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AN EXPERIMENTAL INVESTIGATION OF TERTIARY RECOVERY OF OIL BY ALKALINE STEAM FLOODING

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AN EXPERIMENTAL INVESTIGATION OF TERTIARY RECOVERY OF

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By

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ABSTRACT

Laboratory studies were undertaken to investigate the potential of improving tertiary oil recovery of heavy to intermediate oil by alkaline steam flooding. Four kinds of alkali: sodium hydroxide, sodium silicate, sodium carbonate and potassium hydroxide were combined with steam, each on separate case, as chemical additive to enhance oil recovery from water flooded sandpacks and cores.

These studies examined the feasibility of achieving the following goals: (1) combination of the individual oil recovery mechanisms of steam flood and alkaline flood to improve the net recovery performance over either single process, (2) improvement of sweep and displacement efficiencies by having alkaline condensate sweep the lower portion of the formation usually overridden by steam, (3) low interfacial tension displacement induced by in situ solvent drive, (4) favorable wettability alteration, (5) rigid film breaking, (6) viscosity reduction, (7) temperature reduction, below that for conventional steam flooding, in alkaline steam flooding without loss in oil recovery performance, (8) determination of the optimal temperature range for alkaline steam flooding in tertiary oil recovery processes and (9) evaluation of the recovery performance of alkaline steam flooding compared to conventional steam flooding at low residual oil saturations.

Six aspects of caustic steam flooding were investigated with water flooded glass beadpacks to determine the optimal process or processes for

alkaline steam flooding. These cases are as follows: (1) cool caustic flooding followed by steam flooding, (2) caustic steam flooding immediately after water flooding, (3) cool caustic flooding followed by caustic steam flooding, (4) steam flooding alternated with cool caustic flooding, (5) two aspects of hot caustic flooding that were combined with cases 2 and 3 to determine the optimal temperature range for alkaline hot water and steam flooding and (6) conventional steam flooding which served as the basis for comparison and contrasting of various caustic displacement cases.

Based on the recovery performance of these cases, caustic steam flooding following water flooding was used for evaluating the improved oil recovery performance for the four alkali on sandpacks and berea cores.

Two cases of caustic steam flooding in glass beadpacks recovered about 14 percent more of initial oil in place than conventional steam flooding. Caustic steam flooding, potassium hydroxide and sodium silicate steam flooding in sandpacks recovered 9 percent more of initial oil in place than conventional steam flooding. With berea core as displacement media, caustic steam flooding and sodium silicate steam flooding recovered 10 and 6.5 percent, respectively, more of initial oil in place than regular steam flooding. Caustic potash-steam flooding was not conducted in berea core because of the nonunique performance on sandpack and the cost, both of which rendered it uneconomical for practical applications. Sodium carbonate-steam flooding failed in both sandpack and core tests because it recovered far less oil than conventional steam flooding in both situations.

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CHAPTER I

INTRODUCTION

Steam flooding has been demonstrated in the field to have considerable potential for improving oil recovery from fields containing heavy to intermediate (6° to 25°) A P I gravity oils. During steam displacement, however, steam has a tendency to override the bottom half of the formation which becomes essentially flooded by hot to warm condensate. It has been observed in most steam floods that the top half of the formation swept by steam has its residual oil almost reduced to near zero, while substantial residual oil saturation is observed in the condensate swept portion of the reservoir.

Some investigators[1] have suggested that oil steam ratio could be significantly reduced if suitable additives were found which would reduce oil saturations in the lower portion of the formation often overridden by steam and essentially swept by hot or warm condensate. Nutting[2] in experimental water floods of Torpedo sandstone using sodium hydroxide solution as an additive reported increased oil recovery of 20 percent, compared to ordinary water flood. He attributed the increase in oil recovery to the reduction in interfacial tension between oil and water

brought about by either chemical reaction or absorption of the alkaline solution with silica at the interface. Dunning[3] et al performed a similar experiment and claimed that improved oil recovery was due to the surfactant produced by the reaction of crude oil with sodium hydroxide and that the produced surfactant displaced the interfacially active asphaltic aggregate responsible for the rigidity of the interface that inhibits effective oil displacement.

More recent investigators [4,5] have determined that alkaline flooding enhances oil recovery by one or more of the following mechanisms: interfacial tension reduction, spontaneous emulsification, and wettability alteration. These mechanisms are related to the in situ formation of surfactants from the neutralization of petroleum acids. Since the content of such natural petroleum acids is normally higher in low A P I gravity crude oils, this process seems to be applicable primarily, or exclusively, to the recovery of moderately viscous, low to intermediate A P I gravity, naphatenic type crudes. Although emulsification during alkaline flooding process provides mobility control, to a certain degree, emulsification alone may not be sufficient in sweeping highly viscous crudes; other chemicals may be required to reduce mobility contrast. This limitation would, however, be reduced to a minimum when alkaline steam drive is employed as improved oil recovery process.

Statement of the Problem

The purpose of this study was to investigate the applicability of alkaline solutions as chemical additives in steam floods where their ability as improved oil recovery agent would serve to reduce the residual oil saturation in the lower portion of the formation usually overridden by steam and generally believed to be swept by hot to warm condensate. The

combined properties of steam and alkaline solution would complement each other and could result in greater improved oil recovery over either single process. This would be achieved when alkaline additive has altered the physical and chemical properties of the condensate thus inducing spontaneous emulsification which provides a miscible or semimiscible frontal zone that will recover more residual oil in the bottom half of the formation than condensate from conventional steam drive. Also, since alkaline solution would be in steam phase at the upper part of the formation, it is believed that the combination of individual oil displacement properties of steam and alkaline would give the same or better sweep and displacement efficiencies at lower steam temperature and steam oil ratio. The net benefit of alkaline steam drive would be higher oil recovery at lower steam oil ratio and perhaps at lower temperature than ordinary steam drive.

The most evident effects of using alkaline solution as a chemical additive in steam flooding are: formation of emulsion induced by acidic oil-alkaline solution reaction and sharp reduction in interfacial tension at the oil water interface. Other benefits that could be derived from alkaline steam flooding are as follows:

1. Wider application of this combined process than either of the single processes, i.e., steam flooding or alkaline water flooding. Since alkaline water flooding has been moderately successful in reservoirs with medium range (20° to 30°) A P I gravity oils, while steam flooding has been quite successful in recovering low (6° to 20°) A P I gravity oils, the combined technique could span a range of 6° to 30° A P I gravity oils. Formation depth would, of course, limit the range of alkaline steam applicability, but even in such a situation, alkaline hot water flooding could be employed rather than hot water flooding or alkaline water flooding.

2. Increase in solvent density due to alkaline content would improve sweep efficiency while alkaline distillate ahead of the steam front would displace crude oil at reduced mobility, thus improving the displacement efficiency.

3. Assumed in this process is that oil expansion and solvent extraction attributed to steam interaction with crude oil would be enhanced with alkaline steam, thus improving the sweep and displacement efficiencies.

4. Since vaporization of oil due to steam injection induces a miscible front ahead of the steam front, alkaline steam, owing to its interfacial tension reduction property, would induce a larger and more stable miscible front than ordinary steam with the resultant improvement in displacement efficiency.

5. The principal problems with conventional steam flooding process are gravity override of the low half of the formation and severe emulsification of produced fluids. While gravity override reduces the area contacted by steam, severe emulsion problem increases the cost of treatment of produced fluids. The alkaline steam process would alleviate the problem of gravity override because of higher density of alkaline steam compared to ordinary steam, while the hot alkaline condensate, because of the emulsification and interfacial tension reduction properties, would be more effective in sweeping the lower part of the formation than ordinary hot condensate. The emulsion problem is cheaper and easier to treat for alkaline steam flood process (with cheap acid and common salt as opposed to heat treatment) than for conventional steam flood process.

It is hoped that this technique of enhanced oil recovery would be applicable to many reservoirs that have been water flooded and are not

amenable to other processes of enhanced oil recovery. Also, fields with acidic to mildly acid (at least 0.5 acid number) that are currently being alkaline water flooded or steam flooded would be potential candidates for this process. Where formation depth rules out alkaline steam flooding, alkaline hot water flooding being more effective than alkaline water flooding should be adopted if it is economically feasible. The range of oils amenable to either alkaline hot water flood or alkaline steam flood should span heavy to intermediate (6° to 30° A P I). Most oil below 20° A P I are acidic to some extent while some oils in the range of 21° to 30° A P I are acidic.

The composition of the oil and formation will to a large degree dictate the applicability of alkaline steam displacement process. The availability of acidic oil is a prerequisite for applying this technique, while large clay and carbonate contents, which exacerbate the deterioration and loss of alkaline due to adsorption and precipitation of insoluble carbonates, could preclude its application. Alkaline steam flooding will, therefore, be limited to fairly clean sand reservoirs with acidic to mildly acid oils.

Among the alkali, i.e., sodium hydroxide, sodium silicate, sodium carbonate and potassium hydroxide, examined, only sodium hydroxide and sodium silicate seemed likely to be effective as well as economical as chemical additive in steam and hot water flooding. While potassium hydroxide was almost as effective in enhancing oil recovery as sodium hydroxide, the cost could make its use economically unfeasible. Sodium carbonate was ineffective as a chemical additive in steam displacement. Instead of improving oil recovery, soidum carbonate steam drive hindered recovery well below the recovery for conventional steam drive.

This experimental study being reported here, is partly based on previous laboratory investigation carried out by this author and reported with Tiab, D., and Osman, M. M.[6] From that laboratory study, it was concluded that caustic steam displacement immediately after water flooding was the most effective oil recovery process for this aspect of enhanced oil recovery. Thus, this process was adopted in evaluating all the alkali investigated as chemical additives in steam drive.

CHAPTER II

LITERATURE REVIEW

The earliest known patent on caustic flooding for improved oil recovery was reportedly[7] issued to Flyeman in Canada in 1920 for developing a process using sodium carbonate to separate bitumen from tar sands. In 1927, the first patent in the United States was issued to Atkinson[8]. Since then, however, several other patents on various mechanisms of caustic flooding were obtained by several investigators. There have also been extensive records and publication of research work and field testing[9]. According to Johnson et al.[9] and deZabala et al.[10], there are currently eight postulated recovery mechanisms of caustic flooding. These include: (1) emulsification with entrainment [11], (2) emulsification with entrapment,[13] (3) emulsification with coalescence (i.e., spontaneous or shear induced) [7], (4) wettability reversal (i.e., oil-wet to water-wet) [8], (5) wettability reversal (water-wet to oil-wet) [9], (6) wettability gradients, oil-phase swelling (i.e., from water in oil emulsions)[10], (7) reduction of interfacial tension (from saponification or reaction with oil)[12] and (8) disruption of ridig films.[9]

There are contradictions among these mechanisms, caused primarily by the chemical sensitivity of certain crude oils and reservoir rock types to reaction with alkali. Under varying conditions such as: concentration, temperature, salinity and pH, different crude oils in different reservoir

rock types may lead to widely disparate behavior upon reaction with alkali. Consequently, the alkaline flooding process has still remained complicated and not well understood.

Mechanisms

The prerequisite for any of the proposed mechanisms to be operational, however, is that the crude oil must contain certain acidic components (based on acidic number or the chain length of the acidic group, linked to CH_2) that will react with the alkali to produce salts. Some of these salts are surface active and hence will induce saponification while others can break rigid surface films which reportedly[21] can enhance emulsification and alter wettability when adsorbed on polar materials on rock surfaces. The proposed mechanisms for alkaline oil recovery processes enumerated above will be discussed. This review will embrace: (a) the conditions necessary for successful application (b) recommended laboratory screening methods and (c) the published results of laboratory and field testing.

While Atkinson[8] was the first to patent alkaline flooding on oil bearing sands in the United States in 1927, Squires[22], way back in 1917, was well aware of the benefits of alkaline flooding on oil bearing sands. He concluded that the displacement of oil could be more effective by introducing an alkali into flooding water. The mechanism by which alkaline flooding enhances oil was not that clear to early investigators. Atkinson[8] asserted that alkali acted to improve water flood oil recovery by overcoming capillary, adhesion and viscous forces to release oil held within spaces between sand grains. He was apparently referring to the combined mechanisms of wettability change (oil-wet to water-wet) and interfacial tension reduction. Squires[22] noted that alkaline waterflood improved oil

recovery but did not explain how. Nutting[2] explained the mechanism of alkaline water flooding in terms of alkali reacting with the oil or the surface to release residual oil from adherence to sand surfaces, essentially wettability alteration (from oil-wet to water-wet). He also observed that alkaline solutions hindered the formation of semisolid oil-water interfacial films but dismissed the benefit of this property in enhancing oil recovery.

Subkow's[12] explanation of the mechanism of alkaline water flood oil recovery process was that the essential first step entailed formation of oil-in-water emulsion in situ within the pore space of the rock. The second step he contended was entrainment of the emulsified oil in the flowing alkaline solution, with both being produced concurrently. Subkow described clearly the reaction of sodium hydroxide solutions and the organic acids naturally present in some crude oils, leading to generation of emulsifying soaps. He did emphasize the importance of caustic concentration and warned that, while it must be sufficiently high to be effective, excessive concentration could produce inverted emulsions (water-in-oil), or no emulsion at all. Because some of the eight mechanisms listed are part and parcel of the other, a detailed description of the mechanisms will be given under four broader classifications as follows: (1) emulsification and entrainment, (2) emulsification and entrapment, (3) wettability reversal (oil-wet to water-wet), and (4) wettability reversal (water-wet to oil-wet).

Emulsification and entrainment

Subkow[12] was one of the earliest investigators to propose this mechanism for alkaline flooding. He contended that it was the most plausible and viable mechanism. Reisberg and Doscher[20] worked with a Ventura

crude oil and considered the ability of alkaline flooding to reverse oil-wetting of the formation to water-wetting, as well as suppressing the formation of semisolid film at the oil-water interface, as the contributing mechanisms besides emulsification and entrainment which according to them results in reduction of interfacial tension. The principal mechanism they contended was reduction of interfacial tension owing to saponification which preceeds the formation of oil in water emulsion.

Rasberg and Doscher were pessimistic about the practical application of alkaline flooding as a process of enhanced oil recovery. They believed that since the oil would be produced as an emulsion in produced caustic solution, adsorption, reaction with rock, and displacement of connate water would cause the alkaline to fall behind the oil-water displacement front and consequently delay uneconomically any increase in oil recovery before water breakthrough. Increased oil could only be produced, they felt, after several pore volumes of alkaline had been injected, an unfavorable economic situation. Doscher and Reisberg did, however, obtain a Canadian patent[23] on caustic flooding of tar sands as an improved oil recovery process. In a pilot project, Doscher et al.,[24] reported substantial increase in oil recovery when alkaline aqueous solution and steam were injected into Athabasca oil sands, compared to regular steam drive.

Emulsification and entrapment

Another mechanism whereby alkaline injection can improve oil recovery was proposed by Jennings et al[13,25] From their laboratory experiments they showed that if interfacial tension was low enough, residual oil in a preferentially water-wet core could be emulsified in situ, moved downstream with the flowing alkaline and could be entrapped again by pore throats too small for the oil emulsion droplets to penetrate. They

believed that the mechanism of emulsification and entrapment results in a reduction of mobility which improves both areal and vertical sweep efficiency. This property is particularly desirable for water flooding viscous oils during which areal and volumetric sweep efficiencies are usually very poor. This process, they contended, does not significantly reduce the capillary retained residual oil saturation because the emulsified oil is quickly entrapped and is not eventually recovered. According to this mechanism the emulsified oil is not entrained and produced as an emulsion because the interfacial tension is not low enough to allow emulsion droplets to penetrate all the smaller pore-throat constrictions between sand grains in natural reservoir rocks. Also, they speculated that in radial geometry, the diminished pressure drops beyond the injection well may not be sufficient to force emulsion particles through all the pore throats.

McAuliffe[26,27] prepared dilute emulsions externally and then injected them into cores in the laboratory. Their work showed oil recovery by injecting externally prepared caustic-oil emulsion to be comparable to the recovery by in situ emulsification during caustic flooding. Reporting on laboratory caustic flooding of a viscous Lloydminister crude oil. Dranckuk et al.[28] observed that stable oil-in-water emulsions were produced in situ and that there was evidence for reduction in water mobility during displacement.

Since this mechanism may not significantly reduce the ultimate residual oil saturation, these investigators recommended it for viscous oils or oils in heterogeneous reservoirs where sweep efficiency is poor. This mechanism, therefore, by improving the mobility ratio could be more

economical than the mechanism that recovers residual oil from a smaller volume of the reservoir swept at poor mobility ratio.

Wettability reversal (oil-wet to water-wet)

Wagner and Leach[29] demonstrated that rock wettability could be reversed from oil-wet to water-wet by adding chemicals (acids, bases and salts) that changed injection-water pH. They presented laboratory test results which showed increased oil recovery over conventional waterflood by injecting solutions that reversed rock wettability from oil-wet to water-wet. Wagner and Leach felt that since the injected chemical was always preceded by displaced connate water the chemically treated flood water would only encounter residual oil left behind the banked connate water front. Because the residual oil in a water-wet reservoir is discontinuous and immobile as compared to the continuous residual oil phase in an oil-wet reservoir, Wagner and Leach asserted that water-wet rocks were not amenable to wettability reversal, i.e., water-wet to oil-wet.

These investigators[29] reasoned that improvement in oil recovery would result largely from the favorable changes in relative oil and water permeability that would be induced by a reversal of wettability from oil-wet to water-wet in the region where oil is still flowing. The change in permeabilities would provide a more favorable mobility ratio that would persist even if the chemically treated water is displaced by an untreated water.

While Wagner and Leach achieved wettability change (oil-wet to water-wet) with either acids or alkali, the use of acids have not found practicality because they tend to be too reactive with most reservoir rocks. Mungan[30] obtained results similar to Wagner and Leach using sodium hydroxide solution for reversing wettability in oil-wet porous media to water-wet.

Like previous investigators, he reported improved oil recovery over conventional water flooding. Mungan was also the first to observe that caustic flooding was temperature sensitive and noted that, for the particular crude he used, caustic flooding worked well at 160°F but did not work at all at 70°F. He also showed that after caustic wettability reversal from oil-wet to water-wet, the water relative permeability was quite lower than that of water flooded oil-wet porous medium. The consequence of lowering water relative permeability was a more favorable water-oil mobility ratio despite very high water saturation values.

Cooper[31] also reported about the optimal temperature for caustic flooding in connection with another crude oil type. He agreed with Mungan on the optimal temperature of 160°F for caustic flooding in spite of the fact that he used different crude oil from the former investigator.

Ehrlich et al.[32,33] included in this mechanism the reduction of interfacial tension below a critical value and suggested that this property, together with wettability reversal, should form the main criteria for evaluating alkaline flooding in the laboratory for potential field application. They also noted that a substantial reduction of interfacial tension below a critical value would enhance oil recovery by emulsification and entrainment mechanism.

Wettability reversal (water-wet to oil-wet)

The fourth class of the broad mechanism by which alkaline flooding could improve oil recovery was first reported in 1974 by Cooke et al.[34] They reported that organic acids naturally occurring in some crude oils will react with alkaline solution to produce surfactant at the oil-water interface. The surfactant (soaps) thus formed would lower the interfacial tension between oil and water by several hundred fold. Also, they

observed that the surfactant would, under appropriate conditions of pH, salinity and temperature, change the wettability of the porous medium from water-wet to oil-wet.

They explained that the mechanics of the process involves: first the alteration of the rock wettability from water-wet to oil-wet, so that a discontinuous nonwetting residual oil is converted to a continuous wetting phase, thus providing a path for the oil that would have been trapped and, second, the low interfacial tension would induce an oil-external emulsion of water droplets in the continuous wetting oil phase. The flow properties of this type of emulsion, Cooke et al. contended, would permit a high pressure gradient to be generated in the region where emulsion droplets form. The high pressure they said would be sufficient to overcome the capillary forces already decreased by low interfacial tension, thus reducing residual oil saturation further.

Cooke et al. showed that oil saturation as low as 5 percent would be left from the drainage of oil from the volume between emulsified water drops.

The distinctive feature of this mechanism, in spite of the role played by interfacial tension, is the conversion from water-wet system to oil-wet system. These investigators pointed out the importance of the salinity of the alkaline in this process because it supposedly ensures sand oil-wet tendency and promotes formation of water-in-oil emulsions.

Other Aspects of Alkaline Flooding

All the four broad mechanisms reviewed have some superficial similarities. Particularly, they share in common the requirements that the crude oil contain sufficient and proper organic acids and the caustic

concentration be adequately adjusted to give the desired wettability reversal and low interfacial tension.

Caustic flooding requirement

Laboratory experiments have shown that successful alkaline flooding performance will depend on: (1) crude composition, (2) water composition, (3) rock type and reactivity and (4) alkaline concentration, especially how it interacts with the aforementioned parameters.

Laboratory evaluation for field trials

All recent investigators [9,32] agree that for reliable oil recovery tests for field trials preserved core samples, unaltered crude oil and actual connate and injection waters should be used. The displacement test should also be made at reservoir temperature and at rates or pressure gradient close to those expected in the field.

Alkaline steam flooding

The first known case of alternating steam injection with heated alkaline solution was reported by Doscher et al.[24] They reported substantial increase in oil recovery from the Athabasca oil sands by this process over conventional steam drive. The laboratory experiments carried out before the field test were not published. The published report on the field trial did not discuss the mechanism that provided the source of oil recovery enhancement.

In 1974, Robinson et al.[35], after laboratory tests, conducted a field test of caustic steam flood at Kern River Field. Their laboratory tests indicated that the addition of caustic to steam improved oil recovery over conventional steam flooding by as much as 9.9 percent. The mechanism adopted by Robinson et al. was interfacial tension reduction. Using Pendant Drop Method, they established minimum interfacial tension of oil-

caustic steam system of about 0.2 dynes/cm at temperature of 275°F and sodium hydroxide concentration of 540 ppm. The result of field test was very discouraging. The caustic solution additive to steam seemed to have been detrimental to oil recovery because the production was below that of the conventional steam drive.

On studying the report[35] of the field application procedure, however, one wonders how much the mechanical problems that necessitated separate injection of steam and caustic solution twice above the determined optimal concentration accounted for the failure. The operators of this pilot project seemed to have made a serious error of compensating for caustic solution adsorption and consumption in reaction with reservoir fluids by using the caustic solution concentration above the optimum for the minimum interfacial tension. Also, the mechanism for improved oil recovery was narrowed to reduction of interfacial tension. Recent investigators[34] have concluded that interfacial tension reduction alone may not ensure enhanced oil recovery. The importance of caustic concentration was emphasized by Subkow[12] and other investigators[32,34] and it seems to be the paramount variable among others for a successful alkaline flooding.

CHAPTER III

THEORETICAL CONSIDERATIONS

Recently, several investigators[10,36,38] have presented models for caustic water flooding. Breit et al.[36] model includes hydroxide consumption by irreversible rock reaction and divalent-ion precipitation. deZabala et al.[10] expanded the scope of the former model by accounting for the reaction with and extraction of surface active components in the oil into the aqueous phase. In the most recent model presented by Ramakrishnan et al.,[38] the dependency of interfacial potential on variables such as caustic salinity and concentration was revealed.

Since all these models dealt with the chemistry of caustic water flooding, the effect of temperature on caustic-oil and caustic-rock reactions was not addressed. The model that will be presented is for alkaline steam flooding and, therefore, will include the effect of temperature on alkaline solution reaction with reservoir fluids and rock. This model will consist of three main components: (1) system chemistry, (2) system fluid displacement, and (3) temperature distribution ahead of advancing steam zone.

System Chemistry

The chemical model describing the system chemistry can be subdivided into two components. These components will be subtitled Alkaline-oil chemistry and Alkaline-rock chemistry.

Alkaline-oil chemistry

As adopted by previous investigators[10,36,38], it is being assumed the mixture of acid species in a crude oil can be represented by one component HA. Several investigators including Siefert and Howells[39] have analyzed acid crude oils to ascertain the particular components yielding surface activity upon saponification. Siefert and Howells isolated numerous aromatic carboxylic acids as the main source of interfacial activity from California Midway Sunset Crude Oil. Analyzing similar crude oils, Faramian et al.[40], suggested that phenolics and porphyrins could act as cosurfactants. They also showed that surface-active hydrolyzed acids are associated with the asphaltene fraction of the crude oil. Pasquarelli and Wasan[41] also made a similar observation. These two groups of investigators[40,41] further suggested that the acids which induce low interfacial tension are part of the resins stabilizing colloidal asphaltenes.

The complex AH is assumed to be sufficiently insoluble in the aqueous phase at neutral pH. Hence, ordinary water flooding will not extract it. In the presence of an alkaline solution, this complex acid is assumed to distribute itself between the oleic and aqueous phases in constant ratio under all encountered conditions of ionic strength. The water soluble anionic surfactant A^- is presumed to aid oil recovery by reduction of interfacial tension and emulsification (entrainment or entrapment).

The distribution of the complex acid in the oleic and aqueous phase when alkaline solution reacts with crude oil is, thus, represented as:

$$HA_w \rightleftarrows HA_o \qquad (1)$$

The overall hydrolysis and extraction in the oleic phase is given by:

$$HA_o + NaOH \rightleftarrows Na^+ + A^- + H_3O^+ \qquad (2)$$

while the reaction in the aqueous phase is represented as:

$$HA_W + H_2O \rightleftarrows H_3O^+ + A^- \tag{3}$$

and the dissociation constant for water is:

$$K_W = (H_3O^+)(OH^-) \tag{4}$$

This follows from water hydrolysis in the presence of an alkaline. From equations (2) and (3), the distribution ratio is defined as:

$$K_D = \frac{(HA_o)}{(HA_w)} \tag{5}$$

The acid dissociation constant is also defined from equations (2) and (3) as:

$$K_A = \frac{(H_3O^+)(A^-)}{HA_W} \tag{6}$$

The acid dissociation constant controls the pH range for which surfactant hydrolysis in the aqueous phase, reaction 3, occurs and the solubility of the acid is controlled by the acid distribution ratio, equation (5). Hence, the complex acid can generate two surface active species, A^- and HA at the oil-water interface. It is worth noting that equations (5) and (6) are simplified because the activity coefficients are excluded.

Several investigators[17,25,42] have noticed that as NaCl concentration increases, minimum interfacial tension occurs at lower NaOH concentration. This at face value tends to contradict the fact that NaOH will increase the concentration of A^- in the bulk while NaCl and NaOH will both lower the interfacial potential, thus increasing the adsorption of A^- at the interface. Apparently, the increase or reduction of charge density at the interface and the reduction of interfacial tension may not have cause and effect relationship. The formation of an undissociated salt which is non-interfacially active was proposed by Yen et al.[42] Assuming that the presumed undissociated salt is represented as NaA, the formation of this salt

in the aqueous phase where it can have only slight solubility is given by:

$$NaA_w \rightleftarrows Na^+ + A^- \tag{7}$$

$$NaA_w \rightleftarrows NaA_o$$

The dissociation constant becomes:

$$K_S = \frac{(Na^+)(A^-)}{(NaA_w)} \tag{8}$$

while the distribution ratio of the "insoluble salt" is given as:

$$K_{DS} = \frac{(NaA_w)}{(NaA_o)} \tag{9}$$

$$K_{DS} << 1,\ K_{TS} = K_S\ K_{DS} \tag{10}$$

The conservation of A^- species entails a molal balance which leads to:

$$S_o'(HA_o) + A_w(HA_w) + S_w'(A^-) + S_o(NaA_o) = S_o'(HA_o)_n \tag{11}$$

where S_o' and S_w' are the volume of the oleic and aqueous phases, respectively, and $[HA_o]_n$ is the initial concentration of the acid in the crude oil. The conservation of the Na^+ concentration is given as follows:

$$S_o'(NaA) + S_w'(Na^+) = S_w'(NaCl) + S_w'(NaOH) \tag{12}$$

if the initial NaOH and NaCl concentrations are denoted by C_1 and C_2 respectively, equation (12) becomes:

$$Na^+ + \frac{S_o'}{S_w'}(NaA_o) = C_1 + C_2 \tag{13}$$

Using the equilibrium constants from equations (8) to (10)

$$[Na^+] = \frac{C_1 + C_2}{1 + \frac{(A^-)}{K_{TS}} \frac{S_o'}{S_w'}} \tag{14}$$

The charge balance or electroneutrality in the aqueous phase becomes:

$$Na^+ + H_3O^+ = A^- + OH^- + Cl^- \tag{15}$$

Cl^- concentration is equal to C_2 and $OH^- >> H_3O^+$ in alkaline environment from equation (15)

$$(OH^-) = Na^+ + H_3O^+ - A^- - Cl^- \tag{16}$$

The surfactant concentration in A^- will be very small compared to other variables, so that the approximate concentration of $[OH^-]$ becomes:

$$(OH^-) = (Na^+) - C_2 = \frac{C_1 + C_2}{1 + \frac{(A^-)}{K_{TS}} \frac{S'_o}{S'_w}} - C_2 \tag{17}$$

In order for A^- to impart significant interfacial activity, it has to be highly hydrophobic. Hence, K_D has to be greater than 1. Combining equations (4) to (17) gives:

$$(A^-)\left[\frac{S'_w}{S'_o} + \frac{C_2 + (OH^-)}{K_{TS}} + \frac{K_D K_w}{K_A (OH^-)} \right] = (HA_o)_n \tag{18}$$

Solving equation (18) for the surfactant concentration gives:

$$[A^-] = \frac{(HA_o)_n}{\frac{S'_w}{S'_o} + \frac{C_2 + (OH^-)}{K_{TS}} + \frac{K_D K_w}{K_A [OH^-]}} \tag{19}$$

since $[Na^+] = [OH^-] = C_1$

$$[A^-] = \frac{(HA_o)_n}{\frac{S'_w}{S'_o} + \frac{C_1 + C_2}{K_{TS}} + \frac{K_D K_w}{C_1 K_A}} \tag{20}$$

The caustic concentration is given by C_1, so that assuming or knowing other variables the caustic concentration can be calculated as shown above.

