.23	33.22	55.45	1.67	0.98	67.10	1725	111
65	22.24	34.42	56.66	1.71	0.99	67.13	1700	111
66	22.26	35.52	57.78	1.74	0.98	67.19	1660	113
67	22.26	36.72	58.98	1.78	1.00	67.19	1720	110
68	22.26	38.02	60.28	1.82	1.00	67.19	1760	108
69	22.33	39.32	61.65	1.86	0.95	67.40	1740	108
70	22.33	40.52	62.85	1.90	1.00	67.40	1780	108
71	22.39	41.62	64.01	1.93	0.95	67.58	1740	107
72	22.39	42.82	65.21	1.97	1.00	67.58	1680	108
73	22.39	44.12	66.51	2.01	1.00	67.58	1685	107
74	22.39	45.32	67.71	2.04	1.00	67.58	1700	106
75	22.45	46.62	69.07	2.08	0.96	67.76	1750	104
76	22.45	47.82	70.27	2.12	1.00	67.76	1790	102
77	22.46	48.92	71.38	2.15	0.99	67.79	1800	101
78	22.46	50.12	72.58	2.19	1.00	67.79	1780	102
79	22.46	51.42	73.88	2.23	1.00	67.79	1790	100
80	22.53	52.62	75.15	2.27	0.94	68.00	1810	98

Table B.8 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	22.53	53.72	76.25	2.30	1.00	68.00	1820	98
82	22.59	54.72	77.31	2.33	0.94	68.19	1840	97
83	22.59	55.92	78.51	2.37	1.00	68.19	1830	97
84	22.66	56.92	79.58	2.40	0.93	68.40	1810	96
85	22.66	58.02	80.68	2.44	1.00	68.40	1800	96
86	22.66	59.22	81.88	2.47	1.00	68.40	1780	96
87	22.66	60.42	83.08	2.51	1.00	68.40	1770	96
88	22.73	61.52	84.25	2.54	0.94	68.61	1760	96
89	22.73	62.82	85.55	2.58	1.00	68.61	1790	96
90	22.73	64.02	86.75	2.62	1.00	68.61	1880	94
91	22.73	65.22	87.95	2.65	1.00	68.61	1880	92
92	22.81	66.12	88.93	2.68	0.92	68.85	1850	93
93	22.82	67.12	89.94	2.71	0.99	68.88	1805	93
94	22.82	68.12	90.94	2.74	1.00	68.88	1780	94
95	22.86	69.12	91.98	2.78	0.96	69.00	1850	93
96	22.86	70.22	93.08	2.81	1.00	69.00	1865	93
97	22.86	71.42	94.28	2.85	1.00	69.00	1860	93
98	22.89	72.52	95.41	2.88	0.97	69.09	1855	93
99	22.89	73.72	96.61	2.92	1.00	69.09	1840	94
100	22.89	74.92	97.81	2.95	1.00	69.09	1795	97
101	22.96	76.12	99.08	2.99	0.94	69.30	1860	94
102	22.96	77.32	100.28	3.03	1.00	69.30	1880	93
103	22.96	78.52	101.48	3.06	1.00	69.30	1860	92
104	23.01	79.52	102.53	3.09	0.95	69.45	1850	93
105	23.01	80.52	103.53	3.12	1.00	69.45	1830	94
106	23.01	81.52	104.53	3.16	1.00	69.45	1800	94
107	23.08	82.62	105.70	3.19	0.94	69.66	1795	96
108	23.08	83.82	106.90	3.23	1.00	69.66	1810	96
109	23.08	85.02	108.10	3.26	1.00	69.66	1850	94
110	23.15	86.02	109.17	3.30	0.93	69.88	1865	93
111	23.15	87.22	110.37	3.33	1.00	69.88	1865	92
112	23.15	88.22	111.37	3.36	1.00	69.88	1865	92
113	23.22	89.32	112.54	3.40	0.94	70.09	1870	90
114	23.22	90.62	113.84	3.44	1.00	70.09	1880	88
115	23.22	91.82	115.04	3.47	1.00	70.09	1890	86
116	23.22	93.02	116.24	3.51	1.00	70.09	1880	85
117	23.22	94.02	117.24	3.54	1.00	70.09	1860	85
118	23.29	95.22	118.51	3.58	0.94	70.30	1865	83
119	23.29	96.22	119.51	3.61	1.00	70.30	1865	82
120	23.29	97.52	120.81	3.65	1.00	70.30	1860	83

Table B.8 : Continued.

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Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
121	23.36	98.82	122.18	3.69	0.95	70.51	1870	85
122	23.36	100.12	123.48	3.73	1.00	70.51	1870	84
123	23.36	101.32	124.68	3.76	1.00	70.51	1870	84
124	23.40	102.42	125.82	3.80	0.96	70.63	1870	84
125	23.40	103.62	127.02	3.83	1.00	70.63	1870	84
126	23.40	104.82	128.22	3.87	1.00	70.63	1870	84
127	23.40	106.12	129.52	3.91	1.00	70.63	1880	82

Table B.9 : Raw and Computed Results for Run# 20

(hot water with solvent slug=5.21 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	7	106
2	0.00	0.00	0.00	0.00	0.00	0.00	8	104
3	0.00	0.00	0.00	0.00	0.00	0.00	10	109
4	0.00	0.00	0.00	0.00	0.00	0.00	15	106
5	0.00	0.00	0.00	0.00	0.00	0.00	19	100
6	0.00	0.00	0.00	0.00	0.00	0.00	22	96
7	0.00	0.00	0.00	0.00	0.00	0.00	35	92
8	0.00	0.00	0.00	0.00	0.00	0.00	54	90
9	0.00	0.00	0.00	0.00	0.00	0.00	82	86
10	1.00	0.00	1.00	0.03	0.00	2.99	156	83
11	2.20	0.00	2.20	0.07	0.00	6.58	305	80
12	3.40	0.00	3.40	0.10	0.00	10.18	505	77
13	4.90	0.00	4.90	0.15	0.00	14.67	680	74
14	6.20	0.00	6.20	0.19	0.00	18.56	300	80
15	7.50	0.00	7.50	0.22	0.00	22.45	270	82
16	8.70	0.00	8.70	0.26	0.00	26.04	270	84
17	10.00	0.00	10.00	0.30	0.00	29.93	255	87
18	11.20	0.00	11.20	0.34	0.00	33.52	290	88
19	12.30	0.00	12.30	0.37	0.00	36.82	280	91
20	13.30	0.00	13.30	0.40	0.00	39.81	310	92
21	14.50	0.00	14.50	0.43	0.00	43.40	315	95
22	15.80	0.00	15.80	0.47	0.00	47.29	318	96
23	16.28	0.60	16.88	0.51	0.56	48.73	315	99
24	16.41	1.90	18.31	0.55	0.91	49.12	307	101
25	16.50	3.10	19.60	0.59	0.93	49.39	315	103
26	16.61	4.20	20.81	0.62	0.91	49.72	330	104
27	16.70	5.50	22.20	0.66	0.94	49.99	325	106
28	16.82	6.80	23.62	0.71	0.92	50.34	317	108
29	16.87	7.90	24.77	0.74	0.96	50.49	340	109
30	16.97	9.00	25.97	0.78	0.92	50.79	350	110
31	17.03	10.20	27.23	0.82	0.95	50.97	348	111
32	17.14	11.40	28.54	0.85	0.92	51.30	305	112
33	17.16	12.60	29.76	0.89	0.98	51.36	370	112
34	17.20	13.90	31.10	0.93	0.97	51.48	355	114
35	17.22	15.10	32.32	0.97	0.98	51.54	360	115
36	17.31	16.30	33.61	1.01	0.93	51.81	375	114
37	17.35	17.60	34.95	1.05	0.97	51.93	370	116
38	17.40	18.90	36.30	1.09	0.96	52.08	365	114
39	17.42	20.00	37.42	1.12	0.98	52.14	380	116
40	17.47	21.20	38.67	1.16	0.96	52.29	322	116

Table B.9 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	17.48	22.40	39.88	1.19	0.99	52.32	370	114
42	17.51	23.60	41.11	1.23	0.98	52.41	365	114
43	17.53	24.90	42.43	1.27	0.98	52.47	350	114
44	17.56	26.10	43.66	1.31	0.98	52.56	420	111
45	17.59	27.30	44.89	1.34	0.98	52.65	375	112
46	17.62	28.70	46.32	1.39	0.98	52.74	375	111
47	17.62	30.00	47.62	1.43	1.00	52.74	395	110
48	17.68	31.00	48.68	1.46	0.94	52.92	380	110
49	17.71	32.30	50.01	1.50	0.98	53.01	365	110
50	17.73	33.50	51.23	1.53	0.98	53.07	375	108
51	17.77	34.70	52.47	1.57	0.97	53.19	405	107
52	17.77	36.00	53.77	1.61	1.00	53.19	402	107
53	17.80	37.30	55.10	1.65	0.98	53.28	380	106
54	17.84	38.50	56.34	1.69	0.97	53.40	395	106
55	17.86	39.70	57.56	1.72	0.98	53.46	400	104
56	17.89	40.90	58.79	1.76	0.98	53.55	430	104
57	17.90	42.10	60.00	1.80	0.99	53.58	305	104
58	17.90	43.40	61.30	1.83	1.00	53.58	395	103
59	17.92	44.70	62.62	1.87	0.98	53.64	430	102
60	17.95	45.90	63.85	1.91	0.98	53.73	420	102
61	17.99	47.20	65.19	1.95	0.97	53.85	430	102
62	17.99	48.50	66.49	1.99	1.00	53.85	405	102
63	18.05	49.90	67.95	2.03	0.96	54.03	425	102
64	18.06	51.10	69.16	2.07	0.99	54.06	415	102
65	18.06	52.30	70.36	2.11	1.00	54.06	425	100
66	18.06	53.50	71.56	2.14	1.00	54.06	450	100
67	18.09	54.70	72.79	2.18	0.98	54.15	465	99
68	18.09	56.00	74.09	2.22	1.00	54.15	350	100
69	18.09	57.20	75.29	2.25	1.00	54.15	320	102
70	18.13	58.50	76.63	2.29	0.97	54.27	370	100
71	18.13	59.70	77.83	2.33	1.00	54.27	407	99
72	18.18	60.80	78.98	2.36	0.96	54.41	450	99
73	18.18	62.00	80.18	2.40	1.00	54.41	435	98
74	18.18	63.30	81.48	2.44	1.00	54.41	405	99
75	18.18	64.50	82.68	2.47	1.00	54.41	425	98
76	18.21	65.90	84.11	2.52	0.98	54.50	460	98
77	18.21	67.30	85.51	2.56	1.00	54.50	470	97
78	18.25	68.30	86.55	2.59	0.96	54.62	437	98
79	18.25	69.40	87.65	2.62	1.00	54.62	495	96
80	18.25	70.60	88.85	2.66	1.00	54.62	410	97

Table B.9 : Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	18.25	71.70	89.95	2.69	1.00	54.62	378	99
82	18.26	72.90	91.16	2.73	0.99	54.65	475	96
83	18.30	74.10	92.40	2.77	0.97	54.77	490	96
84	18.30	75.30	93.60	2.80	1.00	54.77	470	98
85	18.33	76.40	94.73	2.84	0.97	54.86	490	98
86	18.33	77.70	96.03	2.87	1.00	54.86	505	98
87	18.35	79.00	97.35	2.91	0.98	54.92	450	99
88	18.35	80.20	98.55	2.95	1.00	54.92	420	100
89	18.38	81.50	99.88	2.99	0.98	55.01	465	100
90	18.38	82.70	101.08	3.03	1.00	55.01	417	102
91	18.41	84.00	102.41	3.07	0.98	55.10	508	102
92	18.41	85.20	103.61	3.10	1.00	55.10	472	103
93	18.44	86.50	104.94	3.14	0.98	55.19	490	103
94	18.44	87.70	106.14	3.18	1.00	55.19	455	104
95	18.47	88.90	107.37	3.21	0.98	55.28	480	105
96	18.47	90.10	108.57	3.25	1.00	55.28	460	106
97	18.50	91.30	109.80	3.29	0.98	55.37	457	107
98	18.50	92.70	111.20	3.33	1.00	55.37	470	107
99	18.52	93.80	112.32	3.36	0.98	55.43	475	108
100	18.52	94.80	113.32	3.39	1.00	55.43	472	108
101	18.52	95.10	114.62	3.43	1.00	55.43	432	111
102	18.52	97.20	115.72	3.46	1.00	55.43	425	111
103	18.52	98.30	116.82	3.50	1.00	55.43	490	110
104	18.52	99.50	118.02	3.53	1.00	55.43	450	111
105	18.52	100.80	119.32	3.57	1.00	55.43	470	113
106	18.52	102.00	120.52	3.61	1.00	55.43	470	113
107	18.52	103.10	121.62	3.64	1.00	55.43	470	113
108	18.52	104.30	122.82	3.68	1.00	55.43	445	114
109	18.52	105.40	123.92	3.71	1.00	55.43	418	116
110	18.52	106.40	124.92	3.74	1.00	55.43	417	116
111	18.52	107.40	125.92	3.77	1.00	55.43	433	116
112	18.52	108.70	127.22	3.81	1.00	55.43	380	117
113	18.52	109.90	128.42	3.84	1.00	55.43	405	116
114	18.52	111.20	129.72	3.88	1.00	55.43	470	113
115	18.52	112.50	131.02	3.92	1.00	55.43	435	113
116	18.52	113.70	132.22	3.96	1.00	55.43	427	113
117	18.52	115.00	133.52	4.00	1.00	55.43	460	112
118	18.52	116.20	134.72	4.03	1.00	55.43	405	113
119	18.52	117.40	135.92	4.07	1.00	55.43	435	110
120	18.52	118.60	137.12	4.10	1.00	55.43	427	110

Table B.10: Raw and Computed Results for Run# 21

(hot water with solvent slug=5.21 %THPV, Q=1 cc/min)

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	10	108
2	0.00	0.00	0.00	0.00	0.00	0.00	13	112
3	0.00	0.00	0.00	0.00	0.00	0.00	16	116
4	0.00	0.00	0.00	0.00	0.00	0.00	22	120
5	0.00	0.00	0.00	0.00	0.00	0.00	31	118
6	0.00	0.00	0.00	0.00	0.00	0.00	44	112
7	0.00	0.00	0.00	0.00	0.00	0.00	63	106
8	0.00	0.00	0.00	0.00	0.00	0.00	89	102
9	0.00	0.00	0.00	0.00	0.00	0.00	165	98
10	0.00	0.00	0.00	0.00	0.00	0.00	310	94
11	0.00	0.00	0.00	0.00	0.00	0.00	415	92
12	0.75	0.00	0.75	0.02	0.00	2.22	165	94
13	1.75	0.00	1.75	0.05	0.00	5.18	185	94
14	2.95	0.00	2.95	0.09	0.00	8.74	185	95
15	4.25	0.00	4.25	0.13	0.00	12.59	190	97
16	5.45	0.00	5.45	0.16	0.00	16.14	200	98
17	6.65	0.00	6.65	0.20	0.00	19.70	210	100
18	7.82	0.00	7.82	0.23	0.00	23.16	215	103
19	9.12	0.00	9.12	0.27	0.00	27.01	215	106
20	10.42	0.00	10.42	0.31	0.00	30.86	220	109
21	11.62	0.00	11.62	0.34	0.00	34.42	225	112
22	12.82	0.00	12.82	0.38	0.00	37.97	210	116
23	14.02	0.00	14.02	0.42	0.00	41.53	215	116
24	15.12	0.00	15.12	0.45	0.00	44.79	217	120
25	16.30	0.00	16.30	0.48	0.00	48.28	225	122
26	17.40	0.00	17.40	0.52	0.00	51.54	232	122
27	17.80	0.70	18.50	0.55	0.64	52.73	238	122
28	17.92	1.60	19.52	0.58	0.88	53.08	240	123
29	18.02	2.70	20.72	0.61	0.92	53.38	237	123
30	18.10	3.80	21.90	0.65	0.93	53.61	235	123
31	18.25	4.90	23.15	0.69	0.88	54.06	238	123
32	18.39	6.00	24.39	0.72	0.89	54.47	247	123
33	18.53	7.20	25.73	0.76	0.90	54.89	250	123
34	18.65	8.40	27.05	0.80	0.91	55.24	250	123
35	18.74	9.70	28.44	0.84	0.94	55.51	251	123
36	18.84	10.80	29.64	0.88	0.92	55.81	253	123
37	18.91	11.90	30.81	0.91	0.94	56.01	256	123
38	18.98	13.10	32.08	0.95	0.94	56.22	262	123
39	19.10	14.30	33.40	0.99	0.91	56.58	255	123
40	19.21	15.50	34.71	1.03	0.92	56.90	258	123

Table B.10: Continued.

Time	Hp	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	19.24	16.70	35.94	1.06	0.98	56.99	265	123
42	19.32	17.90	37.22	1.10	0.94	57.23	267	123
43	19.36	19.10	38.46	1.14	0.97	57.35	273	123
44	19.39	20.30	39.69	1.18	0.98	57.43	277	123
45	19.44	21.50	40.94	1.21	0.96	57.58	280	123
46	19.54	22.50	42.04	1.25	0.91	57.88	282	122
47	19.59	23.70	43.29	1.28	0.96	58.03	281	122
48	19.65	25.00	44.65	1.32	0.96	58.20	291	122
49	19.70	26.10	45.80	1.36	0.96	58.35	289	122
50	19.80	27.20	47.00	1.39	0.92	58.65	293	122
51	19.85	28.40	48.25	1.43	0.96	58.80	288	122
52	19.89	29.60	49.49	1.47	0.97	58.92	290	122
53	20.02	30.70	50.72	1.50	0.89	59.30	285	123
54	20.05	31.80	51.85	1.54	0.97	59.39	280	123
55	20.12	33.00	53.12	1.57	0.94	59.60	285	122
56	20.17	34.30	54.47	1.61	0.96	59.75	287	123
57	20.18	35.50	55.68	1.65	0.99	59.77	285	122
58	20.26	36.80	57.06	1.69	0.94	60.01	270	123
59	20.26	38.10	58.36	1.73	1.00	60.01	272	123
60	20.31	39.30	59.61	1.77	0.96	60.16	285	122
61	20.31	40.40	60.71	1.80	1.00	60.16	293	122
62	20.48	41.50	61.98	1.84	0.87	60.66	290	122
63	20.48	42.90	63.38	1.88	1.00	60.66	287	122
64	20.48	44.20	64.68	1.92	1.00	60.66	283	122
65	20.48	45.30	65.78	1.95	1.00	60.66	275	123
66	20.58	46.50	67.08	1.99	0.92	60.96	285	122
67	20.60	47.50	68.10	2.02	0.98	61.02	293	122
68	20.60	48.80	69.40	2.06	1.00	61.02	277	123
69	20.66	50.00	70.66	2.09	0.95	61.20	272	123
70	20.66	51.30	71.96	2.13	1.00	61.20	290	121
71	20.66	52.40	73.06	2.16	1.00	61.20	283	122
72	20.83	53.30	74.13	2.20	0.84	61.70	285	122
73	20.83	54.60	75.43	2.23	1.00	61.70	285	122
74	20.83	55.80	76.63	2.27	1.00	61.70	283	122
75	20.83	57.00	77.83	2.31	1.00	61.70	274	122
76	20.83	58.30	79.13	2.34	1.00	61.70	288	121
77	20.83	59.50	80.33	2.38	1.00	61.70	300	121
78	20.83	60.70	81.53	2.41	1.00	61.70	290	122
79	20.93	61.90	82.83	2.45	0.92	62.00	285	121
80	20.93	62.90	83.83	2.48	1.00	62.00	283	121

Table B.10: Continued.

Time	Np	Wp	Wi	Qiw	FW	RL	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	20.93	63.80	84.73	2.51	1.00	62.00	292	121
82	20.98	65.00	85.98	2.55	0.96	62.14	300	121
83	20.98	66.30	87.28	2.59	1.00	62.14	292	121
84	21.04	67.40	88.44	2.62	0.95	62.32	295	121
85	21.04	68.50	89.54	2.65	1.00	62.32	285	121
86	21.04	69.70	90.74	2.69	1.00	62.32	275	121
87	21.04	70.90	91.94	2.72	1.00	62.32	283	121
88	21.07	71.90	92.97	2.75	0.97	62.41	292	120
89	21.07	73.00	94.07	2.79	1.00	62.41	286	121
90	21.07	74.20	95.27	2.82	1.00	62.41	282	121
91	21.13	75.40	96.53	2.86	0.95	62.59	288	121
92	21.13	76.50	97.63	2.89	1.00	62.59	275	121
93	21.13	77.70	98.83	2.93	1.00	62.59	267	121
94	21.13	78.90	100.03	2.96	1.00	62.59	270	121
95	21.13	80.00	101.13	3.00	1.00	62.59	280	121
96	21.18	81.10	102.28	3.03	0.96	62.74	282	121
97	21.18	82.20	103.38	3.06	1.00	62.74	274	121
98	21.18	83.40	104.58	3.10	1.00	62.74	263	122
99	21.18	84.50	105.68	3.13	1.00	62.74	266	121
100	21.20	85.70	106.90	3.17	0.98	62.80	276	120
101	21.20	86.90	108.10	3.20	1.00	62.80	285	120
102	21.20	88.00	109.20	3.23	1.00	62.80	287	120
103	21.20	89.20	110.40	3.27	1.00	62.80	285	120
104	21.20	90.30	111.50	3.30	1.00	62.80	288	120
105	21.20	91.40	112.60	3.34	1.00	62.80	288	120
106	21.20	92.50	113.70	3.37	1.00	62.80	273	120
107	21.20	93.70	114.90	3.40	1.00	62.80	253	121
108	21.20	94.90	116.10	3.44	1.00	62.80	257	120
109	21.20	96.10	117.30	3.47	1.00	62.80	262	120
110	21.20	97.40	118.60	3.51	1.00	62.80	273	120
111	21.20	98.60	119.80	3.55	1.00	62.80	273	120
112	21.20	99.80	121.00	3.58	1.00	62.80	295	118
113	21.20	101.00	122.20	3.62	1.00	62.80	295	118
114	21.20	102.10	123.30	3.65	1.00	62.80	292	118
115	21.20	103.20	124.40	3.68	1.00	62.80	265	120
116	21.20	104.20	125.40	3.71	1.00	62.80	260	120
117	21.20	105.30	126.50	3.75	1.00	62.80	267	118
118	21.20	106.50	127.70	3.78	1.00	62.80	273	120
119	21.20	107.70	128.90	3.82	1.00	62.80	277	120
120	21.20	108.90	130.10	3.85	1.00	62.80	285	118

Table B.11: Raw and Computed Results for Run# 22

(hot water with solvent slug=13.99 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	12	109
2	0.00	0.00	0.00	0.00	0.00	0.00	16	114
3	0.00	0.00	0.00	0.00	0.00	0.00	22	120
4	0.00	0.00	0.00	0.00	0.00	0.00	29	123
5	0.00	0.00	0.00	0.00	0.00	0.00	41	115
6	0.00	0.00	0.00	0.00	0.00	0.00	59	109
7	0.00	0.00	0.00	0.00	0.00	0.00	87	104
8	0.00	0.00	0.00	0.00	0.00	0.00	136	99
9	0.00	0.00	0.00	0.00	0.00	0.00	257	95
10	0.00	0.00	0.00	0.00	0.00	0.00	400	89
11	0.00	0.00	0.00	0.00	0.00	0.00	550	87
12	0.00	0.00	0.00	0.00	0.00	0.00	675	82
13	0.00	0.00	0.00	0.00	0.00	0.00	800	80
14	1.60	0.00	1.60	0.05	0.00	4.71	650	79
15	3.00	0.00	3.00	0.09	0.00	8.84	452	85
16	4.30	0.00	4.30	0.13	0.00	12.67	448	85
17	5.60	0.00	5.60	0.16	0.00	16.49	462	87
18	7.00	0.00	7.00	0.21	0.00	20.62	451	88
19	8.20	0.00	8.20	0.24	0.00	24.15	450	89
20	9.40	0.00	9.40	0.28	0.00	27.69	452	91
21	10.70	0.00	10.70	0.32	0.00	31.52	465	92
22	11.90	0.00	11.90	0.35	0.00	35.05	470	94
23	13.10	0.00	13.10	0.39	0.00	38.59	470	95
24	14.20	0.00	14.20	0.42	0.00	41.83	470	96
25	15.40	0.00	15.40	0.45	0.00	45.36	496	96
26	16.20	0.00	16.20	0.48	0.00	47.72	503	96
27	16.57	0.60	17.17	0.51	0.62	48.81	512	98
28	16.67	1.60	18.27	0.54	0.91	49.10	528	99
29	16.84	2.50	19.34	0.57	0.84	49.60	540	99
30	16.99	3.50	20.49	0.60	0.87	50.04	547	101
31	17.10	4.60	21.70	0.64	0.91	50.37	531	101
32	17.19	5.80	22.99	0.68	0.93	50.63	540	101
33	17.35	6.90	24.25	0.71	0.87	51.10	543	101
34	17.40	8.00	25.40	0.75	0.96	51.25	560	101
35	17.49	9.00	26.49	0.78	0.92	51.52	561	101
36	17.56	10.10	27.66	0.81	0.94	51.72	596	102
37	17.67	11.30	28.97	0.85	0.92	52.05	600	101
38	17.72	12.20	29.92	0.88	0.95	52.19	620	101
39	17.76	13.40	31.16	0.92	0.97	52.31	642	101
40	17.83	14.60	32.43	0.96	0.94	52.52	640	101