Ramakrishnan and Wason[38] obtained a similar formula and by assumint that Na^+ consumption was negligible when C_2 is sufficiently large, they obtained this equation below:

$$[A^-] = \frac{(HA_o)_n}{\frac{S'_w}{S'_o} + \frac{C_1 + C_2}{K_{TS}} + \frac{K_D K_w}{K_A C_1} + \frac{(HA_o)_n}{K_{TS}} \frac{S'_o C_2}{S'_w C_1}} \tag{21}$$

They also showed that for negligible consumption and high caustic concentration equation (21) reduces to:

$$[A^-] = \frac{K_{TS}(HA_o)_n}{C_1 + C_2} \tag{22}$$

Hence, the surfactant concentration $[A^-]$ will be independent of the phase ratio. This simplification is unrealistic in actual situations where caustic consumption could be substantial.

The rate law has the form:

$$\text{Rate} = K[Na^+]^m[A^-]^n \tag{23}$$

where K is the specific rate constant and $[Na^+]$ and $[A^-]$ are the concentrations of the reacting substances (caustic and acid, respectively). The sum m + n will be the overall order of reaction. The specific constant, K, and the other of individual reactants m and n, cannot be predicted theoretically. They must be determined experimentally.

Svante Arrhenius[43] proposed equation relating the specific rate constant K to absolute temperature as:

$$K = \rho A^* (e^{-\varepsilon_a/RT}) \tag{24}$$

where A*is a constant characteristic of the particular reaction, ρ is a steric factor related to the shape and the orientations of the reacting molecules, ε_a is the activation energy and T is the absolute temperature. For an irreversible reaction equation (24) becomes for the rate of disappearance of reactants:

$$\text{Rate} = r(T,x) = Z(e^{-\varepsilon_a/RT}) f(x) \tag{25}$$

where with a feed concentration of reactant C_f, $f(x) = C_f(1 - x)$, a decreasing function of x. Since ε_a is positive, the rate increases with temperature at any composition. Hence, the optimal reaction temperature will be the highest temperature that is practical. Properties of the

product and side reactions can, however, limit the temperature. For a reversible reaction equation (25) becomes

$$r(T,x) = Z(e^{-\varepsilon_a/RT}) f(x) - Z'(e^{-\varepsilon'_a/RT}) g(x) \qquad (26)$$

where ε'_a and g(x) apply for the case of reverse reaction. The function g(x) is an increasing function since the concentration of the products increases with conversion. Here again, the rate increases with temperature for the conversion.

Since the rate is directly proportional to the product of caustic and acid concentrations, i.e., $[Na^+]^m[A^-]^n$, the consumption of caustic will increase with temperature. Also, the generation of surfactant will increase with temperature but so also will its breakdown by reverse and side reactions as equation (26) indicates. By combining equations (23) and (25), the surfactant concentration becomes:

$$[A^-]^n = \frac{Z(e^{-\varepsilon_a/RT})C_1}{K(C_1)^m} \qquad (27)$$

where $C_1 \approx f(x)$ and $Na^+ = C_1$ as defined previously. If the product of reaction is considered, however, equation (23) becomes modified as:

$$\text{Rate} = K\{[Na^+]^m[A^-]^n - [NaA]^o\} \qquad (28)$$

Equating equation (28) to equation (26) gives

$$[A^-]^n = \frac{Z(e^{-\varepsilon_a/RT})C'_1 - Z'(e^{-\varepsilon'_a/RT})C'_1 + [NaA]^oK}{K(C_1)^m} \qquad (29)$$

Alkali-rock chemistry

Sodium hydroxide can react with reservoir rock in several fashions depending on rock minerology. For instance, irreversible dissociation of silica and anahydrite can occur and base exchange of divalent ions

accompanied by precipitation of insoluble hydroxides can take place. One caustic-rock interaction that clearly occurs is the reversible sodium-hydroxide base exchange with rock mineral. If M denotes the mineral base, the sodium-hydrogen base exchange becomes:

$$NaOH + MH \rightleftarrows M^- + Na^+ + H_3O^+ \qquad (30)$$

Adsorption process

It is necessary to derive the appropriate adsorption isotherm in order to relate the interfacial tension in a given system to the bulk concentration of the active species. For phase distribution ratio of the other of 10,000[39,40] the HA_w values are very low so that interfacial tension is likely to be lowered by the adsorption of A^- ions. The adsorption rate for the surfactant ions A^- was given by Ramakrishnan and Wasan[38] as:

$$\frac{dn_{A^-}}{dt} = K_1(A^-)_s(1 - \theta) = K_1(A^-)_s\left(1 - \frac{n_{A^-}}{n_o}\right) \qquad (31)$$

where n_{A^-} is the number of moles of A^- per unit area at the interface, θ is the fractional surface covered by adsorption and is equal to n_{A^-}/n_o, n_o is the maximum number of moles that can be adsorbed per unit area, and K_1 is the adsorption rate constant. In deriving this rate relationship, they assumed the following: a diffused double layer as described by the Govy-Chapman theory[44], the sublayer of the aqueous phase as the beginning of the double layer, a planar interface on which the charges due to A^- adsorption are uniformly distributed, the tail of A^- is pointed away from the interface into the oleic phase, the sublayers are adjacent to this uniformly charged interface and the distance between the interface and the sublayer approaches zero.

The desorption kinetics suggested by Guastallo and later adopted by Davies[42] is given by:

$$-\frac{dn_{A^-}}{dt} = K_2 n_{A^-}(e^{-\varepsilon_a/RT}) \tag{32}$$

where K_2 is the desorption rate constant, ε_a is the activation energy barrier for adsorption per mol, R and T as defined previously. Addition of Equations 31 and 32 gives the net adsorption rate as:

$$\frac{dn_{A^-}}{dt} = K_1(A^-)_s(1 - \theta) - K_2 n_{A^-}(e^{-\varepsilon_a/RT}) \tag{33}$$

Since at equilibrium,

$$\frac{dn_{A^-}}{dt} = 0$$

and the surfactant concentration can be solved for. The Boltzmann equation can be used to describe A^- in terms of the bulk concentration, $[A^-]$, i.e.,

$$[A^-]_s = (A^-)e^{-\frac{z_{A^-}\psi(0)\varepsilon}{kT}} \tag{34}$$

where z_{A^-}, is the valency of $A^- = -1$, is the electronic charge and k if the Boltzmann constant, and $\psi(0)$ is the Gouy potential at a distance zero from the interface; i.e., the potential at sublayer. When equation 34 is substituted in equation 33 at equilibrium, i.e., $dn_{A^-}/dt = 0$,

$$(A^-) = \frac{K_2 n_{A^-}}{K_1 \theta} \exp\left[-\frac{\varepsilon_a + N\varepsilon\psi(0)}{RT}\right] \tag{35}$$

where N is Avogadro's number. The potential $\psi(0)$ is given by

$$\psi(0) = \frac{-2KT}{\varepsilon} \operatorname{Sinh}^{-1}\left[\frac{n_{A^-} - \varepsilon N^{1/2}}{2^{3/2}(\varepsilon_r\varepsilon_o)^{1/2}(kT)^{1/2}C^{1/2}}\right] \tag{36}$$

where ε_o is the permitivity of vacuum and ε_r is the relative permitivity of the medium.

System Fluid Displacement

The following classic assumptions are adopted for this linear chemical displacement model: homogeneous porous medium, uniform initial saturation of the fluids, immiscible and incompressible fluids, instantaneous thermodynamic equilibrium, average constant temperature, negligible dispersion and capillary pressure. Emulsion dispersion is accounted for only in terms of instantaneous coalescence into continuous flowing oil or water. Also, continuous injection of alkaline solution is assumed.

The six molar species developed from the chemistry of alkaline flooding are the following: HA_w, HA, A^-, Na^+, OH^-, and H_3O^+. These species are derived from three main chemical components, i.e., acid, reservoir fluids and sodium hydroxide. The treatment of alkaline steam recovery scheme will, thus, be trivariant.

Conservation of reservoir water requires:

$$\frac{\partial M}{\partial \tau} + \frac{\partial m}{\partial \tilde{x}} = 0 \qquad (37)$$

where M is the fraction of displaced or displacing fluid per unit pore volume, i.e., S_o, S_g and S_w; hence,

$$M = c_{vw}\rho_w S_w + c_{vr}\rho_r\left(\frac{1-\phi}{\phi}\right)(T_f - T_o) \qquad \text{where}$$

m is the heat content such that $m = H = c_{rw}\rho_w(T_f - T_o)$, τ is the dimensionless time defined as $\tau = ut/\phi L$ and $\tilde{x} = x/L$ is the dimensionless distance. When these definitions are introduced, Eqn. 37 becomes

$$\frac{\partial\left|c_{vw}\rho_w S_w + c_{vr}\rho_r\left(\frac{1-\phi}{\phi}\right)(T_f - T_o)\right|}{\partial\tau} + \frac{\partial[c_{vw}\rho_w(T_f - T_o)]}{\partial\tilde{x}} = 0 \qquad (38)$$

A sodium-ion balance gives:

$$\frac{\partial n_{Na}}{\partial\tau} + \frac{\left|c_{vw}\rho_w S_w + c_{vr}\rho_r\left(\frac{1-\phi}{\phi}\right)(T_f - T_o)\right|}{\partial\tau} + \frac{\partial n_{Na} + [c_{vw\,w}(T_f - T_o)]}{\partial\tilde{x}} = 0 \qquad (39)$$

Sodium hydroxide is assumed to exist in the aqueous phase where its convection and accumulation is taken into account. Since $n_{Na^+} \approx n_{OH^-}$, the equilibrium assumption requires:

$$\frac{\partial n_{Na^+}}{\partial\tau} = \left(\frac{\partial n_{OH^-}}{\partial[OH^-]}\right)\frac{\partial[Na^+]}{\partial\tau} \qquad (40)$$

The exchange isotherm for alkaline is believed[10,11,46] to be concave to the abscissa indicating that a shock front will develop when alkaline solution is injected. The concentration of the velocity of this shock wave which regulates the isotherm chord was given by Dezabala et al[10] in terms of pore volume delay parameter, α:

$$\alpha = \left(\frac{1-\phi}{\phi}\right)\frac{n_{OH^-}}{[OH^-]} \qquad (41)$$

The sodium or hydroxium ion is taken as zero at neutral pH in the porous medium. When the alkaline contacts the acidic oil, a slight drop in pH should occur because of the generation of the surfactant, A^-. Equation 38 assumes that the rock is water wet in the region where alkaline flows.

The material balance for the acid species becomes:

$$\frac{\partial}{\partial \tau}\left[c_{vw}\rho_w(A^- + HA_w) + c_{vr}\rho_r\left(\frac{1-\phi}{\phi}\right)(T_f - T_o)\right] + \frac{\partial}{\partial \tilde{x}}\left[c_{vw}\rho_w(T_f - T_o)\right] = 0 \tag{42}$$

The bank breakthrough alkaline saturation, S_{FB}, and the dimensionless frontal advance rate v_B are related by this expression:

$$v_B = \frac{\partial c_{vw}\rho_w}{\partial\left[c_{vw}\rho_w S_{FB}(A^- \simeq 0) + \left(\frac{1-\phi}{\phi}\right)c_v\rho_r\right]} \tag{43}$$

$$\approx \frac{c_{vw}\rho_w}{c_{vw}\rho_w[S_{FB}(A^- \simeq 0) - S_{wc}(A^- \simeq 0)] + \frac{(1-\phi)}{\phi}c_{vr}\rho_r} \tag{44}$$

A chemical and a companion saturation shock will occur at the rear of the oil bank. The reduced velocity v_c and the change in water saturation from S_{F1} to S_{F2} will follow the integral material balances on sodium and hydroxium ions. v_c becomes:

$$v_c = \frac{\Delta(c_{vw}\rho_w)}{\Delta(c_{vw}\rho_w)[S_{F2}(A^-) - S_F1(A^- \simeq 1)] + \Delta\left[\frac{(1-\phi)}{\phi}c_{vr}\rho_r\right]} \tag{45}$$

Equation 45 applies for both secondary and tertiary displacement; however, for tertiary displacement, the reduced velocity of the oil bank v_T is governed by

$$v_T = \frac{1 - \Delta(c_{vw}\rho_w)}{\Delta(c_{vw}\rho_w)[(1 - S_{or})(A^- \simeq 0) - S_{F1}] + \Delta\left[\frac{(1-\phi)}{\phi}c_{vr}\rho_r\right]} \tag{46}$$

Using mass balance on saponified surfactant, the saturation at which the oil is stranded behind the aqueous slug can be found. The mass balance requires that oil stranded behind the surfactant pulse equal

that flowing in the aqueous phase. Thus, the mass balance gives the following relation:

$$[A^-] - [S_{F2} - (v_c - \frac{d}{dM} m(S_d,[A^-]) + m(S_D,[A^-]) - m(S_{F2},[A^-])$$

$$- (S_D - S_{F2}) \frac{d}{dM} m(S_D,[A^-])] = [HA_o](1 - S_D) \frac{d}{dM} m(S_D,[A^-]) \quad (47)$$

where S_D is the constant saturation at which oil is stranded. All the other terms remain as defined previously. In Eq. 47, all the quantities are known from the relations with the previous equations given except S_D. Hence, S_D can be determined from Eq. 47 and once determined, the velocity of the back pressure pulse becomes:

$$v_D = \frac{dm(S_D,[A^-])}{dM} \quad (48)$$

If Eqs. 38, 39 and 42 are redefined, as suggested by Helferich[47] and Hirasaki,[48] as dependent variables of total flow M_i' and concentration C_i for each component, the outcome becomes:

$$M_i' = m_j' C_{ij} + m_k' C_{ik} \quad (49)$$

where m_j' is the fractional flow phase j and C_{ij} is the concentration of component i in phase j. In a similar way, the total concentration of component i is given by:

$$C_i = M_j' C_{ij} + M_k' C_{ik} + \frac{(1 - \phi)}{\phi} n_i \quad (50)$$

where M_j' is the saturation phase and n_i is the rock adsorption of species i. Phase j represents water while the oil saturation and fractional flow are given by:

$$M_k' = 1 - M \tag{51}$$

$$m_k = 1 - m \tag{52}$$

It is worth noting that oil and water phases are assumed essentially immiscible in this model. The entire system in this model is trivariant and expresses Eqs. 38, 39 and 42 as:

$$\frac{\partial C_i}{\partial \tau} + \frac{\partial M_i'}{\partial \tilde{x}} = 0, \text{ for } i = 1,2,3 \tag{53}$$

where i = 1, 2, and 3 represent water, sodium ion and acid, respectively. Because the concentration of water is zero in the oil phase and unity in the water phase, the following expressions become:

$$M_1' = M(S_w'[A^-]) \tag{54}$$

and

$$C_1 = m \tag{55}$$

For the sodium ion:

$$M_2' = M(S_w'[A^-])C_2 \tag{56}$$

$$C_2 = mC_2 + \frac{(1 - \phi)}{\phi} n_2C_2 \tag{57}$$

where n_2C_2 is the equilibrium adsorption isotherm for sodium ions. Finally, for the acid phase, the total flow and concentration of the complex acid are:

$$M_3' = M([A^-] + [HA_w]) + (1 - M)([HA_w]) \tag{58}$$

and

$$C_3 = m([A^-] + [HA_w]) + (1 - m)([HA_o]) \tag{59}$$

where $[A^-a]$, $[HA_w]$ and $[HA_o]$ remain as defined previously.

Helfferich and Klein[49] discussed the concenpt of obtaining a solution to trivariant systems of first order nonlinear partial differential equations by the principle of coherence. The coherence technique requires that all dependent variables at any given point in space and time advance with the same velocity. Expressing this mathematically, as adopted by Dezabala, it becomes

$$\frac{dM_i'}{dC_i} = \lambda \tag{60}$$

where Equation 60 is the differential coherence condition and the integral coherence condition defined by Helfferich[47] for shock or jump becomes:

$$\frac{\Delta M_i'}{\Delta C_i} = \Lambda \tag{61}$$

where the dimensionless velocity of a given shock wave and composition are given as

$$v_{\Delta c} = \lambda v \tag{62}$$

and

$$v_c = \Lambda v \tag{63}$$

respectively. The velocities are obtained by solving the following set of nonlinear algebraic equations:

$$\begin{vmatrix} \beta_{11} & \beta_{12}\frac{dC_2}{dC_1} & \beta_{13}\frac{dC_3}{dC_1} \\ \beta_{21}\frac{dC_1}{dC_2} & \beta_{22} & \beta_{23}\frac{dC_3}{dC_2} \\ \beta_{31}\frac{dC_1}{dC_3} & \beta_{32}\frac{dC_2}{dC_3} & \beta_{33} \end{vmatrix} = 0 \tag{64}$$

where β_{ij} is defined as

$$\beta_{ij} = \frac{\partial M_i'}{\partial C_j}, \quad \text{all } C_k,\ j \neq k \text{ constant}$$

and $\frac{dC_i}{dC_j}$ are vector directions in composition space, which is a coordinate system with all the C_k concentrations as coordinates. Since this system is trivariant, composition in space corresponds to a three-dimensional cube. The stipulation provides that each point in the composition space should have three paths: fast, intermediate and slow. These paths are transitions allowable by coherence and results from three positive eigenvalues of varying magnitude for λ given in Eq. 64. The overall direction of each path in the composition space is defined by dC_3/dC_1 and dC_3/dC_2.

The major task required in order to find a solution entails finding the correct route leading from the feed point to a presaturation point. Helfferich[47] and Hirasaki[48] discussed the rules for constructing the route and stipulated that the velocity along a route must never decrease which, of course, requires a unique solution. Hence, the solution must follow paths in the order of increasing velocity.

The displacement model presented applies only to the mechanism involving saponified surfactants from alkaline-oil interaction in the porous medium. The generated surfactant provides the source of interfacial tension reduction. The other mechanisms which include: (1) emulsification with entrapment, (2) emulsification with entrainment, (3) wettability alteration (oil-wet to water-wet) and (4) wettability alteration (water-wet to oil-wet), are not easily amenable to fractional flow analysis.

The theoretical models presented and discussed above are based on existing models in literature for alkaline water flooding. Since this investigation deals with alkaline steamflooding, those models were modified for this purpose. Because of the limitation of the scope of this work, certain quantities and parameters in both the chemical and displacement models were not available and hence these models were not completely tested or evaluated. Rather, the models are presented as a proposal for evaluating alkaline steamflooding in future investigations.

Flow and Physical Parameters

The capillary pressure in the porous medium is defined as follows:

$$P_c = (\rho_w - \rho_o)gh \tag{65}$$

Using the simpler cylindrical formula, P_c is related to pore radius and Eq. 65 becomes:

$$P_c = \sigma\left(\frac{1}{R} + \frac{1}{R}\right) = \frac{2\sigma \cos \theta c}{r_c} \tag{66}$$

where the contact angle is defined as the angle between solid and interface, r_c is the radius of the pore or capillary, σ is the surface tension. Dupre's equation relates the surface tension, σ, to the contact angle, θ_c, as follows:

$$\cos \theta_c = \frac{\sigma_{so} - \sigma_{sw}}{\sigma_{ow}} \tag{67}$$

The interfacial tension, γ, in an aqueous-oleic system is defined as the force per unit length at the oil-water interface. Cayias et al[50] derived a formula used in calculating interfacial tension for a limiting

case. This is given as:

$$\gamma = \frac{1}{4} \Delta\rho\omega^2 y_o^3 \tag{68}$$

where $\Delta\rho$ is the density difference between, in this case, oil and alkali, in g/cc; ω, the angular velocity in radians/sec; and y_o, the cylindrical radius, is in cm.

Temperature Distribution Ahead of Advancing Steam Zone

Since a knowledge of the temperature distribution or build-up is required in order to predict the location and rate of advance of the steam zone or to assess the temperature development ahead of a steam zone when its rate of advance and location are known, the theoretical treatment presented by Durie[51] will be adopted in this study. Durie's theoretical treatment is an extension of Lauwerier's[52] theoretical work which describes the temperature distribution in a line drive model with hot water injection. Durie altered the boundary conditions to represent the situation for steam injection.

In this model, a plane condensation front is assumed to advance through the permeable strata bounded by an impermeable cap rock and base rock. The schematic of the idealized vertical cross section is shown in Figure 1. The following assumptions were adopted in formulating this model: (1) The reservoir is isotropic, homogeneous and of constant thickness. (2) The condensation front is vertical within the sand layer while the hot condensate flows uniformly through the oil sand ahead of the condensation front. (3) Instantaneous thermal equilibrium occurs between the fluid and the sand grains. (4) The thermal conductivities and heat capacities are temperature and pressure independent. (5) The cap rock,

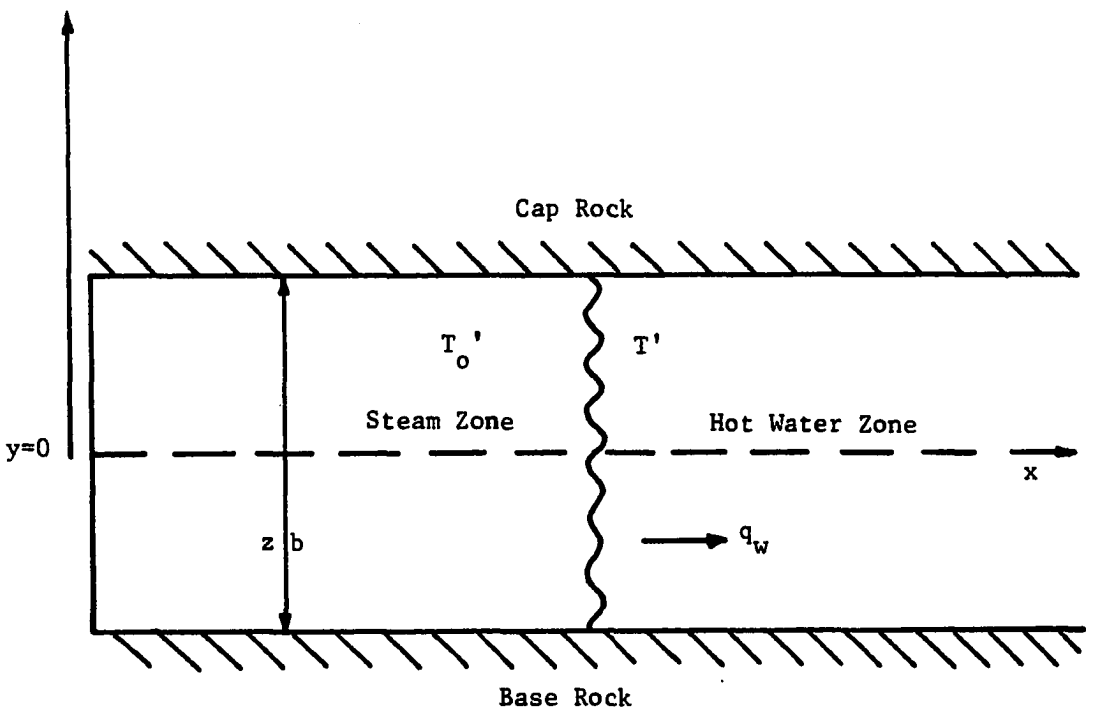

FIGURE 1

(from Durie, R. W.[51])

base rock and oil sand thermal conductivities are equal. And (6) the conduction of heat in the horizontal direction is neglected.

With the above assumptions, the problem can be formulated taking advantage of the symmetry about the mid-point of the oil sand shown in Figure 1. The set of partial differential equations describing the temperature distribution are as follows. In the oil sand:

$$b\rho_1 c_1 \frac{\partial T'}{\partial t} + b\rho_w c_w v_c \frac{\partial T'}{\partial x} - \lambda_2 \frac{\partial T'}{\partial y} = 0; \; y \leq b \tag{69}$$

In the cap rock:

$$\lambda_2 \frac{\partial^2 T'}{\partial y^2} = \rho_2 c_2 \frac{\partial T'}{\partial t} \; ; \quad y \geq b \tag{70}$$

subject to the following conditions:

$$T'(x,y,0) = 0 \tag{71a}$$

$$T'(x,\infty,t) = 0 \tag{71b}$$

$$T'(ct,y,t) = T'_o \; , \quad y \leq b \tag{71c}$$

where Eq. 71c is required to describe the position of the condensation front over considerable time intervals especially at long times or with thin steam zones.

Using the following dimensionless groups:

$$T = \frac{T'}{T'_o} \; , \qquad \xi = \frac{x\lambda^2}{b^2 \rho_w c_w v_w} \; , \qquad \eta = \frac{y}{b} - 1 \; ,$$

$$\tau = \frac{t\lambda_2}{b^2 \rho_1 c_1} \; , \qquad \theta = \frac{\rho_1 c_1}{\rho_2 c_2} \; , \qquad A = \frac{C\rho_1 c_1}{\rho_w c_w v_w}$$

Eqs. 69, 70 and 71 become:

$$\frac{\partial T}{\partial \tau} + \frac{\partial T}{\partial \xi} - \frac{\partial T}{\partial \eta} = 0, \quad \eta = 0 \tag{72}$$

$$\frac{\partial^2 T}{\partial \eta^2} = \frac{\partial T}{\partial \tau}, \quad \eta \geq 0 \tag{73}$$

subject to these conditions:

$$T(\xi,\eta,0) = 0 \tag{74a}$$

$$T(\xi,\infty,\tau) = 0 \tag{74b}$$

$$T(A\tau,0,\tau) = 1 \tag{74c}$$

Applying Laplace transforms to Eqs. 72, 73 and 74 when

$$\mathcal{L}\{T(\xi,\eta,\tau)\} = v(\xi,\infty,\tau)$$

gives:

$$Sv + \frac{\partial v}{\partial \xi} - \frac{\partial v}{\partial \eta} = 0 \tag{75}$$

$$\theta \frac{d^2 v}{d\eta^2} - Sv = 0 \tag{76}$$

When boundary condition 74b is considered:

$$v(\xi,\eta,S) = u(\xi,S)\, e^{-\frac{\sqrt{S}}{\theta}\eta} \tag{77a}$$

which gives

$$v(\xi,\eta,S) = w(S)\, e^{-(S + \beta\sqrt{S})\xi - \sqrt{S}\,\beta\eta} \tag{77b}$$

If $Su + \beta\sqrt{S}\, u + \frac{du}{d\xi} = 0$ is substituted in Eq. (77a) where $\beta = \theta^{-1/2}$.

With the application of the inverse Laplace transform of the form

$$T(\xi,\eta,\tau) = \frac{1}{2\pi i} \lim_{\beta\to\infty} \int_{\gamma-i\beta}^{\gamma+i\beta} v(\xi,\eta,S)\, e^{S\tau}\, dS$$

Eq. 77b becomes:

$$T = \frac{1}{2\pi i} \int w(S)\, \exp[S(\tau - \xi) - \sqrt{S}(\xi + \eta)\beta]\, dS \qquad (77c)$$

and the boundary condition 74c gives

$$1 = \frac{1}{2\pi i} \int w(S)\, \exp[S(1 - A)\tau - \beta\sqrt{S}(A\tau)]\, dS \qquad (77d)$$

Substituting

$$S = \frac{A^2\beta^2 + A\beta[A^2\beta^2 + 4\sigma(1 - A)]^{1/2} + 2\sigma(1 - A)}{2(1 - A)^2}$$

in Eq. 77d gives:

$$1 = \frac{1}{2\pi} \int w(S) \frac{2\sqrt{S}}{2(1 - A)\sqrt{S} - A\beta} e^{\sigma\tau}\, d\sigma \qquad (77e)$$

With

$$\frac{1}{\sigma} = w(S) \frac{2\sqrt{S}}{2(1 - A)\sqrt{S} - A\beta}$$

Eq. 77c becomes:

$$T(\xi,\eta,\tau) = \frac{1}{2\pi i} \int \frac{2(1 - A)\sqrt{S} - A\beta}{2\sqrt{S}[S(1 - A) - A\beta\sqrt{S}]} \exp[S(\tau - \xi) - \sqrt{S}(\xi + \eta)\beta]\, dS \qquad (78)$$

The solution given by Durie for Eq. 78 is:

$$T(\xi,\eta,\tau) = \frac{1}{2} \exp\left[\frac{A(\xi + \eta)}{\theta(A - 1)}\right] \exp\left[\frac{A^2(\tau - \xi)}{\theta(A - 1)^2}\right] \operatorname{erfc}\left[\frac{A\sqrt{\tau - \xi}}{\sqrt{\theta}(A - 1)} + \frac{\xi + \eta}{2\sqrt{\theta}\sqrt{\tau - \xi}}\right]$$

$$+ \frac{1}{2} \operatorname{erfc}\left[\frac{\xi + \eta}{2\sqrt{\theta}\sqrt{\tau - \xi}}\right]; \quad A\tau < \xi,\ \tau > \xi,\ A < 1 \qquad (79)$$

Figure 2 shows the actual model encountered in, say a prototype reservoir, or a fairly large scale physical model. The graphical representation of Eq. 79 is shown in Figures 33 and 34. Figure 34 compares Durie's solution with Lawerier's.

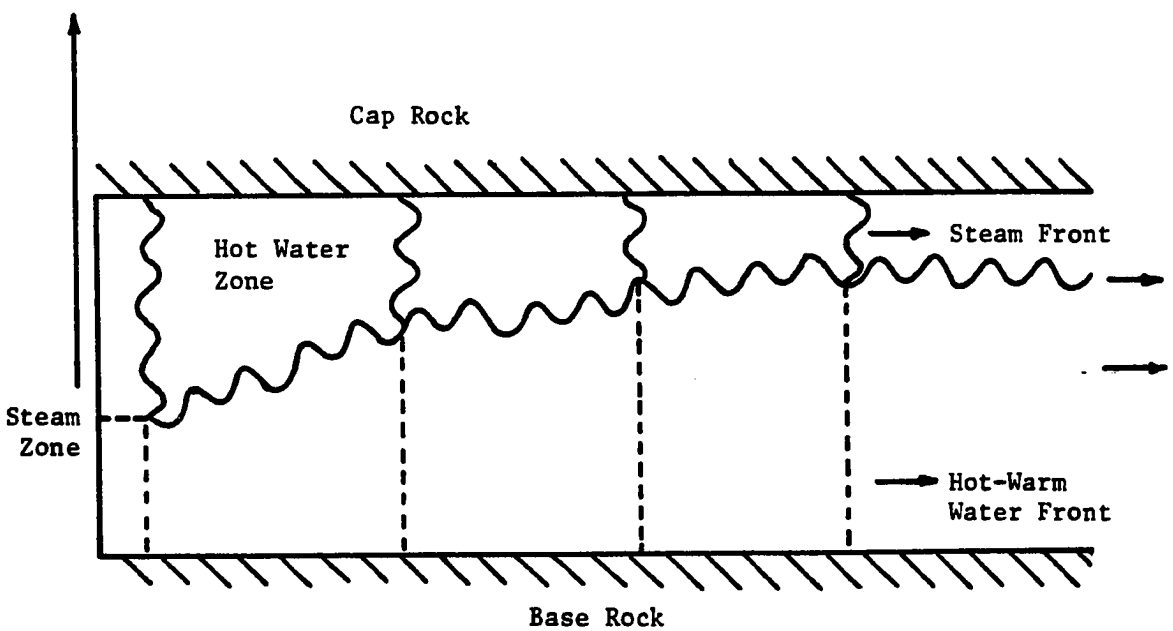

FIGURE 2

CHAPTER IV

EXPERIMENTAL EQUIPMENT AND MATERIALS

Figure 3 shows the schematic diagram of the entire set-up: The essential components of this set-up include the following: (1) water, alkaline solution and oil feed tanks, (2) injection pumps, (3) pressure gauges and filters, (4) forward pressure and back pressure regulators, (5) flow meters, (6) steam generator, (7) feed and injection pumps, (8) network of flowlines, (9) core assembly housing the porous medium, (10) super-heaters, (11) temperature sensing devices and recorders, (12) transducers and pressure recorders, (13) pH meter and (14) fluid collection equipment. The detailed description of the equipment is as follows:

1. Core Tube Assembly shown in Figure 4 consists of: (1) a stainless steel Hassler-type core holder whose dimensions are: 3 inch internal diameter, 0.25 inch wall thickness and 24 inch length, (2) stainless steel end caps sealed with corrosion resistant, high pressure and high temperature O-rings, (3) a stainless 'swagelok' T pipe fitting connecting two lines of 3/8 inch stainless steel tubing used as inlets to the core tube, (4) an axial thermocouple with dimensions of: 30 inches length, 0.072 inch outside diameter and 0.099 inch wall thickness and closed at the lower end, used for measuring the axial temperatures and this thermocouple was held in place by a 3/8 inch conax fitting to the core tube and (5) twelve fixed immersion thermocouples with identical dimensions as the axial thermocouple but only one

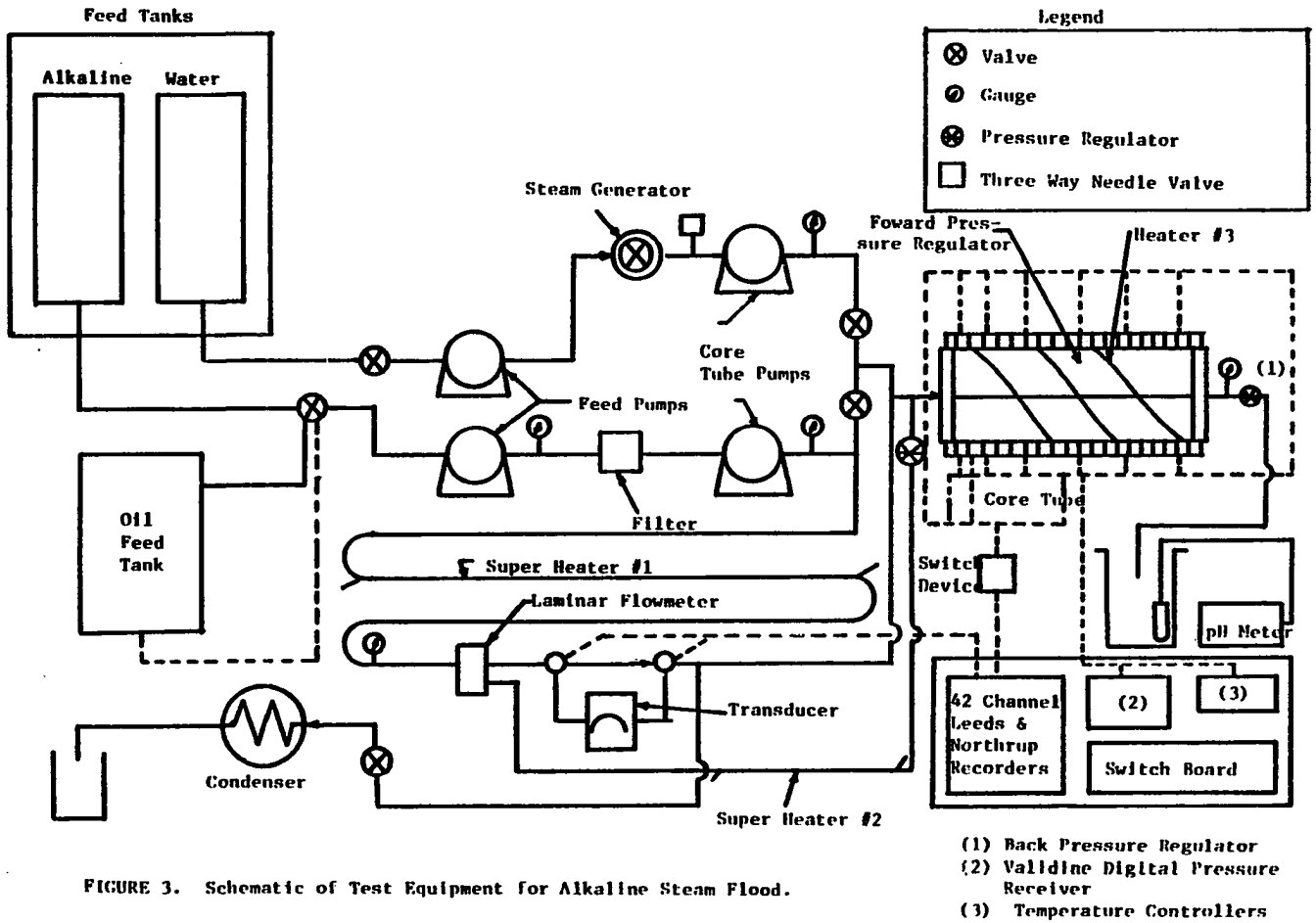

FIGURE 3. Schematic of Test Equipment for Alkaline Steam Flood.

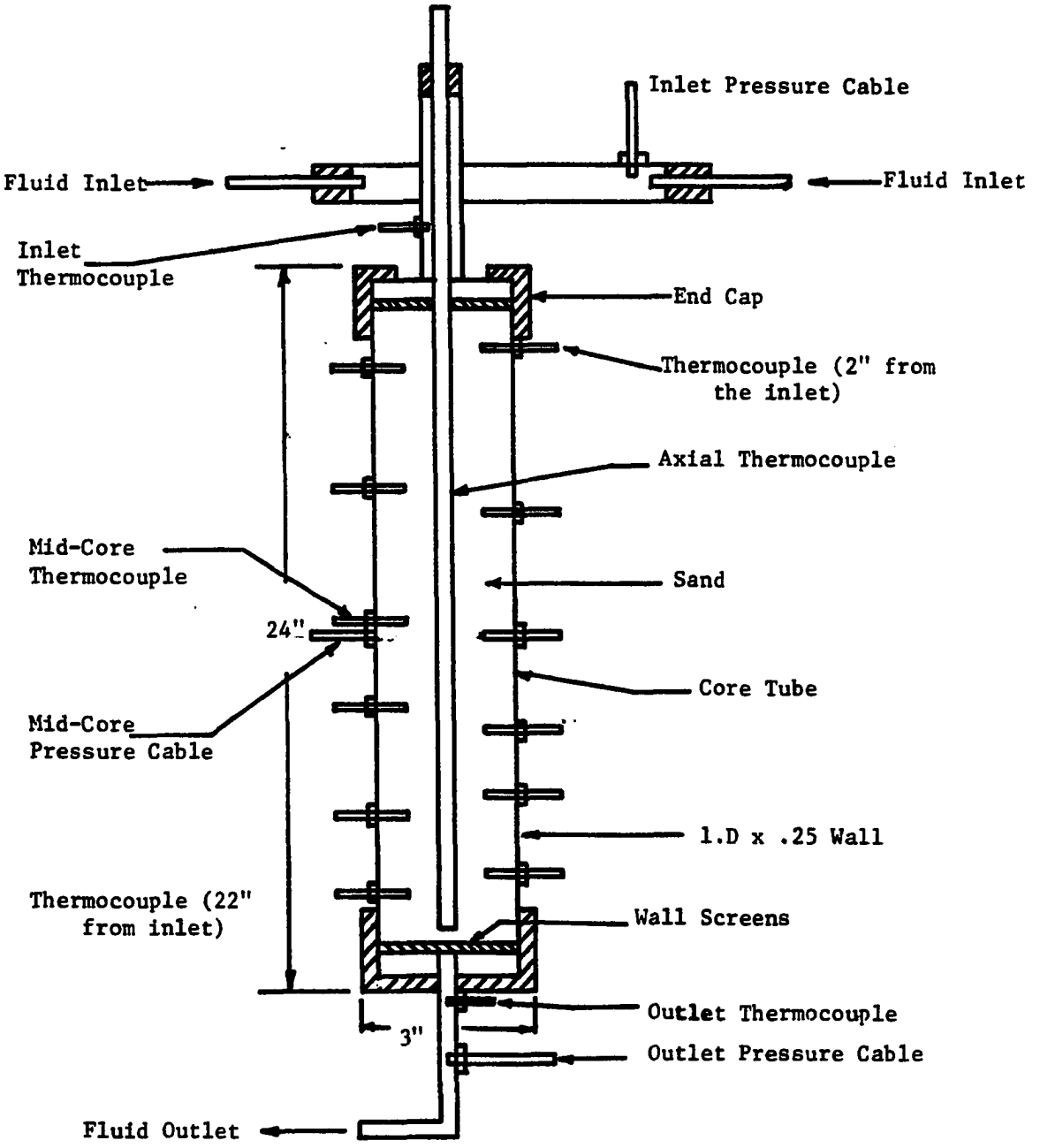

FIGURE 4. Core Tube Assembly

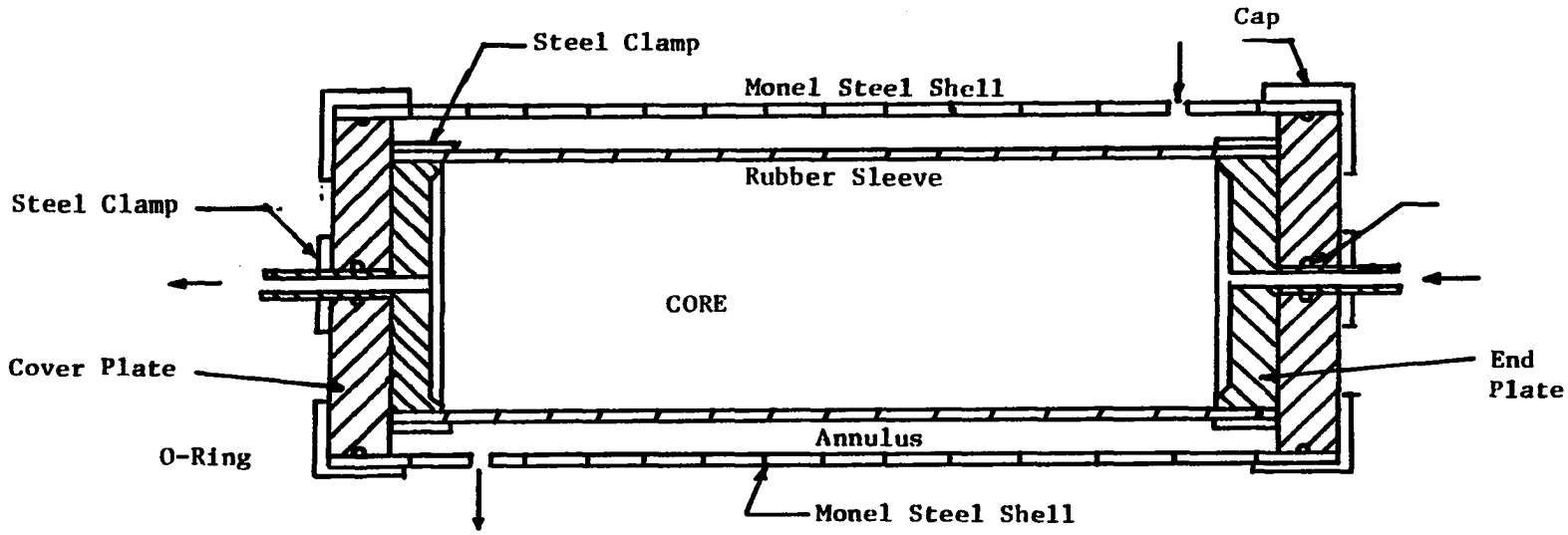

FIGURE 5. Core Holder Assembly

fifth as long and these thermocouples were fitted across the core tube at distances of 2, 3, 5.5, 7, 9, 11, 13.5, 15, 18, 18.5, 21 and 22 inches from the inlet end of the core tube. A fixed immersion thermocouple was also housed by the conax fitting to measure the temperature exactly at the inlet point of the fluid. Finally, the core tube end was connected to 1/4 inch T pipe fitting which housed another immersion thermocouple which measured the fluid temperature exactly at the outlet end of the core tube. The lateral thermocouples were fitted in order top and bottom as enumerated above. The bottom thermocouples measured the temperature of the bottom half of the sandpack while top thermocouples measured the temperature of the top half of the sandpack.

2. Porous Media consisted of sieved 28-35 mesh size sandpacks or 23 inch long and 2 inch diameter cylindrical berea cores. The sandpack was prepared by sieving a range of 28-35 mesh size sand which was then dried at low temperature (200°F) to a constant weight in a drying oven. The low temperature drying was necessary in order to retain whatever small clay content of this Halliburton frac sand. This sand was packed into the core tube which was kept under constant vibration. The purpose of the vibration was to enhance the packing process. The sand was held in place by two metal screens on each end followed by the O-rings and the end caps of the core tube.

For the core displacement tests, the core was put into a Hassler-type sleeve whose length is 24 inches and diameter 2 1/8 inches. Annulus pressure on this sleeve surrounding the core was applied to insure that fluid only flowed through the core. End plates inside the caps abutted the ends of the core and were held in place by steel clamps over the Vitron-A rubber sleeve enclosing the core. The end plates were flared to permit fluid entry and exit from the entire face of the core. Both the upper and low end

plates contained vitron rubber O-rings which sealed off the annulus. The O-rings were designed to tolerate temperature of 500°F and pressure of 3000 psia, but repeated use caused hardening and leakage, necessitating periodic replacement to ensure trouble free operation. The Hassler-type sleeve was made to withstand the same pressure and temperature range as the O-rings. The manufacturers did not guarantee that the sleeve would be alkali tolerant and during the course of the experiment, it was observed that the alkali gradually but steadily undermined the sleeve.

The porosities of the sandpacks and cores were determined volumetrically during water saturations. Sandpacks' porosity averaged 41.73 percent, while the cores' porosity averaged 21.25 percent. The permeabilities were determined with liquid and gas permeaters for the cores and from displacement test using Darcy's law for fluid flowing under a changing potential head of pressure. The flow rate was plotted against the differential pressure and from the slope of the straight line graph, the permeabilities were calculated. Average permeability of the sandpacks was 6.3 darcies while the cores averaged 0.351 darcies.

3. Fluid Injection System was designed and constructed to allow rapid interchange from one type of injection fluid to another. It consisted of two parallel injection flow lines which were connected to a common junction by series of valves as shown in figure 3. Any of the fluids (oil, water, steam or alkaline) could be directed into the reservoir (core tube) bypassing the superheater loops or through the superheater loops as the case might be.

The steam input stream consisted of distilled cool water fed into a Hotshot Model MB-3C steam generator capable of producing saturated stream at 50 psig. The steam generator was connected through flow lines to two

series of superheaters each consisting of two loops of flow lines upon which were coiled 1/4 inch copper heating element. The heating element could be heated up to 700°F and at this temperature, with good insulation, the system would generate superheated steam of more than 500°F. The superheaters' temperatures were controlled automatically by Love Control Model 49 proportioning controls. The range of these controls was 0°F to 2400°F.

4. Flow and Injection Rate Determination entailed essentially measuring the cumulative liquid produced and injected, respectively, at time intervals. Brooks Full View rotometer with needle-valve control, was used to meter liquid injection rates. Two Wallace & Tiernan metering pumps provided the required mass rate of injection into the sandpack or core. The single simplex metering pump was used for fluid injection into the sandpack while a double simplex metering pump provided fluid injection into the core.

The technique of measuring steam injection rate was more difficult to develop than liquid injection rate. From several techniques investigated, a laminar flow device[53] was selected. It consisted of a 10 inch length of stainless steel whose inside diameter was 0.097 inches and pressure cables emanating from each end were connected to a transducer which monitored the differential pressure. Pressure meters and thermocouples were connected at each end of the laminar tube to measure inlet and outlet pressures and temperatures respectively. The mass rate of the steam was determined by timed weighing of the condensate.

5. Thermocouples, Transducers, Receiver and Recorders were used to monitor temperatures, pressures and to receive and record them respectively. The axial thermocouple traversed the length of the porous medium (sandpack only) inside an axial thermowell. There were fourteen immersion thermocouples, one of which was fitted at the inlet and outlet ends of the core tube and

the remaining twelve were inserted across the porous medium (sandpack) at distances from the inlet stipulated earlier. Thermocouples were also taped to: (1) end points of the superheaters, (2) both ends of the laminar flowmeter, (3) outlet of the steam generator, and (4) fluid production end. All the thermocouples were connected through a switching device to a Leeds & Northrup Speedmax W, 48-point recorder.

The superheaters thermocouple, were in addition connected to the automatic temperature control. All the twenty thermocouples could be recorded in at most 20 seconds and a complete transverse could be read and recorded in 11 seconds. The time required for the thermocouples to attain thermal equilibrium was determined by making a series of tests in which the thermocouples traversed several inches and the temperature at the new location recorded after a period of several seconds. From the results of these tests and for the temperature ranges investigated with this equipment, it was observed that the thermocouples responded instantaneously. A network of pressure cables connecting the inlet, the midpoint and the outlet of the core tube and both ends of the laminar flowmeter were connected to transducers mounted on a panel which formed part of the control system. The transducers were connected through switching device to a Validine model MCI digital pressure receiver which in turn was coupled to a Leeds & Northrup speedomax W, 48-point pressure recorder. While the Validine digital pressure receiver could display the differential pressures between the inlet, midcore and outlet points digitally on the screen, the pressure recorder recorded the exact pressures at these points.

6. Meters, Regulators and Other Measuring Devices embrace a host of pieces of equipment that include: (1) pressure meters, (2) flow meters, (3) forward and back pressure regulators, (4) pH meter, (5) porosimeter,

(6) permeameters, (7) viscosimeters, (8) densiometer, (9) Du Noüy interfaciometer and (10) spinning drop interfaciometer.

7. Auxiliary Equipment includes: (1) feed tanks, (2) mixing tanks, (3) mixers, (4) water analyzer, (5) water bath and (6) drying oven.

8. Materials are covered by such items as: (1) insulation material which in this case was 2 inches thick Owen-Corning fiberglass of reported[57] density 1.9 lb/ft^3 and thermal conductivity of 0.15 BTU/ft^3-hr-°F, (2) high temperature (up to 1200°F), fast setting insulation cement used for cementing the heating elements and fiberglass to the core tube, (3) chemicals such as: NaOH, KOH, Na_2CO_3, NaCl and Na_2SiO_3, (4) oil samples (17°-20°API) from Conoco Loco field in Ardmore County, Oklahoma, (5) cleaning oils such as: iso-octane, normal hexane, acetone, iso-propyl alcohol, toluene and naphtha, (6) Halliburton 20-40 frac sand and custom fashioned 2 inch diameter, 24 inch long cylindrical berea sandstone.

The entire flow system was wrapped in 2 inch thick Owen-Corning fiberglass for insulation. The core assembly was further insulated with two more layers of the fiberglass in order to reduce heat loss to a minimum.

CHAPTER V

EXPERIMENTAL PROCEDURE

The crude oil used in this experimental investigation was obtained from Conoco Loco field in Ardmore area in Oklahoma. The oil samples were waterflood produced and had an average A P I gravity of 18° at 75°F. Each of the first six tests were performed with fresh sandpacks. All of these six tests were run in 3 inch diameter and 24 inch long stainless steel core holder packed with unconsolidated 28-35 mesh Halliburton frac sand. The next four tests were each performed with fresh 2 inch diameter, 23 inch long unbaked berea core. The cores were not baked in order to retain the clay content.

The permeability of each sandpack and core were determined during the water and oil saturation period during which varying injection rate produced varying differential pressure values. By plotting rate against pressure differential, the permeabilities were calculated from the slope of the straight line graph using Darcy's law. Gas and liquid permeameters were also employed to measure berea core permeabilities. The calculated average sandpack permeability was 6.3 darcies, while the core permeability varied from 0.147 to 0.176 darcies for the first two core tests and from .320 to 0.373 darcies for the last two core tests.

The porosity of the sandpack was first determined gravimetrically during packing and, next, volumetrically, as were that of the cores during

water saturation, i.e., by noting the volume of water required to completely saturate the sandpack or core and dividing this volume which represented the pore volume by the entire volume of the sandpack or core.

The oil viscosity temperature relationship is illustrated in Figure 6 which was drawn from data obtained by the use of reverse-flow type viscometers in constant temperature baths. The average A P I gravity of the oil samples was 18° and the relationship of A P I gravity with temperature is depicted in Figure 7.

Before starting the displacement tests, the core tube and associated fittings were pressure tested to ensure no leakage in the system. The core tube was pressure tested empty at 500 psi for 24 hours and then filled with clean dry sand. The sandpack was then saturated with water and retested at a pressure of 2500 psi. A similar pressure testing of the core tube was conducted with water saturated core at a pressure of 1200 psi and annulus (confining) pressure of 2500 psi.

The procedure for making a displacment run was essentially similar for all the ten tests. The first six texts were conducted with sandpacks as the porous media and practically all the other tests followed similar steps which are as follows:

1. The sandpack and the flow system were vacuumed for twenty four hours and then the sandpack was completely saturated with water (distilled water made saline with 0.4 percent by weight of NaCl) followed by oil injection to irreducible water saturation. Both water and oil saturations were accomplished with minimal injection rate in order to minimize the creation of flow channels and saturation profiles.
2. Each saturated sandpack was water flooded to about water oil ratio of 35. The remaining procedures were identical for the other tests with

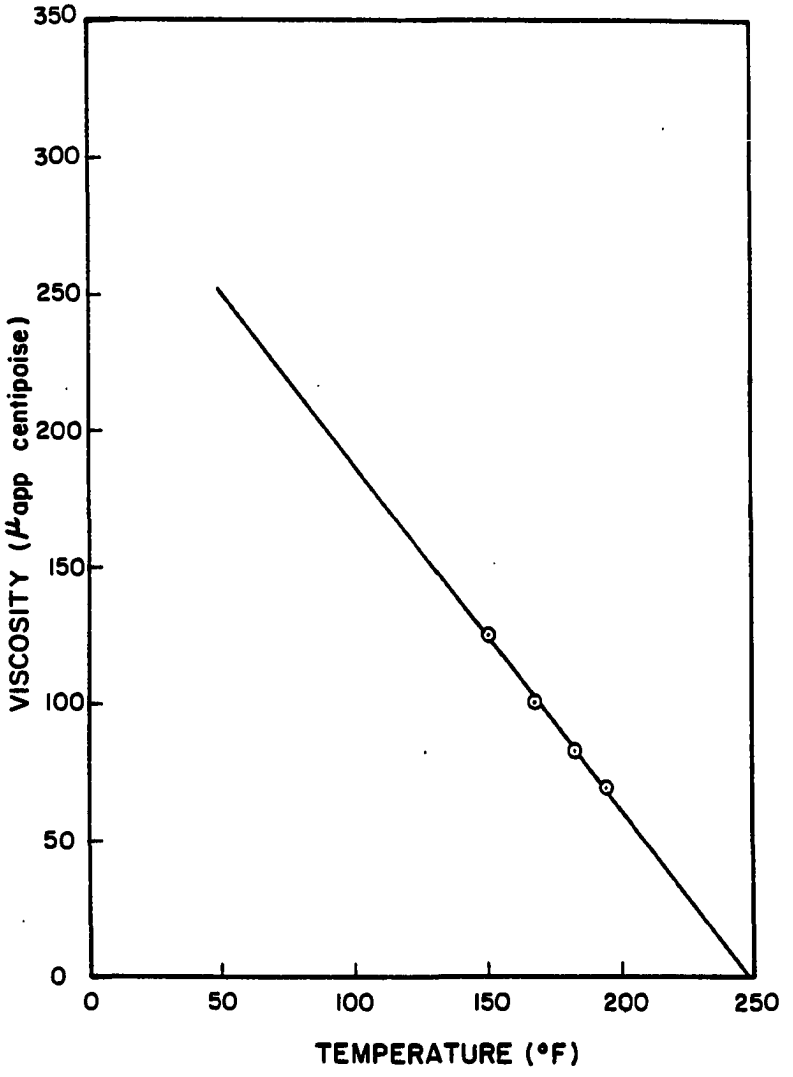

FIGURE 6. Temperature Effect on the Viscosity of the Original Oil.