Table B.11: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	17.93	15.70	33.63	0.99	0.92	52.81	640	101
42	18.03	16.80	34.83	1.03	0.92	53.11	631	102
43	18.03	18.10	36.13	1.06	1.00	53.11	638	102
44	18.08	19.30	37.38	1.10	0.96	53.25	660	102
45	18.08	20.60	38.68	1.14	1.00	53.25	658	102
46	18.19	21.80	39.99	1.18	0.92	53.58	637	102
47	18.20	23.00	41.20	1.21	0.99	53.61	660	102
48	18.21	24.30	42.51	1.25	0.99	53.64	672	102
49	18.36	25.40	43.76	1.29	0.88	54.08	640	102
50	18.36	26.40	44.76	1.32	1.00	54.08	637	104
51	18.42	27.50	45.92	1.35	0.95	54.26	640	105
52	18.46	28.70	47.16	1.39	0.97	54.37	645	104
53	18.46	30.00	48.46	1.43	1.00	54.37	650	106
54	18.46	31.10	49.56	1.46	1.00	54.37	655	106
55	18.57	32.30	50.87	1.50	0.92	54.70	655	106
56	18.66	33.50	52.16	1.54	0.93	54.96	660	106
57	18.76	34.70	53.46	1.57	0.92	55.26	670	106
58	18.86	36.00	54.86	1.62	0.93	55.55	666	106
59	18.86	37.20	56.06	1.65	1.00	55.55	645	107
60	18.96	38.40	57.36	1.69	0.92	55.85	652	108
61	19.12	39.50	58.62	1.73	0.87	56.32	650	108
62	19.12	40.70	59.82	1.76	1.00	56.32	665	108
63	19.12	42.00	61.12	1.80	1.00	56.32	682	107
64	19.17	43.20	62.37	1.84	0.96	56.47	658	108
65	19.27	44.40	63.67	1.88	0.92	56.76	650	110
66	19.27	45.70	64.97	1.91	1.00	56.76	645	110
67	19.32	47.00	66.32	1.95	0.96	56.91	678	108
68	19.41	48.20	67.61	1.99	0.93	57.17	691	108
69	19.41	49.50	68.91	2.03	1.00	57.17	692	108
70	19.51	50.70	70.21	2.07	0.92	57.47	703	108
71	19.61	51.90	71.51	2.11	0.92	57.76	670	111
72	19.73	53.10	72.83	2.15	0.91	58.11	690	110
73	19.78	54.40	74.18	2.18	0.96	58.26	730	108
74	19.78	55.70	75.48	2.22	1.00	58.26	720	108
75	19.88	56.80	76.68	2.26	0.92	58.56	720	108
76	19.90	58.00	77.90	2.29	0.98	58.62	690	110
77	20.03	59.10	79.13	2.33	0.89	59.00	702	110
78	20.05	60.30	80.35	2.37	0.98	59.06	708	109
79	20.05	61.50	81.55	2.40	1.00	59.06	700	108
80	20.15	62.70	82.85	2.44	0.92	59.35	700	110

Table B.11: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	20.25	63.90	84.15	2.48	0.92	59.65	710	110
82	20.25	65.20	85.45	2.52	1.00	59.65	710	110
83	20.36	66.50	86.86	2.56	0.92	59.97	695	110
84	20.36	67.80	88.16	2.60	1.00	59.97	700	110
85	20.46	69.00	89.46	2.64	0.92	60.27	715	109
86	20.46	70.20	90.66	2.67	1.00	60.27	728	108
87	20.56	71.40	91.96	2.71	0.92	60.56	730	108
88	20.66	72.60	93.26	2.75	0.92	60.85	740	108
89	20.83	73.70	94.53	2.78	0.87	61.35	750	108
90	20.83	74.80	95.63	2.82	1.00	61.35	732	108
91	20.83	75.90	96.73	2.85	1.00	61.35	730	108
92	20.91	77.10	98.01	2.89	0.94	61.59	735	108
93	20.91	78.20	99.11	2.92	1.00	61.59	730	106
94	21.03	79.50	100.53	2.96	0.92	61.94	728	107
95	21.03	80.80	101.83	3.00	1.00	61.94	750	106
96	21.03	82.10	103.13	3.04	1.00	61.94	770	105
97	21.03	83.30	104.33	3.07	1.00	61.94	760	104
98	21.04	84.50	105.54	3.11	0.99	61.97	775	104
99	21.04	85.60	106.64	3.14	1.00	61.97	746	106
100	21.04	86.70	107.74	3.17	1.00	61.97	750	105
101	21.06	87.80	108.86	3.21	0.98	62.03	762	103
102	21.07	88.90	109.97	3.24	0.99	62.06	725	103
103	21.16	90.10	111.26	3.28	0.93	62.33	710	107
104	21.16	91.30	112.46	3.31	1.00	62.33	720	105
105	21.16	92.60	113.76	3.35	1.00	62.33	732	105
106	21.16	93.70	114.86	3.38	1.00	62.33	735	103
107	21.16	94.90	116.06	3.42	1.00	62.33	700	107
108	21.16	96.20	117.36	3.46	1.00	62.33	692	106
109	21.16	97.50	118.66	3.50	1.00	62.33	680	107
110	21.16	98.70	119.86	3.53	1.00	62.33	705	106
111	21.16	99.90	121.06	3.57	1.00	62.33	750	103
112	21.16	101.00	122.16	3.60	1.00	62.33	770	101
113	21.16	102.00	123.16	3.63	1.00	62.33	720	104
114	21.16	103.10	124.26	3.66	1.00	62.33	708	104
115	21.16	104.40	125.56	3.70	1.00	62.33	720	104
116	21.16	105.70	126.86	3.74	1.00	62.33	748	102
117	21.16	107.00	128.16	3.77	1.00	62.33	750	102
118	21.16	108.30	129.46	3.81	1.00	62.33	748	102
119	21.16	109.60	130.76	3.85	1.00	62.33	780	100
120	21.16	110.90	132.06	3.89	1.00	62.33	754	100

Table B.12: Raw and Computed Results for Run# 23

(hot water with solvent slug=20.14 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	12	108
2	0.00	0.00	0.00	0.00	0.00	0.00	13	110
3	0.00	0.00	0.00	0.00	0.00	0.00	15	113
4	0.00	0.00	0.00	0.00	0.00	0.00	24	116
5	0.00	0.00	0.00	0.00	0.00	0.00	28	124
6	0.00	0.00	0.00	0.00	0.00	0.00	36	127
7	0.00	0.00	0.00	0.00	0.00	0.00	49	119
8	0.00	0.00	0.00	0.00	0.00	0.00	67	114
9	0.00	0.00	0.00	0.00	0.00	0.00	89	110
10	0.00	0.00	0.00	0.00	0.00	0.00	124	104
11	0.00	0.00	0.00	0.00	0.00	0.00	212	101
12	0.00	0.00	0.00	0.00	0.00	0.00	110	100
13	1.50	0.00	1.50	0.05	0.00	4.63	74	122
14	3.50	0.00	3.50	0.11	0.00	10.80	50	144
15	5.10	0.00	5.10	0.16	0.00	15.73	44	134
16	6.70	0.00	6.70	0.21	0.00	20.67	36	124
17	8.20	0.00	8.20	0.25	0.00	25.29	43	118
18	9.20	0.00	9.20	0.28	0.00	28.38	50	114
19	10.20	0.00	10.20	0.31	0.00	31.46	68	110
20	11.10	0.00	11.10	0.34	0.00	34.24	74	107
21	12.12	0.00	12.12	0.37	0.00	37.38	79	107
22	12.92	0.00	12.92	0.40	0.00	39.85	74	107
23	14.42	0.00	14.42	0.44	0.00	44.48	68	124
24	16.02	0.00	16.02	0.49	0.00	49.41	67	130
25	17.42	0.00	17.42	0.54	0.00	53.73	62	130
26	17.72	0.60	18.32	0.57	0.67	54.66	64	127
27	17.97	1.70	19.67	0.61	0.81	55.43	66	126
28	18.16	2.60	20.76	0.64	0.83	56.01	64	124
29	18.28	3.70	21.98	0.68	0.90	56.38	67	123
30	18.44	4.70	23.14	0.71	0.86	56.88	67	122
31	18.54	6.00	24.54	0.76	0.93	57.19	64	122
32	18.65	7.20	25.85	0.80	0.92	57.53	66	122
33	18.75	8.40	27.15	0.84	0.92	57.83	65	123
34	18.79	9.60	28.39	0.88	0.97	57.96	65	123
35	18.86	10.70	29.56	0.91	0.94	58.17	66	124
36	18.92	11.70	30.62	0.94	0.94	58.36	64	125
37	18.92	13.00	31.92	0.98	1.00	58.36	65	126
38	19.02	14.40	33.42	1.03	0.93	58.67	65	126
39	19.02	15.70	34.72	1.07	1.00	58.67	62	128
40	19.11	16.90	36.01	1.11	0.93	58.95	65	126

Table B.12: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	19.16	18.10	37.26	1.15	0.96	59.10	65	127
42	19.21	19.30	38.51	1.19	0.96	59.25	63	127
43	19.28	20.60	39.88	1.23	0.95	59.47	65	126
44	19.36	21.90	41.26	1.27	0.94	59.72	64	127
45	19.36	23.10	42.46	1.31	1.00	59.72	64	127
46	19.43	24.40	43.83	1.35	0.95	59.93	65	128
47	19.47	25.70	45.17	1.39	0.97	60.06	63	128
48	19.47	26.90	46.37	1.43	1.00	60.06	63	128
49	19.57	28.20	47.77	1.47	0.93	60.36	65	128
50	19.57	29.50	49.07	1.51	1.00	60.36	61	126
51	19.61	30.80	50.41	1.55	0.97	60.49	64	123
52	19.61	32.10	51.71	1.60	1.00	60.49	61	122
53	19.65	33.30	52.95	1.63	0.97	60.61	64	121
54	19.65	34.50	54.15	1.67	1.00	60.61	61	120
55	19.65	35.70	55.35	1.71	1.00	60.61	65	118
56	19.72	36.80	56.52	1.74	0.94	60.83	62	118
57	19.72	38.00	57.72	1.78	1.00	60.83	65	117
58	19.81	39.10	58.91	1.82	0.92	61.10	63	117
59	19.81	40.20	60.01	1.85	1.00	61.10	64	115
60	19.86	41.40	61.26	1.89	0.96	61.26	64	115
61	19.86	42.70	62.56	1.93	1.00	61.26	63	115
62	19.86	43.90	63.76	1.97	1.00	61.26	65	115
63	19.96	45.20	65.16	2.01	0.93	61.57	62	115
64	19.96	46.50	66.46	2.05	1.00	61.57	65	114
65	19.96	47.60	67.56	2.08	1.00	61.57	61	114
66	20.13	48.80	68.93	2.13	0.88	62.09	65	114
67	20.13	50.10	70.23	2.17	1.00	62.09	61	114
68	20.13	51.40	71.53	2.21	1.00	62.09	65	113
69	20.13	52.60	72.73	2.24	1.00	62.09	63	113
70	20.23	53.70	73.93	2.28	0.92	62.40	64	113
71	20.23	54.90	75.13	2.32	1.00	62.40	65	113
72	20.23	56.10	76.33	2.35	1.00	62.40	64	113
73	20.29	57.30	77.59	2.39	0.95	62.58	65	112
74	20.29	58.40	78.69	2.43	1.00	62.58	62	112
75	20.34	59.50	79.84	2.46	0.96	62.74	65	112
76	20.34	60.70	81.04	2.50	1.00	62.74	62	112
77	20.37	61.80	82.17	2.53	0.97	62.83	64	111
78	20.37	62.80	83.17	2.57	1.00	62.83	63	112
79	20.37	63.90	84.27	2.60	1.00	62.83	65	111
80	20.42	65.10	85.52	2.64	0.96	62.99	62	112

Table B.12: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	20.42	66.20	86.62	2.67	1.00	62.99	63	111
82	20.42	67.40	87.82	2.71	1.00	62.99	64	111
83	20.44	68.60	89.04	2.75	0.98	63.05	63	111
84	20.49	69.80	90.29	2.79	0.96	63.20	65	111
85	20.49	70.90	91.39	2.82	1.00	63.20	68	111
86	20.49	72.20	92.69	2.86	1.00	63.20	69	111
87	20.49	73.50	93.99	2.90	1.00	63.20	69	112
88	20.54	74.70	95.24	2.94	0.96	63.36	69	115
89	20.59	76.00	96.59	2.98	0.96	63.51	68	125
90	20.59	77.20	97.79	3.02	1.00	63.51	63	129
91	20.59	78.50	99.09	3.06	1.00	63.51	63	128
92	20.69	79.70	100.39	3.10	0.92	63.82	61	128
93	20.79	81.00	101.79	3.14	0.93	64.13	63	125
94	20.79	82.20	102.99	3.18	1.00	64.13	64	124
95	20.79	83.40	104.19	3.21	1.00	64.13	62	123
96	20.86	84.60	105.46	3.25	0.94	64.34	65	121
97	20.86	85.80	106.66	3.29	1.00	64.34	65	121
98	20.86	87.20	108.06	3.33	1.00	64.34	65	120
99	20.86	88.30	109.16	3.37	1.00	64.34	67	120
100	20.86	89.30	110.16	3.40	1.00	64.34	63	119
101	20.86	90.50	111.36	3.43	1.00	64.34	66	118
102	20.86	91.60	112.46	3.47	1.00	64.34	66	118
103	20.86	92.80	113.66	3.51	1.00	64.34	64	118
104	20.86	93.90	114.76	3.54	1.00	64.34	67	118
105	20.86	95.20	116.06	3.58	1.00	64.34	66	118
106	20.86	96.40	117.26	3.62	1.00	64.34	66	118
107	20.86	97.60	118.46	3.65	1.00	64.34	67	118
108	20.86	98.80	119.66	3.69	1.00	64.34	64	118
109	20.86	100.00	120.86	3.73	1.00	64.34	67	118
110	20.86	101.30	122.16	3.77	1.00	64.34	66	118
111	20.86	102.40	123.26	3.80	1.00	64.34	65	118
112	20.86	103.70	124.56	3.84	1.00	64.34	67	118
113	20.86	104.80	125.66	3.88	1.00	64.34	64	119
114	20.86	105.90	126.76	3.91	1.00	64.34	66	118
115	20.86	107.20	128.06	3.95	1.00	64.34	67	120
116	20.86	108.40	129.26	3.99	1.00	64.34	64	120
117	20.86	109.50	130.36	4.02	1.00	64.34	68	120
118	20.86	110.70	131.56	4.06	1.00	64.34	66	119
119	20.86	111.80	132.66	4.09	1.00	64.34	66	118
120	20.86	113.00	133.86	4.13	1.00	64.34	68	118

Table B.13: Raw and Computed Results for Run# 24

(hot water with solvent slug=24.75 %THPV, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	8	106
2	0.00	0.00	0.00	0.00	0.00	0.00	11	110
3	0.00	0.00	0.00	0.00	0.00	0.00	14	114
4	0.00	0.00	0.00	0.00	0.00	0.00	17	117
5	0.00	0.00	0.00	0.00	0.00	0.00	22	122
6	0.00	0.00	0.00	0.00	0.00	0.00	29	119
7	0.00	0.00	0.00	0.00	0.00	0.00	40	113
8	0.00	0.00	0.00	0.00	0.00	0.00	55	108
9	0.00	0.00	0.00	0.00	0.00	0.00	74	104
10	0.00	0.00	0.00	0.00	0.00	0.00	102	100
11	0.00	0.00	0.00	0.00	0.00	0.00	154	96
12	0.00	0.00	0.00	0.00	0.00	0.00	260	93
13	2.00	0.00	2.00	0.06	0.00	6.16	375	90
14	3.90	0.00	3.90	0.12	0.00	12.01	128	88
15	5.90	0.00	5.90	0.18	0.00	18.17	78	104
16	7.40	0.00	7.40	0.23	0.00	22.78	63	138
17	8.80	0.00	8.80	0.27	0.00	27.09	59	132
18	10.10	0.00	10.10	0.31	0.00	31.10	59	128
19	11.30	0.00	11.30	0.35	0.00	34.79	58	124
20	12.60	0.00	12.60	0.39	0.00	38.79	62	121
21	13.90	0.00	13.90	0.43	0.00	42.80	66	120
22	15.40	0.00	15.40	0.47	0.00	47.41	68	118
23	16.60	0.00	16.60	0.51	0.00	51.11	68	122
24	17.35	0.32	17.67	0.54	0.30	53.42	62	126
25	17.64	1.42	19.06	0.59	0.79	54.31	64	124
26	17.68	2.32	20.00	0.62	0.96	54.43	62	122
27	17.83	3.32	21.15	0.65	0.87	54.90	62	121
28	17.98	4.42	22.40	0.69	0.88	55.36	64	119
29	18.10	5.42	23.52	0.72	0.89	55.73	62	118
30	18.23	6.62	24.85	0.77	0.90	56.13	62	118
31	18.34	7.72	26.06	0.80	0.91	56.47	65	117
32	18.45	8.92	27.37	0.84	0.92	56.80	62	117
33	18.52	10.12	28.64	0.88	0.94	57.02	63	115
34	18.58	11.22	29.80	0.92	0.95	57.20	65	114
35	18.62	12.32	30.94	0.95	0.96	57.33	63	115
36	18.85	13.62	32.47	1.00	0.85	58.04	64	114
37	18.95	14.72	33.67	1.04	0.92	58.34	66	114
38	19.01	15.92	34.93	1.08	0.95	58.53	66	113
39	19.12	17.02	36.14	1.11	0.91	58.87	63	113
40	19.23	18.22	37.45	1.15	0.92	59.21	66	113

Table B.13: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	$^{\circ}$ C
41	19.23	19.32	38.55	1.19	1.00	59.21	65	114
42	19.34	20.52	39.86	1.23	0.92	59.54	63	114
43	19.40	21.72	41.12	1.27	0.95	59.73	66	113
44	19.40	22.82	42.22	1.30	1.00	59.73	66	113
45	19.56	24.02	43.58	1.34	0.88	60.22	64	113
46	19.61	25.22	44.83	1.38	0.96	60.38	66	113
47	19.71	26.22	45.93	1.41	0.91	60.68	66	112
48	19.82	27.32	47.14	1.45	0.91	61.02	64	112
49	19.82	28.42	48.24	1.49	1.00	61.02	66	112
50	19.82	29.52	49.34	1.52	1.00	61.02	66	112
51	19.93	30.62	50.55	1.56	0.91	61.36	64	112
52	19.96	31.82	51.78	1.59	0.98	61.45	65	112
53	20.01	33.02	53.03	1.63	0.96	61.61	66	112
54	20.03	34.22	54.25	1.67	0.98	61.67	63	112
55	20.10	35.42	55.52	1.71	0.94	61.88	65	112
56	20.13	36.52	56.65	1.74	0.97	61.98	66	112
57	20.18	37.72	57.90	1.78	0.96	62.13	63	112
58	20.22	38.72	58.94	1.81	0.96	62.25	65	112
59	20.22	39.82	60.04	1.85	1.00	62.25	66	112
60	20.28	40.92	61.20	1.88	0.95	62.44	63	112
61	20.32	42.02	62.34	1.92	0.96	62.56	65	112
62	20.43	43.12	63.55	1.96	0.91	62.90	66	112
63	20.50	44.32	64.82	2.00	0.94	63.12	64	114
64	20.50	45.42	65.92	2.03	1.00	63.12	65	113
65	20.62	46.52	67.14	2.07	0.90	63.49	67	113
66	20.70	47.72	68.42	2.11	0.94	63.73	66	113
67	20.70	48.92	69.62	2.14	1.00	63.73	66	112
68	20.75	50.12	70.87	2.18	0.96	63.89	68	112
69	20.75	51.22	71.97	2.22	1.00	63.89	66	112
70	20.80	52.22	73.02	2.25	0.95	64.04	66	112
71	20.80	53.32	74.12	2.28	1.00	64.04	68	112
72	20.80	54.42	75.22	2.32	1.00	64.04	66	112
73	20.86	55.52	76.38	2.35	0.95	64.22	66	112
74	20.86	56.72	77.58	2.39	1.00	64.22	67	113
75	20.89	57.92	78.81	2.43	0.98	64.32	66	113
76	20.92	59.12	80.04	2.46	0.98	64.41	64	113
77	20.98	60.32	81.30	2.50	0.95	64.59	66	113
78	20.98	61.42	82.40	2.54	1.00	64.59	66	114
79	21.03	62.42	83.45	2.57	0.95	64.75	63	114
80	21.03	63.42	84.45	2.60	1.00	64.75	66	114

Table B.13: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	21.13	64.62	85.75	2.64	0.92	65.06	65	114
82	21.13	65.82	86.95	2.68	1.00	65.06	62	115
83	21.17	66.92	88.09	2.71	0.96	65.18	64	116
84	21.20	68.02	89.22	2.75	0.97	65.27	64	116
85	21.20	69.22	90.42	2.78	1.00	65.27	62	116
86	21.25	70.42	91.67	2.82	0.96	65.42	65	116
87	21.30	71.62	92.92	2.86	0.96	65.58	65	116
88	21.32	72.62	93.94	2.89	0.98	65.64	62	116
89	21.37	73.72	95.09	2.93	0.96	65.79	64	116
90	21.37	74.82	96.19	2.96	1.00	65.79	65	116
91	21.42	75.92	97.34	3.00	0.96	65.95	62	116
92	21.47	77.12	98.59	3.04	0.96	66.10	64	116
93	21.52	78.32	99.84	3.07	0.96	66.26	64	116
94	21.55	79.42	100.97	3.11	0.97	66.35	62	116
95	21.59	80.52	102.11	3.14	0.96	66.47	64	116
96	21.63	81.52	103.15	3.18	0.96	66.59	65	116
97	21.63	82.72	104.35	3.21	1.00	66.59	62	116
98	21.68	83.92	105.60	3.25	0.96	66.75	63	116
99	21.68	84.92	106.60	3.28	1.00	66.75	65	116
100	21.70	85.92	107.62	3.31	0.98	66.81	62	116
101	21.72	87.02	108.74	3.35	0.98	66.87	63	116
102	21.72	88.12	109.84	3.38	1.00	66.87	64	116
103	21.72	89.12	110.84	3.41	1.00	66.87	63	116
104	21.72	90.12	111.84	3.44	1.00	66.87	63	116
105	21.72	91.22	112.94	3.48	1.00	66.87	65	116
106	21.72	92.42	114.14	3.51	1.00	66.87	64	116
107	21.72	93.62	115.34	3.55	1.00	66.87	62	116
108	21.72	94.72	116.44	3.58	1.00	66.87	65	115
109	21.72	95.82	117.54	3.62	1.00	66.87	64	114
110	21.72	97.02	118.74	3.66	1.00	66.87	62	114
111	21.72	98.12	119.84	3.69	1.00	66.87	65	115
112	21.72	99.32	121.04	3.73	1.00	66.87	65	115
113	21.72	100.42	122.14	3.76	1.00	66.87	62	116
114	21.72	101.52	123.24	3.79	1.00	66.87	63	115
115	21.72	102.62	124.34	3.83	1.00	66.87	64	116
116	21.72	103.72	125.44	3.86	1.00	66.87	61	116
117	21.72	104.82	126.54	3.90	1.00	66.87	62	116
118	21.72	106.02	127.74	3.93	1.00	66.87	65	116
119	21.72	107.22	128.94	3.97	1.00	66.87	62	116
120	21.72	108.42	130.14	4.01	1.00	66.87	64	115

Table B.14: Raw and Computed Results for Run# 16

(cold water, no tar, no solvent, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	2	22
2	0.00	0.00	0.00	0.00	0.00	0.00	2	22
3	0.00	0.00	0.00	0.00	0.00	0.00	3	22
4	0.80	0.00	0.80	0.04	0.00	3.92	4	22
5	1.80	0.00	1.80	0.09	0.00	8.82	4	22
6	2.80	0.00	2.80	0.14	0.00	13.72	4	22
7	3.80	0.00	3.80	0.19	0.00	18.62	5	22
8	4.80	0.00	4.80	0.24	0.00	23.52	5	22
9	5.80	0.00	5.80	0.28	0.00	28.42	5	22
10	6.80	0.00	6.80	0.33	0.00	33.32	5	22
11	7.80	0.00	7.80	0.38	0.00	38.22	5	22
12	8.90	0.00	8.90	0.44	0.00	43.61	5	22
13	9.90	0.00	9.90	0.49	0.00	48.51	5	22
14	10.90	0.00	10.90	0.53	0.00	53.41	5	22
15	11.90	0.00	11.90	0.58	0.00	58.30	5	22
16	12.90	0.00	12.90	0.63	0.00	63.20	6	22
17	13.90	0.00	13.90	0.68	0.00	68.10	6	22
18	14.33	1.40	15.73	0.77	0.77	70.21	6	22
19	14.33	2.50	16.83	0.82	1.00	70.21	6	22
20	14.39	3.70	18.09	0.89	0.95	70.50	6	22
21	14.39	4.80	19.19	0.94	1.00	70.50	6	22
22	14.46	5.80	20.26	0.99	0.93	70.85	6	22
23	14.46	6.80	21.26	1.04	1.00	70.85	6	22
24	14.51	7.70	22.21	1.09	0.95	71.09	6	22
25	14.51	8.90	23.41	1.15	1.00	71.09	6	22
26	14.56	9.90	24.46	1.20	0.95	71.34	6	22
27	14.56	11.00	25.56	1.25	1.00	71.34	6	22
28	14.64	12.00	26.64	1.31	0.93	71.73	6	22
29	14.64	13.10	27.74	1.36	1.00	71.73	6	24
30	14.64	14.20	28.84	1.41	1.00	71.73	6	24
31	14.68	15.20	29.88	1.46	0.96	71.93	6	24
32	14.68	16.30	30.98	1.52	1.00	71.93	6	24
33	14.72	17.30	32.02	1.57	0.96	72.12	6	24
34	14.72	18.50	33.22	1.63	1.00	72.12	6	24
35	14.72	19.80	34.52	1.69	1.00	72.12	6	24
36	14.77	20.90	35.67	1.75	0.96	72.37	6	24
37	14.77	22.00	36.77	1.80	1.00	72.37	6	24
38	14.77	23.10	37.87	1.86	1.00	72.37	6	24
39	14.77	24.20	38.97	1.91	1.00	72.37	6	24
40	14.85	25.30	40.15	1.97	0.93	72.76	6	24

Table B.14: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	14.85	26.40	41.25	2.02	1.00	72.76	6	24
42	14.85	27.60	42.45	2.08	1.00	72.76	6	24
43	14.85	28.60	43.45	2.13	1.00	72.76	6	24
44	14.85	29.70	44.55	2.18	1.00	72.76	6	24
45	14.85	30.80	45.65	2.24	1.00	72.76	6	24
46	14.92	31.80	46.72	2.29	0.93	73.10	6	24
47	14.92	32.90	47.82	2.34	1.00	73.10	6	24
48	14.92	34.00	48.92	2.40	1.00	73.10	6	24
49	14.92	35.10	50.02	2.45	1.00	73.10	6	24
50	14.92	36.30	51.22	2.51	1.00	73.10	6	24
51	14.92	37.40	52.32	2.56	1.00	73.10	6	24
52	14.92	38.50	53.42	2.62	1.00	73.10	6	24
53	15.01	39.50	54.51	2.67	0.92	73.54	6	24
54	15.01	40.60	55.61	2.72	1.00	73.54	6	24
55	15.01	41.70	56.71	2.78	1.00	73.54	6	24
56	15.01	42.90	57.91	2.84	1.00	73.54	6	24
57	15.01	44.00	59.01	2.89	1.00	73.54	6	24
58	15.01	45.10	60.11	2.95	1.00	73.54	6	24
59	15.01	46.30	61.31	3.00	1.00	73.54	6	24
60	15.01	47.40	62.41	3.06	1.00	73.54	6	24
61	15.01	48.50	63.51	3.11	1.00	73.54	6	24
62	15.04	49.50	64.54	3.16	0.97	73.69	6	24
63	15.04	50.60	65.64	3.22	1.00	73.69	6	24
64	15.04	51.70	66.74	3.27	1.00	73.69	6	24
65	15.04	52.80	67.84	3.32	1.00	73.69	6	24
66	15.04	53.80	68.84	3.37	1.00	73.69	6	24
67	15.04	54.90	69.94	3.43	1.00	73.69	6	24
68	15.04	56.00	71.04	3.48	1.00	73.69	6	24
69	15.04	57.00	72.04	3.53	1.00	73.69	6	24
70	15.04	58.10	73.14	3.58	1.00	73.69	6	24
71	15.04	59.30	74.34	3.64	1.00	73.69	6	24
72	15.04	60.40	75.44	3.70	1.00	73.69	6	24
73	15.12	61.40	76.52	3.75	0.93	74.08	5	24
74	15.12	62.40	77.52	3.80	1.00	74.08	5	24
75	15.12	63.50	78.62	3.85	1.00	74.08	5	24
76	15.12	64.50	79.62	3.90	1.00	74.08	5	24
77	15.12	65.60	80.72	3.95	1.00	74.08	5	24
78	15.12	66.70	81.82	4.01	1.00	74.08	5	24
79	15.12	67.80	82.92	4.06	1.00	74.08	5	24
80	15.12	68.90	84.02	4.12	1.00	74.08	5	24

Table B.14: Continued.

Time	Np	Wp	Wi	Qiw	FW	Re	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	15.12	70.00	85.12	4.17	1.00	74.08	5	24
82	15.12	71.00	86.12	4.22	1.00	74.08	5	24
83	15.12	72.00	87.12	4.27	1.00	74.08	5	24
84	15.12	73.00	88.12	4.32	1.00	74.08	5	24
85	15.12	74.10	89.22	4.37	1.00	74.08	5	24
86	15.12	75.20	90.32	4.43	1.00	74.08	5	24
87	15.12	76.30	91.42	4.48	1.00	74.08	5	24
88	15.12	77.40	92.52	4.53	1.00	74.08	5	24
89	15.20	78.30	93.50	4.58	0.92	74.47	5	24
90	15.20	79.40	94.60	4.63	1.00	74.47	5	24
91	15.20	80.50	95.70	4.69	1.00	74.47	5	24
92	15.20	81.60	96.80	4.74	1.00	74.47	5	24
93	15.20	82.70	97.90	4.80	1.00	74.47	5	24
94	15.20	83.80	99.00	4.85	1.00	74.47	5	24
95	15.20	84.90	100.10	4.90	1.00	74.47	5	24
96	15.20	86.00	101.20	4.96	1.00	74.47	5	24
97	15.20	87.10	102.30	5.01	1.00	74.47	5	24
98	15.20	88.20	103.40	5.07	1.00	74.47	5	24
99	15.20	89.30	104.50	5.12	1.00	74.47	5	24
100	15.20	90.40	105.60	5.17	1.00	74.47	5	24

Table B.15: Raw and Computed Results for Run# 17

(cold water, no tar, no solvent, Q= 2 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	6	22
2	0.00	0.00	0.00	0.00	0.00	0.00	9	22
3	0.50	0.00	0.50	0.02	0.00	2.50	11	22
4	2.00	0.00	2.00	0.10	0.00	9.98	13	22
5	3.90	0.00	3.90	0.19	0.00	19.46	13	22
6	5.80	0.00	5.80	0.29	0.00	28.94	14	22
7	7.90	0.00	7.90	0.39	0.00	39.42	14	22
8	9.70	0.00	9.70	0.48	0.00	48.40	14	22
9	11.30	0.00	11.30	0.56	0.00	56.39	14	22
10	12.70	0.00	12.70	0.63	0.00	63.37	14	22
11	12.87	1.60	14.47	0.72	0.90	64.22	14	22
12	12.94	3.30	16.24	0.81	0.96	64.57	14	22
13	12.96	5.20	18.16	0.91	0.99	64.67	14	22
14	13.02	7.10	20.12	1.00	0.97	64.97	14	22
15	13.06	9.10	22.16	1.11	0.98	65.17	14	22
16	13.10	11.10	24.20	1.21	0.98	65.37	13	22
17	13.17	13.00	26.17	1.31	0.96	65.72	13	22
18	13.18	15.00	28.18	1.41	1.00	65.77	13	22
19	13.18	16.90	30.08	1.50	1.00	65.77	13	22
20	13.26	18.70	31.96	1.59	0.96	66.17	13	22
21	13.26	20.60	33.86	1.69	1.00	66.17	13	22
22	13.34	22.40	35.74	1.78	0.96	66.57	13	22
23	13.38	24.20	37.58	1.88	0.98	66.77	13	22
24	13.38	26.20	39.58	1.98	1.00	66.77	13	22
25	13.43	28.00	41.43	2.07	0.97	67.02	13	22
26	13.43	30.00	43.43	2.17	1.00	67.02	13	22
27	13.43	31.90	45.33	2.26	1.00	67.02	13	22
28	13.43	33.70	47.13	2.35	1.00	67.02	13	22
29	13.43	35.70	49.13	2.45	1.00	67.02	13	22
30	13.43	37.70	51.13	2.55	1.00	67.02	13	22
31	13.50	39.50	53.00	2.64	0.96	67.37	13	22
32	13.50	41.40	54.90	2.74	1.00	67.37	13	22
33	13.50	43.30	56.80	2.83	1.00	67.37	13	22
34	13.58	45.20	58.78	2.93	0.96	67.76	13	22
35	13.58	47.10	60.68	3.03	1.00	67.76	13	22
36	13.58	48.90	62.48	3.12	1.00	67.76	13	22
37	13.58	50.80	64.38	3.21	1.00	67.76	13	22
38	13.66	52.60	66.26	3.31	0.96	68.16	13	24
39	13.66	54.50	68.16	3.40	1.00	68.16	13	24
40	13.66	56.40	70.06	3.50	1.00	68.16	13	24

Table B.15: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	13.66	58.40	72.06	3.60	1.00	68.16	13	24
42	13.72	60.10	73.82	3.68	0.97	68.46	13	24
43	13.72	62.10	75.82	3.78	1.00	68.46	13	24
44	13.72	64.20	77.92	3.89	1.00	68.46	13	24
45	13.72	66.30	80.02	3.99	1.00	68.46	13	24
46	13.72	68.40	82.12	4.10	1.00	68.46	13	24
47	13.72	70.30	84.02	4.19	1.00	68.46	13	24
48	13.72	72.40	86.12	4.30	1.00	68.46	13	24
49	13.72	74.40	88.12	4.40	1.00	68.46	13	24
50	13.72	76.40	90.12	4.50	1.00	68.46	13	24
51	13.72	78.40	92.12	4.60	1.00	68.46	13	24
52	13.72	80.50	94.22	4.70	1.00	68.46	13	24
53	13.72	82.50	96.22	4.80	1.00	68.46	13	24
54	13.78	84.40	98.18	4.90	0.97	68.76	13	24
55	13.78	86.40	100.18	5.00	1.00	68.76	13	24
56	13.78	88.50	102.28	5.10	1.00	68.76	13	24
57	13.78	90.50	104.28	5.20	1.00	68.76	13	24
58	13.82	92.60	106.42	5.31	0.98	68.96	13	24
59	13.82	94.50	108.32	5.41	1.00	68.96	13	24
60	13.82	96.40	110.22	5.50	1.00	68.96	13	24
61	13.88	98.20	112.08	5.59	0.97	69.26	13	24
62	13.88	100.10	113.98	5.69	1.00	69.26	13	24
63	13.88	102.00	115.88	5.78	1.00	69.26	13	24
64	13.88	103.90	117.78	5.88	1.00	69.26	13	24
65	13.88	105.90	119.78	5.98	1.00	69.26	13	24
66	13.88	107.90	121.78	6.08	1.00	69.26	13	24
67	13.88	109.90	123.78	6.18	1.00	69.26	13	24
68	13.88	112.00	125.88	6.28	1.00	69.26	13	24
69	13.88	114.10	127.98	6.39	1.00	69.26	13	24
70	13.88	116.20	130.08	6.49	1.00	69.26	13	24
71	13.96	118.10	132.06	6.59	0.96	69.66	13	24
72	13.96	120.20	134.16	6.69	1.00	69.66	13	24
73	13.96	122.20	136.16	6.79	1.00	69.66	13	24
74	14.00	124.20	138.20	6.90	0.98	69.86	13	24
75	14.00	126.20	140.20	7.00	1.00	69.86	13	24
76	14.00	128.20	142.20	7.10	1.00	69.86	13	24
77	14.00	130.30	144.30	7.20	1.00	69.86	13	24
78	14.00	132.00	146.00	7.29	1.00	69.86	13	24
79	14.00	134.00	148.00	7.39	1.00	69.86	13	24
80	14.00	136.00	150.00	7.49	1.00	69.86	13	24

Table B.16: Raw and Computed Results for Run# 18

(cold water, no tar, solvent, Q=4 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	C
1	0.00	0.00	0.00	0.00	0.00	0.00	6	18
2	0.00	0.00	0.00	0.00	0.00	0.00	12	18
3	1.65	0.00	1.65	0.08	0.00	8.04	17	18
4	4.05	0.00	4.05	0.20	0.00	19.73	19	22
5	6.55	0.00	6.55	0.32	0.00	31.90	21	24
6	9.25	0.00	9.25	0.45	0.00	45.06	24	24
7	11.85	0.00	11.85	0.58	0.00	57.72	27	24
8	13.15	0.00	13.15	0.64	0.00	64.05	29	24
9	13.35	2.80	16.15	0.79	0.93	65.03	30	24
10	13.47	5.80	19.27	0.94	0.96	65.61	32	24
11	13.50	9.50	23.00	1.12	0.99	65.76	33	24
12	13.51	13.30	26.81	1.31	1.00	65.81	34	24
13	13.51	17.20	30.71	1.50	1.00	65.81	34	24
14	13.56	21.00	34.56	1.68	0.99	66.05	35	24
15	13.56	24.80	38.36	1.87	1.00	66.05	35	24
16	13.62	28.50	42.12	2.05	0.98	66.34	35	24
17	13.62	32.60	46.22	2.25	1.00	66.34	35	24
18	13.62	36.40	50.02	2.44	1.00	66.34	35	24
19	13.69	40.10	53.79	2.62	0.98	66.68	35	24
20	13.69	44.00	57.69	2.81	1.00	66.68	36	24
21	13.69	47.90	61.59	3.00	1.00	66.68	36	24
22	13.69	51.70	65.39	3.19	1.00	66.68	37	24
23	13.69	55.70	69.39	3.38	1.00	66.68	37	24
24	13.69	59.50	73.19	3.57	1.00	66.68	37	24
25	13.69	63.20	76.89	3.75	1.00	66.68	37	24
26	13.74	67.00	80.74	3.93	0.99	66.93	38	24
27	13.74	70.70	84.44	4.11	1.00	66.93	38	24
28	13.78	74.50	88.28	4.30	0.99	67.12	38	24
29	13.78	78.10	91.88	4.48	1.00	67.12	38	24
30	13.78	81.80	95.58	4.66	1.00	67.12	38	24
31	13.78	85.40	99.18	4.83	1.00	67.12	38	24
32	13.78	89.10	102.88	5.01	1.00	67.12	38	24
33	13.78	92.90	106.68	5.20	1.00	67.12	38	24
34	13.78	96.60	110.38	5.38	1.00	67.12	38	24
35	13.78	100.40	114.18	5.56	1.00	67.12	38	24
36	13.81	104.30	118.11	5.75	0.99	67.27	38	24
37	13.81	108.10	121.91	5.94	1.00	67.27	38	24
38	13.81	111.90	125.71	6.12	1.00	67.27	37	24
39	13.81	115.80	129.61	6.31	1.00	67.27	37	24
40	13.81	119.50	133.31	6.49	1.00	67.27	37	24

Table B.17: Raw and Computed Results for Run# 13

(hot water , no tar, no solvent, Q=1 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	1	101
2	0.00	0.00	0.00	0.00	0.00	0.00	2	103
3	0.31	0.00	0.31	0.02	0.00	1.54	3	98
4	1.61	0.00	1.61	0.08	0.00	8.00	5	92
5	3.21	0.00	3.21	0.16	0.00	15.95	6	89
6	4.41	0.00	4.41	0.22	0.00	21.92	6	108
7	5.71	0.00	5.71	0.28	0.00	28.38	6	104
8	6.91	0.00	6.91	0.34	0.00	34.34	6	97
9	8.21	0.00	8.21	0.41	0.00	40.81	6	94
10	9.71	0.00	9.71	0.48	0.00	48.26	6	91
11	11.21	0.00	11.21	0.56	0.00	55.72	6	102
12	11.91	0.00	11.91	0.59	0.00	59.19	6	110
13	12.11	0.80	12.91	0.64	0.80	60.19	6	102
14	12.12	1.80	13.92	0.69	0.99	60.24	6	97
15	12.14	3.00	15.14	0.75	0.98	60.34	6	94
16	12.20	4.40	16.60	0.83	0.96	60.64	6	91
17	12.22	5.70	17.92	0.89	0.98	60.74	6	94
18	12.32	7.00	19.32	0.96	0.93	61.23	6	95
19	12.38	8.40	20.78	1.03	0.96	61.53	6	92
20	12.46	9.70	22.16	1.10	0.94	61.93	6	91
21	12.51	11.10	23.61	1.17	0.97	62.18	6	89
22	12.55	12.70	25.25	1.25	0.98	62.38	6	88
23	12.57	14.00	26.57	1.32	0.98	62.48	6	94
24	12.57	15.40	27.97	1.39	1.00	62.48	6	100
25	12.64	16.70	29.34	1.46	0.95	62.82	6	100
26	12.64	17.90	30.54	1.52	1.00	62.82	6	102
27	12.79	18.90	31.69	1.58	0.87	63.57	6	105
28	12.79	19.90	32.69	1.62	1.00	63.57	6	98
29	12.92	21.00	33.92	1.69	0.89	64.21	6	94
30	12.92	22.50	35.42	1.76	1.00	64.21	6	91
31	12.98	23.90	36.88	1.83	0.96	64.51	6	88
32	12.98	25.40	38.38	1.91	1.00	64.51	6	89
33	12.98	26.70	39.68	1.97	1.00	64.51	6	96
34	13.08	27.70	40.78	2.03	0.91	65.01	6	99
35	13.16	28.80	41.96	2.09	0.93	65.41	6	98
36	13.16	30.10	43.26	2.15	1.00	65.41	6	94
37	13.16	31.50	44.66	2.22	1.00	65.41	6	91
38	13.16	32.80	45.96	2.28	1.00	65.41	6	88
39	13.22	34.10	47.32	2.35	0.96	65.71	6	87
40	13.22	35.40	48.62	2.42	1.00	65.71	6	89

Table B.17: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	13.22	36.80	50.02	2.49	1.00	65.71	6	91
42	13.29	38.10	51.39	2.55	0.95	66.05	6	99
43	13.29	39.60	52.89	2.63	1.00	66.05	6	97
44	13.29	40.90	54.19	2.69	1.00	66.05	6	95
45	13.29	42.20	55.49	2.76	1.00	66.05	6	95
46	13.29	43.50	56.79	2.82	1.00	66.05	6	96
47	13.35	44.80	58.15	2.89	0.96	66.35	6	95
48	13.45	46.20	59.65	2.96	0.93	66.85	6	95
49	13.45	47.40	60.85	3.02	1.00	66.85	6	94
50	13.45	48.50	61.95	3.08	1.00	66.85	6	94
51	13.52	49.60	63.12	3.14	0.94	67.20	6	95
52	13.52	51.00	64.52	3.21	1.00	67.20	6	96
53	13.52	52.40	65.92	3.28	1.00	67.20	6	95
54	13.52	53.80	67.32	3.35	1.00	67.20	6	87
55	13.52	55.10	68.62	3.41	1.00	67.20	6	95
56	13.52	56.40	69.92	3.48	1.00	67.20	6	94
57	13.52	57.70	71.22	3.54	1.00	67.20	6	95
58	13.52	59.00	72.52	3.60	1.00	67.20	6	95
59	13.54	60.40	73.94	3.67	0.99	67.30	6	96
60	13.54	61.80	75.34	3.74	1.00	67.30	6	95
61	13.54	63.20	76.74	3.81	1.00	67.30	6	98
62	13.54	64.60	78.14	3.88	1.00	67.30	6	100
63	13.54	66.00	79.54	3.95	1.00	67.30	6	99
64	13.54	67.30	80.84	4.02	1.00	67.30	6	99
65	13.54	68.60	82.14	4.08	1.00	67.30	6	98
66	13.54	69.80	83.34	4.14	1.00	67.30	6	97
67	13.54	70.90	84.44	4.20	1.00	67.30	6	95
68	13.54	72.10	85.64	4.26	1.00	67.30	6	97
69	13.54	73.50	87.04	4.33	1.00	67.30	6	97
70	13.54	74.90	88.44	4.40	1.00	67.30	6	95
71	13.54	76.30	89.84	4.47	1.00	67.30	6	94
72	13.63	77.50	91.13	4.53	0.93	67.74	6	94
73	13.63	78.70	92.33	4.59	1.00	67.74	6	95
74	13.63	80.00	93.63	4.65	1.00	67.74	6	96
75	13.63	81.40	95.03	4.72	1.00	67.74	6	97
76	13.63	82.80	96.43	4.79	1.00	67.74	6	97
77	13.63	84.20	97.83	4.86	1.00	67.74	6	97
78	13.63	85.60	99.23	4.93	1.00	67.74	6	96
79	13.63	86.90	100.53	5.00	1.00	67.74	6	100
80	13.63	88.30	101.93	5.07	1.00	67.74	6	102

Table B.18: Raw and Computed Results for Run# 14

(hot water, no tar, no solvent, Q=2 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	12	104
2	0.00	0.00	0.00	0.00	0.00	0.00	14	104
3	0.40	0.00	0.40	0.02	0.00	2.06	18	107
4	1.30	0.00	1.30	0.07	0.00	6.70	14	106
5	3.00	0.00	3.00	0.15	0.00	15.47	18	100
6	4.80	0.00	4.80	0.25	0.00	24.76	20	98
7	6.80	0.00	6.80	0.35	0.00	35.07	25	96
8	8.80	0.00	8.80	0.45	0.00	45.38	26	96
9	10.80	0.00	10.80	0.56	0.00	55.70	24	102
10	11.10	0.70	11.80	0.61	0.70	57.25	24	108
11	11.23	2.50	13.73	0.71	0.93	57.92	24	108
12	11.57	4.20	15.77	0.81	0.83	59.67	23	112
13	11.57	6.10	17.67	0.91	1.00	59.67	22	111
14	11.63	8.00	19.63	1.01	0.97	59.98	20	108
15	11.73	10.00	21.73	1.12	0.95	60.50	21	103
16	11.95	11.70	23.65	1.22	0.89	61.63	22	101
17	11.95	13.50	25.45	1.31	1.00	61.63	22	100
18	11.95	15.60	27.55	1.42	1.00	61.63	22	99
19	11.95	17.60	29.55	1.52	1.00	61.63	22	100
20	11.95	19.60	31.55	1.63	1.00	61.63	21	99
21	12.05	21.50	33.55	1.73	0.95	62.15	20	101
22	12.05	23.50	35.55	1.83	1.00	62.15	20	99
23	12.07	25.40	37.47	1.93	0.99	62.25	21	98
24	12.07	27.30	39.37	2.03	1.00	62.25	21	97
25	12.19	29.10	41.29	2.13	0.94	62.87	21	98
26	12.19	31.00	43.19	2.23	1.00	62.87	20	101
27	12.19	32.80	44.99	2.32	1.00	62.87	17	93
28	12.29	34.80	47.09	2.43	0.95	63.38	19	92
29	12.29	36.70	48.99	2.53	1.00	63.38	19	91
30	12.29	38.50	50.79	2.62	1.00	63.38	19	90
31	12.29	40.50	52.79	2.72	1.00	63.38	21	99
32	12.39	42.30	54.69	2.82	0.95	63.90	16	99
33	12.39	44.20	56.59	2.92	1.00	63.90	16	97
34	12.47	46.00	58.47	3.02	0.96	64.31	17	93
35	12.56	47.90	60.46	3.12	0.95	64.78	17	91
36	12.56	49.90	62.46	3.22	1.00	64.78	18	90
37	12.56	51.90	64.46	3.32	1.00	64.78	18	88
38	12.56	53.80	66.36	3.42	1.00	64.78	19	88
39	12.64	55.70	68.34	3.52	0.96	65.19	20	87
40	12.64	57.70	70.34	3.63	1.00	65.19	20	87

Table B.18: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	12.74	59.70	72.44	3.74	0.95	65.70	20	87
42	12.74	61.80	74.54	3.84	1.00	65.70	20	87
43	12.74	63.90	76.64	3.95	1.00	65.70	20	87
44	12.84	65.70	78.54	4.05	0.95	66.22	19	87
45	12.84	67.60	80.44	4.15	1.00	66.22	20	87
46	12.84	69.60	82.44	4.25	1.00	66.22	20	100
47	12.84	71.70	84.54	4.36	1.00	66.22	19	104
48	12.84	73.80	86.64	4.47	1.00	66.22	18	107
49	12.84	75.80	88.64	4.57	1.00	66.22	18	107
50	12.84	77.70	90.54	4.67	1.00	66.22	18	107
51	12.84	79.70	92.54	4.77	1.00	66.22	18	107
52	12.84	81.60	94.44	4.87	1.00	66.22	18	107
53	12.84	83.40	96.24	4.96	1.00	66.22	18	107
54	12.84	85.20	98.04	5.06	1.00	66.22	17	107