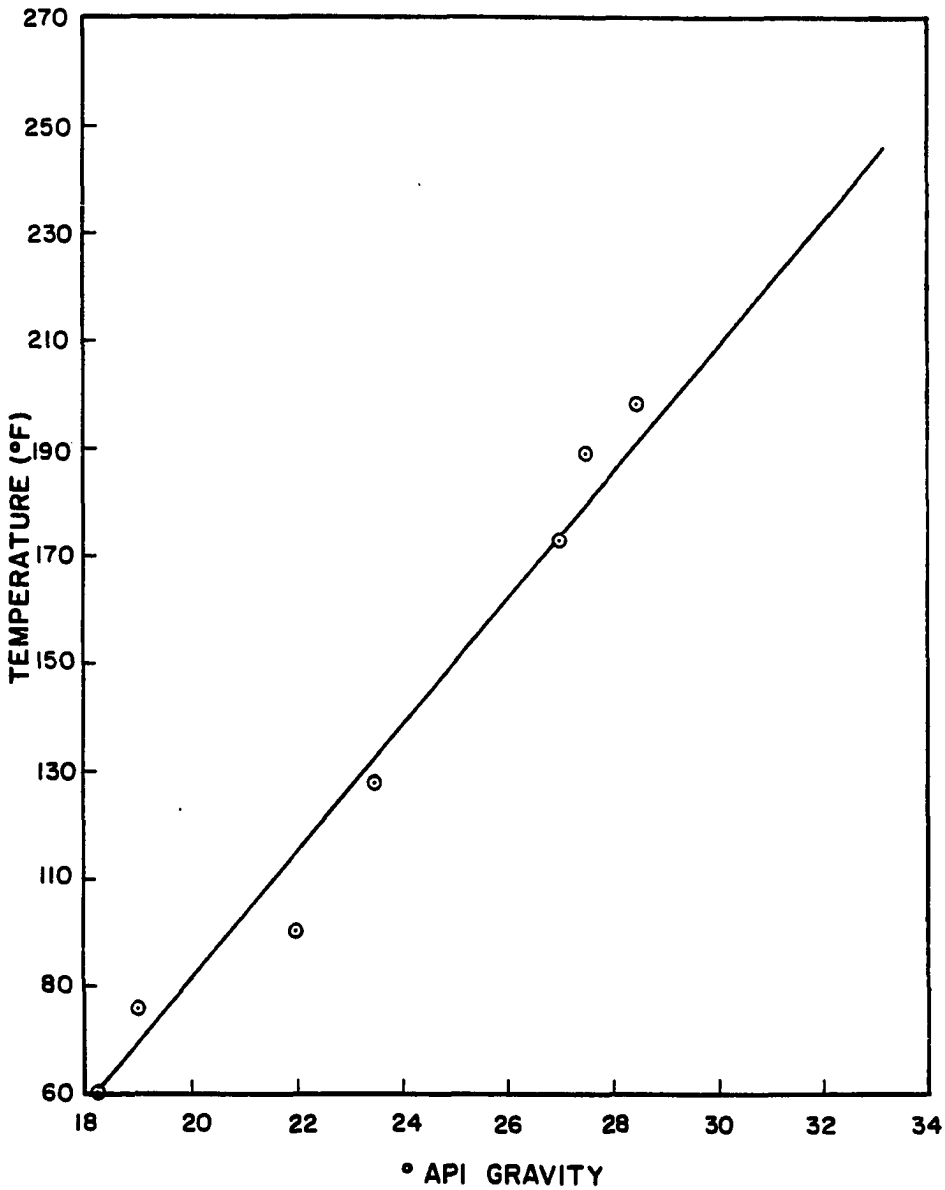

FIGURE 7. Temperature vs °API Gravity.

sandpack except for the first test.

3. The next step for the first test was steam flooding. Steam was charged from the steam generator which was turned on and set to maintain a pressure of about 30 psig. The steam was injected into the flow system where two series of superheaters, each consisting of 1/2 inch I.D. and 6 feet long tube lined with 1/4 inch thick heating element, form part of the flow line to the sand pack. The superheaters were set to 550°F and were able to superheat the incoming steam to about 385°F at a pressure of 30 psig. The core tube inlet thermocouple recorded inlet steam temperature of 355°F at a pressure range of 25 to 32 psig.

4. For the next five alkaline displacement tests, the cool alkaline solution, in each case, was charged from the feed reservoir into the superheaters to be heated in situ in the flow system. To ensure the generation of alkaline steam, the heating elements were turned on and set at 550°F and the system allowed to attain ambient temperature of about 350°F at about 30 to 50 psig before opening the inlet valve to the core tube.

5. Next, the back flushing through the sandpack was shut off, and the inlet valve to the core tube was opened to start the displacement test. The inlet pressure and the fluid injection rate were regulated with injection pump controller and forward and back pressure regulators. The fluid injection pressures varied initially from as high as 500 psig for Na_2CO_3 steam flooding to as low as 25 psig for KOH steam flooding. During the displacement tests, however, the alkaline steam injection pressures were

reduced to as low as 65 psig for Na_2CO_3 and 25 psig for steam and the rest of the alkali.

6. The upstream, midstream and downstream pressures were monitored by the transducers and recorded on strip chart recorder. The Validine digital pressure receiver with a push of button displayed digitally the differential pressure between various points designated by channels. The temperature distribution in the sandpack as well as at various points in the flow system were monitored by the thermocouples installed at these points. The temperatures were recorded from each thermocouple six times every seven minutes at intervals of about one minute.

7. The inlet temperature and pressure were continuously monitored and controlled to maintain an average steam or alkaline steam superheat for all the tests.

Similar steps were followed for core displacement tests with exception of a few modifications here and there. Like with the sandpack, the core and the flow system were evacuated overnight. High pressure nitrogen gas was used to introduce pressure in the annulus of the core tube in order to confine the rubber sleeve to the core. A confining pressure of 200 psig was introduced during the evacuation of the core. After the nitrogen gas was introduced into the annulus, the flow line to the tank was shut off so that maintenance of the pressure on the annulus during evacuation would assure that the annulus was completely sealed off and that there was no leakage.

For each core test case, the core was completely water saturated followed by oil saturation to irreducible water saturation. The sleeve confining pressure was always maintained at 200 psig above the injection

pressure which was as high as 1300 psig during oil saturation. The oil saturated core was water flooded to about water oil ratio of 30 for each test.

The first test involved steam flooding the water flooded core. The steam was generated and superheated in the same process described for the sandpack test. The steam temperature fluctuated between 320 and 345°F at inlet pressure of 35 psig and back pressure of 20 psig. In all cases, the back pressure was removed after steam breakthrough if the steam oil ratio was above 50.

The other test involved alkaline (NaOH, Na_2SiO_3 and Na_2CO_3) steam flooding after water flooding. The alkaline steam in each of these tests was generated exactly in the manner described for alkaline steam sandpack tests. The inlet steam temperatures for these three alkaline tests were: 360°F for NaOH-steam flood with inlet pressure of 350 psig and back pressure of 50 psig, 380°F for Na_2SiO_3-steam flood with inlet pressure of 1150 psig and back pressure of 50 psig, and 400°F for Na_2CO_3-steam flood with inlet pressure of 1250 psig and back pressure of 50 psig.

Only the fluid inlet and outlet, and the annulus temperatures were monitored and recorded for the core tests. This was because it was not practical to install the thermocouples inside the core without interferring with the flow paths. Also, the pressures monitored and recorded were the inlet, outlet and annulus fluid pressures.

The displacement tests were generally concluded when the steam oil ratio exceeded 60.

TABLE 1: SATURATION VALUES (Based on Pore Volume)

Type of Test on Glass Beads Pack	Initial Water Saturation	Initial Oil Saturation	After Water Flood Saturations		After Cool Caustic Flood (1 gm/l) Saturations		Caustic Steam Flood (1 gm/l) Saturations		Steam Flood Saturations		Caustic Steam Flood (1.5 gm/l) Saturations	
	S_{wi}	S_{oi}	S_w	S_{or}	S_w	S_{or}	S_w	S_{or}	S_w	S_{or}	S_w	S_{or}
Case I Cool Caustic Flood & Steam Flood	39.3	60.7	52.37	47.63	58.79	41.21			74.0	26.0		
Case II Caustic Steam Flood	46.1	53.99	73.47	26.53			90.75	9.25				
Case III Cyclic Caustic/ Steam Flood	22.03	77.97	55.36	44.64			78.84	21.16			82.61	17.39
Case IV Steam Flood	38.1	61.9	5.20	48.0					80.17	19.83		
Case V Cool Caustic Flood + Caustic Steam Flood	11.2	88.8	48.56	51.44	52.0	48.0	64.88	35.12				
Case VI Cyclic Steam/ Caustic Flood	14.2	85.8	56.59	43.41			84.31	15.69				

TABLE 2: OIL RECOVERY RESULTS

Oil Recovery as a Percentage of Initial Oil in Place

Type of Test on Glass Beads Pack	Water Flood	Cool Caustic Flood (1 gm/l)	Caustic Steam Flood (1 gm/l)	Steam Flood	Caustic Steam Flood (1.5 g/l)	Total Recovery
Case I Cool Caustic Flood & Steam Flood	21.52	10.6		25.0		57.19
Case II Caustic Steam Flood	50.86		32			82.0
Case III Cyclic Caustic/ Steam Flood	42.75		30.11		4.84	77.7
Case IV Steam Flood	22.46			45.5		67.97
Case V Cool Caustic Flood + Caustic Steam Flood	42.07	3.87	14.5			60.44
Case VI Cyclic Steam/ Caustic Flood	49.41		32.3			81.71

CHAPTER VI

RESULTS AND INTERPRETATIONS

The primary objective of these studies was to investigate the applicability of alkali (NaOH, Na_2SiO_3, Na_2CO_3 and KOH) as chemical additives for steam flooding. Several types of experiments were required in this investigation. They are grouped as follows: (1) process determination, (2) evaluation and comparison of alkaline steam flood types and (3) displacement mechanism evaluation. While results from each group will be presented separately, the results from all the experimental groups will be integrated in the discussion and interpretation of results. Finally, the standard theoretical temperature distribution ahead of the advancing steam zone will be compared with experimental cases.

Process Determination

Tables 1 and 2 contain the summary of saturation values and oil recovery performances for all the seven experimental cases employed for determining the optimal process. Included in these cases was also the evaluation of the optimal temperatures for alkaline steam flooding.

Case I: Water flood followed by cool caustic flood and finally by caustic steam flood.

In case 1, water flood recovered 21.5 percent of original oil in place. Flooding thereafter with cool caustic solution, conc. 1 gm/ℓ,

recovered about 10.6 percent of initial oil in place. The subsequence process was steam flood which recovered 25 percent of initial oil in place, adding to a total overall recovery of 57 percent of initial oil in place from the two processes.

Case II: Water flood followed by caustic steam flood.

In case 2, 50 percent of initial oil in place was recovered from water flooding. This water flood recovery was a little above twice the recovery from case 1 and required about twice as much injected water pore volume as in case 1 to accomplish. The extended water flooding in case 2 was not by design but rather due to underestimation of water oil ratio during the experiment. Subsequent hot caustic to caustic steam injection recovered 32 percent of initial oil in place. The total oil recovery from this case was 82 percent.

As in the previous experimental case, the caustic solution concentration was 1 gm/ℓ. The caustic phase during displacement is characterized as above because the heating system which formed part of the flow system tended to generate hot caustic, following the injection into the porous medium, before furnishing caustic steam. During the subsequent phases of this study, i.e., sandpack and berea core displacement tests, caustic steam could be generated at the onset by increasing the length of the heating elements and increasing the ambient temperature of the heating system from 300°F to 500°F.

Case III: Water flood followed by two cycles of caustic steam flood of varying concentrations.

In case 3, water flood recovered 43 percent of initial oil in place. Then, hot caustic and caustic steam recovered 30 percent of initial oil in place. After increasing the caustic solution concentration to 1.5 gm/ℓ,

5 percent more oil in place was recovered. The total oil recovered in this case as a percentage of original oil in place was about 78 percent.

The incremental oil recovery following the injection of higher caustic concentration was due more to the pore volume (1.5) injected than the effect of the caustic concentration. Further investigation of the effect of caustic concentration on recovery showed that the concentration of 1.5 gm/ℓ was too high and in fact detrimental to the type of oil employed in these studies. This observation will be discussed further in connection with aspects of the second group of experiments.

Case IV: Water flood followed by conventional steam flood.

The oil recovered from water flood was 22.5 percent of oil in place while steam flood following thereafter recovered 45.5 percent of oil in place. The overall oil recovered by these two processes was 68 percent of original oil in place.

Case V: Water flood followed by cool caustic flood and caustic steam flood.

Water flood recovered 42 percent of initial oil in place while cool caustic flood recovered only additional 4 percent of initial oil in place. Caustic steam flood yielded 14.5 percent more of initial oil in place. The combined recovery from the two caustic processes was about 19 percent of initial oil in place. The total recovery from all the processes was 66.44 percent.

Case VI: Water flood followed by cyclic steam flood and cool caustic solution flood.

In this test case, water flood recovered 49.4 percent of initial oil in place, while the cyclic steam-caustic flood recovered 32.3 percent of original oil in place. The total oil recovery was about 81.7 percent of initial oil in place. The sequence of the procedure used in this test was steam injection after water flood and alternated by cool caustic

solution injection. The average temperature in the porous medium fluctuated between 250°F, during steam injection, and 165°F during cool caustic solution injection.

Case VII: Optimal temperature evaluation.

In this case, the optimal temperature for hot to caustic steam flood was examined. To this end, hot caustic solution was injected after water flood in separate runs at temperature of 125°F and 175°F. The results of these runs were combined with the results obtained from cool caustic flood in case 1 and those of caustic steam flood in cases 2 and 3 to determine the optimal temperature for caustic solution flooding.

From this and subsequent studies the optimal temperature for hot caustic to caustic steam flooding covered the range of about 250°-300°F. The upper temperature limit actually should be earmarked when there is a rapid consumption or breakdown of alkaline solution. Experimental evidence showed that the pH of the alkaline solution declined only slightly with temperature up to 350°F. Above this temperature alkaline consumption increases rapidly and this will be indicated by the rapid decrease in pH values. Tables B2 and B8 contain the initial pH values of 1 gm/liter caustic solution and the pH values of the produced fluids. The low pH values after successive increases occurred just before the caustic steam breakthrough during which the temperature in the porous medium averaged about 300°F or above.

By examining the recovery performances of all these cases described, it is abundantly clear that the processes and their sequences in cases 2 and 6 were more effective than those of other cases in recovering oil. Case 1 results provided evidence which was reaffirmed in a test in case 7 that cool caustic flooding as a tertiary recovery process is only marginally

effective at high residual oil saturation and practically ineffective at low residual oil saturation. Figures, 8, 9 and 10 show the plots of cumulative oil recovery versus cumulative injected pore volumes for cases 2, 4 and 6 respectively. These plots in addition to that of a hot caustic water flood are combined, for the sake of comparison, in Figure 11.

Clearly, from this figure, Case 2, water flood followed immediately by caustic steam flood process, provided the most effective mechanism for displacing oil from glass bead packs. Based on this result, case 2 processes were adopted for displacement tests on sandpacks and berea cores.

Figure 12 combines all the plots in Figure 11 as well as the performance plots of cool caustic water flood (80°F), and two hot caustic water floods at temperatures of 125°F and 175°F. The optimal temperature for tertiary caustic water flood or steam flood is shown clearly from these plots to be at 250°F. Later experiments, the results of which will be described shortly, showed that tertiary caustic steam flood is not significantly affected by temperature (measured in terms of drop in pH value) up to about 350°F. The nature and type of multiple mechanisms involved in caustic steam drive, particularly, the fact that the effectiveness of steam drive oil recovery mechanisms become greater as the temperature increases, will more often than not ensure more oil recovery with increase in temperature.

In actual reservoirs, however, the temperature of the bottom half of the formation will lag behind that of the top half of the formation. Since this experimental process is aimed at recovery of oil in the bottom half of the formation that is essentially swept by hot water, having been bypassed by steam because of gravity override, the degradation of caustic solution at high temperature will be less problematic.

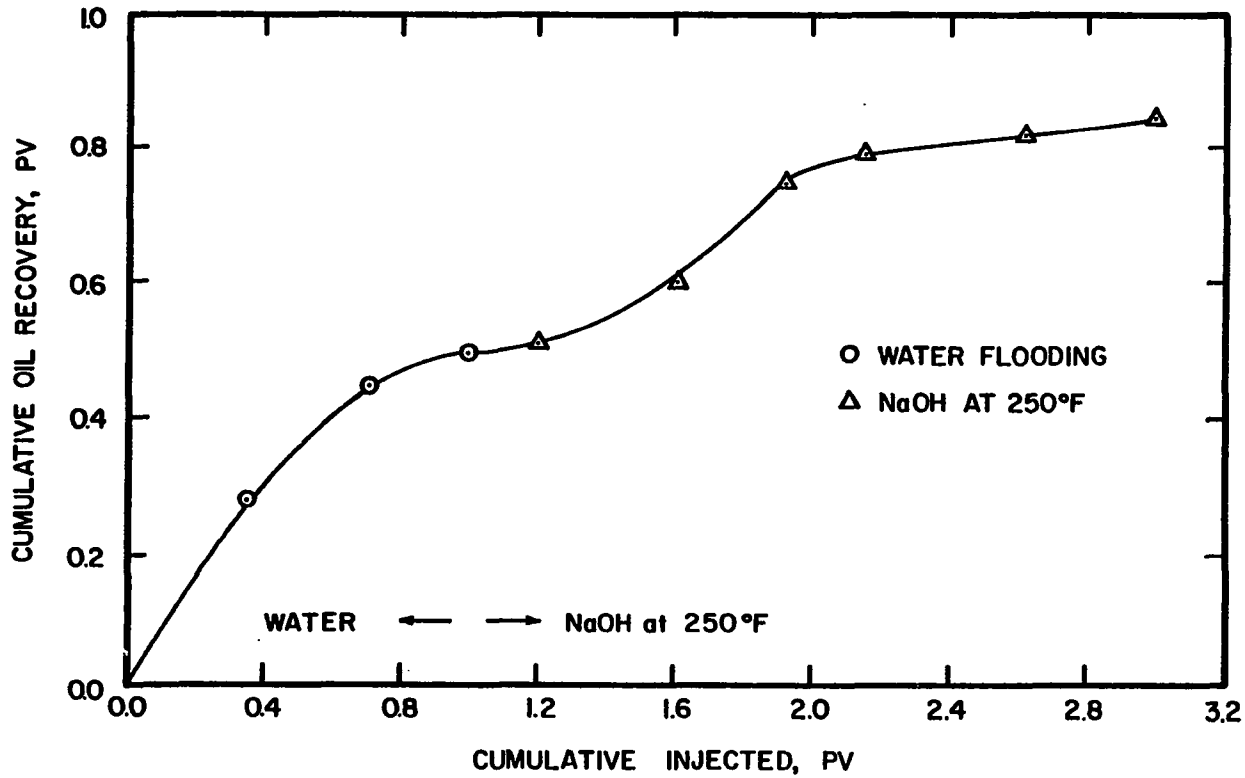

FIGURE 8. Oil Recovery Performance of Water Flood and Caustic Steam Flood.

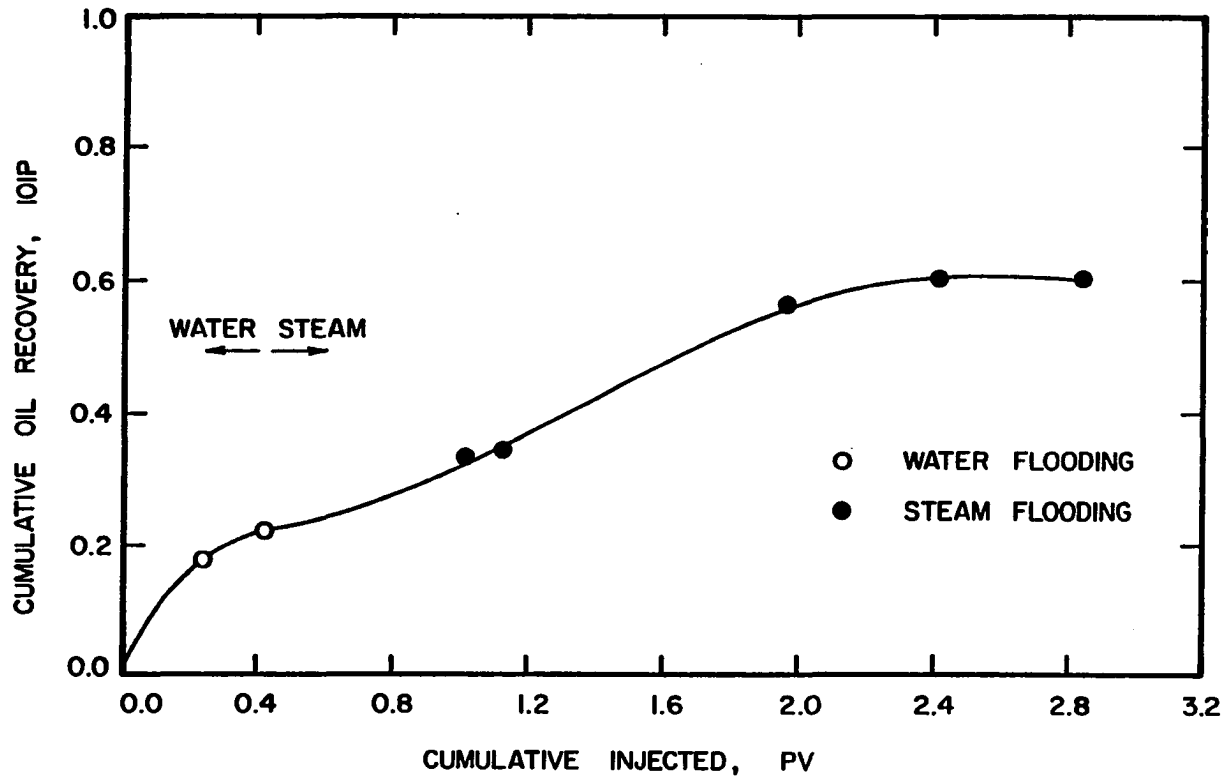

FIGURE 9. Oil Recovery Performance of Water Flood and Steam Flood.

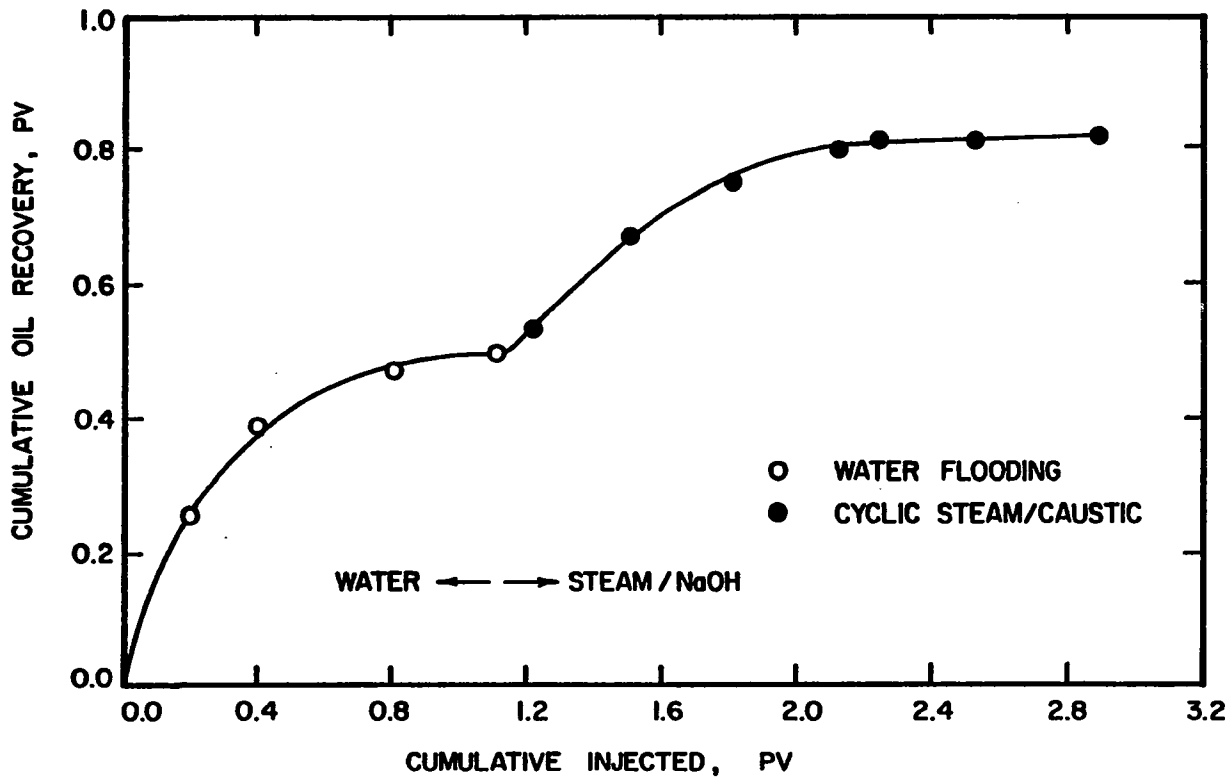

FIGURE 10. Oil Recovery Performance of Water Flood and Cyclic Steam/Cool Caustic Water Flood.

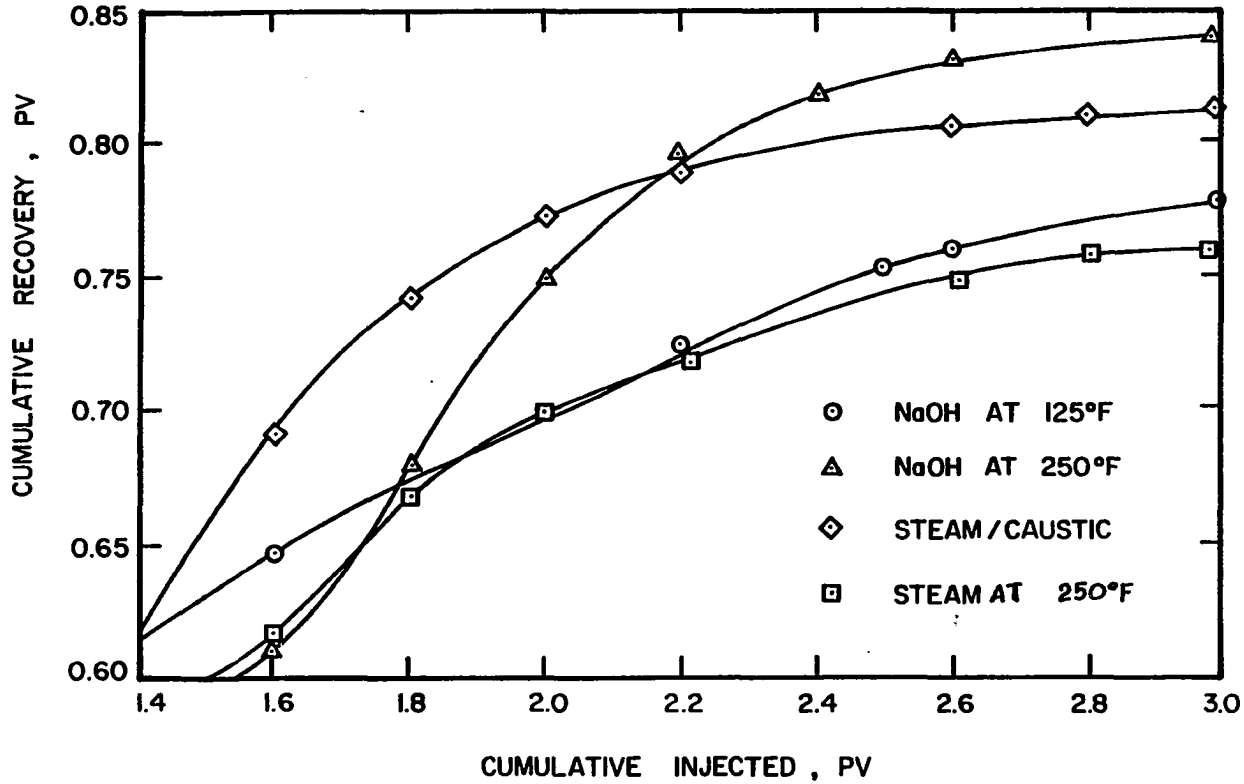

Figure 11. The Effect of Temperature on Oil Recovery of Caustic Hot Water Flood Compared to Steam Flood.