Table B.19: Raw and Computed Results for Run# 15

(hot water, no tar, no solvent, Q=4 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	13	90
2	1.00	0.00	1.00	0.05	0.00	4.98	20	96
3	4.00	0.00	4.00	0.20	0.00	19.90	24	104
4	7.30	0.00	7.30	0.36	0.00	36.32	26	104
5	10.80	0.00	10.80	0.54	0.00	53.73	31	106
6	11.20	3.10	14.30	0.71	0.89	55.72	28	104
7	11.37	6.80	18.17	0.90	0.96	56.57	28	104
8	11.59	10.60	22.19	1.10	0.95	57.66	28	104
9	11.79	14.30	26.09	1.30	0.95	58.66	28	102
10	11.97	18.10	30.07	1.50	0.95	59.55	28	100
11	12.06	21.80	33.86	1.68	0.98	60.00	26	97
12	12.06	25.70	37.76	1.88	1.00	60.00	27	95
13	12.10	29.50	41.60	2.07	0.99	60.20	27	92
14	12.19	33.30	45.49	2.26	0.98	60.65	26	90
15	12.29	37.20	49.49	2.46	0.98	61.14	26	89
16	12.29	41.20	53.49	2.66	1.00	61.14	26	88
17	12.39	45.00	57.39	2.86	0.97	61.64	25	88
18	12.39	49.00	61.39	3.05	1.00	61.64	25	89
19	12.45	52.80	65.25	3.25	0.98	61.94	25	89
20	12.46	56.70	69.16	3.44	1.00	61.99	25	90
21	12.51	60.70	73.21	3.64	0.99	62.24	26	93
22	12.58	64.60	77.18	3.84	0.98	62.59	25	96
23	12.58	68.60	81.18	4.04	1.00	62.59	25	99
24	12.63	72.50	85.13	4.24	0.99	62.84	24	101
25	12.67	76.30	88.97	4.43	0.99	63.03	24	103
26	12.67	80.10	92.77	4.62	1.00	63.03	23	106
27	12.67	84.00	96.67	4.81	1.00	63.03	22	104
28	12.77	87.90	100.67	5.01	0.98	63.53	23	103
29	12.79	91.80	104.59	5.20	0.99	63.63	23	102
30	12.79	95.80	108.59	5.40	1.00	63.63	23	101
31	12.79	99.70	112.49	5.60	1.00	63.63	23	99
32	12.79	103.70	116.49	5.80	1.00	63.63	23	98
33	12.90	107.60	120.50	6.00	0.97	64.18	23	96
34	12.90	111.60	124.50	6.19	1.00	64.18	23	96
35	12.90	115.60	128.50	6.39	1.00	64.18	23	95

Table B.20: Raw and Computed Results for Run# 11

(hot water with tar, no solvent, Q=2 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	2	103
2	0.00	0.00	0.00	0.00	0.00	0.00	3	105
3	0.00	0.00	0.00	0.00	0.00	0.00	4	96
4	0.00	0.00	0.00	0.00	0.00	0.00	17	92
5	0.00	0.00	0.00	0.00	0.00	0.00	60	88
6	0.00	0.00	0.00	0.00	0.00	0.00	210	84
7	1.80	0.00	1.80	0.05	0.00	5.40	495	82
8	3.80	0.00	3.80	0.11	0.00	11.39	780	78
9	5.70	0.00	5.70	0.17	0.00	17.09	1020	75
10	7.80	0.00	7.80	0.23	0.00	23.38	1120	74
11	9.80	0.00	9.80	0.29	0.00	29.38	1120	72
12	11.90	0.00	11.90	0.36	0.00	35.67	1080	75
13	13.90	0.00	13.90	0.42	0.00	41.67	1080	79
14	14.40	1.40	15.80	0.47	0.74	43.17	1070	84
15	14.57	3.20	17.77	0.53	0.91	43.68	1080	88
16	14.57	5.10	19.67	0.59	1.00	43.68	1085	93
17	14.69	6.90	21.59	0.65	0.94	44.03	1055	99
18	14.79	8.90	23.69	0.71	0.95	44.33	1100	101
19	14.89	10.80	25.69	0.77	0.95	44.63	1105	105
20	15.02	12.80	27.82	0.83	0.94	45.02	1120	109
21	15.02	14.80	29.82	0.89	1.00	45.02	1120	112
22	15.17	16.70	31.87	0.96	0.93	45.47	1135	114
23	15.29	18.50	33.79	1.01	0.94	45.83	1145	118
24	15.29	20.50	35.79	1.07	1.00	45.83	1145	119
25	15.44	22.50	37.94	1.14	0.93	46.28	1160	121
26	15.44	24.30	39.74	1.19	1.00	46.28	1145	121
27	15.44	26.30	41.74	1.25	1.00	46.28	1150	121
28	15.59	28.30	43.89	1.32	0.93	46.73	1150	120
29	15.59	30.30	45.89	1.38	1.00	46.73	1180	118
30	15.59	32.30	47.89	1.44	1.00	46.73	1185	116
31	15.75	34.10	49.85	1.49	0.92	47.21	1185	113
32	15.75	36.20	51.95	1.56	1.00	47.21	1170	110
33	15.75	38.10	53.85	1.61	1.00	47.21	1190	107
34	15.75	40.00	55.75	1.67	1.00	47.21	1195	103
35	15.75	42.10	57.85	1.73	1.00	47.21	1200	100
36	15.75	44.10	59.85	1.79	1.00	47.21	1210	97
37	15.75	46.10	61.85	1.85	1.00	47.21	1180	95
38	15.75	48.20	63.95	1.92	1.00	47.21	1195	93
39	15.75	50.20	65.95	1.98	1.00	47.21	1230	91
40	15.75	52.10	67.85	2.03	1.00	47.21	1155	89

Table B.20: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	15.75	54.10	69.85	2.09	1.00	47.21	1155	89
42	15.79	56.00	71.79	2.15	0.98	47.33	1165	89
43	15.79	58.00	73.79	2.21	1.00	47.33	1150	89
44	15.82	59.90	75.72	2.27	0.98	47.42	1190	90
45	15.82	62.10	77.92	2.34	1.00	47.42	1220	90
46	15.82	64.20	80.02	2.40	1.00	47.42	1240	91
47	15.82	66.20	82.02	2.46	1.00	47.42	1140	95
48	15.82	68.00	83.82	2.51	1.00	47.42	1080	98
49	15.84	69.80	85.64	2.57	0.99	47.48	1110	100
50	15.85	71.70	87.55	2.62	0.99	47.51	1170	99
51	15.85	73.70	89.55	2.68	1.00	47.51	1230	99
52	15.85	75.80	91.65	2.75	1.00	47.51	1270	99
53	15.85	77.60	93.45	2.80	1.00	47.51	1280	100
54	15.85	79.40	95.25	2.86	1.00	47.51	1300	102
55	15.85	81.50	97.35	2.92	1.00	47.51	1250	104
56	15.85	83.70	99.55	2.98	1.00	47.51	1280	106
57	15.85	85.80	101.65	3.05	1.00	47.51	1310	106
58	15.85	87.80	103.65	3.11	1.00	47.51	1300	107
59	15.85	89.70	105.55	3.16	1.00	47.51	1270	108
60	15.87	91.60	107.47	3.22	0.99	47.57	1220	108
61	15.87	93.60	109.47	3.28	1.00	47.57	1220	107
62	15.87	95.60	111.47	3.34	1.00	47.57	1250	106
63	15.87	97.70	113.57	3.40	1.00	47.57	1290	103
64	15.87	99.70	115.57	3.46	1.00	47.57	1320	101
65	15.87	101.80	117.67	3.53	1.00	47.57	1280	98
66	15.87	103.80	119.67	3.59	1.00	47.57	1310	96

Table B.21: Raw and Computed Results for Run# 12

(hot water with tar, no solvent, Q=4 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	12	89
2	0.00	0.00	0.00	0.00	0.00	0.00	50	87
3	0.00	0.00	0.00	0.00	0.00	0.00	360	85
4	2.80	0.00	2.80	0.09	0.00	8.54	795	83
5	7.00	0.00	7.00	0.21	0.00	21.34	680	85
6	11.00	0.00	11.00	0.34	0.00	33.54	520	96
7	11.80	2.00	13.80	0.42	0.71	35.98	470	100
8	12.30	5.30	17.60	0.54	0.87	37.50	452	103
9	12.65	8.60	21.25	0.65	0.90	38.57	440	102
10	12.80	12.30	25.10	0.77	0.96	39.02	432	101
11	13.03	15.80	28.83	0.88	0.94	39.73	420	98
12	13.10	19.30	32.40	0.99	0.98	39.94	422	96
13	13.27	22.90	36.17	1.10	0.95	40.46	420	94
14	13.40	26.60	40.00	1.22	0.97	40.85	425	91
15	13.40	30.40	43.80	1.34	1.00	40.85	400	90
16	13.53	34.10	47.63	1.45	0.97	41.25	417	90
17	13.55	37.70	51.25	1.56	0.99	41.31	420	88
18	13.62	41.40	55.02	1.68	0.98	41.52	412	90
19	13.71	45.20	58.91	1.80	0.98	41.80	420	90
20	13.83	48.80	62.63	1.91	0.97	42.16	415	92
21	13.83	52.40	66.23	2.02	1.00	42.16	408	94
22	13.92	56.10	70.02	2.13	0.98	42.44	400	96
23	14.02	59.60	73.62	2.24	0.97	42.74	400	98
24	14.02	63.40	77.42	2.36	1.00	42.74	402	100
25	14.02	67.10	81.12	2.47	1.00	42.74	415	100
26	14.16	70.80	84.96	2.59	0.96	43.17	421	99
27	14.16	74.40	88.56	2.70	1.00	43.17	400	99
28	14.16	78.20	92.36	2.82	1.00	43.17	403	98
29	14.16	82.00	96.16	2.93	1.00	43.17	350	98
30	14.16	85.70	99.86	3.04	1.00	43.17	342	96
31	14.16	89.20	103.36	3.15	1.00	43.17	407	95
32	14.16	93.00	107.16	3.27	1.00	43.17	410	95
33	14.16	96.70	110.86	3.38	1.00	43.17	420	94
34	14.16	100.50	114.66	3.50	1.00	43.17	410	94
35	14.29	104.00	118.29	3.61	0.96	43.57	418	93
36	14.29	107.60	121.89	3.72	1.00	43.57	400	93
37	14.53	111.20	125.73	3.83	0.94	44.30	407	93
38	14.53	114.90	129.43	3.95	1.00	44.30	415	93
39	14.53	118.70	133.23	4.06	1.00	44.30	390	92
40	14.53	122.50	137.03	4.18	1.00	44.30	397	91

Table B.21: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	14.53	126.20	140.73	4.29	1.00	44.30	416	92
42	14.53	130.00	144.53	4.41	1.00	44.30	390	91
43	14.53	133.80	148.33	4.52	1.00	44.30	405	91
44	14.68	137.40	152.08	4.64	0.96	44.76	400	91
45	14.68	141.20	155.88	4.75	1.00	44.76	390	91
46	14.68	145.00	159.68	4.87	1.00	44.76	408	91
47	14.78	148.70	163.48	4.98	0.97	45.06	422	91
48	14.78	152.50	167.28	5.10	1.00	45.06	404	91
49	14.78	156.20	170.98	5.21	1.00	45.06	425	91
50	14.93	159.90	174.83	5.33	0.96	45.52	408	91
51	14.93	163.70	178.63	5.45	1.00	45.52	396	91
52	14.93	167.50	182.43	5.56	1.00	45.52	393	91
53	14.93	171.20	186.13	5.67	1.00	45.52	392	91
54	14.93	174.80	189.73	5.78	1.00	45.52	395	91

Table B.22: Raw and Computed Results for Run# 8

(hot-water-driven solvent slug, Q=2 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	14	114
2	0.00	0.00	0.00	0.00	0.00	0.00	52	114
3	0.00	0.00	0.00	0.00	0.00	0.00	73	113
4	0.00	0.00	0.00	0.00	0.00	0.00	88	112
5	0.00	0.00	0.00	0.00	0.00	0.00	94	112
6	0.00	0.00	0.00	0.00	0.00	0.00	94	110
7	1.80	0.00	1.80	0.06	0.00	6.28	88	108
8	3.50	0.00	3.50	0.12	0.00	12.20	410	102
9	5.00	0.00	5.00	0.17	0.00	17.43	735	100
10	6.50	0.00	6.50	0.23	0.00	22.66	850	96
11	8.00	0.00	8.00	0.28	0.00	27.89	880	94
12	9.30	0.00	9.30	0.32	0.00	32.43	920	93
13	10.60	0.00	10.60	0.37	0.00	36.96	960	92
14	12.10	0.00	12.10	0.42	0.00	42.19	1000	90
15	13.50	0.00	13.50	0.47	0.00	47.07	1042	91
16	13.70	1.20	14.90	0.52	0.86	47.77	1100	93
17	13.92	2.50	16.42	0.57	0.86	48.54	1100	93
18	14.07	3.60	17.67	0.62	0.88	49.06	1120	97
19	14.22	4.90	19.12	0.67	0.90	49.58	1160	100
20	14.36	6.20	20.56	0.72	0.90	50.07	1130	102
21	14.48	7.50	21.98	0.77	0.92	50.49	1180	104
22	14.60	8.90	23.50	0.82	0.92	50.91	1170	108
23	14.70	10.30	25.00	0.87	0.93	51.26	1200	110
24	14.81	11.80	26.61	0.93	0.93	51.64	1200	114
25	14.88	13.20	28.08	0.98	0.95	51.88	1175	116
26	14.97	14.60	29.57	1.03	0.94	52.20	1180	118
27	15.05	16.00	31.05	1.08	0.95	52.48	1160	119
28	15.14	17.40	32.54	1.13	0.94	52.79	1150	119
29	15.19	18.60	33.79	1.18	0.96	52.96	1160	118
30	15.27	20.10	35.37	1.23	0.95	53.24	1200	118
31	15.34	21.60	36.94	1.29	0.96	53.49	1180	114
32	15.41	23.10	38.51	1.34	0.96	53.73	1240	111
33	15.47	24.80	40.27	1.40	0.97	53.94	1220	108
34	15.52	26.20	41.72	1.45	0.97	54.11	1220	105
35	15.58	27.80	43.38	1.51	0.96	54.32	1180	101
36	15.61	29.20	44.81	1.56	0.98	54.43	1205	99
37	15.67	30.70	46.37	1.62	0.96	54.64	1090	96
38	15.72	32.00	47.72	1.66	0.96	54.81	1170	93
39	15.74	33.60	49.34	1.72	0.99	54.88	1200	90
40	15.80	35.10	50.90	1.77	0.96	55.09	1260	86

Table B.22: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	15.84	36.40	52.24	1.82	0.97	55.23	1202	88
42	15.86	37.80	53.66	1.87	0.99	55.30	1235	88
43	15.89	39.40	55.29	1.93	0.98	55.40	1245	88
44	15.89	41.10	56.99	1.99	1.00	55.40	1175	90
45	15.91	42.60	58.51	2.04	0.99	55.47	1195	91
46	15.92	44.00	59.92	2.09	0.99	55.51	1245	94
47	15.93	45.50	61.43	2.14	0.99	55.54	1220	96
48	16.00	47.10	63.10	2.20	0.96	55.79	1230	98
49	16.01	48.50	64.51	2.25	0.99	55.82	1230	101
50	16.06	50.00	66.06	2.30	0.97	56.00	1260	102
51	16.08	51.50	67.58	2.36	0.99	56.07	1220	105
52	16.09	53.30	69.39	2.42	0.99	56.10	1260	107
53	16.13	54.80	70.93	2.47	0.97	56.24	1160	110
54	16.13	56.30	72.43	2.53	1.00	56.24	1180	111
55	16.14	57.80	73.94	2.58	0.99	56.28	1120	112
56	16.14	59.40	75.54	2.63	1.00	56.28	1260	114
57	16.20	60.80	77.00	2.68	0.96	56.49	1175	115
58	16.20	62.40	78.60	2.74	1.00	56.49	1200	115
59	16.22	63.80	80.02	2.79	0.99	56.56	1280	116
60	16.22	65.30	81.52	2.84	1.00	56.56	1300	118
61	16.22	66.90	83.12	2.90	1.00	56.56	1300	118
62	16.22	68.60	84.82	2.96	1.00	56.56	1260	119
63	16.23	70.70	86.93	3.03	1.00	56.59	1250	119
64	16.25	72.40	88.65	3.09	0.99	56.66	1240	118
65	16.26	73.90	90.16	3.14	0.99	56.69	1240	116
66	16.26	75.50	91.76	3.20	1.00	56.69	1280	114
67	16.26	77.00	93.26	3.25	1.00	56.69	1200	111
68	16.26	78.60	94.86	3.31	1.00	56.69	880	107
69	16.27	80.10	96.37	3.36	0.99	56.73	1070	103
70	16.27	81.70	97.97	3.42	1.00	56.73	1110	98
71	16.27	83.30	99.57	3.47	1.00	56.73	1260	95
72	16.29	84.80	101.09	3.52	0.99	56.80	1360	91
73	16.29	86.40	102.69	3.58	1.00	56.80	1280	88
74	16.29	88.00	104.29	3.64	1.00	56.80	1280	84
75	16.30	89.70	106.00	3.70	0.99	56.83	1350	80
76	16.31	91.40	107.71	3.76	0.99	56.87	1325	78
77	16.31	93.10	109.41	3.81	1.00	56.87	1340	77
78	16.31	94.70	111.01	3.87	1.00	56.87	1300	78
79	16.32	96.20	112.52	3.92	0.99	56.90	1330	79
80	16.32	97.80	114.12	3.98	1.00	56.90	1350	80

Table B.23: Raw and Computed Results for Run# 9

(hot-water-driven solvent slug, Q=4 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	8	106
2	0.00	0.00	0.00	0.00	0.00	0.00	22	101
3	0.00	0.00	0.00	0.00	0.00	0.00	53	97
4	0.60	0.00	0.60	0.02	0.00	2.04	152	94
5	3.50	0.00	3.50	0.12	0.00	11.90	450	93
6	6.30	0.00	6.30	0.21	0.00	21.42	405	100
7	9.10	0.00	9.10	0.31	0.00	30.94	408	106
8	12.00	0.00	12.00	0.41	0.00	40.80	460	112
9	13.00	2.40	15.40	0.52	0.71	44.20	480	114
10	13.40	5.40	18.80	0.64	0.88	45.56	480	118
11	13.75	8.80	22.55	0.77	0.91	46.75	450	116
12	14.11	12.60	26.71	0.91	0.91	47.98	430	113
13	14.39	16.50	30.89	1.05	0.93	48.93	418	108
14	14.63	20.30	34.93	1.19	0.94	49.74	405	104
15	14.83	23.80	38.63	1.31	0.95	50.43	395	100
16	15.09	27.40	42.49	1.44	0.93	51.31	382	96
17	15.21	31.20	46.41	1.58	0.97	51.72	410	90
18	15.29	35.10	50.39	1.71	0.98	51.99	410	90
19	15.41	38.90	54.31	1.85	0.97	52.40	395	92
20	15.52	42.60	58.12	1.98	0.97	52.77	395	96
21	15.61	46.20	61.81	2.10	0.98	53.08	385	102
22	15.62	50.00	65.62	2.23	1.00	53.11	375	108
23	15.62	53.90	69.52	2.36	1.00	53.11	360	109
24	15.78	57.80	73.58	2.50	0.96	53.66	360	109
25	15.78	61.60	77.38	2.63	1.00	53.66	345	107
26	15.90	65.50	81.40	2.77	0.97	54.06	345	104
27	15.94	69.30	85.24	2.90	0.99	54.20	340	100
28	15.99	73.20	89.19	3.03	0.99	54.37	340	96
29	16.03	77.00	93.03	3.16	0.99	54.51	345	92
30	16.09	80.90	96.99	3.30	0.98	54.71	360	88
31	16.09	84.80	100.89	3.43	1.00	54.71	360	88
32	16.09	88.60	104.69	3.56	1.00	54.71	360	89
33	16.09	92.50	108.59	3.69	1.00	54.71	350	92
34	16.09	96.50	112.59	3.83	1.00	54.71	350	96
35	16.09	100.20	116.29	3.95	1.00	54.71	345	99
36	16.09	104.00	120.09	4.08	1.00	54.71	340	102
37	16.22	107.90	124.12	4.22	0.97	55.15	340	104
38	16.29	111.70	127.99	4.35	0.98	55.39	340	104
39	16.29	115.50	131.79	4.48	1.00	55.39	340	104
40	16.29	119.30	135.59	4.61	1.00	55.39	338	102

Table B.23: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	16.29	122.90	139.19	4.73	1.00	55.39	330	99
42	16.29	126.80	143.09	4.87	1.00	55.39	330	96
43	16.29	130.60	146.89	4.99	1.00	55.39	350	92
44	16.29	134.50	150.79	5.13	1.00	55.39	360	90
45	16.29	138.30	154.59	5.26	1.00	55.39	358	90
46	16.29	142.20	158.49	5.39	1.00	55.39	350	90
47	16.29	146.00	162.29	5.52	1.00	55.39	345	96
48	16.29	149.70	165.99	5.64	1.00	55.39	340	100
49	16.29	153.60	169.89	5.78	1.00	55.39	330	102
50	16.29	157.40	173.69	5.91	1.00	55.39	330	101
51	16.29	161.30	177.59	6.04	1.00	55.39	330	98
52	16.29	165.20	181.49	6.17	1.00	55.39	330	96
53	16.29	169.10	185.39	6.30	1.00	55.39	328	92
54	16.29	172.90	189.19	6.43	1.00	55.39	325	88

Table B.24: Raw and Computed Results for Run# 10

(hot-water-driven solvent slug, Q=6 cc/min).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	10	99
2	0.00	0.00	0.00	0.00	0.00	0.00	19	99
3	2.00	0.00	2.00	0.07	0.00	7.04	49	98
4	5.10	0.00	5.10	0.18	0.00	17.95	64	98
5	8.10	0.00	8.10	0.29	0.00	28.51	67	100
6	11.40	0.00	11.40	0.40	0.00	40.13	79	101
7	12.90	3.20	16.10	0.57	0.68	45.41	250	102
8	13.10	8.70	21.80	0.77	0.96	46.11	308	104
9	13.10	14.20	27.30	0.96	1.00	46.11	315	107
10	13.30	19.70	33.00	1.16	0.96	46.81	320	107
11	13.30	25.10	38.40	1.35	1.00	46.81	338	108
12	13.60	30.40	44.00	1.55	0.95	47.87	342	110
13	13.60	36.00	49.60	1.75	1.00	47.87	340	110
14	13.90	41.40	55.30	1.95	0.95	48.93	330	110
15	14.10	46.90	61.00	2.15	0.96	49.63	325	111
16	14.17	52.50	66.67	2.35	0.99	49.88	320	111
17	14.25	58.10	72.35	2.55	0.99	50.16	318	111
18	14.31	63.80	78.11	2.75	0.99	50.37	315	111
19	14.41	69.60	84.01	2.96	0.98	50.72	302	108
20	14.45	75.30	89.75	3.16	0.99	50.86	293	105
21	14.45	81.10	95.55	3.36	1.00	50.86	288	101
22	14.48	86.80	101.28	3.56	0.99	50.97	282	97
23	14.53	92.40	106.93	3.76	0.99	51.14	292	94
24	14.56	98.20	112.76	3.97	0.99	51.25	285	93
25	14.61	104.00	118.61	4.17	0.99	51.43	280	94
26	14.67	109.60	124.27	4.37	0.99	51.64	275	96
27	14.67	115.40	130.07	4.58	1.00	51.64	270	98
28	14.71	121.20	135.91	4.78	0.99	51.78	270	101
29	14.71	127.00	141.71	4.99	1.00	51.78	273	102
30	14.76	132.00	146.76	5.17	0.99	51.95	270	104
31	14.76	137.90	152.66	5.37	1.00	51.95	268	106
32	14.86	143.50	158.36	5.57	0.98	52.31	268	106
33	14.86	149.30	164.16	5.78	1.00	52.31	270	106
34	14.86	155.10	169.96	5.98	1.00	52.31	270	104
35	14.91	161.00	175.91	6.19	0.99	52.48	277	103
36	14.91	166.00	180.91	6.37	1.00	52.48	268	103
37	14.98	171.60	186.58	6.57	0.99	52.73	268	102
38	14.98	176.60	191.58	6.74	1.00	52.73	265	102
39	14.98	182.30	197.28	6.94	1.00	52.73	265	100
40	14.98	188.20	203.18	7.15	1.00	52.73	265	100

Table B.24: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	15.06	193.20	208.26	7.33	0.98	53.01	272	100
42	15.06	198.20	213.26	7.51	1.00	53.01	275	100
43	15.06	204.10	219.16	7.71	1.00	53.01	270	102
44	15.11	209.90	225.01	7.92	0.99	53.19	265	106
45	15.11	215.80	230.91	8.13	1.00	53.19	262	111
46	15.11	221.70	236.81	8.34	1.00	53.19	277	118
47	15.11	227.50	242.61	8.54	1.00	53.19	275	123
48	15.11	233.40	248.51	8.75	1.00	53.19	273	128
49	15.11	238.40	253.51	8.92	1.00	53.19	250	131
50	15.11	243.40	258.51	9.10	1.00	53.19	265	133
51	15.11	249.30	264.41	9.31	1.00	53.19	272	131
52	15.11	255.10	270.21	9.51	1.00	53.19	267	128
53	15.11	260.10	275.21	9.69	1.00	53.19	258	124
54	15.11	266.00	281.11	9.89	1.00	53.19	258	118
55	15.11	271.00	286.11	10.07	1.00	53.19	258	113