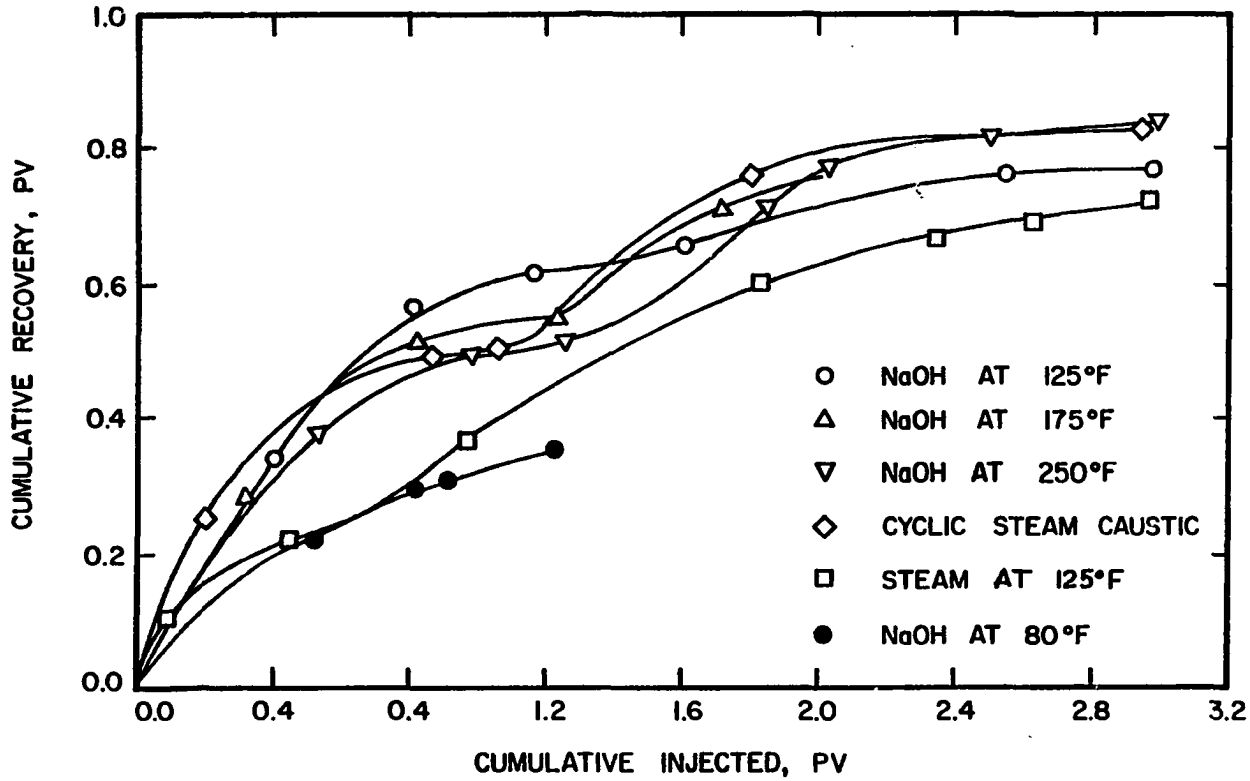

Figure 12. Oil Recovery Performance of Caustic Flood at Various Temperatures Compared to Steam Flood.

Evaluation and Comparison of Alkaline Steam Flood Types

While the process determination involved oil displacement from water flooded glass beadpacks with caustic solution and caustic steam, this phase of the investigation dealt with evaluation and comparison of various alkaline steam floods on sandpacks and Berea cores using process developed in case 2. Six displacement tests consisting of: conventional steam flood, NaOH (1 gm/ℓ)-steam flood, NaOH (1.5 gm/ℓ)-steam flood, Na_2CO_3 (1 gm/ℓ)-steam flood, Na_2SiO_3 (1 gm/ℓ)-steam flood and KOH (1 gm/ℓ)-steam flood were carried out on sandpacks. The core displacement tests involved all the aspects of sandpack tests except NaOH (1.5 gm/ℓ)-steam flood which was eliminated for ineffectiveness and KOH (1 gm/ℓ)-steam flood which, even though as effective as sandpack test no. 2, was considered not economical for field application.

Sandpack Displacement Tests

Tables 3 and 4 contain the summaries of the saturation and oil recovery results as a percentage of oil in place respectively for the six sandpack tests. During the water flooding phase in each test, the residual oil saturation was maintained close to 50 percent in order partly to leave sufficient oil for the displacement mechanisms to operate on and partly to have the six different floods sweep approximately the same pore volume of residual oil. This approximate water flood oil recovery of 50 percent of the pore volume was realized at about water-oil ratio of 35.

Conventional steam flood recovered 50.48 percent of initial oil in place following water flood recovery of 39.62 percent of the original oil in place. The total oil recovery from these two processes was 90.1 percent of the initial oil in place.

TABLE 3: SATURATIONS (Based on Pore Volume)

Types of Tests on Sand Pack	Initial Water Saturation	Initial Oil Saturation	After Water Flooding Saturations		After Alkaline Steam Flooding Saturations		After Steam Flooding Saturations	
	S_{wi}	S_{oi}	S_w	S_{or}	S_w	S_{or}	S_w	S_{or}
Conventional Steam Flooding	19.05	80.95	51.2	48.88			92.0	8.0
Alkaline Steam Flooding (0.1% by wt of NaOH)	14.9	85.08	47.76	52.24	99.225	.775		
Alkaline Steam Flooding (0.15% by wt of NaOH)	27.41	72.59	51.81	48.19	67.76	32.24		
Alkaline Steam Flooding (0.1% by wt of Na_2CO_3)	15.95	84.05	50.26	49.74	87.93	12.07		
Alkaline Steam Flooding (0.1% by wt. of Na_2SiO_3)	16.9	83.1	51.21	48.79	99.31	0.69		
Alkaline Steam Flooding (0.1% by wt. of KOH)	14.92	85.08	47.76	52.24	99.23	0.775		

TABLE 4: OIL RECOVERY RESULTS

Oil Recovery as a Percentage of Initial Oil in Place

Type of Tests on Sand Pack	Water Flooding	Conventional Steam Flooding	Alkaline Steam Flooding	Total Recovery
Conventional Steam Flooding	39.62	50.48		90.10
Alkaline Steam Flooding (0.1% by wt NaOH)	38.60		60.49	99.09
Alkaline Steam Flooding (0.15% by wt NaOH)	33.6		21.97	55.57
Alkaline Steam Flooding (0.1% by wt Na_2CO_3)	40.82		44.82	85.64
Alkaline Steam Flooding (0.1% by wt Na_2SiO_3)	41.29		57.99	99.28
Alkaline Steam Flooding (0.1% by wt KOH)	29.98		68.48	98.46

NaOH (1 gm/ℓ)-steam flood recovered 60.49 percent of initial oil in place after water flood had recovered 38.6 percent of initial oil in place. The total oil recovered in this oil recovery scheme was 99.1 percent of initial oil in place.

In the test 3 which involved NaOH(1.5 gm/ℓ)-steam flood, water flood recovered 33.6 percent of oil in place while the caustic steam flood recovered only 21.97 percent of oil in place. The performance of caustic steam flood at this concentration of caustic soda was far below expectation and resulted in the re-evaluation of the effect of alkaline concentration on oil recovery performance in connection with this process. To this end, various portions of caustic solution concentrations were agitated in test tubes with portions of oil sample to induce oil-water emulsion. It was observed that caustic solution would not form stable emulsion with the sample oil at certain caustic concentrations including 1.5 gm/ℓ. The most stable emulsion was obtained at caustic concentrations of 1 gm/ℓ and 2 gm/ℓ. Based on oil-caustic solution interfacial tension value shown in figures 20 and 22 test no. 3 should have performed quite well. The total oil recovered in this test was only 55.57 percent of initial oil in place. Several pore volumes of regular steamwere injected in an effort to recover more oil, all to no avail. Further discussion of test no. 3 will be undertaken in the next section.

In test 4, water flood recovered 40.82 percent of oil in place while Na_2CO_3-steam flood yielded additional 44.82 percent of initial oil in place. The total oil recovery in this test amounted to 85.64 percent of original oil in place. The concentration of Na_2CO_3 did not significantly increase the pH of the alkaline solution above 1 gm/ℓ. The difference between the pH of

Na_2CO_3 at the concentration of 1 gm/ℓ and 8 gm/ℓ was 0.17 and hence 1 gm/ℓ concentration was used as steam additive in this test. Na_2CO_3 solution would not form a stable emulsion at the considered concentrations when agitated in test tubes with portions of the sample oil. The produced alkaline fluid was, however, highly emulsified and quite stable.

Water flood recovered 41.29 percent of initial oil in place in test 5 and Na_2SiO_3 - steam flood recovered 57.99 percent of initial oil in place adding up to a total oil recovery of 99.28 percent of original oil in place. The performance of sodium silicate steam flood was therefore, as impressive as caustic steam flood. The concentration of sodium silicate solution was not a factor in this scheme because sodium silicate is only slightly soluble in water--less than 0.1 gm/ℓ. The maximum pH attainable with super saturated solution of sodium silicate was 10.53. The test tube test for oil-alkaline emulsion did not produce stable emulsion with this chemical but the produced sodium silicate solution was highly and stably emulsified with oil.

In test 6, water flood recovered about 30 percent of oil in place while KOH (1 gm/ℓ)-steam flood produced 68.48 percent more of initial oil in place to enhance the overall oil recovery to 98.46 percent of original oil in place. The concentration of 1 gm/ℓ of potassium hydroxide when agitated with the oil sample in a test tube easily formed a stable emulsion. The effect of KOH solution concentration on KOH-oil emulsification was found to be similar to that of sodium hydroxide solution. Also, the oil recovery ability of KOH-steam flood was comparable to NaOH-steam flood and Na_2SiO_3-steam flood. Since potassium hydroxide is several times more expensive than sodium hydroxide and sodium silicate, KOH-steam flood may be uneconomical.

Figure 14 contains the plots of steam oil ratio versus oil recovery for each of the six displacement tests involving the sandpacks. All the steam floods were essentially terminated at or above steam oil ratio of 60. On several occasions, as can be seen from tables B1 to B6, the steam oil ratio jumped above 80 shortly after a steam breakthrough. These high steam oil ratio points were not included in the graphs because they exceeded the scale.

The performance curves for conventional steam flood and all of the alkaline steam flood sandpack tests are shown in figure 15. From these plots of cumulative recovery as a percentage of initial oil in place versus cumulative injected pore volume it can be seen that NaOH (1 gm/ℓ)-steam flood, Na_2SiO_3-steam flood and KOH-steam flood recovered almost 100 percent of the remaining oil after water flooding. Combined with the recovery from water flood, conventional steam flood recovered about 90 percent of original oil in place. In effect, these three alkali used separately as chemical additives in steam flood recovered about 9 percent more oil in sandpacks than conventional steam flood.

Figure 16 contains the performance curves for sandpacks involving three water floods followed by conventional steam flood, NaOH (1 gm/ℓ)-steam flood and NaOH (1.5 gm/ℓ)-steam flood in each respect. NaOH (1.5 gm/ℓ)-steam flood recovery performance was very poor in spite of 8 pore volumes of alkaline injected. About three pore volumes of regular steam was injected thereafter, without recovering any additional oil. The produced fluid during the injection of most of the 8 alkaline pore volumes was highly emulsified but yielded essentially water and dregs when the emulsion was broken.

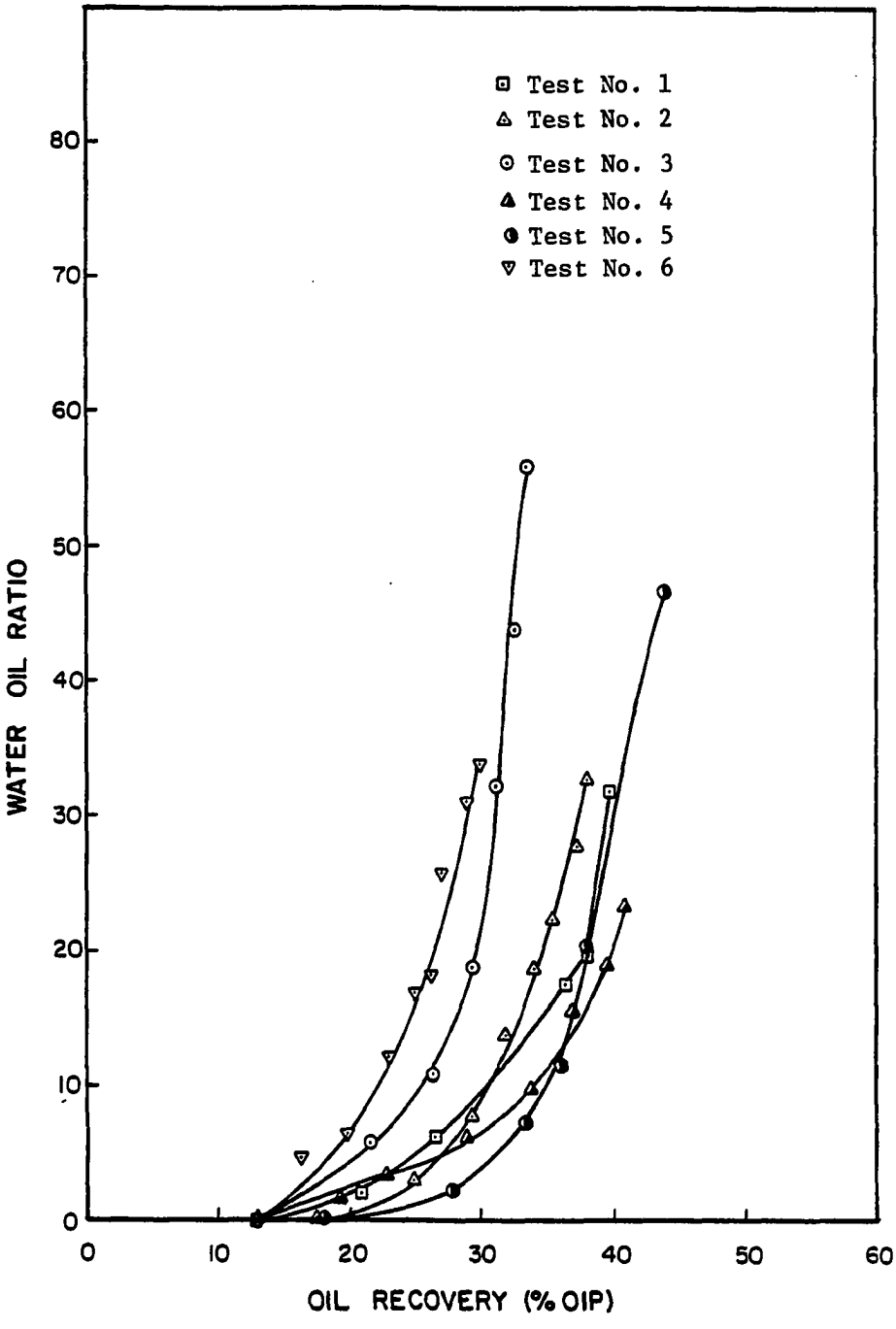

FIGURE 13. Water Oil Ratio versus Oil Recovery for Sandpack Water Floods.

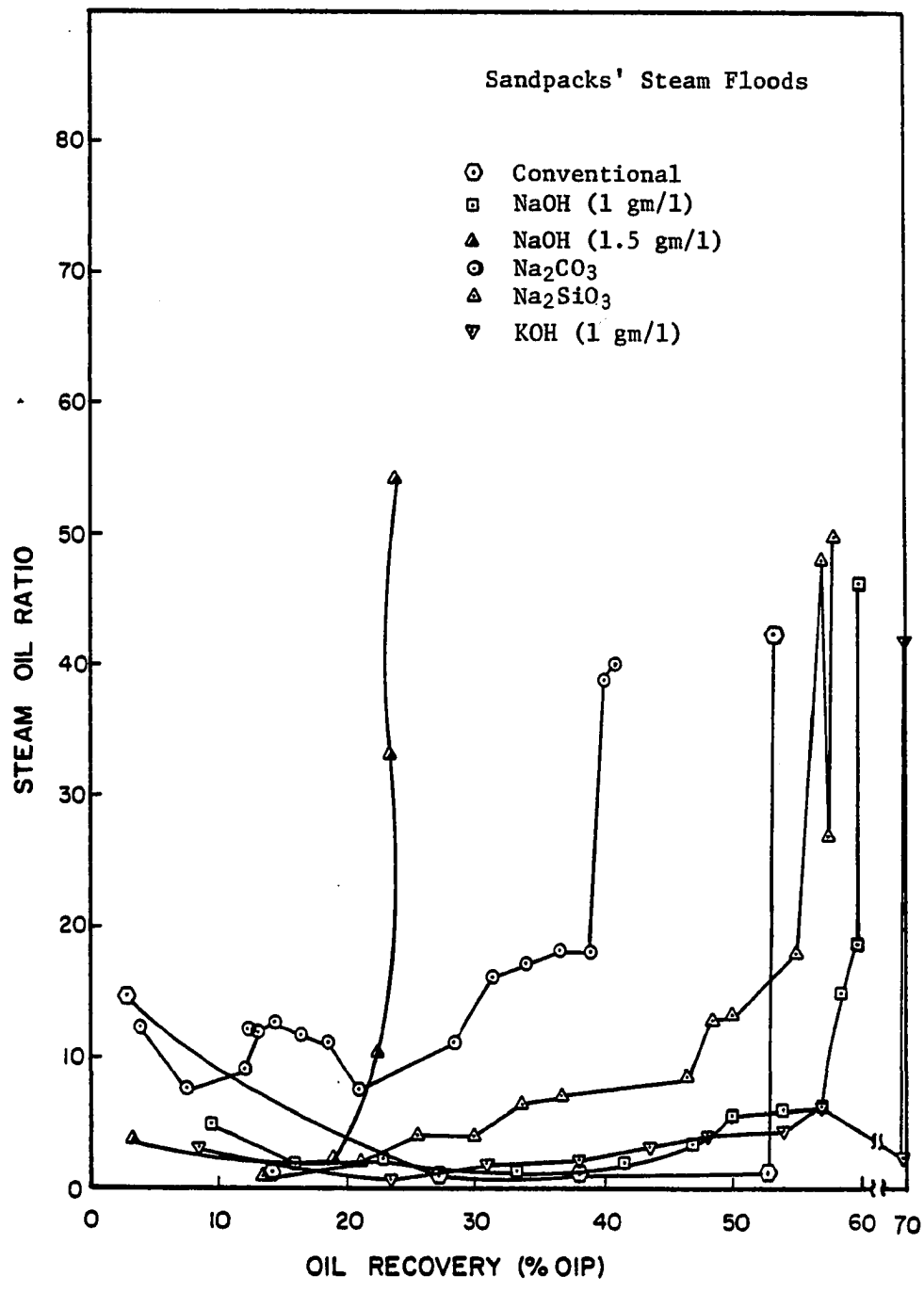

FIGURE 14. Steam Oil Ratio Versus Oil Recovery for Sandpacks' Steam and Alkaline Steam Floods.

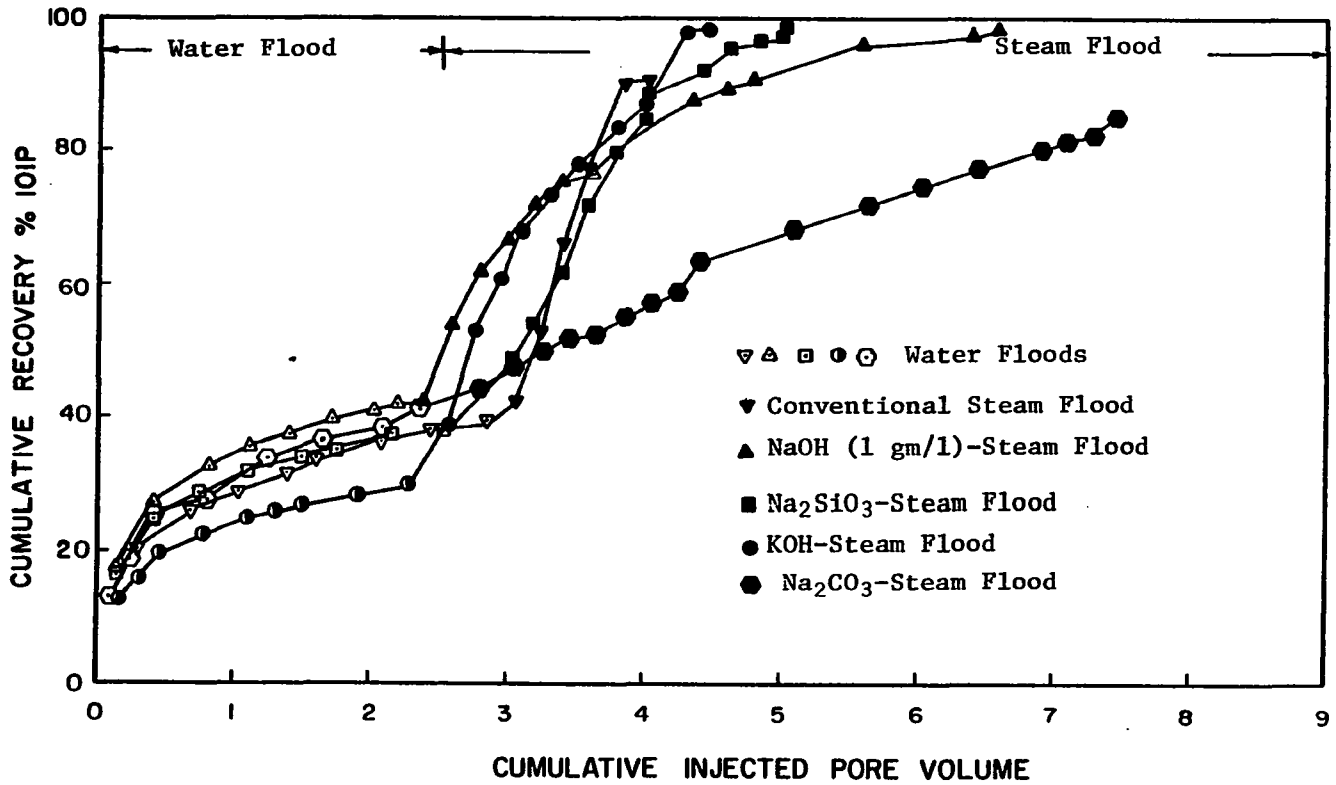

FIGURE 15. Comparison of Oil Recovery Performance for Sandpacks' Water Floods, Steam and Alkaline Steam Floods.

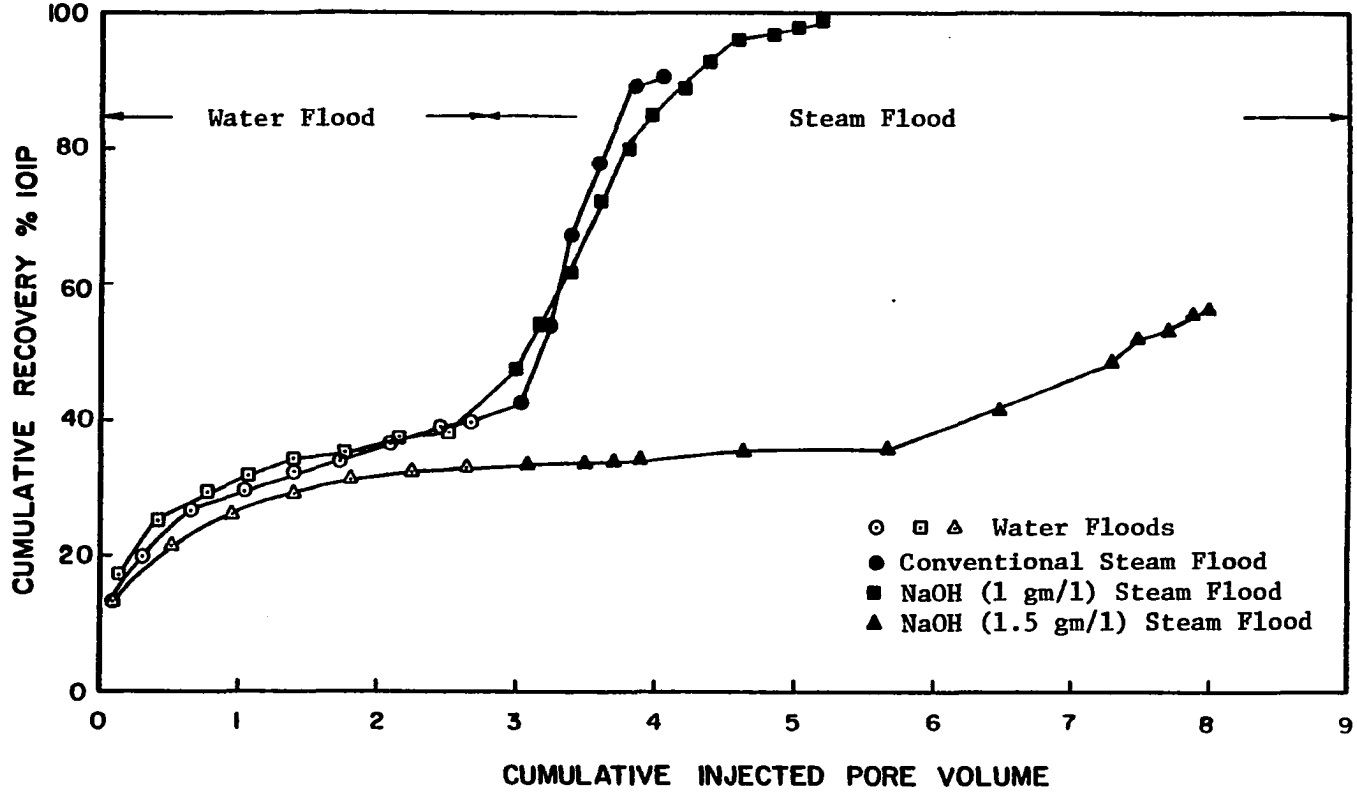

FIGURE 16. Comparison of Oil Recovery Performance for Steam Flood and Varying Concentrations of Caustic Steam Floods.

Berea Core Displacement Tests

Tables 5 and 6 contain the summaries of the saturation and oil recovery as a percentage of oil in place values, respectively. In figure 17, the average water flood water oil ratio for the core tests except test no. 2 was 25. In order to achieve an average water flood oil recovery, the water oil ratio in test no. 2 happened to be 41.

The initial water and oil saturation values for tests 1 through 3 were very close while, although test 4 values were slightly off, about the same percentage of oil in place (40) was recovered in all four tests by water flood.

In test no. 1 water flood recovered 42.02 percent of initial oil in place while conventional steam flood displaced additional 26.12 percent of original oil in place. The total oil recovered in this experimental test was 68.14 percent of oil in place.

Test no. 2 involved water flood which recovered 41.11 percent of initial oil in place and NaOH (1 gm/ℓ)-steam flood which produced 37.22 percent more of initial oil in place. The total oil recovery was 78.33 percent of oil in place.

Water flood process recovered 40.76 percent of initial oil in place in test no. 3 and Na_2CO_3-steam flood yielded only 24.46 percent more of original oil in place for a total oil recovery of 65.22 percent of initial oil in place.

Finally, in test no. 4, water flood produced 39.24 percent of initial oil in place. Na_2SiO_3-steam flood which followed thereafter recovered additional 35.44 percent of original oil in place. The total oil recovery in this test was 74.64 percent of initial oil in place.

TABLE 5: SATURATION VALUES (Based on Pore Volume)

Types of Tests on Berea Core	Initial Water Saturation	Initial Oil Saturation	After Water Flooding Saturations		After Alkaline Steam Flooding Saturations		After Steam Flooding Saturations	
	S_{wi}	S_{oi}	S_w	S_{or}	S_w	S_{or}	S_w	S_{or}
Conventional Steam Flooding	30	70	59.41	40.59			77.7	22.3
Alkaline Steam Flooding (0.1% by wt NaOH)	28.46	71.54	57.9	42.1	84.5	15.5		
Alkaline Steam Flooding (0.1% by wt Na_2CO_3	26.87	73.13	56.68	43.32	74.56	25.44		
Alkaline Steam Flooding (0.1% by wt Na_2SiO_3	37.21	62.79	61.85	38.15	84.1	15.9		

TABLE 6: OIL RECOVERY RESULTS

Oil Recovery as a Percentage of Initial Oil in Place

Type of Tests on Berea Core	Water Flooding	Conventional Steam Flooding	Alkaline Steam Flooding	Total Recovery
Conventional Steam Flooding	42.02	26.12		68.14
Alkaline Steam Flooding (0.1% by wt NaOH)	41.11		37.22	78.33
Alkaline Steam Flooding (0.1% by wt Na_2CO_3)	40.76		24.46	65.22
Alkaline Steam Flooding (0.1% by wt Na_2SiO_3)	39.24		35.44	74.68

From these results summarized in tables 5 and 6, test no. 2 involving caustic steam flood recovered about 10 percent more oil than test no. 1 which involved steam flood. While sodium silicate-steam flood recovered about 6.5 percent more oil than regular steam flood, it did not perform as well in core test compared to caustic steam flood as it did in sandpack. Plugging might have partly accounted for this because the steam drive pressure drops, contained in table B 10, were quite high. The average steam pressure drop in this test was 1000 psi which was about three times as high (366 psi) as in test no. 2, the summary of which is shown in table B 8, and about 23 times as high as in test no. 1 (44 psi) contained in table B 7. Test no. 3 steam pressure drop contained in table B 10, was also quite high, averaging about 1600 psi. The resistance to flow signified by high pressures did not seem to have seriously affected the performance of Na_2SiO_3-steam flood even though the recovery was about 4 percent below NaOH-steam flood but quite above regular steam flood.

Na_2CO_3-steam flood did not perform as well in core test, just as in sandpack test, compared to all the other tests. A common feature of Na_2SiO_3-steam flood and Na_2CO_3-steam flood was, therefore, high pressure drops caused probably by some plugging induced primarily by the flow of high viscosity fluid and probably by precipitation of some insoluble salts. Inducement of emulsion by alkaline oil reaction and subsequent increase in injection pressure was also evident in NaOH-steam flood as can be seen from the steam pressure which was about 10 times higher than that of the regular steam flood.

Figure 18 contains the plots of steam oil ratio versus oil recovery for the four core tests. The performance curves of the core tests water floods and the four types of steam floods are shown in figure 19. A clear

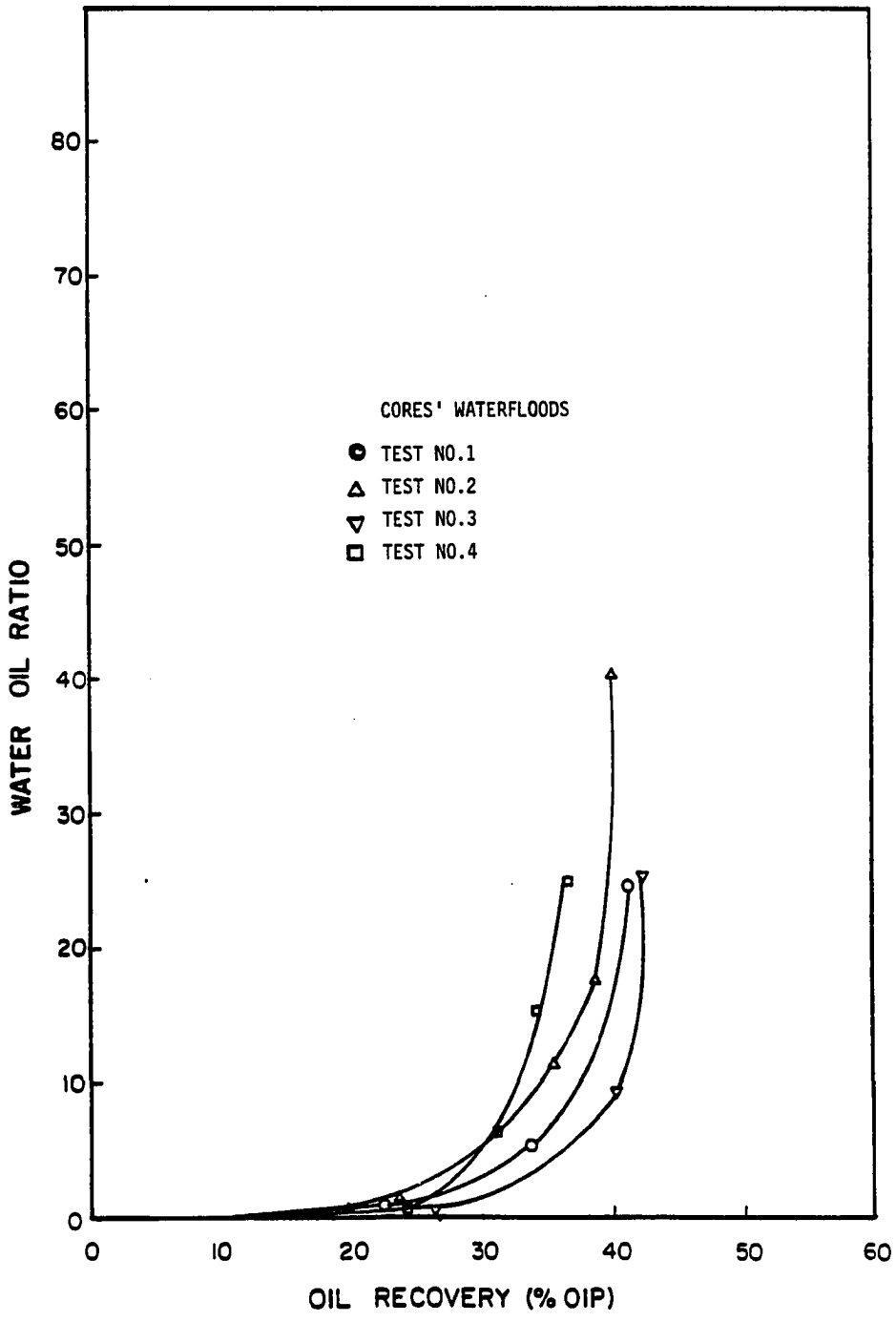

FIGURE 17. Water Oil Ratio versus Oil Recovery for Berea Core Water Floods.

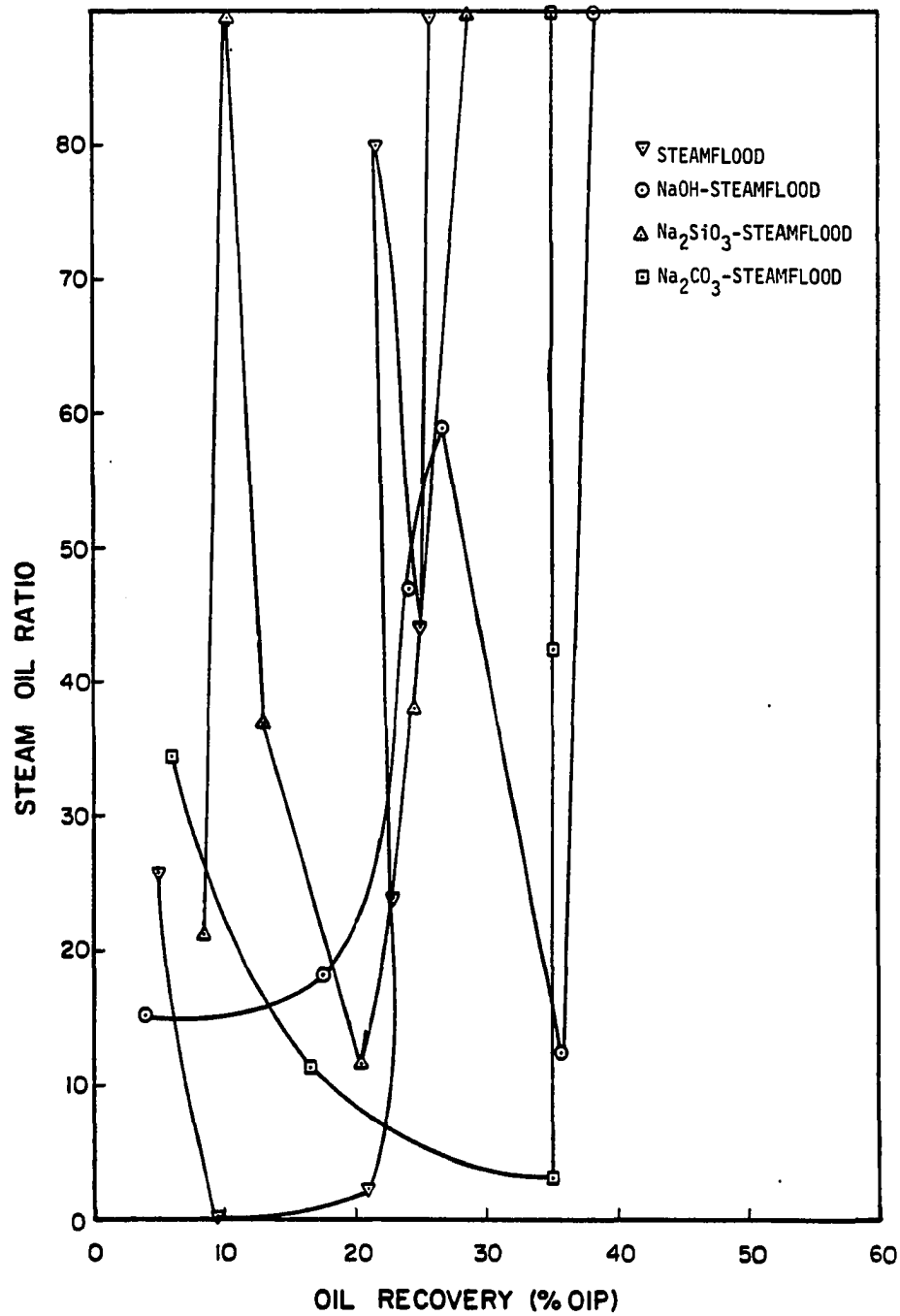

FIGURE 18. Steam Oil Ratio vs. Oil Recovery for Core Steam and Alkaline Floods.

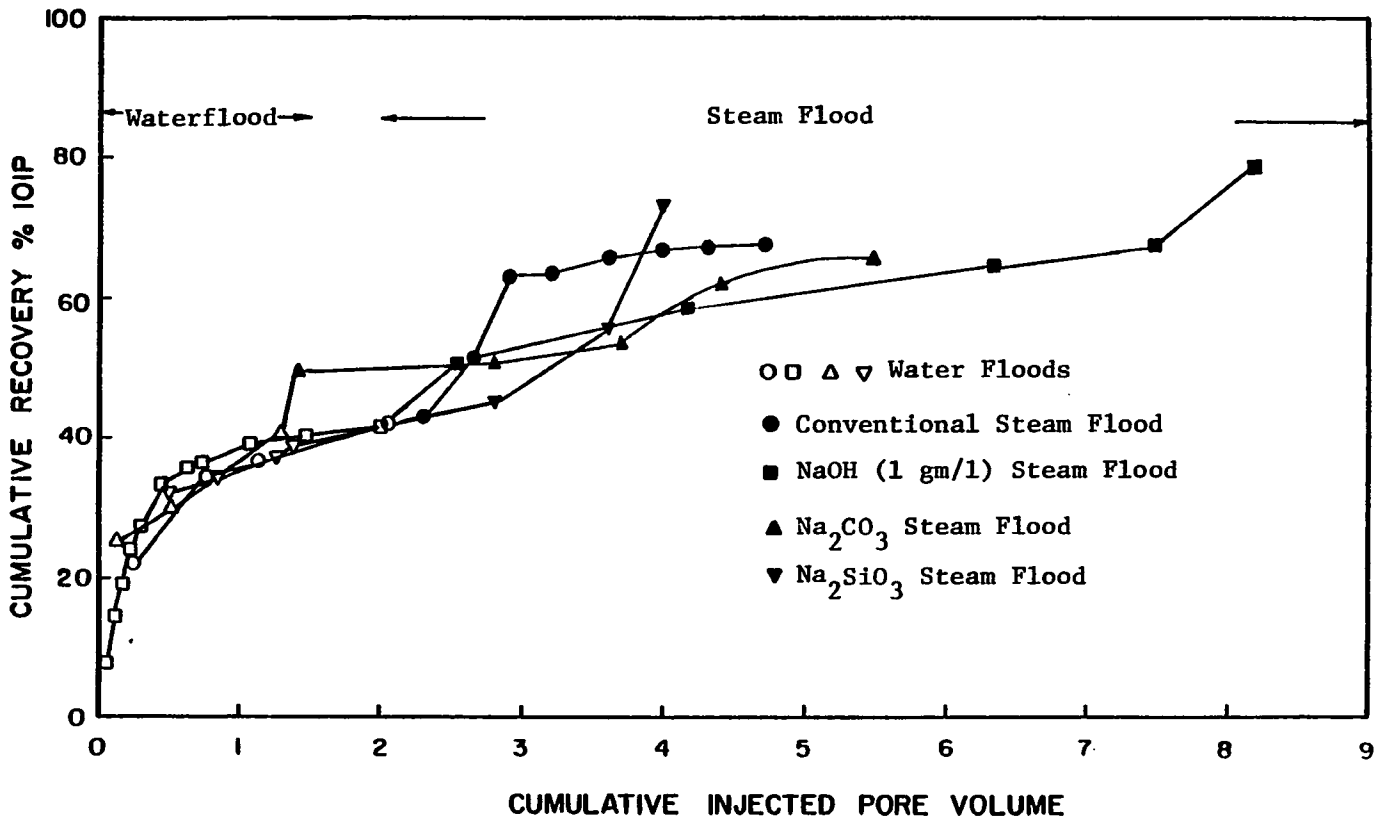

FIGURE 19. Comparison of Oil Recovery Performance for Core Water Floods, Steam and Alkaline Steam Floods.

feature of conventional steam flood, as can be observed from figures 15, 16 and 19, was the attainment of the maximum oil recovery after less pore volumes of fluid injection compared to all the alkaline steam floods. The primary reason for this was because the regular steam acquired superheat faster than the alkaline steam. This occurred because in the case of regular steam drive the steam generator put out saturated steam into the superheaters as opposed to other cases where cool alkaline was injected into the superheaters to be turned into steam and then superheated. While the procedure of generating alkaline steam was adequate for the main purpose, it tended to deliver wet steam for a while before the flow system and the core tube assembly acquired ambient temperature. Then, superheated steam was produced fairly steadily.

Displacement Mechanism Evaluation

While some of the other four broad mechanisms might have operated to some extent, the principal mechanism, as observed from the produced fluids, was emulsification and entrainment. The alkaline steam flood produced alkaline water and some of the oil were highly emulsified. The emulsion seemed to have been oil in water type because it produced several fold more water than oil after being broken. The presence of alkaline in the emulsion provided an easy emulsion breaking process. This consisted of adding small quantity of HCl and common salt to the emulsion and allowing some six to 12 hours for oil and water to separate. About 3 to 5 cc of 1 Normal HCl and a teaspoon of common salt will break a 500 cc emulsion.

The concentration of caustic solution was the determining factor in the inducement of spontaneous emulsion, for a given salt concentration, for caustic-oil system but apparently a non factor for Na_2SiO_3 and Na_2CO_3-

oil systems. Actually, the test tube scheme could not predict the formation of stable emulsions in the porous medium by these alkalines. As stated before, the KOH-oil system behaved practically similar to NaOH-oil system.

The saturation histories of the sandpacks and the core tests should dictate water-wet porous media. In all the tests, the water saturated porous medium which was subsequently oil saturated to residual water saturation was left overnight. This time could not have been sufficient, anyway, for the wettability of the system to change even if the oil contained oil-wetting chemicals. If, therefore, the alkali altered wettability during the displacement test, it would have been from water-wet to oil-wet. There was, however, no evaluation of possible wettability change in this experimental study.

As stated several times in the discussion of the proposed mechanisms of alkaline water flooding, interfacial tension reduction is a feature of all the four broad mechanisms. Thus, in these studies considerable attention was given to evaluating the oil-alkaline water interfacial tension for both fresh samples and produced samples.

Figure 20 contains the plots depicting the effect of temperature on the interfacial tension of varying caustic soda concentration of NaOH-oil system. All the concentrations examined had substantial interfacial tension reducing effect on the oil starting at room temperature and attaining min-mum values close to steam temperature. The concentration of caustic affected the interfacial tension reducing ability more significantly at lower temperatures than at high temperatures. The fact that the caustic solution interacted with the oil at varying temperatures in porous medium before steam breakthrough would make substantial difference

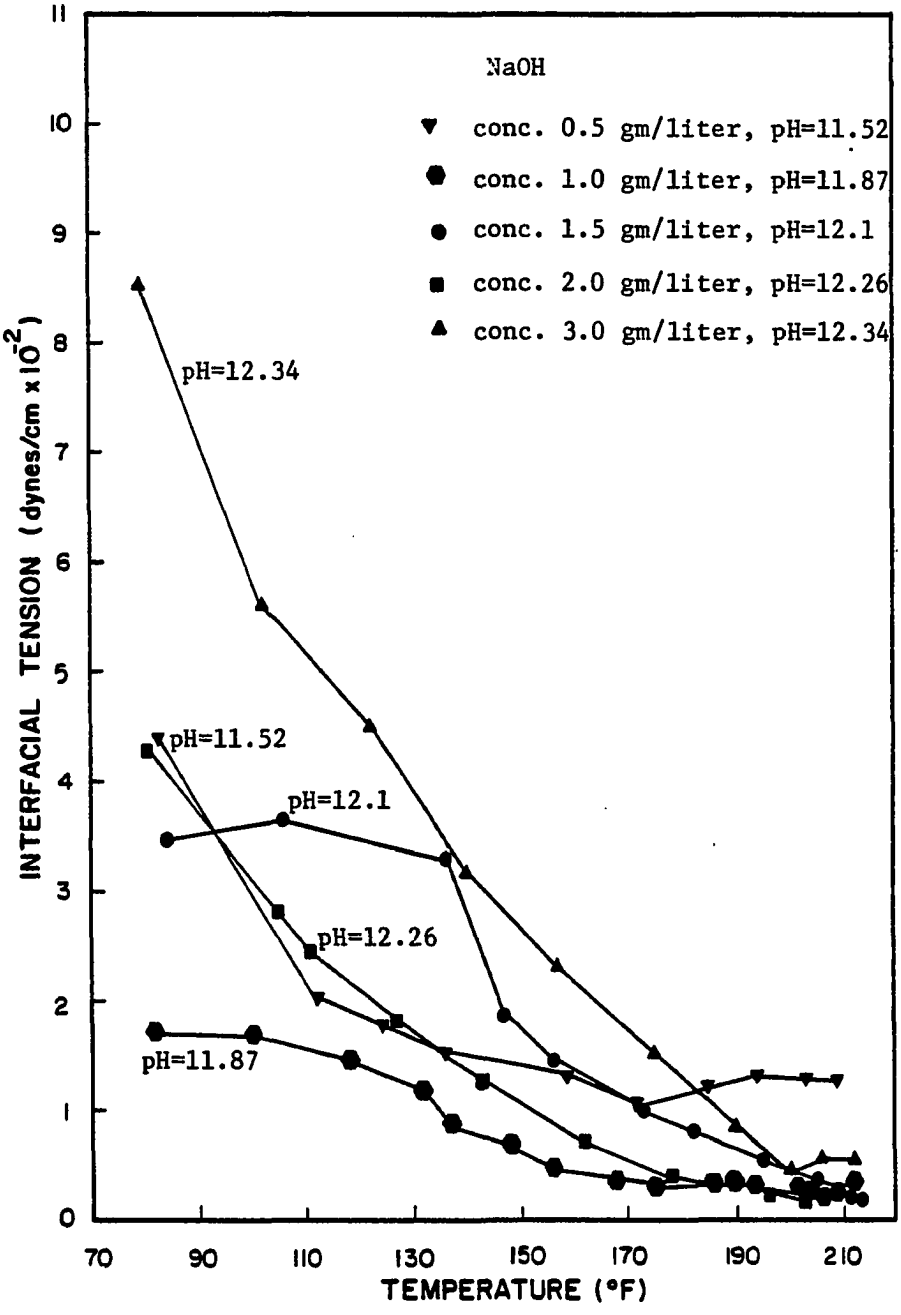

FIGURE 20. The Effect of Temperature on the Interfacial Tension of Varying Caustic Soda Concentration of Sodium Hydroxide-Oil System.

in interfacial tension reduction with temperature important. The most effective concentration (1 gm/ℓ) in terms of oil displacement performance, gave the lowest interfacial tension value of .017 dynes/cm at room temperature than all the others. At steam temperature this value decreased to .003 dynes/cm but the low of .0025 dynes/cm was achieved at 196°F. Figures 21 shows the graphs of comparison between temperature interfacial tension relationship of the original oil-caustic system and produced oil-caustic system. Clearly from this graph the produced fluids had higher interfacial tension values than the fresh fluids. This was expected because adsorption and consumption reduced the pH of the produced fluids in both sandpack and core tests. The core test pH value was the lowest of the three and gave the highest interfacial tension values at both low and high temperatures. It can be inferred, thus, that caustic-rock adsorption occurred more in the berea core than sandpack.

Figures 20 and 22 show the interfacial tension temperature relationship for NaOH (1.5 gm/ℓ)-oil system. It can be seen that even though the interfacial tension was low enough for both fresh and produced fluids, the recovery performance turned out to be very disappointing. Surely, the interfacial tension was lower for NaOH (1 gm/ℓ)-oil system than for NaOH (1.5 gm/ℓ)-oil system, but only marginally at low temperatures, and about equally at high temperatures. The failure of this high concentration caustic steam flood in spite of low interfacial tension reduction does support the observation by previous investigators[27,30] that low interfacial tension does not guarantee improved oil recovery in alkaline water flood. In this case, low IFT could not improve oil recovery in caustic steam flood.

Sodium silicate-oil system interfacial tension temperature relationship, shown in Figure 23, does not depict substantial reduction of

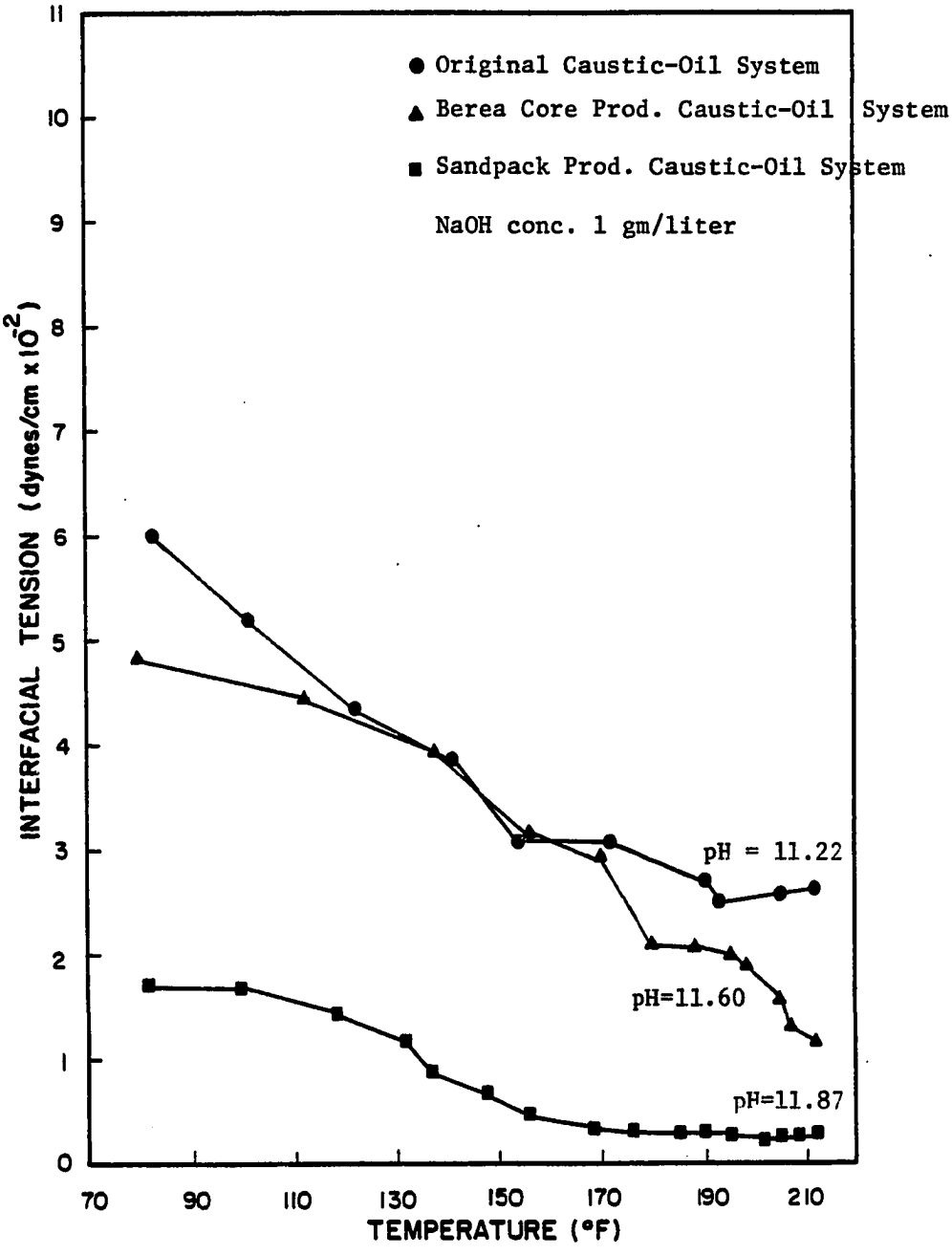

FIGURE 21. Comparison of the Effect of Temperature on the Interfacial Tension of the Original and Core and Sandpack Produced Oil-Caustic Solution Systems.

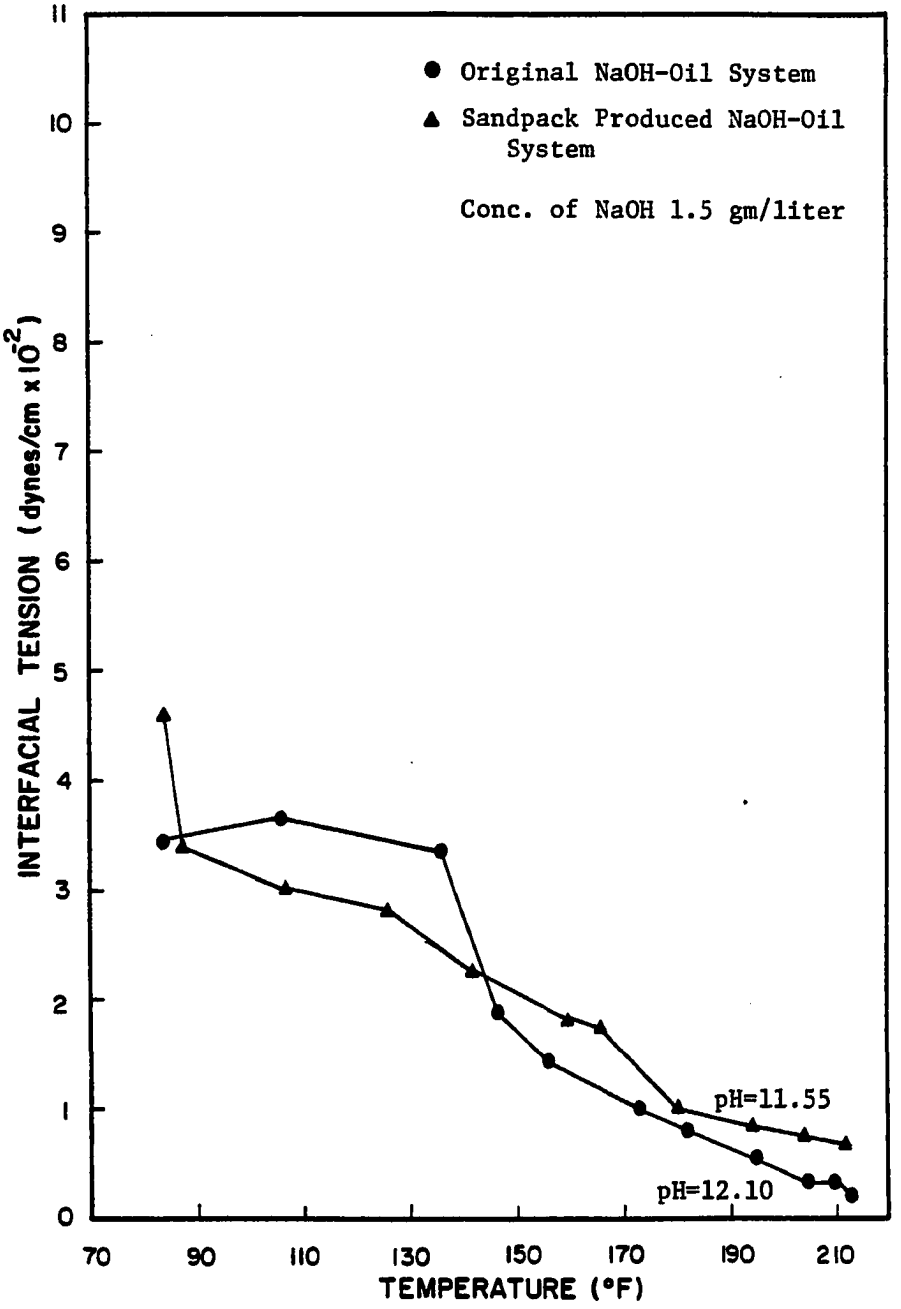

FIGURE 22. Comparison of the Effect of Temperature on the Interfacial Tension of the Original and Produced Oil-Caustic Solution Systems.