Table B.25: Raw and Computed Results for Run# 25

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(hot-water-driven solvent slug, Q=1 cc/min, mode II).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	21	101
2	0.00	0.00	0.00	0.00	0.00	0.00	24	95
3	0.00	0.00	0.00	0.00	0.00	0.00	31	100
4	0.00	0.00	0.00	0.00	0.00	0.00	38	106
5	0.00	0.00	0.00	0.00	0.00	0.00	51	104
6	0.00	0.00	0.00	0.00	0.00	0.00	76	99
7	0.00	0.00	0.00	0.00	0.00	0.00	106	98
8	0.00	0.00	0.00	0.00	0.00	0.00	141	94
9	0.00	0.00	0.00	0.00	0.00	0.00	235	90
10	0.00	0.00	0.00	0.00	0.00	0.00	250	90
11	0.00	0.00	0.00	0.00	0.00	0.00	275	88
12	0.00	0.00	0.00	0.00	0.00	0.00	185	86
13	1.20	0.00	1.20	0.03	0.00	3.41	143	89
14	2.60	0.00	2.60	0.07	0.00	7.40	140	91
15	4.30	0.00	4.30	0.12	0.00	12.23	144	96
16	6.10	0.00	6.10	0.17	0.00	17.35	150	100
17	7.30	0.00	7.30	0.21	0.00	20.77	136	105
18	8.10	0.00	8.10	0.23	0.00	23.04	118	112
19	9.10	0.00	9.10	0.26	0.00	25.89	122	112
20	10.30	0.00	10.30	0.29	0.00	29.30	136	109
21	11.31	0.00	11.31	0.32	0.00	32.18	156	110
22	12.51	0.00	12.51	0.36	0.00	35.59	161	112
23	13.91	0.00	13.91	0.40	0.00	39.57	166	112
24	15.21	0.00	15.21	0.43	0.00	43.27	162	111
25	16.61	0.00	16.61	0.47	0.00	47.25	153	111
26	17.81	0.00	17.81	0.51	0.00	50.67	154	111
27	18.47	0.30	18.77	0.53	0.31	52.55	157	109
28	18.48	1.20	19.68	0.56	0.99	52.57	159	109
29	18.50	2.00	20.50	0.58	0.98	52.63	158	109
30	18.78	2.80	21.58	0.61	0.74	53.43	156	109
31	18.78	3.80	22.58	0.64	1.00	53.43	159	109
32	18.81	4.60	23.41	0.67	0.96	53.51	164	109
33	19.01	5.60	24.61	0.70	0.83	54.08	154	111
34	19.01	6.60	25.61	0.73	1.00	54.08	158	109
35	19.21	7.50	26.71	0.76	0.82	54.65	166	108
36	19.21	8.70	27.91	0.79	1.00	54.65	172	108
37	19.28	9.70	28.98	0.82	0.93	54.85	167	109
38	19.47	10.50	29.97	0.85	0.81	55.39	164	109
39	19.62	11.60	31.22	0.89	0.88	55.82	166	108
40	19.62	12.70	32.32	0.92	1.00	55.82	164	109

Table B.25: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	19.62	13.80	33.42	0.95	1.00	55.82	160	110
42	19.88	14.80	34.68	0.99	0.79	56.56	167	108
43	19.88	15.80	35.68	1.02	1.00	56.56	163	110
44	20.01	16.70	36.71	1.04	0.87	56.93	166	110
45	20.01	17.70	37.71	1.07	1.00	56.93	170	108
46	20.01	18.80	38.81	1.10	1.00	56.93	172	108
47	20.29	19.70	39.99	1.14	0.76	57.72	174	108
48	20.29	20.70	40.99	1.17	1.00	57.72	168	110
49	20.30	21.70	42.00	1.19	0.99	57.75	170	108
50	20.48	22.80	43.28	1.23	0.86	58.26	176	108
51	20.55	23.80	44.35	1.26	0.93	58.46	178	108
52	20.60	24.80	45.40	1.29	0.95	58.61	170	108
53	20.60	25.90	46.50	1.32	1.00	58.61	162	110
54	20.61	27.00	47.61	1.35	0.99	58.63	170	108
55	20.65	28.00	48.65	1.38	0.96	58.75	178	107
56	20.65	29.10	49.75	1.42	1.00	58.75	176	108
57	20.97	30.00	50.97	1.45	0.74	59.66	170	108
58	20.97	31.10	52.07	1.48	1.00	59.66	168	108
59	20.97	32.10	53.07	1.51	1.00	59.66	165	108
60	21.03	33.10	54.13	1.54	0.94	59.83	170	108
61	21.03	34.30	55.33	1.57	1.00	59.83	179	107
62	21.11	35.40	56.51	1.61	0.93	60.06	180	108
63	21.13	36.40	57.53	1.64	0.98	60.11	176	108
64	21.14	37.40	58.54	1.67	0.99	60.14	176	108
65	21.14	38.50	59.64	1.70	1.00	60.14	180	107
66	21.23	39.50	60.73	1.73	0.92	60.40	180	109
67	21.23	40.50	61.73	1.76	1.00	60.40	177	107
68	21.23	41.60	62.83	1.79	1.00	60.40	175	109
69	21.28	42.60	63.88	1.82	0.95	60.54	178	107
70	21.30	43.80	65.10	1.85	0.98	60.60	182	107
71	21.48	44.90	66.38	1.89	0.86	61.11	182	109
72	21.48	46.00	67.48	1.92	1.00	61.11	180	109
73	21.73	47.00	68.73	1.96	0.80	61.82	165	110
74	21.73	48.00	69.73	1.98	1.00	61.82	160	110
75	21.91	48.90	70.81	2.01	0.83	62.33	170	108
76	21.98	49.90	71.88	2.04	0.93	62.53	180	108
77	21.98	51.00	72.98	2.08	1.00	62.53	185	108
78	22.02	52.10	74.12	2.11	0.96	62.65	181	110
79	22.02	53.10	75.12	2.14	1.00	62.65	182	109
80	22.10	54.10	76.20	2.17	0.93	62.87	178	109

Table B.25: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	22.12	55.20	77.32	2.20	0.98	62.93	168	110
82	22.12	56.20	78.32	2.23	1.00	62.93	167	109
83	22.27	57.10	79.37	2.26	0.86	63.36	178	109
84	22.27	58.10	80.37	2.29	1.00	63.36	184	108
85	22.42	59.20	81.62	2.32	0.88	63.78	180	110
86	22.52	60.30	82.82	2.36	0.92	64.07	179	109
87	22.52	61.40	83.92	2.39	1.00	64.07	183	109
88	22.52	62.50	85.02	2.42	1.00	64.07	186	108
89	22.57	63.50	86.07	2.45	0.95	64.21	183	109
90	22.57	64.60	87.17	2.48	1.00	64.21	178	109
91	22.57	65.60	88.17	2.51	1.00	64.21	178	108
92	22.62	66.60	89.22	2.54	0.95	64.35	174	109
93	22.62	67.60	90.22	2.57	1.00	64.35	172	109
94	22.67	68.70	91.37	2.60	0.96	64.50	178	109
95	22.67	69.70	92.37	2.63	1.00	64.50	188	108
96	22.67	70.80	93.47	2.66	1.00	64.50	189	108
97	22.72	71.80	94.52	2.69	0.95	64.64	189	109
98	22.72	72.90	95.62	2.72	1.00	64.64	188	108
99	22.79	74.00	96.79	2.75	0.94	64.84	185	108
100	22.79	75.20	97.99	2.79	1.00	64.84	185	108
101	22.79	76.30	99.09	2.82	1.00	64.84	179	108
102	22.84	77.40	100.24	2.85	0.96	64.98	173	109
103	22.84	78.40	101.24	2.88	1.00	64.98	170	109
104	22.89	79.50	102.39	2.91	0.96	65.12	176	108
105	22.89	80.70	103.59	2.95	1.00	65.12	182	108
106	22.89	81.80	104.69	2.98	1.00	65.12	190	108
107	22.94	82.90	105.84	3.01	0.96	65.26	191	108
108	22.94	84.10	107.04	3.05	1.00	65.26	185	109
109	22.94	85.20	108.14	3.08	1.00	65.26	186	108
110	22.94	86.30	109.24	3.11	1.00	65.26	183	108
111	22.94	87.50	110.44	3.14	1.00	65.26	177	108
112	22.94	88.60	111.54	3.17	1.00	65.26	180	108
113	22.94	89.70	112.64	3.20	1.00	65.26	182	108
114	22.94	90.90	113.84	3.24	1.00	65.26	180	108
115	22.94	92.00	114.94	3.27	1.00	65.26	180	108
116	22.94	93.20	116.14	3.30	1.00	65.26	186	108
117	22.94	94.30	117.24	3.34	1.00	65.26	190	108
118	22.94	95.30	118.24	3.36	1.00	65.26	186	108
119	22.94	96.30	119.24	3.39	1.00	65.26	184	108
120	22.94	97.30	120.24	3.42	1.00	65.26	186	108

Table B.26: Raw and Computed Results for Run# 27

(hot-water-driven solvent slug, Q=1 cc/min, mode III).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	9	105
2	0.00	0.00	0.00	0.00	0.00	0.00	11	108
3	0.00	0.00	0.00	0.00	0.00	0.00	15	103
4	0.00	0.00	0.00	0.00	0.00	0.00	22	95
5	0.00	0.00	0.00	0.00	0.00	0.00	31	93
6	0.00	0.00	0.00	0.00	0.00	0.00	39	90
7	0.00	0.00	0.00	0.00	0.00	0.00	52	86
8	0.00	0.00	0.00	0.00	0.00	0.00	72	82
9	0.00	0.00	0.00	0.00	0.00	0.00	102	81
10	0.00	0.00	0.00	0.00	0.00	0.00	156	78
11	0.00	0.00	0.00	0.00	0.00	0.00	210	76
12	0.64	0.00	0.64	0.02	0.00	1.88	128	76
13	1.84	0.00	1.84	0.05	0.00	5.39	145	76
14	3.44	0.00	3.44	0.10	0.00	10.09	125	76
15	4.94	0.00	4.94	0.14	0.00	14.48	100	77
16	6.14	0.00	6.14	0.18	0.00	18.00	80	79
17	7.44	0.00	7.44	0.22	0.00	21.81	80	81
18	9.04	0.00	9.04	0.27	0.00	26.50	86	81
19	10.44	0.00	10.44	0.31	0.00	30.61	82	89
20	11.89	0.00	11.89	0.35	0.00	34.86	72	95
21	13.39	0.00	13.39	0.39	0.00	39.26	64	101
22	14.79	0.00	14.79	0.43	0.00	43.36	61	114
23	15.99	0.00	15.99	0.47	0.00	46.88	53	121
24	16.91	0.00	16.91	0.50	0.00	49.57	42	138
25	18.01	0.00	18.01	0.53	0.00	52.80	35	125
26	18.53	0.50	19.03	0.56	0.49	54.32	34	117
27	18.81	1.50	20.31	0.60	0.78	55.15	39	115
28	18.97	2.30	21.27	0.62	0.83	55.61	41	110
29	19.14	3.20	22.34	0.65	0.84	56.11	43	108
30	19.30	4.10	23.40	0.69	0.85	56.58	43	104
31	19.44	4.80	24.24	0.71	0.83	56.99	43	101
32	19.48	5.80	25.28	0.74	0.96	57.11	43	98
33	19.58	6.90	26.48	0.78	0.92	57.40	45	96
34	19.78	8.00	27.78	0.81	0.85	57.99	47	94
35	19.91	9.00	28.91	0.85	0.88	58.37	50	94
36	19.96	10.10	30.06	0.88	0.96	58.52	52	94
37	20.07	11.10	31.17	0.91	0.90	58.84	51	96
38	20.27	12.20	32.47	0.95	0.85	59.43	50	104
39	20.35	13.30	33.65	0.99	0.93	59.66	40	130
40	20.39	14.50	34.89	1.02	0.97	59.78	38	131

Table B.26: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	20.46	15.60	36.06	1.06	0.94	59.98	38	128
42	20.47	16.70	37.17	1.09	0.99	60.01	38	126
43	20.49	17.70	38.19	1.12	0.98	60.07	38	126
44	20.64	18.70	39.34	1.15	0.87	60.51	38	126
45	20.87	19.70	40.57	1.19	0.81	61.18	38	126
46	20.87	20.80	41.67	1.22	1.00	61.18	34	130
47	20.95	21.90	42.85	1.26	0.93	61.42	34	126
48	21.01	23.00	44.01	1.29	0.95	61.59	34	122
49	21.13	24.10	45.23	1.33	0.90	61.95	34	119
50	21.31	25.20	46.51	1.36	0.86	62.47	35	116
51	21.31	26.20	47.51	1.39	1.00	62.47	35	115
52	21.31	27.30	48.61	1.43	1.00	62.47	37	112
53	21.43	28.40	49.83	1.46	0.90	62.83	37	111
54	21.57	29.40	50.97	1.49	0.88	63.24	39	108
55	21.57	30.50	52.07	1.53	1.00	63.24	41	108
56	21.57	31.60	53.17	1.56	1.00	63.24	42	106
57	21.64	32.60	54.24	1.59	0.93	63.44	46	104
58	21.64	33.60	55.24	1.62	1.00	63.44	51	103
59	21.64	34.60	55.24	1.65	1.00	63.44	56	101
60	21.88	35.50	57.38	1.68	0.79	64.15	59	100
61	21.91	36.60	58.51	1.72	0.97	64.23	60	100
62	21.91	37.60	59.51	1.74	1.00	64.23	60	93
63	22.08	38.60	60.68	1.78	0.85	64.73	59	98
64	22.19	39.60	61.79	1.81	0.90	65.05	58	99
65	22.26	40.70	62.96	1.85	0.94	65.26	55	100
66	22.32	41.80	64.12	1.88	0.95	65.44	51	100
67	22.35	42.90	65.25	1.91	0.97	65.52	49	102
68	22.35	44.10	66.45	1.95	1.00	65.52	48	104
69	22.41	45.20	67.61	1.98	0.95	65.70	46	107
70	22.49	46.30	68.79	2.02	0.93	65.93	46	108
71	22.49	47.30	69.79	2.05	1.00	65.93	45	111
72	22.55	48.40	70.95	2.08	0.95	66.11	44	114
73	22.55	49.40	71.95	2.11	1.00	66.11	44	115
74	22.55	50.50	73.05	2.14	1.00	66.11	43	116
75	22.55	51.60	74.15	2.17	1.00	66.11	43	118
76	22.57	52.70	75.27	2.21	0.98	66.17	42	118
77	22.57	53.70	76.27	2.24	1.00	66.17	41	120
78	22.57	54.80	77.37	2.27	1.00	66.17	41	120
79	22.61	55.90	78.51	2.30	0.96	66.29	41	122
80	22.61	56.90	79.51	2.33	1.00	66.29	41	122

Table B.26: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°
81	22.61	58.10	80.71	2.37	1.00	66.29	40	122
82	22.61	59.20	81.81	2.40	1.00	66.29	40	123
83	22.65	60.30	82.95	2.43	0.96	66.40	40	123
84	22.65	61.50	84.15	2.47	1.00	66.40	40	124
85	22.68	62.60	85.28	2.50	0.97	66.49	40	124
86	22.68	63.70	86.38	2.53	1.00	66.49	38	122
87	22.71	64.70	87.41	2.56	0.97	66.58	33	115
88	22.78	65.80	88.58	2.60	0.94	66.78	35	109
89	22.80	66.90	89.70	2.63	0.98	66.84	35	108
90	22.81	68.10	90.91	2.67	0.99	66.87	38	106
91	22.82	69.10	91.92	2.69	0.99	66.90	44	102
92	22.88	70.10	92.98	2.73	0.94	67.08	46	100
93	22.88	71.30	94.18	2.76	1.00	67.08	57	96
94	22.89	72.40	95.29	2.79	0.99	67.11	60	94
95	22.89	73.60	96.49	2.83	1.00	67.11	63	91
96	22.89	74.60	97.49	2.86	1.00	67.11	63	90
97	22.95	75.70	98.65	2.89	0.95	67.28	60	87
98	22.95	76.70	99.65	2.92	1.00	67.28	59	84
99	22.95	77.70	100.65	2.95	1.00	67.28	55	84
100	22.97	78.80	101.77	2.98	0.98	67.34	56	76
101	22.98	79.90	102.88	3.02	0.99	67.37	61	75
102	23.00	81.00	104.00	3.05	0.98	67.43	66	78
103	23.00	82.10	105.10	3.08	1.00	67.43	67	81
104	23.03	83.10	106.13	3.11	0.97	67.52	74	82
105	23.03	84.20	107.23	3.14	1.00	67.52	69	85
106	23.07	85.20	108.27	3.17	0.96	67.63	57	86
107	23.07	86.20	109.27	3.20	1.00	67.63	55	88
108	23.11	87.30	110.41	3.24	0.96	67.75	54	89
109	23.11	88.30	111.41	3.27	1.00	67.75	54	91
110	23.11	89.30	112.41	3.30	1.00	67.75	51	92
111	23.11	90.40	113.51	3.33	1.00	67.75	53	92
112	23.11	91.50	114.61	3.36	1.00	67.75	49	94
113	23.11	92.60	115.71	3.39	1.00	67.75	53	94
114	23.11	93.70	116.81	3.42	1.00	67.75	55	94
115	23.11	94.90	118.01	3.46	1.00	67.75	50	95
116	23.11	96.00	119.11	3.49	1.00	67.75	53	95
117	23.11	97.10	120.21	3.52	1.00	67.75	55	95
118	23.11	98.10	121.21	3.55	1.00	67.75	50	96
119	23.11	99.20	122.31	3.59	1.00	67.75	53	98
120	23.11	100.20	123.31	3.62	1.00	67.75	53	98

Table B.27: Raw and Computed Results for Run# 26

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(hot-water-driven solvent slugs, Q=1 cc/min, mode II).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	11	114
2	0.00	0.00	0.00	0.00	0.00	0.00	15	118
3	0.00	0.00	0.00	0.00	0.00	0.00	20	122
4	0.00	0.00	0.00	0.00	0.00	0.00	29	121
5	0.00	0.00	0.00	0.00	0.00	0.00	41	116
6	0.00	0.00	0.00	0.00	0.00	0.00	57	112
7	0.00	0.00	0.00	0.00	0.00	0.00	74	107
8	0.00	0.00	0.00	0.00	0.00	0.00	120	104
9	0.00	0.00	0.00	0.00	0.00	0.00	235	99
10	0.00	0.00	0.00	0.00	0.00	0.00	365	96
11	0.00	0.00	0.00	0.00	0.00	0.00	500	93
12	0.00	0.00	0.00	0.00	0.00	0.00	610	90
13	0.94	0.00	0.94	0.03	0.00	2.82	710	87
14	1.94	0.00	1.94	0.06	0.00	5.82	770	84
15	3.46	0.00	3.46	0.10	0.00	10.37	660	83
16	4.96	0.00	4.96	0.15	0.00	14.87	530	83
17	6.01	0.00	6.01	0.18	0.00	18.02	380	83
18	6.97	0.00	6.97	0.21	0.00	20.90	330	84
19	8.37	0.00	8.37	0.25	0.00	25.10	330	84
20	9.31	0.00	9.31	0.28	0.00	27.92	330	86
21	10.13	0.00	10.13	0.30	0.00	30.37	290	88
22	10.93	0.00	10.93	0.33	0.00	32.77	270	90
23	11.93	0.00	11.93	0.36	0.00	35.77	280	90
24	12.99	0.00	12.99	0.39	0.00	38.95	280	90
25	13.99	0.00	13.99	0.42	0.00	41.95	285	91
26	14.89	0.00	14.89	0.45	0.00	44.65	280	91
27	15.69	0.00	15.69	0.47	0.00	47.05	265	93
28	16.79	0.00	16.79	0.50	0.00	50.34	300	93
29	17.59	0.00	17.59	0.53	0.00	52.74	320	93
30	18.36	0.00	18.36	0.55	0.00	55.05	315	93
31	18.86	0.00	18.86	0.57	0.00	56.55	330	93
32	19.00	0.70	19.70	0.59	0.83	56.97	352	93
33	19.12	1.70	20.82	0.62	0.89	57.33	355	93
34	19.28	2.70	21.98	0.66	0.86	57.81	350	93
35	19.41	3.60	23.01	0.69	0.87	58.20	370	93
36	19.51	4.40	23.91	0.72	0.89	58.50	370	93
37	19.65	5.30	24.95	0.75	0.87	58.92	350	93
38	19.79	6.20	25.99	0.78	0.87	59.34	340	93
39	19.87	7.20	27.07	0.81	0.93	59.58	390	93
40	19.88	8.10	27.98	0.84	0.99	59.61	340	93

Table B.27: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	19.90	9.00	28.90	0.87	0.98	59.67	375	94
42	20.02	10.00	30.02	0.90	0.89	60.03	380	94
43	20.02	11.20	31.22	0.94	1.00	60.03	405	94
44	20.16	12.20	32.36	0.97	0.88	60.45	435	94
45	20.26	13.20	33.46	1.00	0.91	60.75	430	94
46	20.26	14.30	34.56	1.04	1.00	60.75	415	94
47	20.26	15.40	35.66	1.07	1.00	60.75	420	94
48	20.34	16.40	36.74	1.10	0.93	60.99	435	95
49	20.44	17.40	37.84	1.13	0.91	61.29	415	95
50	20.44	18.60	39.04	1.17	1.00	61.29	405	96
51	20.44	19.70	40.14	1.20	1.00	61.29	418	96
52	20.46	20.90	41.36	1.24	0.98	61.35	450	96
53	20.49	22.00	42.49	1.27	0.97	61.44	462	96
54	20.49	23.10	43.59	1.31	1.00	61.44	452	96
55	20.54	24.00	44.54	1.34	0.95	61.59	432	96
56	20.54	25.00	45.54	1.37	1.00	61.59	450	96
57	20.54	26.10	46.64	1.40	1.00	61.59	461	96
58	20.60	27.10	47.70	1.43	0.94	61.77	470	95
59	20.60	28.10	48.70	1.46	1.00	61.77	468	96
60	20.63	29.10	49.73	1.49	0.97	61.86	468	96
61	20.63	30.40	51.03	1.53	1.00	61.86	472	96
62	20.72	31.60	52.32	1.57	0.93	62.13	490	96
63	20.72	32.90	53.62	1.61	1.00	62.13	488	95
64	20.72	34.20	54.92	1.65	1.00	62.13	470	97
65	20.78	35.30	56.08	1.68	0.95	62.31	495	97
66	20.84	36.50	57.34	1.72	0.95	62.49	490	95
67	20.86	37.80	58.66	1.76	0.98	62.55	510	95
68	20.86	39.10	59.96	1.80	1.00	62.55	530	95
69	20.86	40.30	61.16	1.83	1.00	62.55	530	95
70	20.86	41.40	62.26	1.87	1.00	62.55	538	94
71	20.86	42.60	63.46	1.90	1.00	62.55	540	94
72	20.94	43.80	64.74	1.94	0.94	62.79	530	94
73	21.01	45.00	66.01	1.98	0.94	63.00	530	94
74	21.01	46.10	67.11	2.01	1.00	63.00	530	94
75	21.01	47.20	68.21	2.05	1.00	63.00	535	92
76	21.01	48.40	69.41	2.08	1.00	63.00	540	92
77	21.07	49.50	70.57	2.12	0.95	63.18	542	92
78	21.11	50.50	71.61	2.15	0.96	63.30	545	92
79	21.11	51.60	72.71	2.18	1.00	63.30	545	92
80	21.11	52.80	73.91	2.22	1.00	63.30	555	92

Table B.27: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	21.11	53.80	74.91	2.25	1.00	63.30	570	90
82	21.11	54.80	75.91	2.28	1.00	63.30	570	90
83	21.11	55.80	76.91	2.31	1.00	63.30	560	90
84	21.17	56.90	78.07	2.34	0.95	63.48	545	92
85	21.17	58.00	79.17	2.37	1.00	63.48	542	90
86	21.17	59.10	80.27	2.41	1.00	63.48	548	90
87	21.21	60.10	81.31	2.44	0.96	63.60	542	90
88	21.21	61.10	82.31	2.47	1.00	63.60	535	90
89	21.21	62.10	83.31	2.50	1.00	63.60	522	92
90	21.21	63.20	84.41	2.53	1.00	63.60	512	92
91	21.24	64.10	85.34	2.56	0.97	63.69	518	92
92	21.24	65.10	86.34	2.59	1.00	63.69	531	92
93	21.29	66.10	87.39	2.62	0.95	63.84	555	90
94	21.29	67.10	88.39	2.65	1.00	63.84	560	90
95	21.34	68.00	89.34	2.68	0.95	63.99	565	89
96	21.44	68.80	90.24	2.71	0.89	64.29	560	89
97	21.44	69.80	91.24	2.74	1.00	64.29	550	89
98	21.44	70.80	92.24	2.77	1.00	64.29	560	89
99	21.44	71.80	93.24	2.80	1.00	64.29	560	88
100	21.44	72.80	94.24	2.83	1.00	64.29	572	88
101	21.44	73.80	95.24	2.86	1.00	64.29	578	88
102	21.44	74.80	96.24	2.89	1.00	64.29	578	86
103	21.49	75.90	97.39	2.92	0.96	64.44	575	86
104	21.49	77.00	98.49	2.95	1.00	64.44	578	84
105	21.49	78.10	99.59	2.99	1.00	64.44	578	84
106	21.49	79.20	100.69	3.02	1.00	64.44	572	85
107	21.52	80.20	101.72	3.05	0.97	64.53	572	84
108	21.52	81.20	102.72	3.08	1.00	64.53	575	84
109	21.52	82.20	103.72	3.11	1.00	64.53	572	82
110	21.52	83.30	104.82	3.14	1.00	64.53	580	82
111	21.52	84.40	105.92	3.18	1.00	64.53	585	81
112	21.52	85.50	107.02	3.21	1.00	64.53	590	81
113	21.52	86.50	108.02	3.24	1.00	64.53	585	79
114	21.52	87.60	109.12	3.27	1.00	64.53	575	79
115	21.52	88.70	110.22	3.30	1.00	64.53	568	79
116	21.52	89.70	111.22	3.33	1.00	64.53	565	78
117	21.52	90.70	112.22	3.36	1.00	64.53	568	76
118	21.52	91.70	113.22	3.39	1.00	64.53	570	76
119	21.52	92.70	114.22	3.42	1.00	64.53	580	75
120	21.52	93.70	115.22	3.45	1.00	64.53	580	75

Table B.28: Raw and Computed Results for Run# 28

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(hot-water-driven solvent slugs, Q=1 cc/min, mode III).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	30	126
2	0.00	0.00	0.00	0.00	0.00	0.00	45	122
3	0.00	0.00	0.00	0.00	0.00	0.00	65	117
4	0.00	0.00	0.00	0.00	0.00	0.00	95	114
5	0.00	0.00	0.00	0.00	0.00	0.00	190	109
6	0.00	0.00	0.00	0.00	0.00	0.00	290	106
7	0.00	0.00	0.00	0.00	0.00	0.00	395	103
8	0.00	0.00	0.00	0.00	0.00	0.00	275	101
9	0.00	0.00	0.00	0.00	0.00	0.00	80	110
10	1.40	0.00	1.40	0.04	0.00	4.03	68	152
11	2.90	0.00	2.90	0.08	0.00	8.35	55	150
12	4.20	0.00	4.20	0.12	0.00	12.09	49	146
13	5.60	0.00	5.60	0.16	0.00	16.12	47	144
14	6.80	0.00	6.80	0.20	0.00	19.57	45	142
15	7.95	0.00	7.95	0.23	0.00	22.88	44	141
16	9.55	0.00	9.55	0.27	0.00	27.48	43	142
17	10.85	0.00	10.85	0.31	0.00	31.22	43	142
18	12.05	0.00	12.05	0.35	0.00	34.68	43	142
19	13.15	0.00	13.15	0.38	0.00	37.84	44	140
20	14.11	0.00	14.11	0.41	0.00	40.60	44	140
21	15.31	0.00	15.31	0.44	0.00	44.06	43	139
22	16.71	0.00	16.71	0.48	0.00	48.09	41	138
23	18.21	0.00	18.21	0.52	0.00	52.40	41	132
24	18.75	0.30	19.05	0.55	0.36	53.96	40	130
25	19.71	0.50	20.21	0.58	0.17	56.72	40	121
26	19.93	1.40	21.33	0.61	0.80	57.35	50	118
27	20.11	2.30	22.41	0.64	0.83	57.87	55	117
28	20.23	3.40	23.63	0.68	0.90	58.22	56	114
29	20.36	4.40	24.76	0.71	0.88	58.59	57	110
30	20.43	5.40	25.83	0.74	0.93	58.79	57	108
31	20.49	6.40	26.89	0.77	0.94	58.96	54	106
32	20.58	7.60	28.18	0.81	0.93	59.22	57	101
33	20.66	8.70	29.36	0.84	0.93	59.45	68	90
34	20.68	9.80	30.48	0.88	0.98	59.51	78	92
35	20.71	10.80	31.51	0.91	0.97	59.60	77	94
36	20.77	11.90	32.67	0.94	0.95	59.77	78	97
37	20.79	13.10	33.89	0.98	0.98	59.83	75	100
38	20.85	14.20	35.05	1.01	0.95	60.00	71	103
39	20.87	15.20	36.07	1.04	0.98	60.06	66	106
40	20.92	16.20	37.12	1.07	0.95	60.20	62	107

Table B.28: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	20.96	17.10	38.06	1.10	0.96	60.32	59	108
42	20.98	17.90	38.88	1.12	0.98	60.37	57	110
43	20.98	18.80	39.78	1.14	1.00	60.37	56	110
44	21.02	19.80	40.82	1.17	0.96	60.49	54	113
45	21.05	20.80	41.85	1.20	0.97	60.58	54	114
46	21.11	21.90	43.01	1.24	0.95	60.75	54	114
47	21.19	23.00	44.19	1.27	0.93	60.98	53	116
48	21.20	24.10	45.30	1.30	0.99	61.01	51	116
49	21.24	25.20	46.44	1.34	0.96	61.12	50	115
50	21.26	26.20	47.46	1.37	0.98	61.18	50	115
51	21.29	27.20	48.49	1.40	0.97	61.27	50	115
52	21.31	28.20	49.51	1.42	0.98	61.32	50	115
53	21.35	29.30	50.65	1.46	0.96	61.44	49	115
54	21.44	30.20	51.64	1.49	0.91	61.70	49	114
55	21.53	31.20	52.73	1.52	0.92	61.96	49	114
56	21.61	32.30	53.91	1.55	0.93	62.19	48	114
57	21.68	33.30	54.98	1.58	0.93	62.39	48	114
58	21.72	34.40	56.12	1.61	0.96	62.50	47	114
59	21.77	35.30	57.07	1.64	0.95	62.65	47	113
60	21.81	36.40	58.21	1.68	0.96	62.76	47	113
61	21.85	37.50	59.35	1.71	0.96	62.88	46	112
62	21.87	38.60	60.47	1.74	0.98	62.94	46	112
63	21.92	39.80	61.72	1.78	0.96	63.08	46	112
64	21.97	40.90	62.87	1.81	0.96	63.22	45	111
65	21.99	42.00	63.99	1.84	0.98	63.28	45	111
66	22.00	43.10	65.10	1.87	0.99	63.31	45	111
67	22.06	44.10	66.16	1.90	0.94	63.48	45	111
68	22.11	45.10	67.21	1.93	0.95	63.63	45	111
69	22.12	46.20	68.32	1.97	0.99	63.65	44	111
70	22.18	47.10	69.28	1.99	0.94	63.83	44	111
71	22.20	48.10	70.30	2.02	0.98	63.88	44	111
72	22.21	49.20	71.41	2.05	0.99	63.91	44	111
73	22.23	50.20	72.43	2.08	0.98	63.97	44	111
74	22.25	51.30	73.55	2.12	0.98	64.03	43	111
75	22.27	52.40	74.67	2.15	0.98	64.09	43	111
76	22.29	53.50	75.79	2.18	0.98	64.14	43	112
77	22.30	54.50	76.80	2.21	0.99	64.17	44	114
78	22.34	55.50	77.84	2.24	0.96	64.29	45	114
79	22.34	56.60	78.94	2.27	1.00	64.29	45	114
80	22.35	57.70	80.05	2.30	0.99	64.32	49	115

Table B.28: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
81	22.40	58.70	81.10	2.33	0.95	64.46	46	117
82	22.46	59.70	82.16	2.36	0.94	64.63	44	117
83	22.46	60.70	83.16	2.39	1.00	64.63	45	118
84	22.46	61.70	84.16	2.42	1.00	64.63	45	118
85	22.47	62.90	85.37	2.46	0.99	64.66	44	119
86	22.50	64.00	86.50	2.49	0.97	64.75	44	120
87	22.52	65.10	87.62	2.52	0.98	64.81	40	121
88	22.54	66.20	88.74	2.55	0.98	64.86	37	120
89	22.54	67.20	89.74	2.58	1.00	64.86	36	120
90	22.59	68.20	90.79	2.61	0.95	65.01	40	118
91	22.59	69.40	91.99	2.65	1.00	65.01	44	118
92	22.59	70.50	93.09	2.68	1.00	65.01	47	118
93	22.64	71.50	94.14	2.71	0.95	65.15	40	118
94	22.64	72.50	95.14	2.74	1.00	65.15	35	117
95	22.64	73.70	96.34	2.77	1.00	65.15	33	117
96	22.64	74.80	97.44	2.80	1.00	65.15	34	117
97	22.67	75.80	98.47	2.83	0.97	65.24	34	116
98	22.67	76.80	99.47	2.86	1.00	65.24	36	116
99	22.67	77.80	100.47	2.89	1.00	65.24	36	115
100	22.71	78.80	101.51	2.92	0.96	65.35	37	114
101	22.72	79.90	102.62	2.95	0.99	65.38	37	114
102	22.72	81.00	103.72	2.98	1.00	65.38	38	114
103	22.78	82.00	104.78	3.02	0.94	65.55	38	114
104	22.78	83.00	105.78	3.04	1.00	65.55	38	114
105	22.78	84.00	106.78	3.07	1.00	65.55	38	112
106	22.85	85.10	107.95	3.11	0.94	65.76	38	112
107	22.85	86.10	108.95	3.14	1.00	65.76	37	112
108	22.85	87.10	109.95	3.16	1.00	65.76	37	112
109	22.85	88.10	110.95	3.19	1.00	65.76	37	112
110	22.85	89.10	111.95	3.22	1.00	65.76	36	109
111	22.85	90.10	112.95	3.25	1.00	65.76	34	106
112	22.85	91.20	114.05	3.28	1.00	65.76	34	102
113	22.85	92.30	115.15	3.31	1.00	65.76	34	101
114	22.85	93.40	116.25	3.35	1.00	65.76	37	103
115	22.85	94.50	117.35	3.38	1.00	65.76	38	106
116	22.85	95.70	118.55	3.41	1.00	65.76	39	108
117	22.85	96.80	119.65	3.44	1.00	65.76	46	110
118	22.85	97.90	120.75	3.47	1.00	65.76	56	112
119	22.85	98.90	121.75	3.50	1.00	65.76	39	114
120	22.85	99.90	122.75	3.53	1.00	65.76	37	116

Table B.29: Raw and Computed Results for Run# 29

(hot-water-driven solvent slugs, Q=2 cc/min, mode 11).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	20	100
2	0.00	0.00	0.00	0.00	0.00	0.00	55	100
3	0.00	0.00	0.00	0.00	0.00	0.00	106	99
4	0.00	0.00	0.00	0.00	0.00	0.00	253	97
5	0.00	0.00	0.00	0.00	0.00	0.00	530	95
6	1.40	0.00	1.40	0.04	0.00	3.95	200	94
7	5.40	0.00	5.40	0.15	0.00	15.22	113	95
8	7.30	0.00	7.30	0.21	0.00	20.57	135	94
9	9.35	0.00	9.35	0.26	0.00	26.35	140	95
10	11.20	0.00	11.20	0.32	0.00	31.57	150	96
11	13.05	0.00	13.05	0.37	0.00	36.78	153	97
12	14.95	0.00	14.95	0.42	0.00	42.14	155	98
13	16.13	0.20	16.33	0.46	0.14	45.46	164	98
14	16.55	1.80	18.35	0.52	0.79	46.65	168	103
15	16.95	3.50	20.45	0.58	0.81	47.77	175	106
16	17.35	5.30	22.65	0.64	0.82	48.90	180	108
17	17.71	7.00	24.71	0.70	0.83	49.92	175	111
18	17.99	8.80	26.79	0.76	0.87	50.70	175	112
19	18.26	10.70	28.96	0.82	0.88	51.47	188	114
20	18.42	12.60	31.02	0.87	0.92	51.92	195	115
21	18.53	14.40	32.93	0.93	0.94	52.23	203	115
22	18.71	16.20	34.91	0.98	0.91	52.73	205	117
23	18.87	18.10	36.97	1.04	0.92	53.18	217	117
24	19.05	20.00	39.05	1.10	0.91	53.69	220	117
25	19.16	21.80	40.96	1.15	0.94	54.00	223	117
26	19.28	23.60	42.88	1.21	0.94	54.34	226	117
27	19.35	25.60	44.95	1.27	0.97	54.54	232	115
28	19.43	27.60	47.03	1.33	0.96	54.76	242	115
29	19.56	29.40	48.96	1.38	0.93	55.13	256	115
30	19.70	31.40	51.10	1.44	0.93	55.52	245	115
31	19.85	33.30	53.15	1.50	0.93	55.95	257	116
32	20.03	35.30	55.33	1.56	0.92	56.45	257	116
33	20.19	37.10	57.29	1.61	0.92	56.91	273	116
34	20.32	38.90	59.22	1.67	0.93	57.27	265	116
35	20.50	40.60	61.10	1.72	0.90	57.78	283	116
36	20.66	42.60	63.26	1.78	0.93	58.23	275	116
37	20.80	44.40	65.20	1.84	0.93	58.62	277	115
38	20.97	46.40	67.37	1.90	0.92	59.10	286	114
39	21.15	48.30	69.45	1.96	0.91	59.61	280	114
40	21.22	50.30	71.52	2.02	0.97	59.81	296	114

Table B.29: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	21.27	52.40	73.67	2.08	0.98	59.95	297	114
42	21.30	54.40	75.70	2.13	0.99	60.03	310	113
43	21.32	56.50	77.82	2.19	0.99	60.09	310	113
44	21.38	58.60	79.98	2.25	0.97	60.26	310	113
45	21.41	60.60	82.01	2.31	0.99	60.34	298	113
46	21.45	62.60	84.05	2.37	0.98	60.46	275	113
47	21.47	64.50	85.97	2.42	0.99	60.51	285	113
48	21.50	66.30	87.80	2.47	0.98	60.60	315	112
49	21.57	68.20	89.77	2.53	0.96	60.79	333	112
50	21.60	70.10	91.70	2.58	0.98	60.88	320	112
51	21.65	72.10	93.75	2.64	0.98	61.02	325	112
52	21.66	74.10	95.76	2.70	1.00	61.05	324	112
53	21.70	76.10	97.80	2.76	0.98	61.16	315	112
54	21.75	78.00	99.75	2.81	0.97	61.30	317	110
55	21.80	79.90	101.70	2.87	0.97	61.44	323	110
56	21.83	81.90	103.73	2.92	0.99	61.53	338	110
57	21.86	84.00	105.86	2.98	0.99	61.61	322	110
58	21.93	86.10	108.03	3.04	0.97	61.81	307	110
59	21.98	88.10	110.08	3.10	0.98	61.95	320	110
60	22.02	90.20	112.22	3.16	0.98	62.06	245	110
61	22.04	92.30	114.34	3.22	0.99	62.12	245	110
62	22.06	94.30	116.36	3.28	0.99	62.18	300	110
63	22.06	96.30	118.36	3.34	1.00	62.18	342	110
64	22.06	98.30	120.36	3.39	1.00	62.18	353	110

Table B.30: Raw and Computed Results for Run# 30

(hot-water-driven solvent slugs, Q=4 cc/min, mode II).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	20	90
2	0.00	0.00	0.00	0.00	0.00	0.00	45	91
3	1.42	0.00	1.42	0.04	0.00	4.11	186	91
4	3.86	0.00	3.86	0.11	0.00	11.16	540	90
5	8.08	0.00	8.08	0.23	0.00	23.37	100	92
6	11.36	0.00	11.36	0.33	0.00	32.85	101	95
7	14.38	0.00	14.38	0.42	0.00	41.58	101	97
8	15.98	2.40	18.38	0.53	0.60	46.21	106	100
9	16.60	5.70	22.30	0.64	0.84	48.00	107	103
10	17.13	9.10	26.23	0.76	0.87	49.54	108	107
11	17.45	12.50	29.95	0.87	0.91	50.46	106	109
12	17.81	16.00	33.81	0.98	0.91	51.50	104	114
13	18.05	19.50	37.55	1.09	0.94	52.20	102	117
14	18.23	23.10	41.33	1.20	0.95	52.72	108	118
15	18.46	26.80	45.26	1.31	0.94	53.38	114	121
16	18.58	30.40	48.98	1.42	0.97	53.73	117	121
17	18.76	34.20	52.96	1.53	0.95	54.25	118	121
18	19.04	38.00	57.04	1.65	0.93	55.06	118	120
19	19.30	41.90	61.20	1.77	0.94	55.81	120	117
20	19.49	45.70	65.19	1.89	0.95	56.36	121	115
21	19.67	49.50	69.17	2.00	0.95	56.88	122	112
22	19.83	53.40	73.23	2.12	0.96	57.35	124	109
23	19.98	57.40	77.38	2.24	0.96	57.78	122	106
24	20.03	61.60	81.63	2.36	0.99	57.92	123	102
25	20.16	65.60	85.76	2.48	0.97	58.30	122	101
26	20.28	69.50	89.78	2.60	0.97	58.65	122	98
27	20.46	73.40	93.86	2.71	0.96	59.17	122	98
28	20.57	77.40	97.97	2.83	0.97	59.49	122	98
29	20.71	81.30	102.01	2.95	0.97	59.89	121	99
30	20.83	85.20	106.03	3.07	0.97	60.24	120	99
31	20.97	89.10	110.07	3.18	0.97	60.64	121	101
32	21.04	92.90	113.94	3.29	0.98	60.84	117	104
33	21.07	96.70	117.77	3.41	0.99	60.93	118	106
34	21.10	100.60	121.70	3.52	0.99	61.02	118	107
35	21.10	104.40	125.50	3.63	1.00	61.02	116	109
36	21.10	108.20	129.30	3.74	1.00	61.02	116	109

Table B.31: Raw and Computed Results for Run# 31

(hot-water-driven solvent slugs, Q=2 cc/min, mode III).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	5	103
2	0.00	0.00	0.00	0.00	0.00	0.00	26	103
3	0.00	0.00	0.00	0.00	0.00	0.00	42	102
4	0.00	0.00	0.00	0.00	0.00	0.00	71	99
5	0.00	0.00	0.00	0.00	0.00	0.00	90	98
6	1.20	0.00	1.20	0.04	0.00	3.58	144	98
7	3.30	0.00	3.30	0.10	0.00	9.83	235	96
8	5.40	0.00	5.40	0.16	0.00	16.09	245	95
9	8.90	0.00	8.90	0.27	0.00	26.52	237	95
10	11.90	0.00	11.90	0.35	0.00	35.46	180	95
11	14.80	0.00	14.80	0.44	0.00	44.10	108	98
12	17.20	0.00	17.20	0.51	0.00	51.25	98	102
13	17.53	1.70	19.23	0.57	0.84	52.23	88	108
14	17.71	3.60	21.31	0.63	0.91	52.77	73	112
15	17.86	5.50	23.36	0.70	0.93	53.22	62	118
16	17.91	7.40	25.31	0.75	0.97	53.37	56	121
17	18.01	9.20	27.21	0.81	0.95	53.67	58	120
18	18.12	11.10	29.22	0.87	0.95	53.99	61	118
19	18.13	13.10	31.23	0.93	1.00	54.02	62	117
20	18.24	15.00	33.24	0.99	0.95	54.35	63	114
21	18.32	17.00	35.32	1.05	0.96	54.59	64	113
22	18.46	18.90	37.36	1.11	0.93	55.01	64	111
23	18.56	20.80	39.36	1.17	0.95	55.30	63	109
24	18.73	22.70	41.43	1.23	0.92	55.81	63	107
25	18.80	24.70	43.50	1.30	0.97	56.02	62	101
26	18.90	26.60	45.50	1.36	0.95	56.32	61	101
27	19.01	28.60	47.61	1.42	0.95	56.64	60	102
28	19.13	30.50	49.63	1.48	0.94	57.00	58	102
29	19.25	32.50	51.75	1.54	0.94	57.36	58	102
30	19.30	34.40	53.70	1.60	0.97	57.51	58	104
31	19.40	36.30	55.70	1.66	0.95	57.81	59	104
32	19.50	38.10	57.60	1.72	0.95	58.10	59	105
33	19.58	39.90	59.48	1.77	0.96	58.34	58	105
34	19.62	41.80	61.42	1.83	0.98	58.46	57	105
35	19.72	43.70	63.42	1.89	0.95	58.76	56	105
36	19.79	45.70	65.49	1.95	0.97	58.97	56	105
37	19.85	47.70	67.55	2.01	0.97	59.15	55	107
38	19.96	49.70	69.66	2.08	0.95	59.48	55	107
39	20.04	51.70	71.74	2.14	0.96	59.71	55	107
40	20.14	53.60	73.74	2.20	0.95	60.01	58	107

Table B.31: Continued.

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
41	20.24	55.50	75.74	2.26	0.95	60.31	44	107
42	20.29	57.40	77.69	2.31	0.97	60.46	47	107
43	20.36	59.30	79.66	2.37	0.96	60.67	50	107
44	20.46	61.10	81.56	2.43	0.95	60.97	52	107
45	20.59	63.00	83.59	2.49	0.94	61.35	53	107
46	20.62	65.00	85.62	2.55	0.99	61.44	53	107
47	20.72	66.80	87.52	2.61	0.95	61.74	53	107
48	20.72	68.70	89.42	2.66	1.00	61.74	53	107
49	20.82	70.60	91.42	2.72	0.95	62.04	52	107
50	20.88	72.50	93.38	2.78	0.97	62.22	52	107
51	20.92	74.50	95.42	2.84	0.98	62.34	52	107
52	20.99	76.40	97.39	2.90	0.96	62.54	51	107
53	21.09	78.30	99.39	2.96	0.95	62.84	52	107
54	21.19	80.20	101.39	3.02	0.95	63.14	52	107
55	21.29	82.20	103.49	3.08	0.95	63.44	51	107
56	21.39	84.00	105.39	3.14	0.95	63.74	51	107
57	21.45	85.90	107.35	3.20	0.97	63.92	51	107
58	21.54	87.90	109.44	3.26	0.96	64.18	50	106
59	21.64	89.70	111.34	3.32	0.95	64.48	50	106
60	21.67	91.60	113.27	3.38	0.98	64.57	50	106
61	21.67	93.50	115.17	3.43	1.00	64.57	50	106
62	21.67	95.50	117.17	3.49	1.00	64.57	50	106
63	21.67	97.30	118.97	3.54	1.00	64.57	49	106
64	21.67	99.30	120.97	3.60	1.00	64.57	49	106
65	21.67	101.10	122.77	3.66	1.00	64.57	49	106
66	21.67	102.90	124.57	3.71	1.00	64.57	51	106
67	21.67	104.80	126.47	3.77	1.00	64.57	53	106
68	21.67	106.60	128.27	3.82	1.00	64.57	53	106
69	21.67	108.40	130.07	3.88	1.00	64.57	53	106
70	21.67	110.40	132.07	3.94	1.00	64.57	54	106
71	21.67	112.40	134.07	3.99	1.00	64.57	54	106
72	21.67	114.40	136.07	4.05	1.00	64.57	54	106
73	21.67	116.40	138.07	4.11	1.00	64.57	54	106

Table B.32: Raw and Computed Results for Run# 32

(hot-water-driven solvent slugs, Q=4 cc/min, mode III).