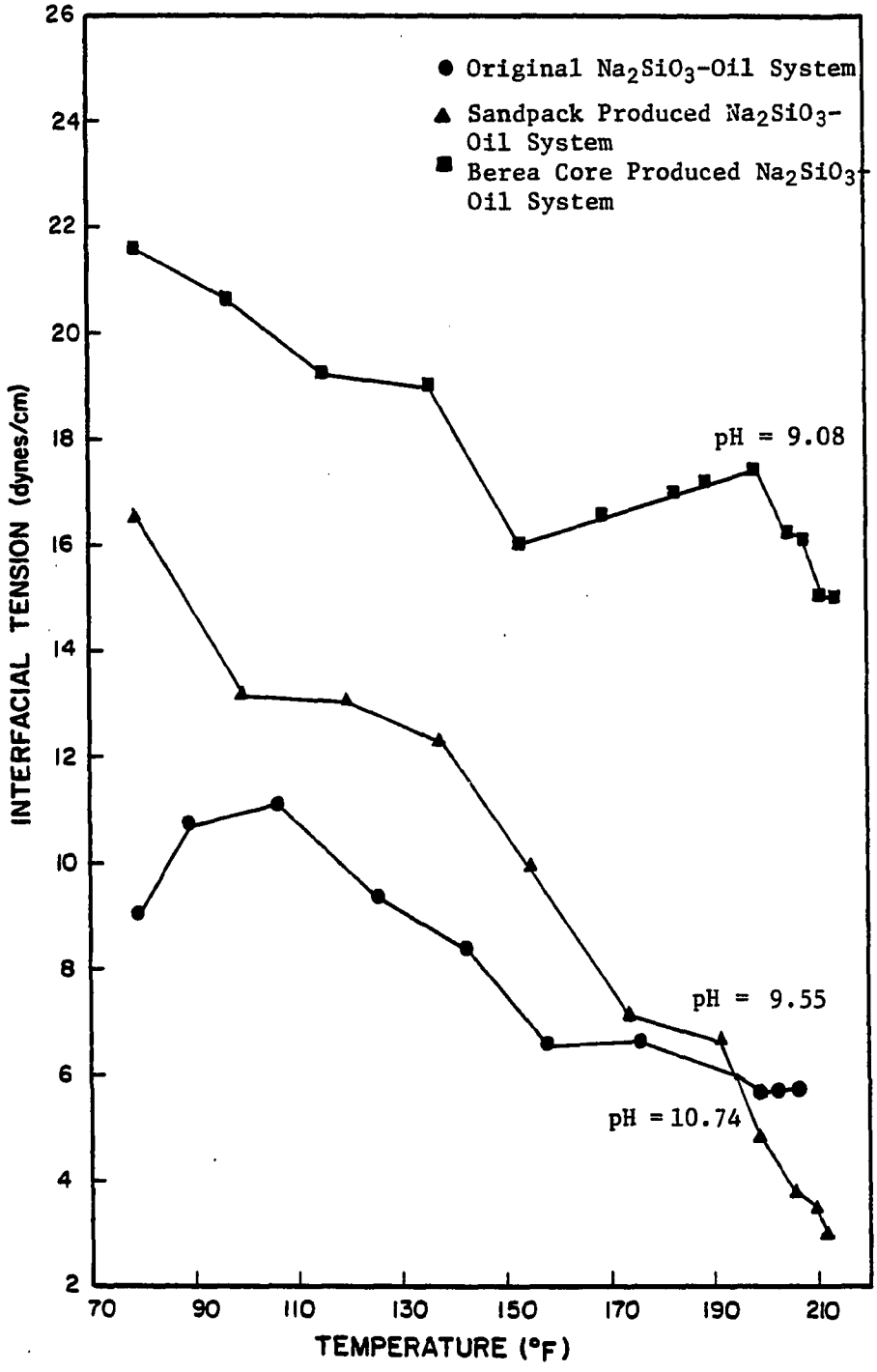

FIGURE 23. Comparison of the Effect of Temperature on the Interfacial Tension of the Original and Core and Sandpack Produced Oil-Na_2SiO_3 Solution Systems.

interfacial tension with temperature compared to the previous case discussed. The lowest values for IFT were realized as usual at high temperature near the steam temperature. For the fresh Na_2SiO_3-oil system the IFT at room temperature was 8.5 dynes/cm and 2.8 dynes/cm at steam temperature. In spite of just moderate IFT reduction, the recovery performances of Na_2SiO_3-steam flood were impressive for both sandpack and core tests. Particularly impressive was the sandpack test which recovered virtually all residual oil after water flood. In this situation, therefore, substantial reduction in IFT was not required for high oil recovery performance. Interfacial tension was, however, reduced by about 10 fold from ordinary water oil-oil system shown in Figure 26.

The results of high oil recovery ability of An_2SiO_3-steam flood, in spite of moderate reduction in interfacial tension, agrees with the contention of some investigators[27,28] that substantially improved oil recovery in alkaline water flood could be achieved at just moderate interfacial tension.

The produced fluids IFT, as expected, was higher than that of the fresh fluids. The core produced oil-water system pH was lower than that of the sandpack, indicating a greater alkaline adsorption in the core than in the sandpack. Accordingly, the sandpack produced fluids gave lower IFT than that of the core.

Figure 24 shows plots of the interfacial tension temperature relationship for Na_2CO_3-oil system for original fluids and produced fluids. The interfacial tension reduction of sodium carbonate solution was very moderate. It can be observed that this reduction was only by two fold of the ordinary water-oil system and that there was virtually no decrease in

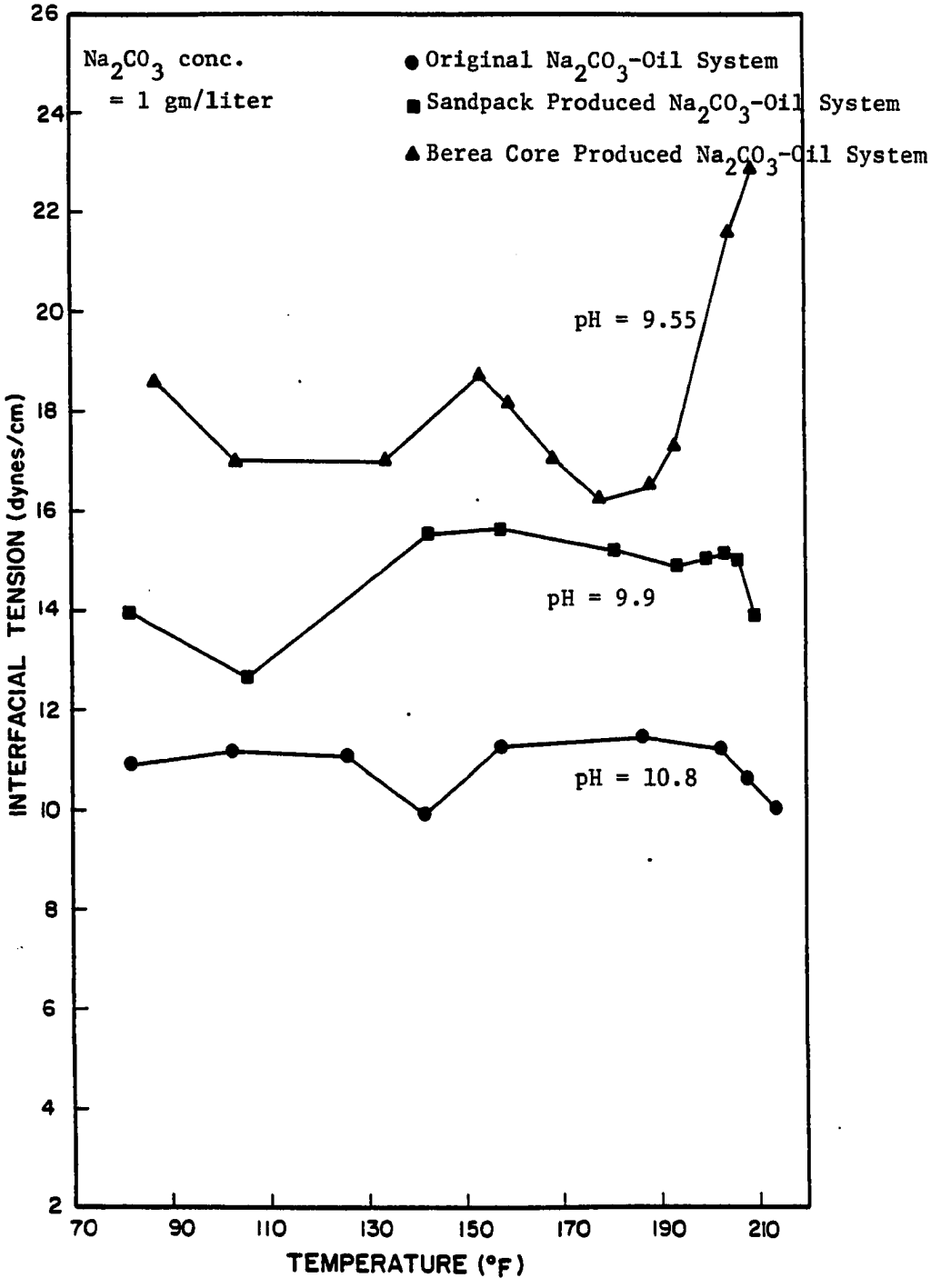

FIGURE 24. Comparison of the Effect of Temperature on the Interfacial Tension of the Original and Core and Sandpack Produced Oil-Na_2CO_3 Solution Systems.

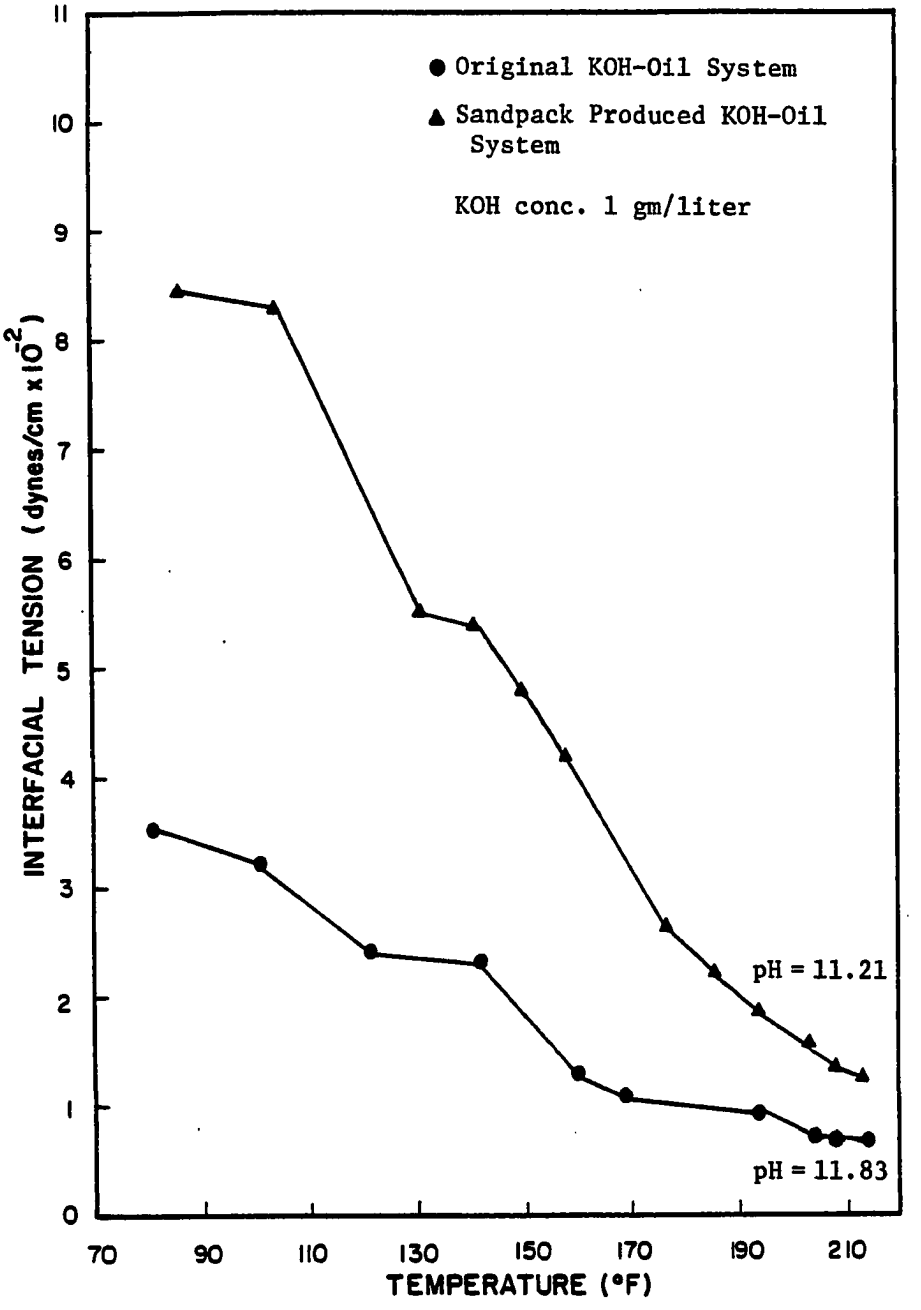

FIGURE 25. Comparison of the Effect of Temperature on the Interfacial Tension of the Original and Produced Oil-KOH Systems.

IFT with temperature increase. Actually, for both sandpack and core tests produced fluids, the IFT increased slightly with temperature for sandpack test and substantially with temperature for core test.

The interfacial tension results in these tests could have predicted the poor recoveries but as noted earlier, IFT cannot be the only factor. It does seem, however, from these tests that a minimum IFT is required for successful improved oil recovery by alkaline steam flood. This is also an impression shared by other investigators[27,28,30] for the case of alkaline water flood.

Figure 25 shows the graphs of IFT temperature relationship for fresh and produced KOH (1 gm/ℓ)-oil system. The IFT was reduced several fold just as was the case for caustic oil systems. As reported earlier, the oil recovery ability was similar to NaOH (1 gm/ℓ) steam flood.

Figure 26 shows the graphs of IFT-temperature relationship for distilled water-oil system and brine-oil system. Here it shows clearly that temperature does reduce interfacial tension to as low as 3.6 dynes/cm for brine-oil system and 5.75 dynes/cm for distilled water-oil system at steam temperature. At moderate hot water temperature (170°F) the reduction is only three fold. The ability of steam to reduce the interfacial tension at oil-water interface is of course one of the mechanisms by which steam enhances oil recovery in the contacted reservoir region.

It should be realized that the measurement of produced oil-alkaline solution interfacial tension at increasing temperature entailed repeated heating of fluids previously heated in the porous media. The effect of this secondary heating was evaluated by repeating the measurement of interfacial tension of samples that were originally fresh but became heated up

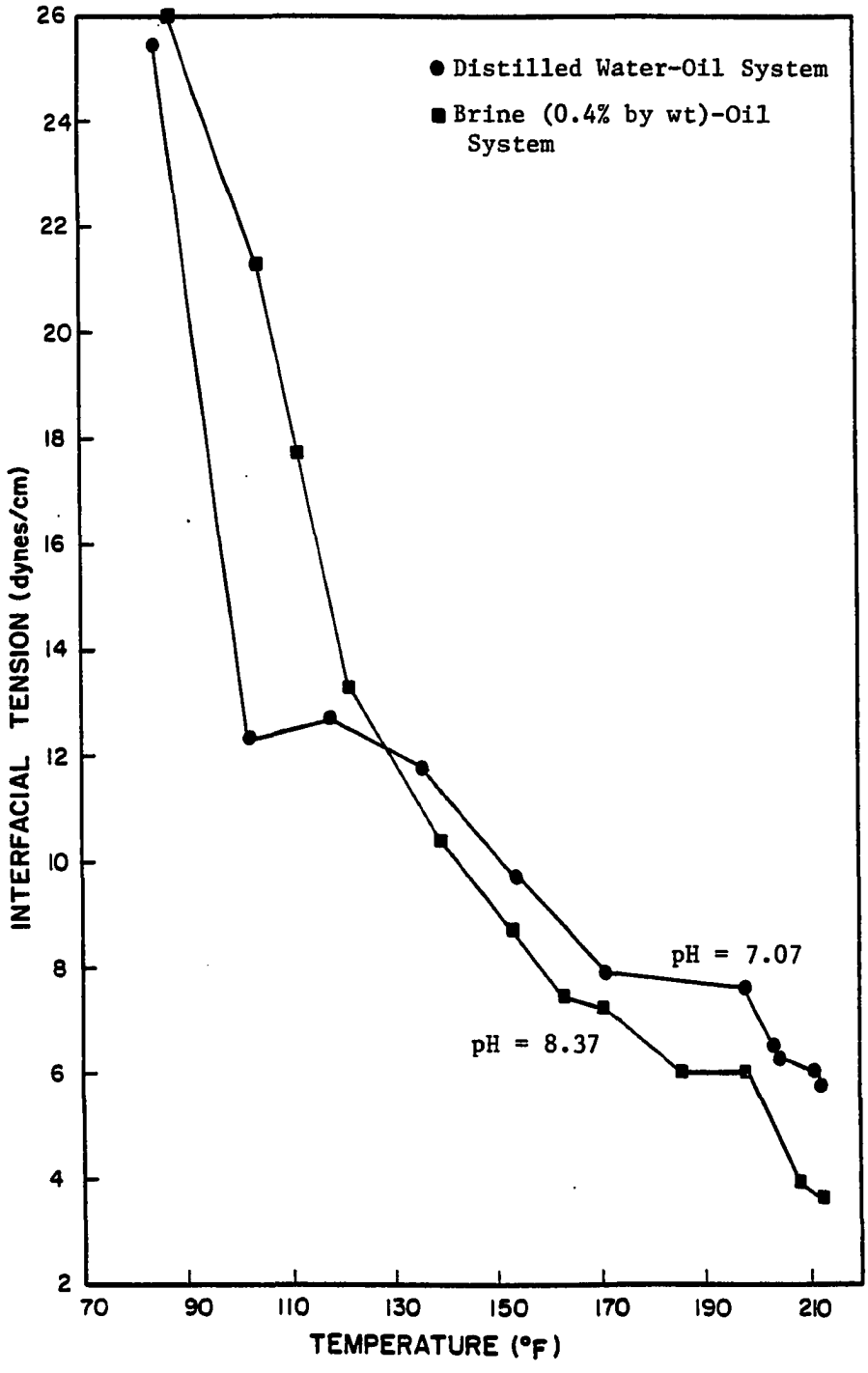

FIGURE 26. Comparison of the Effect of Temperature on the Interfacial Tension of Oil-Distilled Water and Oil-Brine Systems.

to 212°F during initial interfacial tension determination. The process of interfacial tension determination was repeated after cooling these samples. The result of these measurements showed that the interfacial tension of NaOH and KOH-oil system did not increase significantly with repeated heating. The Na_2SiO_3 and Na_2CO_3-oil system did not give a definite trend of increase or decrease. In any case, the change in interfacial tension with repeated heating was always insignificant.

Because the spinning drop interfaciometer could only measure the interfacial tension at atmospheric pressure, the effect of pressure on oil-alkaline interfacial tension could not be evaluated. Hassan et al.[46] investigating the effect of pressure and temperature on oil-water interfacial tensions, found that there was a slight decrease of interfacial tension with pressure at constant temperature. They also observed that the effect of pressure became less as the pressure increased with some indication of a reversal of the effect at higher pressures.

Comparison of Theoretical and Experimental Temperature Distribution Ahead of Advancing Steam Zone

Figures 27 to 32 show the plots of temperature versus distance for various time periods for the six sandpack tests in order. The points alternate starting from the bottom formation temperature to top formation temperature values. The figure for each test shows some high points on the plots during the early hours of the various types of steam floods. These points connected to form the upper plots are essentially for the top half of the formation temperatures. This feature clearly shows that there was a measure of gravity steam override even for small scale model reservoirs. With time, however, this phenomenon became insignificant, particularly near steam breakthrough.

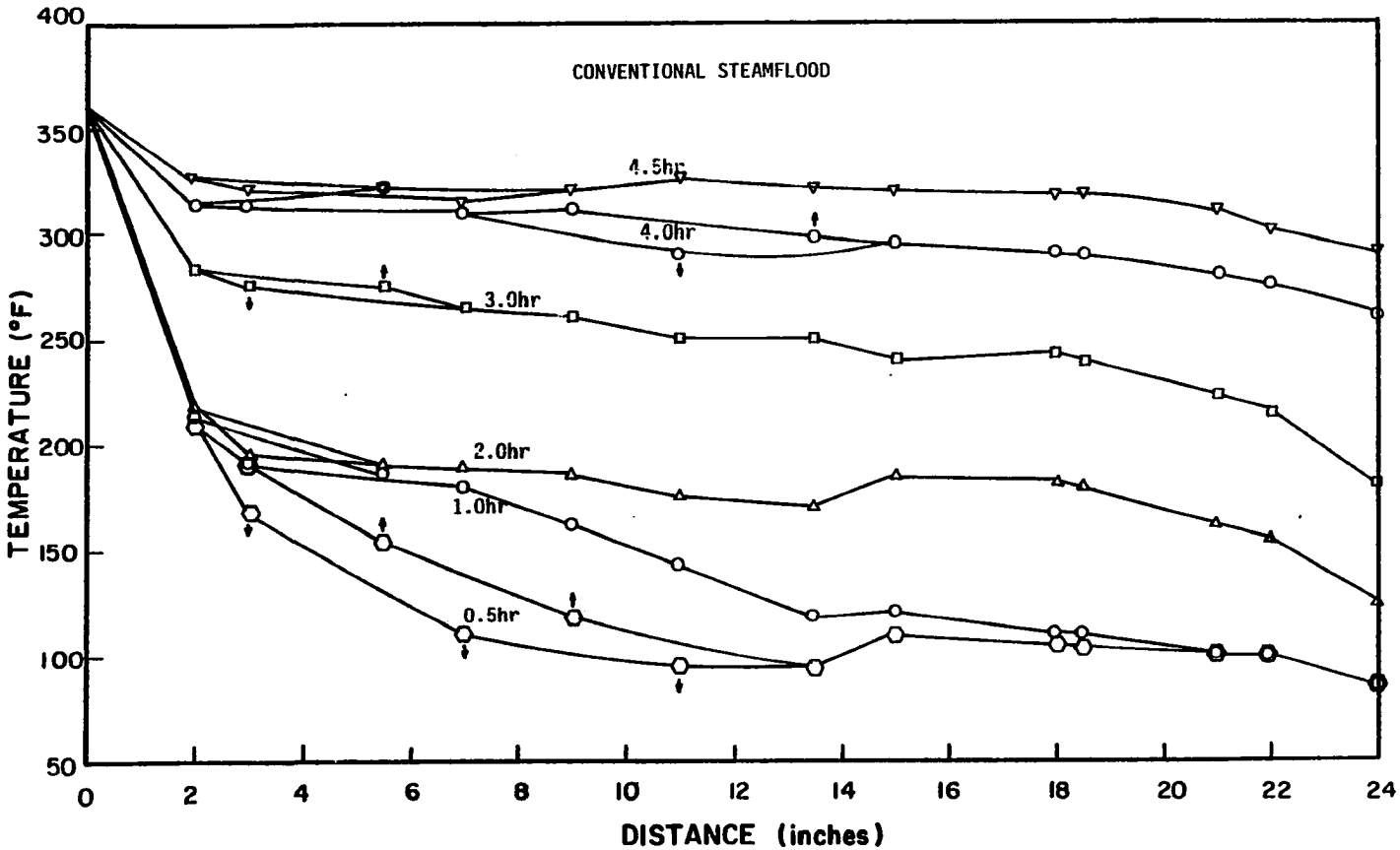

Figure 27. Temperature Distribution Ahead of the Advancing Steam Zone.

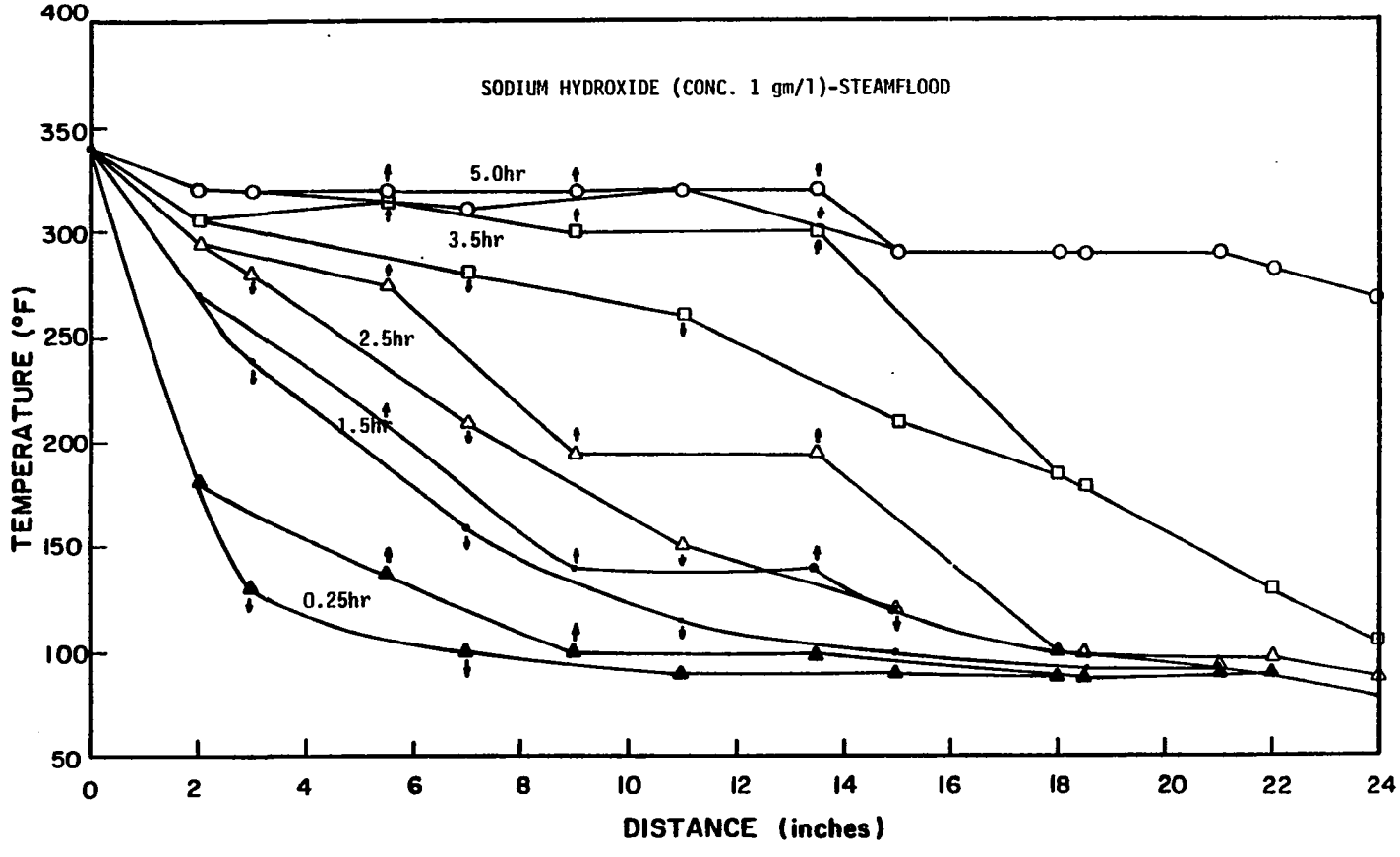

FIGURE 28. Temperature Distribution Ahead of the Advancing Steam Zone.