Time	Np	Wp	Wi	Qiw	FW	Rt	P	T
min	cc	cc	cc	THPV		%(THPV)	Psi	°C
1	0.00	0.00	0.00	0.00	0.00	0.00	9	93
2	0.00	0.00	0.00	0.00	0.00	0.00	36	93
3	1.80	0.00	1.80	0.05	0.00	5.32	400	93
4	5.90	0.00	5.90	0.17	0.00	17.45	635	93
5	9.40	0.00	9.40	0.28	0.00	27.79	68	96
6	12.80	0.00	12.80	0.38	0.00	37.85	80	97
7	16.10	0.00	16.10	0.48	0.00	47.60	81	100
8	17.51	2.70	20.21	0.60	0.66	51.77	79	103
9	18.51	5.80	24.31	0.72	0.76	54.73	76	105
10	19.03	9.40	28.43	0.84	0.87	56.27	76	108
11	19.46	13.00	32.46	0.96	0.89	57.54	81	110
12	19.76	16.80	36.56	1.08	0.93	58.43	78	116
13	19.96	20.70	40.66	1.20	0.95	59.02	70	119
14	20.16	24.60	44.76	1.32	0.95	59.61	69	122
15	20.33	28.50	48.83	1.44	0.96	60.11	76	120
16	20.46	32.40	52.86	1.56	0.97	60.50	77	122
17	20.55	36.40	56.95	1.68	0.98	60.76	78	122
18	20.63	40.50	61.13	1.81	0.98	61.00	79	120
19	20.70	44.40	65.10	1.92	0.98	61.21	81	120
20	20.75	48.30	69.05	2.04	0.99	61.35	83	119
21	20.78	52.20	72.98	2.16	0.99	61.44	84	118
22	20.89	56.00	76.89	2.27	0.97	61.77	85	114
23	21.00	59.80	80.80	2.39	0.97	62.09	84	113
24	21.06	63.80	84.86	2.51	0.99	62.27	82	114
25	21.11	67.70	88.81	2.63	0.99	62.42	83	115
26	21.18	71.60	92.78	2.74	0.98	62.63	82	115
27	21.18	75.60	96.78	2.86	1.00	62.63	82	116
28	21.19	79.60	100.79	2.98	1.00	62.66	83	117
29	21.21	83.70	104.91	3.10	1.00	62.71	82	117
30	21.34	87.60	108.94	3.22	0.97	63.10	86	116
31	21.34	91.50	112.84	3.34	1.00	63.10	88	116
32	21.34	95.50	116.84	3.45	1.00	63.10	89	117
33	21.34	99.60	120.94	3.58	1.00	63.10	86	117
34	21.34	103.60	124.94	3.69	1.00	63.10	84	117
35	21.34	107.60	128.94	3.81	1.00	63.10	83	117
36	21.34	111.60	132.94	3.93	1.00	63.10	82	116

Appendix C
Inlet Pressure and Temperature
Histories for Flood Runs

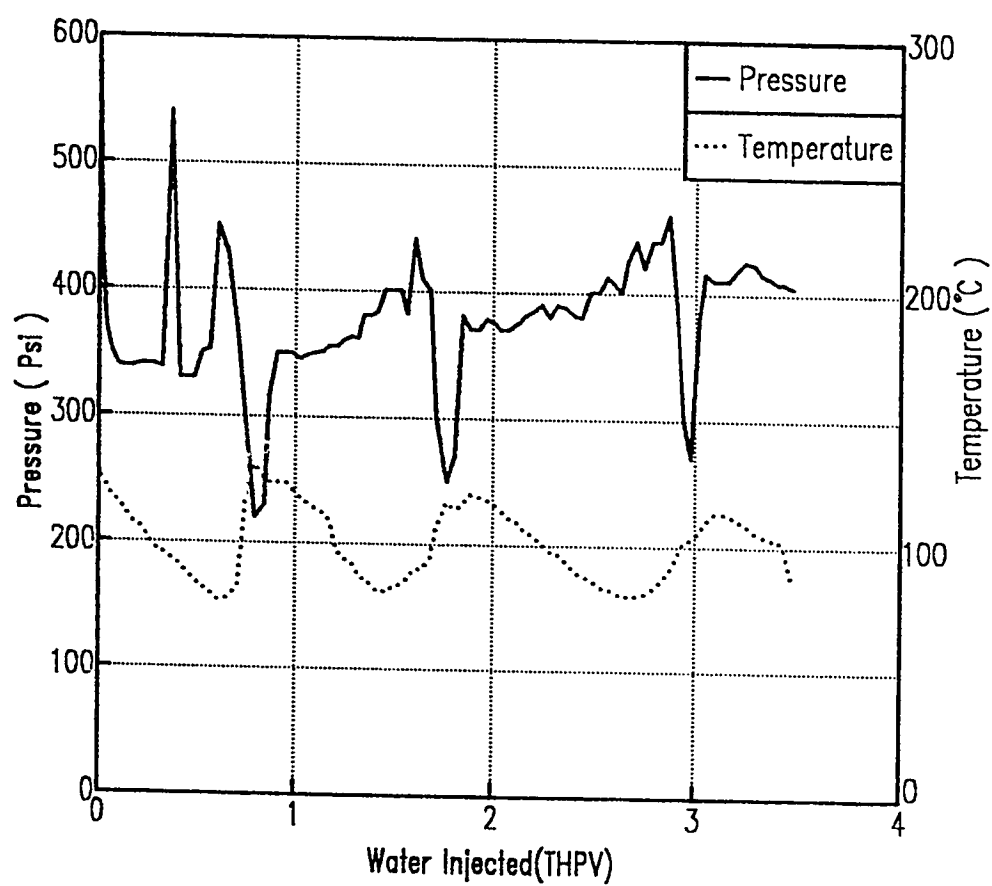


Figure C.1: Inlet pressure and temperature vs. water injected for Run# 3 (hot-water-driven reformat slug, $Q = 1$ cc/min).

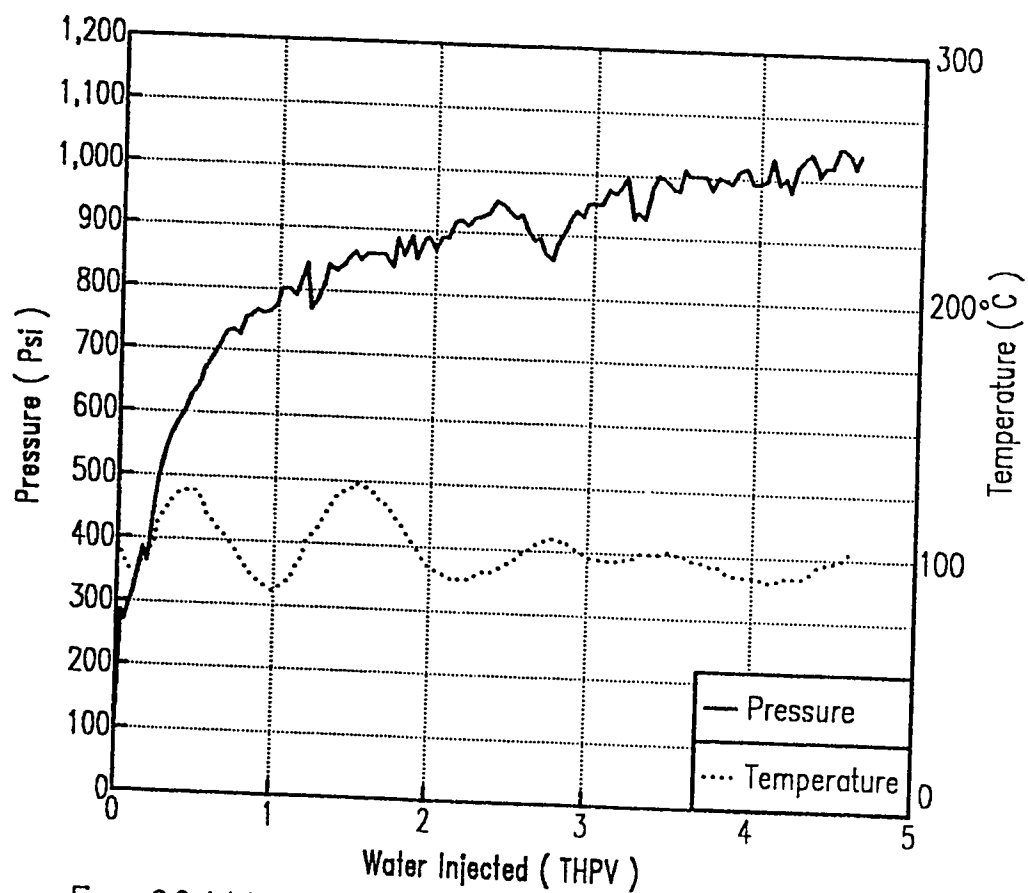


Figure C.2: Inlet pressure and temperature vs. water injected for Run# 4 (hot-water-driven reformate slug, $Q = 1$ cc/min).

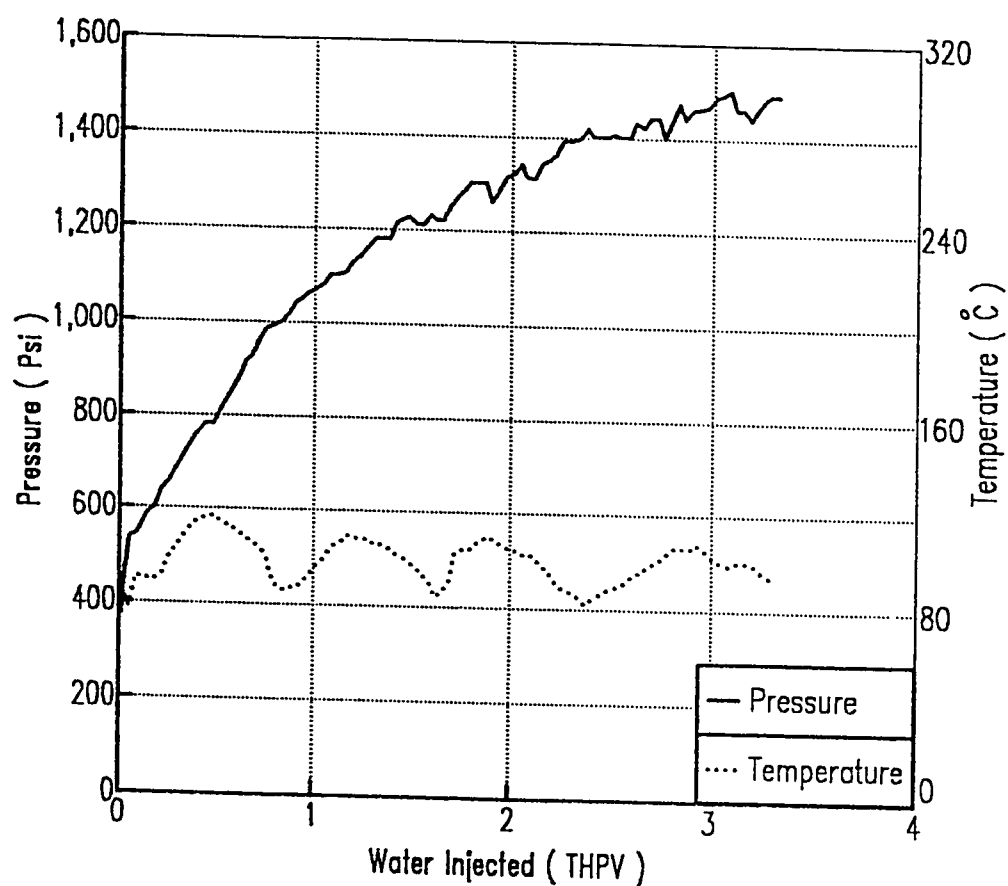


Figure C.3: Inlet pressure and temperature vs. water injected for Run# 6 (hot-water-driven reformat slug, $Q = 1$ cc/min).

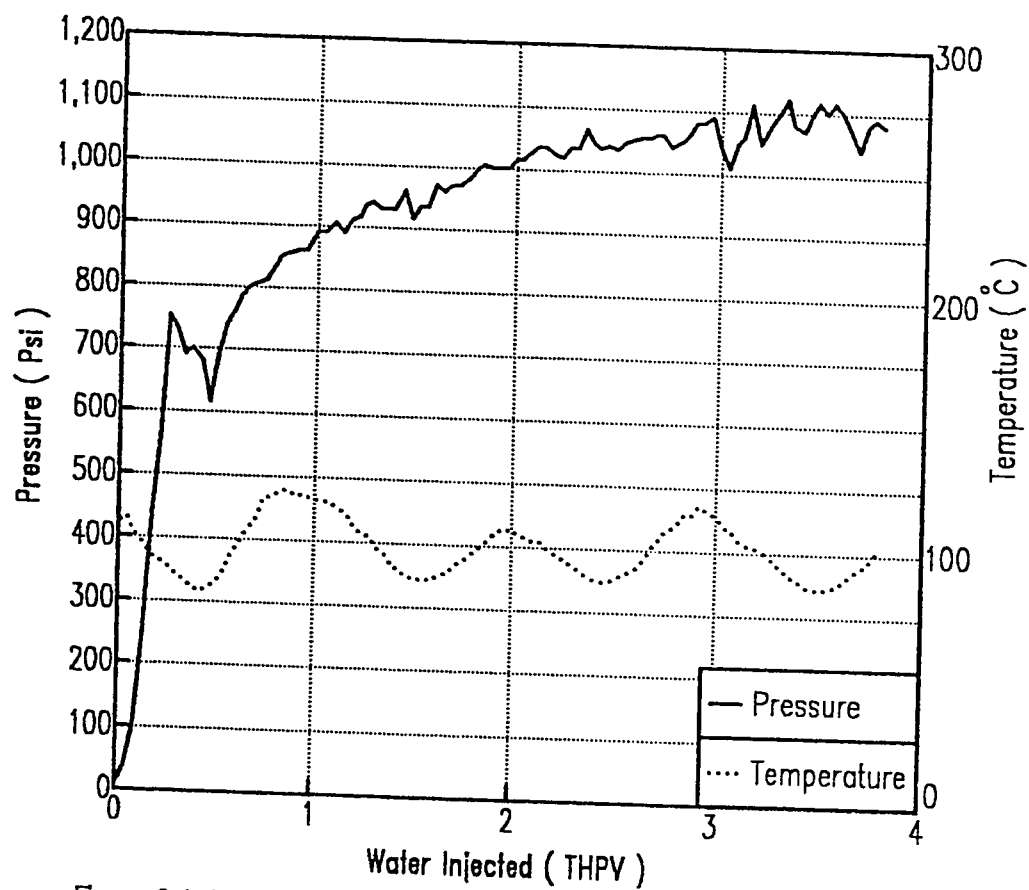


Figure C.4: Inlet pressure and temperature vs. water injected for Run# 7 (hot-water-driven reformat slug, $Q = 1$ cc/min).

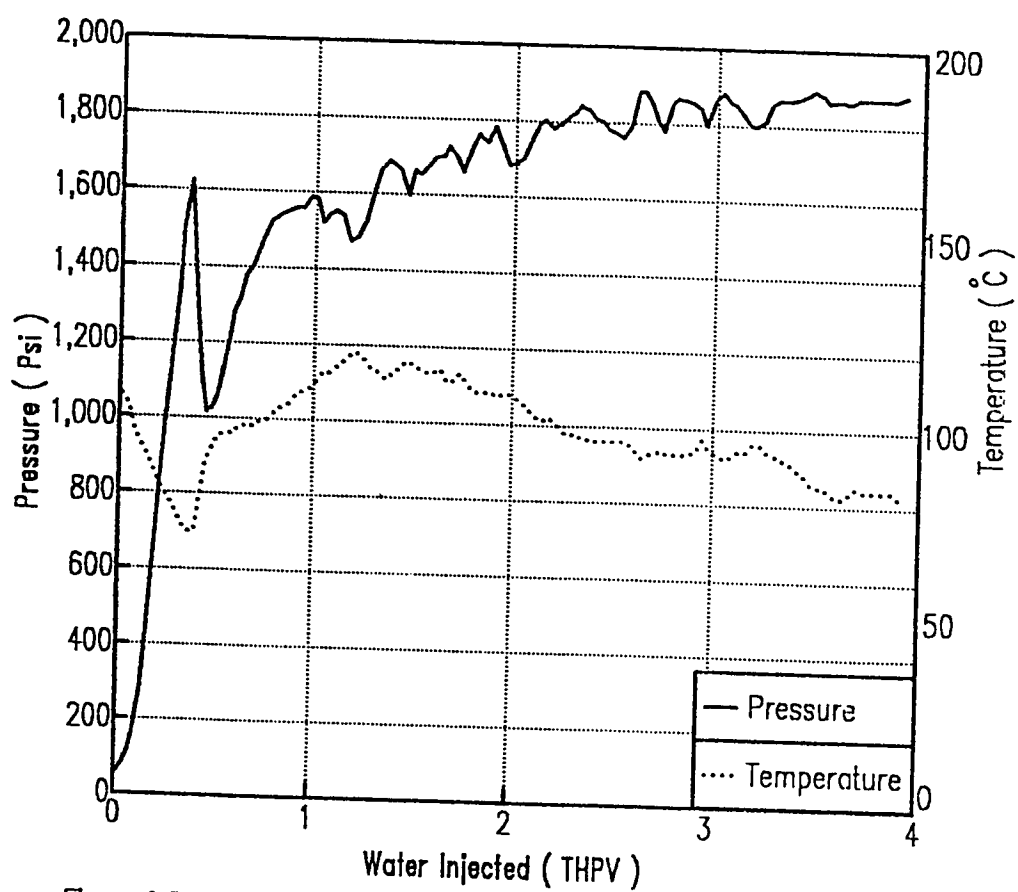


Figure C.5: Inlet pressure and temperature vs. water injected for Run# 19 (hot-water-driven reformat slug, $Q = 1$ cc/min).

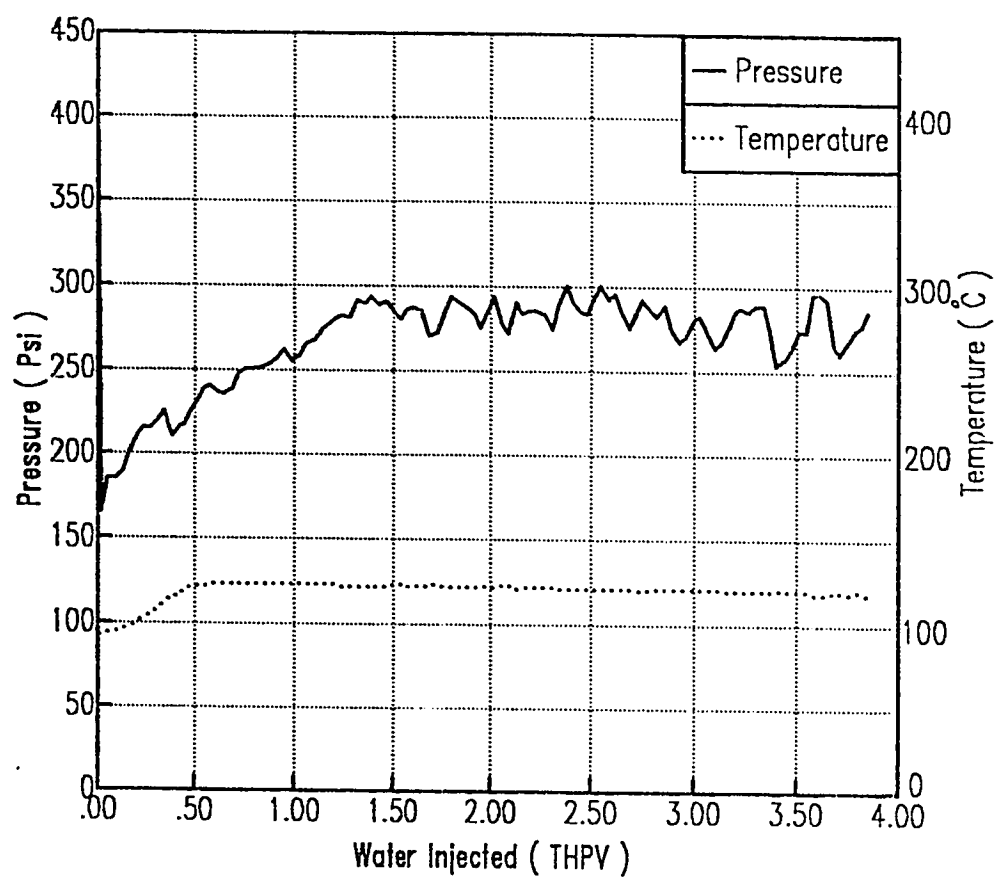


Figure C.6: Inlet pressure and temperature vs. water injected for Run# 21 (hot--water--driven naphtha slug, $Q = 1$ cc/min).

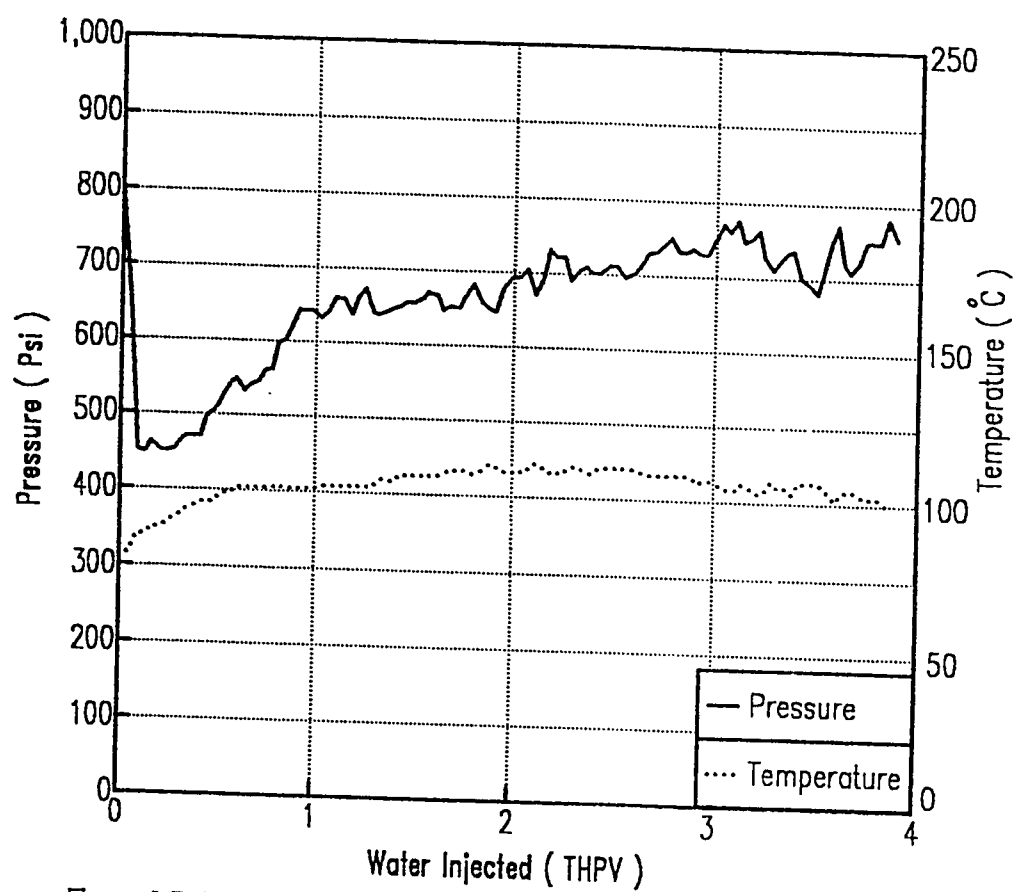


Figure C.7: Inlet pressure and temperature vs. water injected for Run# 22 (hot-water-driven naphtha slug, $Q = 1$ cc/min).

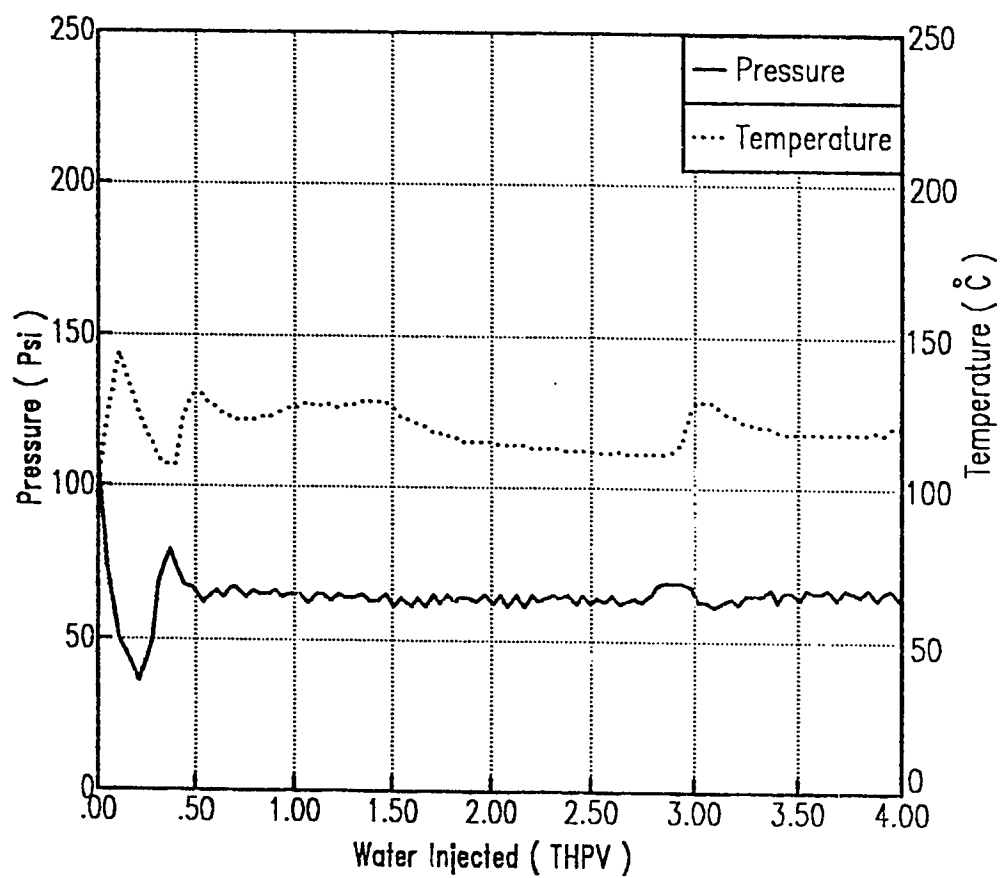


Figure C.8: Inlet pressure and temperature vs. water injected for Run# 23 (hot-water-driven naphtha, $Q = 1$ cc/min).

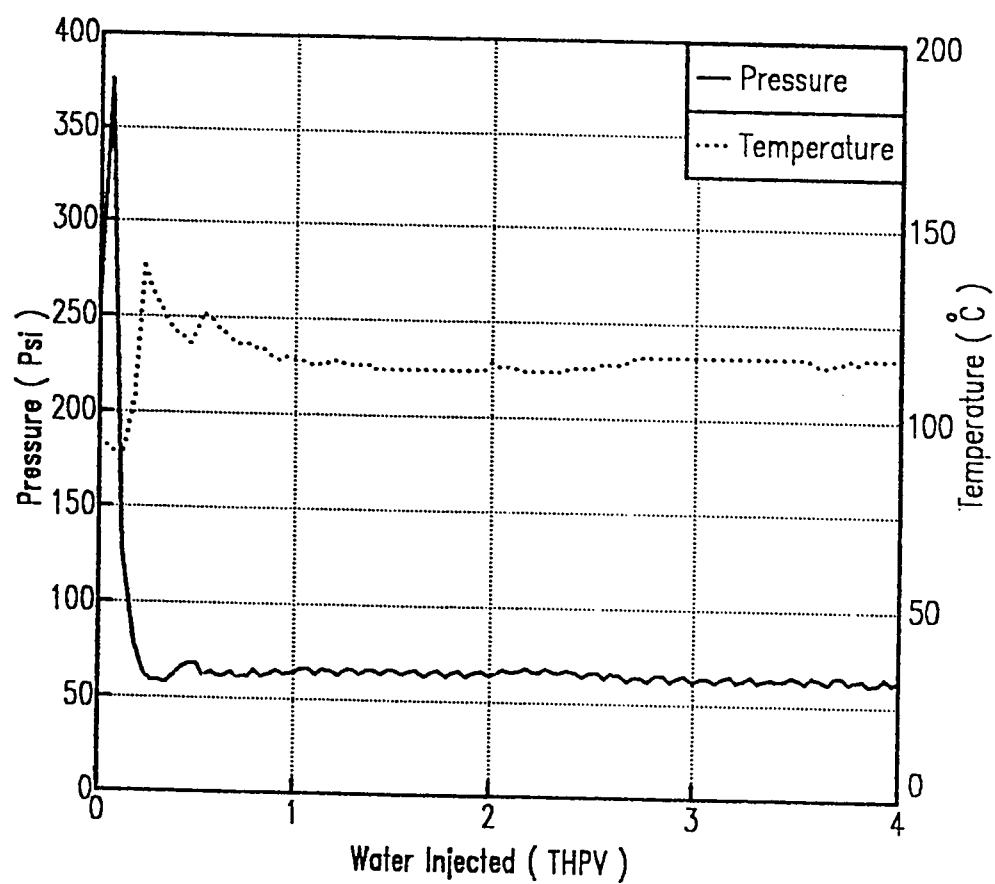


Figure C.9: Inlet pressure and temperature vs. water injected for Run# 24 (hot-water-driven naphtha slug, $Q = 1$ cc/min).

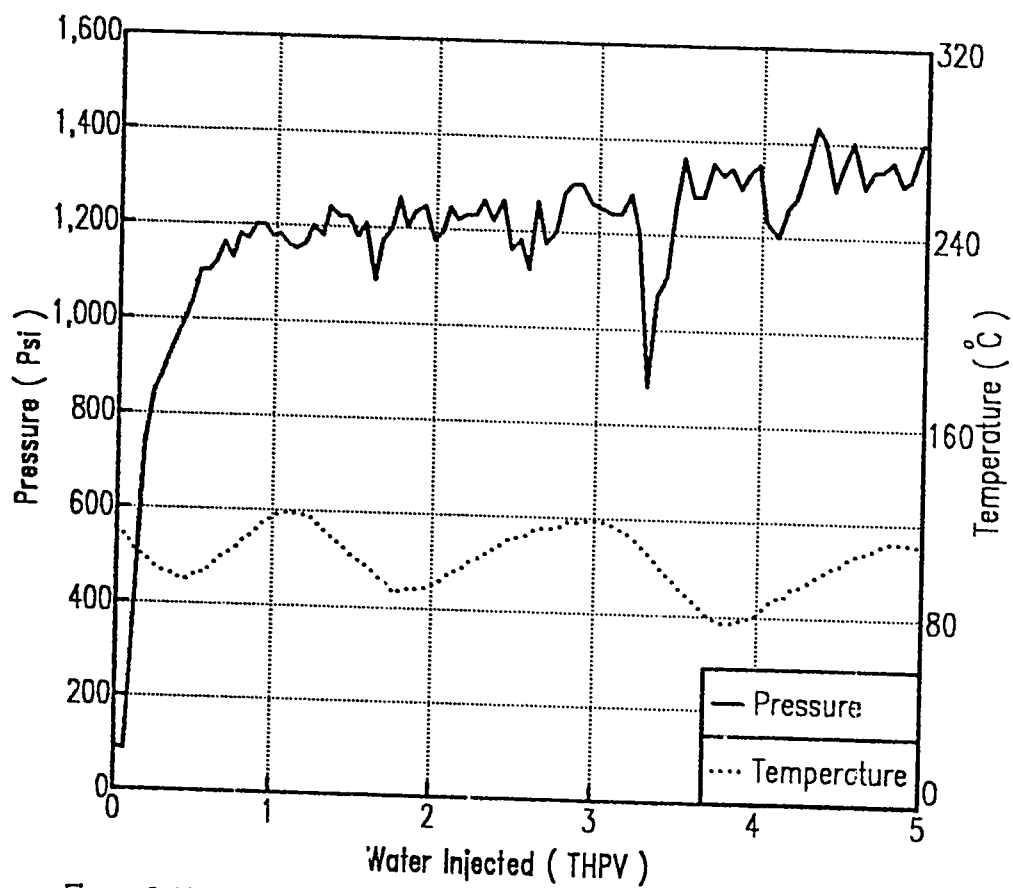


Figure C.10: Inlet pressure and temperature vs. water injected for Run# 8 (hot-water-driven reformat slug, mode I, $Q = 2$ cc/min).

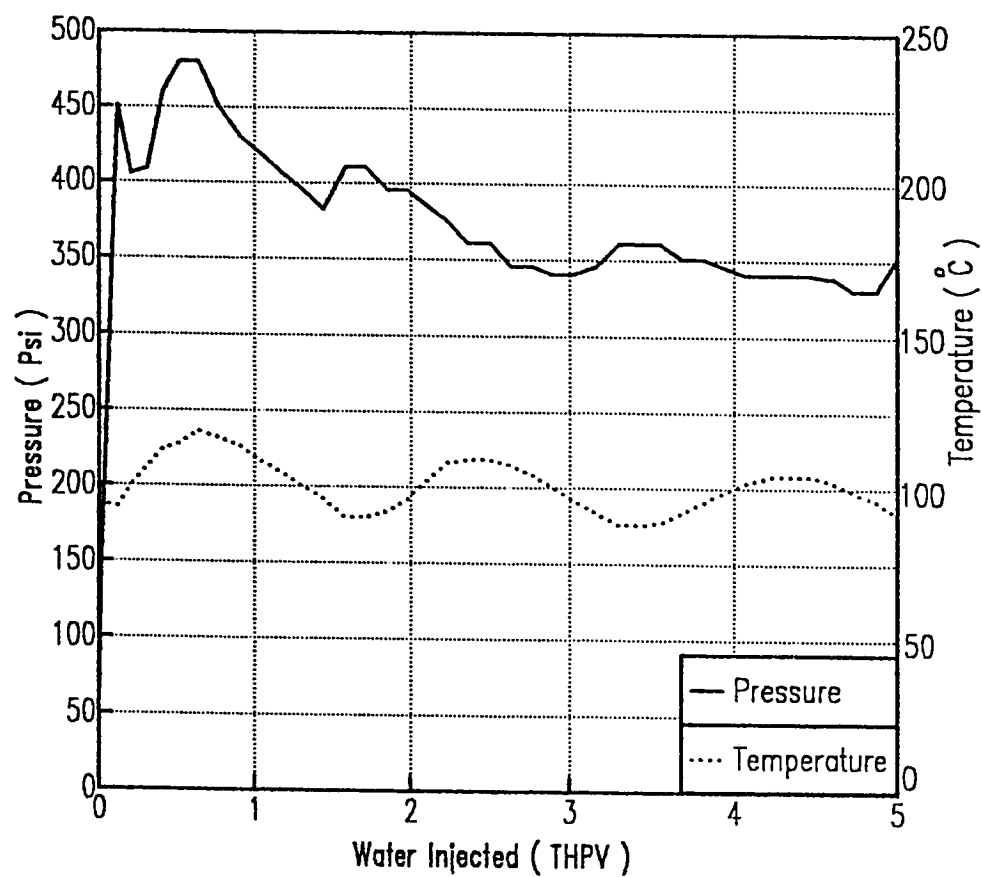


Figure C.11: Inlet pressure and temperature vs. water injected for Run# 9 (hot-water-driven reformat slug, mode I, $Q = 4$ cc/min).

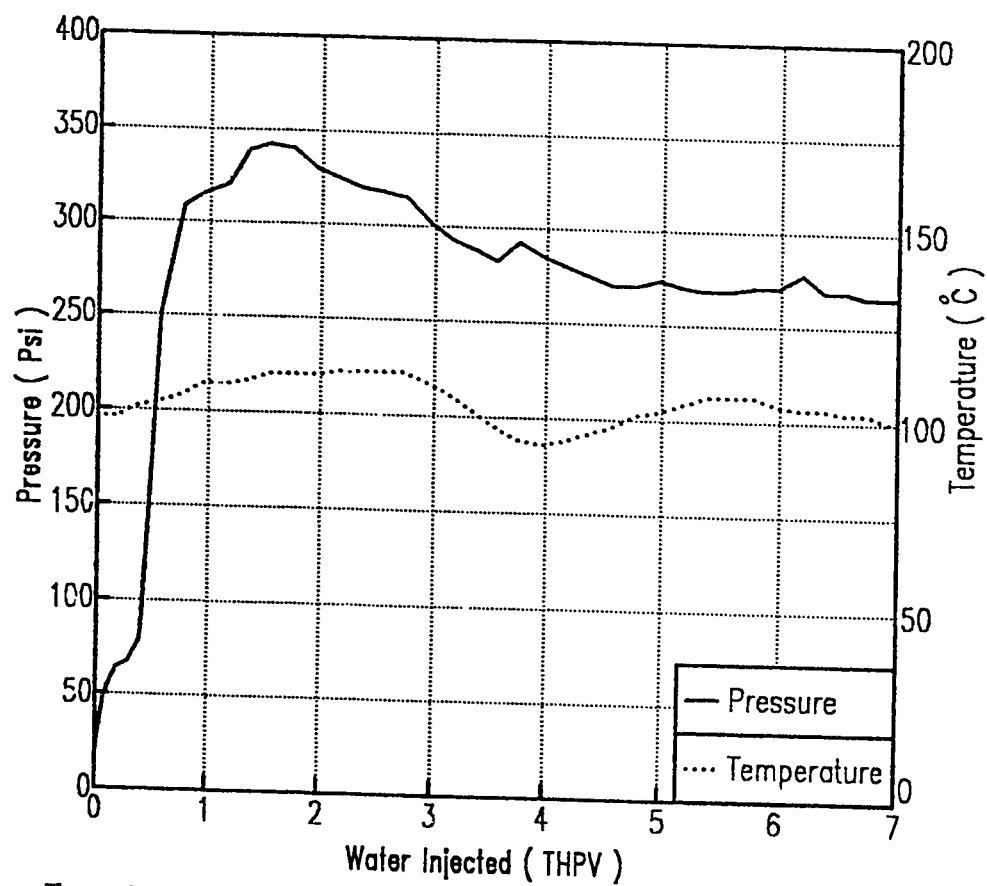


Figure C.12: Inlet pressure and temperature vs water injected for Run# 10 (hot-water-driven reformat slug, $Q = 6$ cc/min).

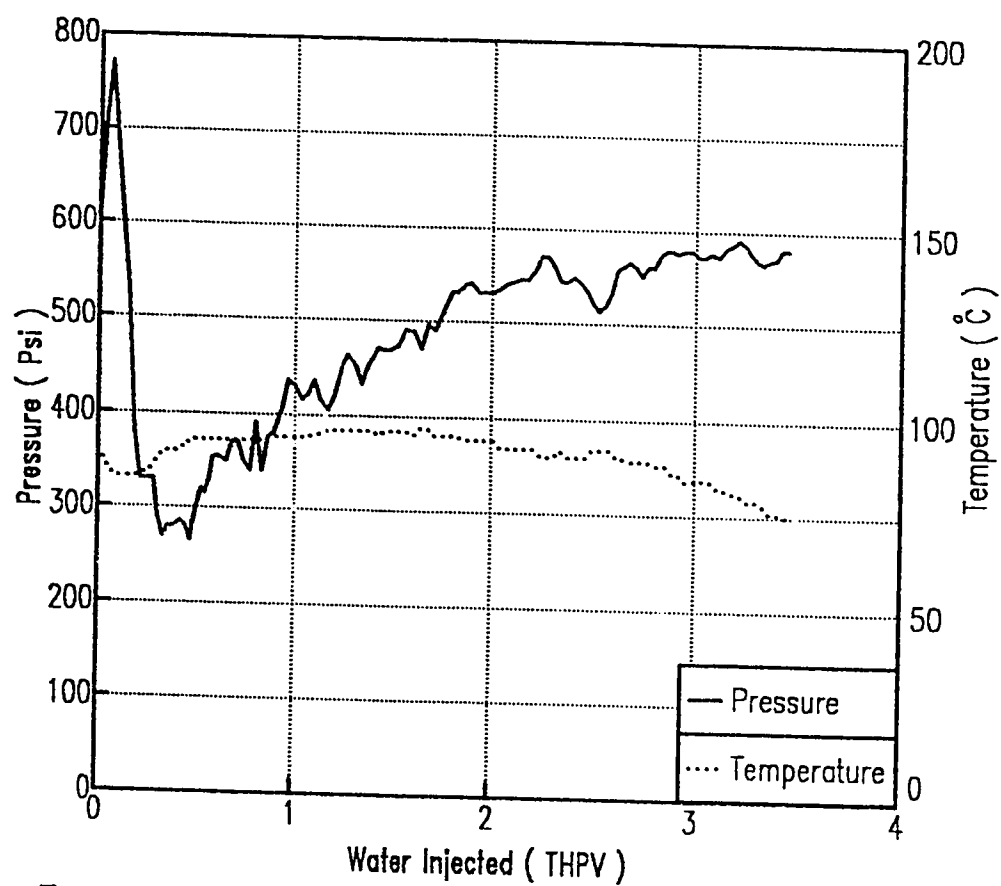


Figure C.13: Inlet pressure and temperature vs. water injected for Run# 26 (hot-water-driven naphtha slug, mode II, $Q = 1$ cc/min).

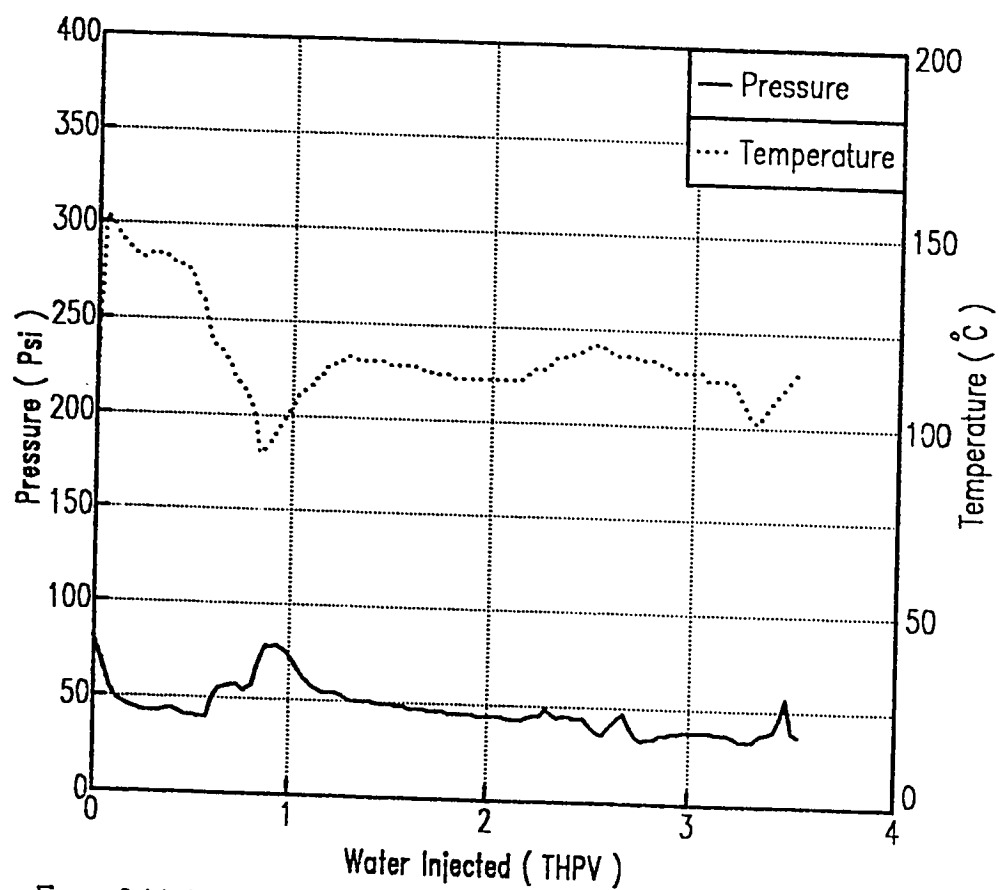


Figure C.14: Inlet pressure and temperature vs. water injected for Run# 28 (hot-water-driven naphtha slug, mode III, $Q = 1$ cc/min).

Appendix D
Average Water Saturation Data Obtained
by Fluid Extraction for Flood Runs

Table D.1: Water Saturation Data (Extraction Method) for All Flooding Runs.

Run #	Zone	Zone Length cm	Core Length cm	Pore Volume cc	Porosity %	Water Extracted cc	Core Sw %	Zone Sw %
1	Tar	8.35	8.35	9.96	23.5	0.9	9.04	9.04
	Oil	16.86	8.12	9.63	23.4	5.0	51.92	53.02
			8.74	10.35	23.4	5.6	54.11	
2	Tar	9.50	9.50	11.47	23.8	1.8	15.74	15.74
	Oil	18.95	9.49	11.31	23.5	6.9	61.02	63.75
			9.46	11.28	23.5	7.5	66.48	
3	Tar	9.10	9.10	11.60	24.2	2.8	25.14	25.14
	Oil	17.45	8.67	10.67	24.3	6.4	59.98	61.24
			8.78	11.04	24.8	6.9	62.50	
4	Tar	9.04	9.04	10.67	23.3	2.5	23.40	23.40
	Oil	18.52	10.18	12.38	24.0	7.4	59.77	61.48
			8.34	9.97	23.6	6.3	63.19	
5	Tar	9.23	9.23	11.41	24.4	2.8	24.50	24.50
	Oil	18.67	8.67	10.59	24.1	6.1	57.60	59.05
			10.00	12.06	23.8	7.3	60.50	
6	Tar	9.14	9.14	10.93	23.6	2.5	22.90	22.90
	Oil	17.80	8.95	11.34	25.0	6.1	53.80	55.15
			8.85	10.98	24.5	6.2	56.50	
7	Tar	8.60	8.60	10.50	24.1	2.7	25.70	25.70
	Oil	17.40	8.95	10.81	23.7	4.8	44.40	45.54
			6.80	8.41	24.4	3.8	45.18	
			1.60	2.02	24.9	0.95	47.03	

Table D.1: Continued.

Run #	Zone	Zone Length cm	Core Length cm	Pore Volume cc	Porosity %	Water Extracted cc	Core Sw %	Zone Sw %
8	Tar	8.44	8.44	10.39	24.3	2.4	23.10	23.10
	Oil	16.57	8.36	9.42	22.3	4.6	48.80	50.34
			8.21	8.87	21.1	4.6	51.88	
9	Tar	8.45	8.45	10.19	23.3	2.6	25.50	25.50
	Oil	16.50	8.22	9.55	22.9	4.4	46.07	47.34
			8.28	9.67	23.1	4.7	48.60	
10	Tar	8.20	8.20	9.74	22.7	2.6	23.60	23.60
	Oil	15.60	7.90	9.24	22.5	4.1	44.34	46.05
			7.70	9.42	22.3	4.5	47.75	
11	Tar	9.22	9.22	11.13	23.1	2.3	20.70	20.70
	Oil	18.41	9.13	11.17	23.4	6.0	53.70	56.70
			9.28	11.06	22.8	6.6	59.60	
12	Tar	9.14	9.14	10.77	22.9	2.0	18.57	18.57
	Oil	18.30	9.09	11.04	23.6	5.7	51.60	54.90
			9.21	10.99	23.2	6.4	58.20	
13	Oil	18.30	9.14	10.18	21.3	6.9	67.80	64.60
			9.23	9.94	20.6	6.1	61.40	
14	Oil	18.83	9.32	9.80	20.12	6.5	66.30	61.30
			9.51	9.59	19.3	5.4	56.30	
15	Oil	18.81	9.46	10.24	20.7	6.3	61.52	60.62
			9.35	9.88	20.2	5.9	59.72	
16	Oil	18.74	8.75	9.48	21.4	6.9	72.80	70.70
			9.99	10.93	21.6	7.5	68.62	

Table D.1: Continued.

Run #	Zone	Zone Length cm	Core Length cm	Pore Volume cc	Porosity %	Water Extracted cc	Core Sw %	Zone Sw %
17	Oil	19.18	10.26	10.55	20.3	7.2	68.20	65.70
			8.92	9.49	21.0	6.0	63.20	
18	Oil	18.82	10.24	11.05	21.3	7.3	66.10	63.15
			8.58	9.48	21.8	5.7	60.20	
19	Tar	9.93	9.93	10.96	21.8	3.0	27.40	27.40
	Oil	20.47	12.73	13.74	21.3	5.5	40.00	40.76
			7.74	8.43	21.5	3.5	41.52	
20	Tar	10.54	10.54	11.34	21.2	3.5	30.86	30.86
	Oil	20.95	10.11	10.86	21.2	5.9	54.33	55.71
			10.84	11.21	20.4	6.4	57.09	
21	Tar	10.06	10.06	11.51	22.6	2.6	22.60	22.60
	Oil	19.99	9.84	10.52	21.1	6.2	58.94	59.74
			10.15	11.73	22.8	7.1	60.53	
22	Tar	10.54	10.54	11.71	21.9	2.5	21.35	21.35
	Oil	20.36	10.08	10.88	21.3	6.3	57.90	59.32
			10.28	11.36	21.8	6.9	60.74	
23	Tar	10.47	10.47	10.82	20.4	2.4	22.20	22.20
	Oil	20.89	10.87	11.07	20.1	5.7	51.49	52.34
			10.02	10.53	20.7	5.6	53.18	
24	Tar	10.29	10.29	10.85	20.8	2.6	23.90	23.90
	Oil	20.57	10.63	11.26	20.9	5.4	47.96	48.57
			9.94	10.73	20.6	5.1	49.18	

Table D.1: Continued.

Run #	Zone	Zone Length cm	Core Length cm	Pore Volume cc	Porosity %	Water Extracted cc	Core Sw %	Zone Sw %
25	Tar	10.11	10.11	11.90	23.2	2.8	23.60	23.60
	Oil	21.11	12.39	13.84	22.0	8.5	61.40	64.27
			8.72	9.41	21.3	6.3	67.00	
26	Tar	10.30	10.30	11.64	22.3	3.2	27.50	27.50
	Oil	20.30	10.26	11.13	21.4	6.6	59.30	62.25
			10.04	10.58	20.8	6.9	65.20	
27	Tar	10.09	10.09	11.85	23.2	2.8	23.60	23.60
	Oil	20.67	10.83	11.74	21.4	7.4	63.00	66.20
			9.84	10.52	21.1	7.3	69.40	
28	Tar	10.14	10.14	11.72	22.8	3.1	26.50	26.50
	Oil	20.10	12.39	13.63	21.7	8.4	61.60	63.80
			8.71	9.40	21.3	6.2	66.00	
29	Tar	10.23	10.23	11.82	22.8	2.7	22.80	22.80
	Oil	21.50	8.18	9.37	22.6	5.6	59.77	60.67
			13.32	14.29	21.2	8.8	61.58	
30	Tar	10.13	10.13	11.86	23.1	3.0	25.30	25.30
	Oil	20.65	11.02	12.67	22.7	6.9	54.46	55.01
			9.63	10.98	22.5	6.1	55.56	
31	Tar	10.18	10.18	11.84	22.9	2.9	24.50	24.50
	Oil	20.58	9.96	10.75	21.3	6.1	56.10	59.10
			10.62	11.89	22.1	7.3	61.40	
32	Tar	10.25	10.25	11.87	22.8	3.1	26.10	24.50
	Oil	21.03	12.30	13.46	21.6	7.3	54.20	56.30
			8.73	9.42	21.3	5.5	58.40	