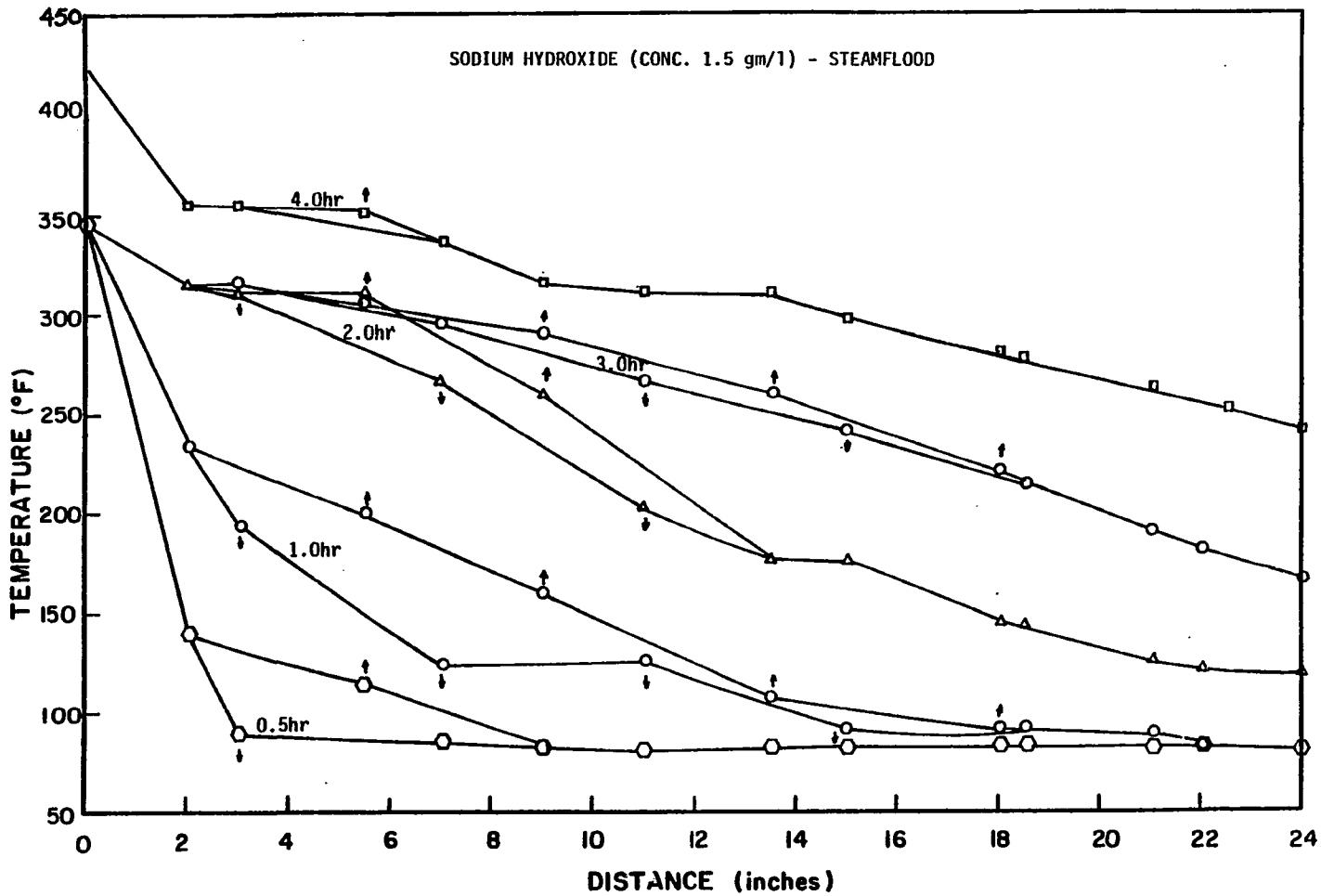

FIGURE 29. Temperature Distribution Ahead of the Advancing Steam Zone.

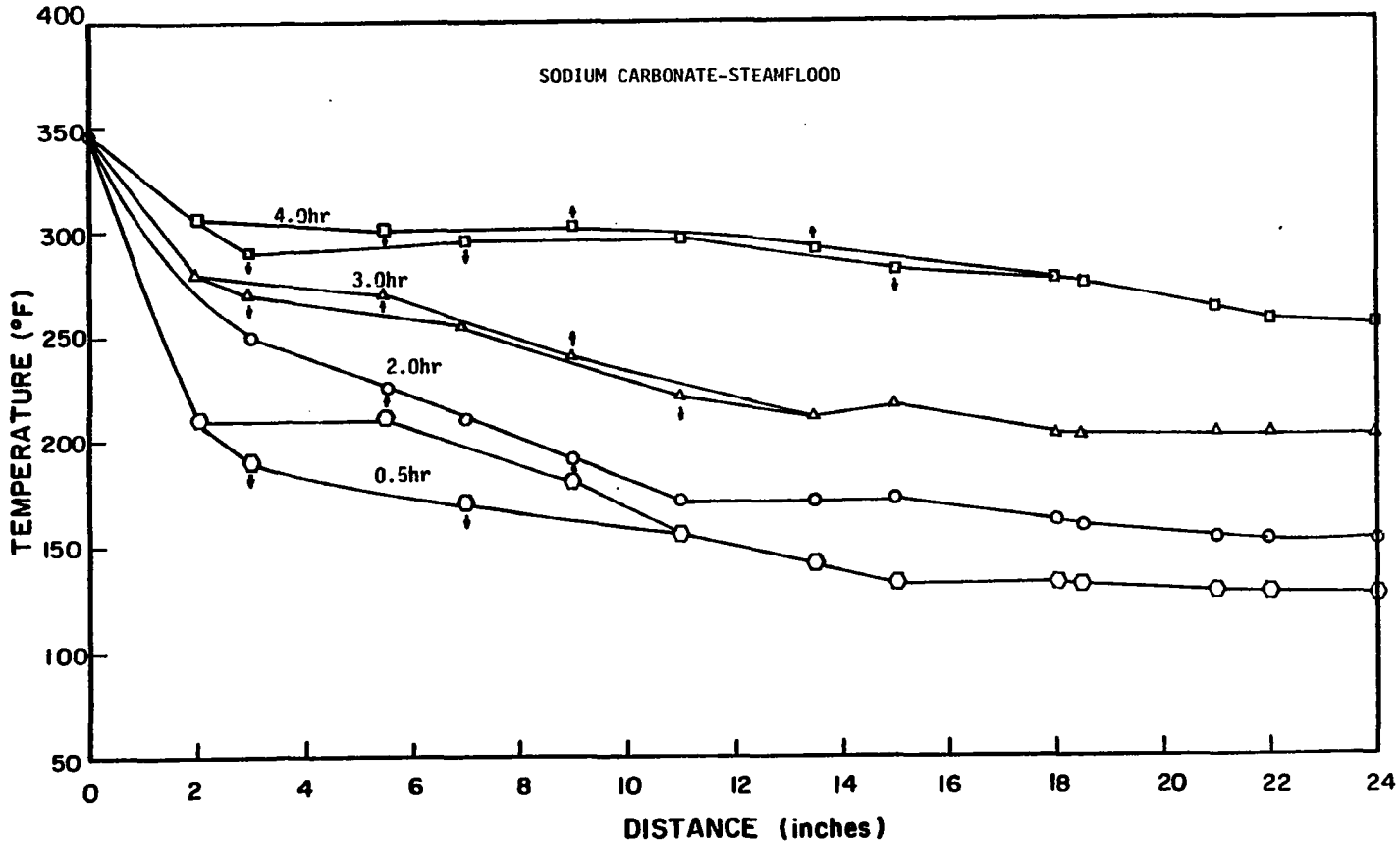

FIGURE 30. Temperature Distribution Ahead of the Advancing Steam Zone.

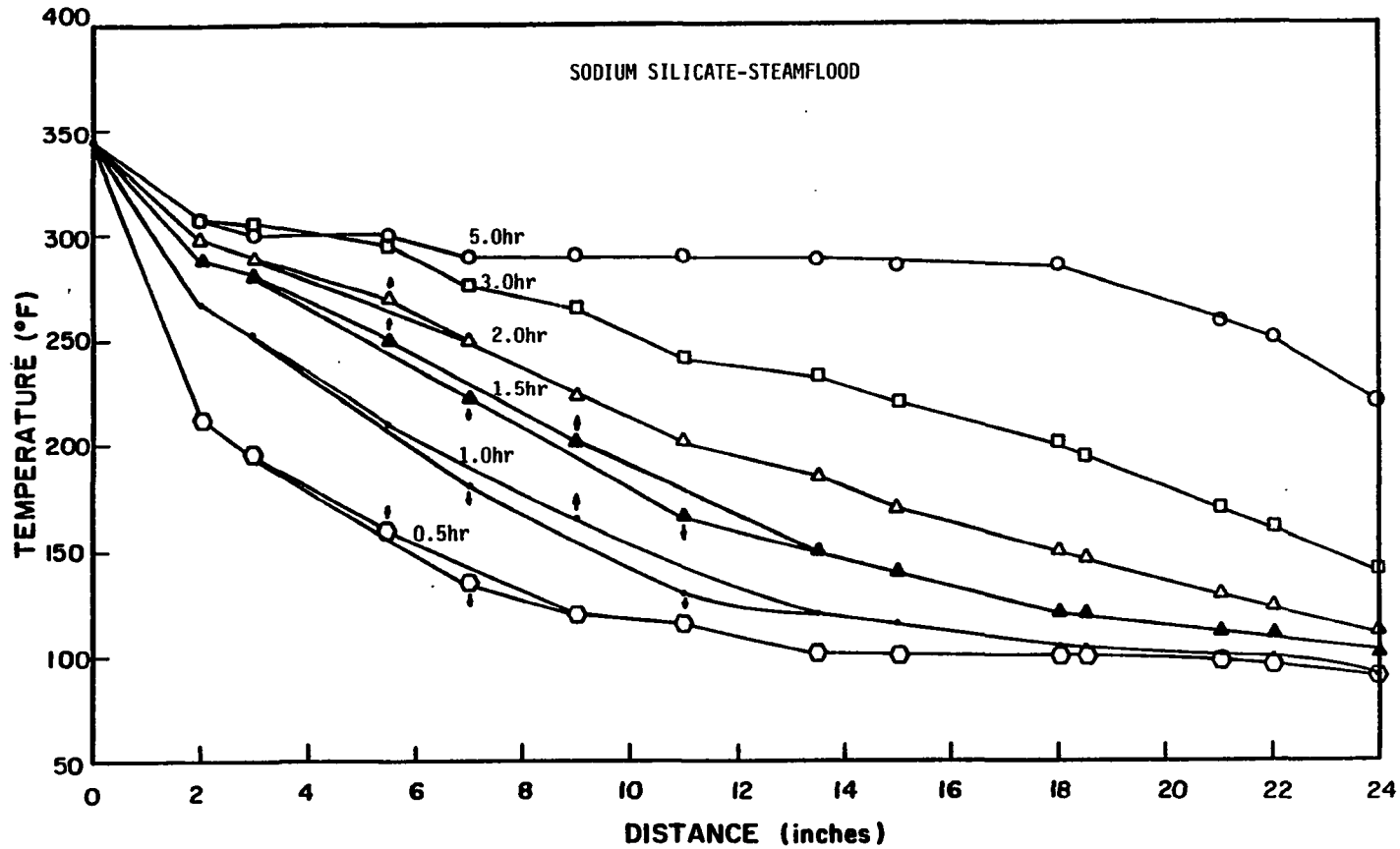

FIGURE 31. Temperature Distribution Ahead of Advancing Steam Zone.

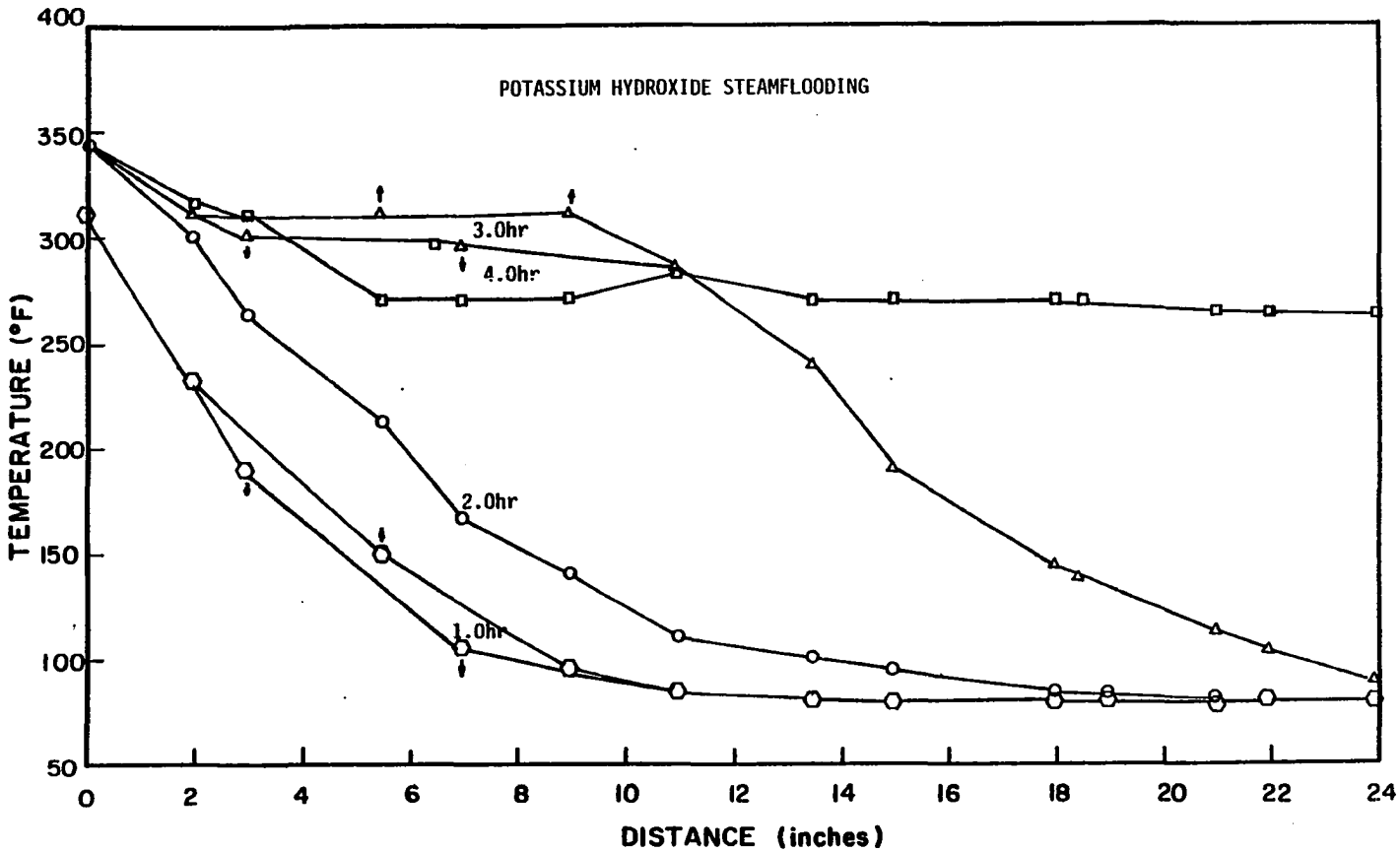

FIGURE 32. Temperature Distribution Ahead of the Advancing Steam Zone.

The phenomenon of gravity override is, however, much more pronounced in actual reservoirs. Owing to scale of magnitude in actual reservoirs, the duration of steam injection does not eliminate steam override where it exists. It is, therefore, to improve steam drive oil recovery in spite of this problem that these alkali discussed were investigated for their suitability in improving oil recovery in the lower formation that is often swept by hot to warm water.

Figure 33 shows the graphical display of Durie's[51] theoretical solution of Eq. 79 in terms of dimensionless variables. In Figure 33, he compared his solution with Lauwerier's[52] solution which his solution reduces to when A = 0, i.e., no steam zone. As can be seen from this figure, the match is excellent near A = 0.

The solutions above, however, are for ideal systems in which the condensation front remains vertical within the sand layer, i.e., no gravity override. Figures 27 to 32 show the temperature-distance profile in actual systems where gravity override occurred to some degree. When Figures 27 to 32 are compared to Figures 33 and 34, the general trend of the plots is the only common characteristic between the ideal solutions and experimental results. This feature, of course, conforms quite well with the basic relationship between theoretical and experimental results.

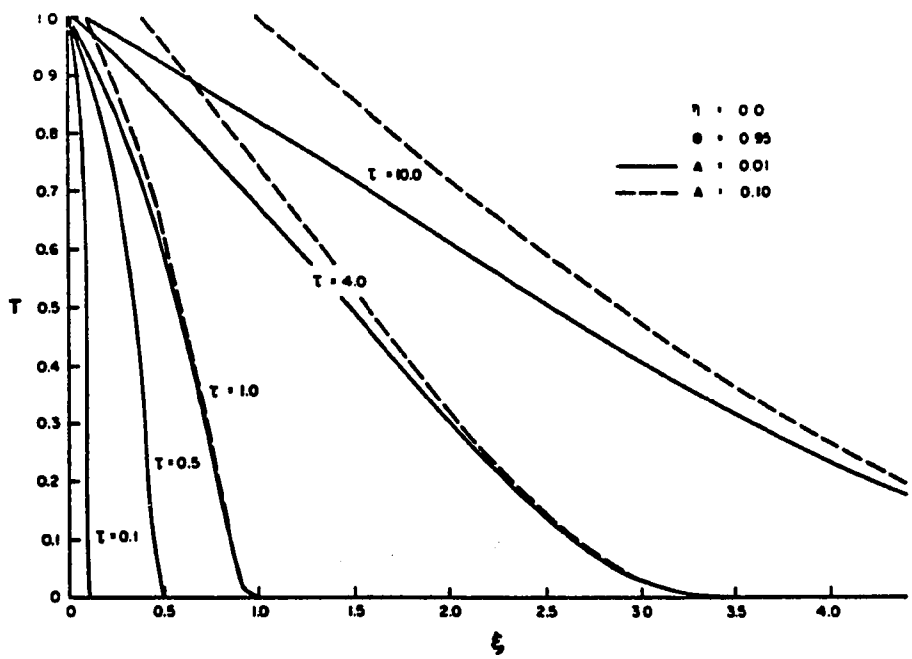

FIGURE 33. Temperature Distribution Ahead of Advancing Steam Zone (Idealized Model from Durie[51]).

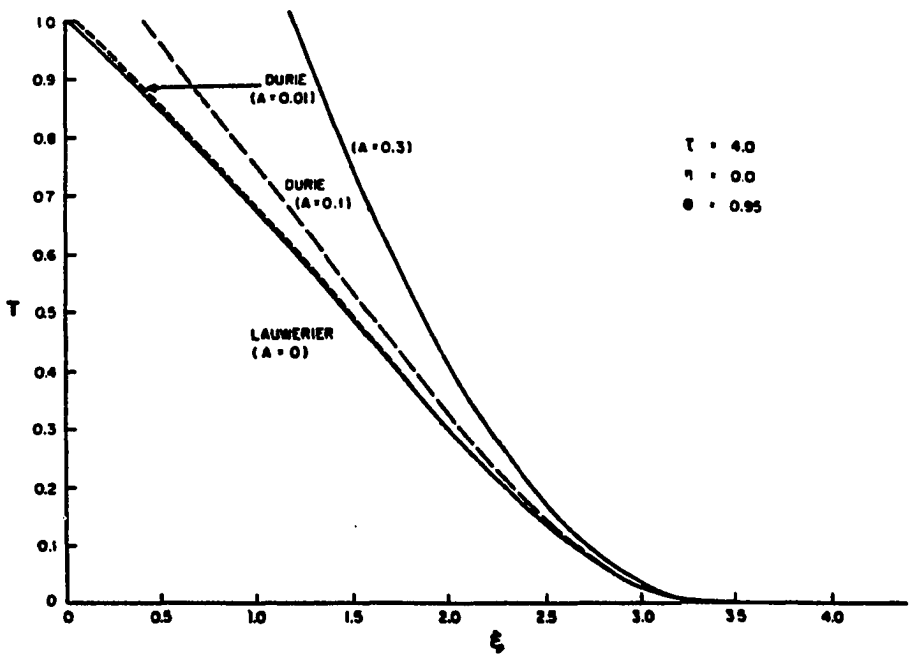

FIGURE 34. Temperature Distribution Ahead of Advancing Steam Zone (Comparison of Durie's[51] to Lauwerier's[52] Solution)

CHAPTER VII

CONCLUSIONS

1. Alkaline solutions of sodium hydroxide and sodium silicate can be employed effectively as chemical additives in tertiary steam flooding to improve oil recovery.

2. Alkaline steam flooding can recover between 9 and 14 percent more of initial oil in place than conventional steam flooding.

3. When the residual oil saturation after water flooding is low, about 0.26, alkaline steam flooding can still more effectively recover most of the remaining oil in place than conventional steam flooding.

4. Based on the observations both visual and otherwise and analysis of produced fluids, the incremental oil recovery of alkaline steam flooding could be attributed to: in situ emulsification and entrapment, low tension displacement which improved the displacement efficiency and lower formation solvent drive which in turn improved the sweep efficiency.

5. The optimal temperature range for alkaline steam flooding seems to lie between 250°F and 300°F above which rapid consumption and deterioration of the alkali begin.

6. The presence of large CO_3^- anions can be detrimental to alkaline steam flooding as can be inferred from the failure of Na_2CO_3-steam flood. Dissolution of silica by NaOH will not harm caustic steam flood because

Na_2SiO_3-steam flood was almost as successful in enhancing oil recovery as NaOH-steam flood.

7. Attainment of very low interfacial tension in alkaline-water system does not guarantee improved oil recovery in alkaline steamflood, but a minimum interfacial tension is required for successful alkaline steam flood.

8. The concentration of caustic soda or potash in alkaline steam or hot water is more critical to achieving favorable alkaline-oil system than the degree which the system's interfacial tension can be lowered.

9. Sodium silicate is only slightly soluble in water and hence the sodium silicate solution-oil system is insensitive to sodium silicate concentration.

10. Although sodium carbonate is fairly soluble in water, its increasing solubility does not significantly increase the solution pH and hence, the concentration of sodium carbonate should not be a factor in the oil recovery potential of sodium carbonate steam flood.

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NOMENCLATURE

$(HA_o)_o$	= Initial concentration of HA_o, mol m^{-3}
C_1	= Initial concentration of NaOH, mol m^{-3}
C_2	= Initial concentration of NaCl, mol m^{-3}
K_S	= Dissociation constant
K_{DS}	= Distribution ratio of NaA, dimensionless
K_{TS}	= Equilibrium constant, mol m^{-3}
K_W	= Dissociation constant of H_2O, mol^2m^{-6}
K_A	= Dissociation constant of HA, mol m^{-3}
K_D	= Distribution ratio of HA, dimensionless
K	= Specific rate constant
m, n, o	= Individual order of reaction
r	= Rate of reaction
f(x), g(x)	= $C_f(1 = c)$, where C_f is the feed concentration of reactant
x	= axial column length, m
$\tilde{x}$	= x/L, reduced column length or dimensionless
α	= Pore-volume delay of caustic due to adsorption
S_w	= Saturation of water
S_{wc}	= Conate water saturation
S_o	= Saturation of oil
S_{or}	= Residual oil saturation
S_{FB}	= Saturation of water at waterflood breakthrough

S_{F1} = Water saturation of oil bank

S_{F2} = Water saturation at alkaline breakthrough

S_D = Eventual constant water saturation at the rear of the surfactant

$S_{or}(A^-)$ = Residual oil saturation at the surfactant concentration $[A^-]$

S = $\frac{S_w - S_{wc}}{1 - S_{or}(A^-) - S_{wc}}$, effective saturation

$\bar{M}$ = Mineral exchange site

M = $k_{rw}\rho_o/k_{ro}\rho_w$, mobilitiy ratio

μ = Viscosity, centipoise

ϕ = Porosity, percent

τ_B = Ion-exchange pore-volume delay of alkaline in a water-saturated core

t = Time, seconds

u = Superficial velocity, m/s

v = Velocity, x/τ, dimensionless

τ = $ut/\phi L$, PV

v_B = Waterflood-breakthrough velocity, dimensionless

v_c = Alkaline-pulse-front velocity, dimensionless

v_C = Differential-composition velocity, dimensionless

$v_{\Delta c}$ = Integral-composition velocity, dimensionless

v_D = Alkaline pulse rear velocity

v_T = velocity of tertiary oil bank, dimensionless

ε_a, ε_a' = Activation energy, cal/mole

A^* = Constant of reaction for particular reaction

ρ = Steric factor, characteristic of the shapes and orientations of reacting molecules

R = Gas constant, J $mol^{-1}K^{-1}$

T_k = Temperature °K

Z, Z' Individual reaction constant

n_o = Maximum adsorbed moles of i per unit area, mol m^{-2}

n_i = Adsorbed moles of i per unit area, mol m^{-2}

$(i)_S$ = Sublayer concentrations of i, mol m^{-3}

k = Boltzmann constant, J K^{-1}

K_1 = Adsorption rate

K_2 = Desorption rate constant, s^{-1}

N = Avogadro's number, mol^{-1}

S'_o = Oleic phase volume, m^3

S'_w = Aqueous phase volume, m^3

W = Energy barrier for desorption, J mol^{-1}

Z_i = Valency of i

$\psi(x)$ = Potential of x, V

ε = Electronic charge, C

ε_r = Relative permittivity, dimensionless

ε_o = Permittivity of vacuum, $C^2N^{-1}m^{-2}$

M = Fraction of displaced or displacing fluid per unit pore volume, i.e., S_o, S_w

m = $H = c_{vw}\rho_w(T_f - T_o)$, heat content

C_{ij} = Component concentration

M'_{ij} = Fractional flow phase saturation

λ' = differential coherence condition eigenvalue

β_{ij} = Partial derivative $(\partial M_i'/\partial C_j)_{C_k}$

Λ = Integral coherence condition eigenvalue

q_t = Total volume flux, cm/sec

T_f = Final reservoir temperature, °F

T_o = Initial reservoir temperature, °F

ρ_i = Density, gram/cc, of phase i

θ_c = Contact angle

σ_i = Surface tension of phase i

γ = Interfacial tension

P_c = Capillary pressure, psia

ω = Angular velocity, rad/sec

y_o = Cylindrical radius, cm

A = Dimensionless constant related to the condensation front

a = Area of condensation front

b = One-half the height of the steam zone

c = Heat capacity

C = Rate of advance of condensation front

T = Dimensionless temperature

y = Vertical position

η = Dimensionless vertical position

θ = Ratio of heat capacities

λ = Thermal conductivity

ξ = Dimensionless horizontal position

IFT = Interfacial tension, dynes/cm

Subscripts

i	= Injected
o	= Oil, condensation front
1	= Oil sand
2	= Cap rock (base rock)
w	= Water
c	= Alkaline
C	= Composition

Superscripts

~	= Reduced or dimensionless

APPENDIX A

PROPERTIES OF OIL AND POROUS MEDIA

TABLE A1

CRUDE OIL PHYSICAL PROPERTIES

(Acidic No. 1.1)

Temperature °F	Gravity °API	Viscosity cp	Density gm/cc
60	18.1		.946
65			
70			
76	19.0		.942
80		285	
85			
90			
95			
102	22.0		.923
110			
125		180	
128	23.5		.913
140			
150		125	
167		100	
173	27.0		.893
180		83	
185			
189	27.5	85	.890
195			
198	28.5	70	.884

TABLE A2

MINERAL CONTENT BY PERCENT WEIGHT OF VARIOUS TYPES

OF POROUS MEDIA USED FOR DISPLACEMENT TEST

	Berea Sandstone	Halliburton 20-40 Frac Sand (28-35 mesh)	Glass Beads (38 mesh)
Quartz	85	98.3	98.8
Feldspar	5	1	1.0
Carbonate	1		
Clays	7	0.5	
Fe, Mg, Al & Ti Minerals	2	0.2	0.2

APPENDIX B

SUMMARY OF DISPLACEMENT TESTS RESULTS

TABLE B1: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 1)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	122	122	5	5	10.52	0.004	13.0	0.109	0.109	0.04	0.092	25	0.704	0.296	
2	75	197	180	185	16.98	0.159	20.9	0.219	0.329	2.4	0.379	45	0.640	0.36	
3	53	250	350	535	21.55	0.461	26.6	0.347	0.678	6.604	0.510	27	0.594	0.406	
4	27	277	400	935	23.88	0.806	29.5	0.368	1.045	14.81	0.485	21	0.594	0.406	
5	25	302	376	1311	26.03	1.13	32.2	0.345	1.39	15.04	0.448	25	0.571	0.429	
6	20	322	385	1696	27.76	1.462	34.3	0.349	1.74	19.25	0.50	10	0.549	0.451	
7	22	344	382	2078	29.66	1.791	36.6	0.348	2.088	17.36	0.413	6	0.532	0.468	
8	20	364	408	2486	31.38	2.143	38.8	0.369	2.457	20.4	0.403	5	0.513	0.487	
9	8	372	256	2742	32.07	2.364	39.62	0.228	2.684	32.0	0.446	3	0.489	0.511	7.36

TABLE B1 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 1)
Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	27	27	398	398	2.33	0.343	2.9	42.5	0.366	0.366	3.05	14.74	0.5	2	0.473	0.527	
2	109	136	114	512	11.72	0.441	14.5	54.1	0.192	0.569	3.24	1.046	0.48	2	0.378	0.622	
3	120	256	97	609	22.07	0.525	27.3	66.9	0.187	0.746	3.43	0.808	1.315	2	0.275	0.725	
4	102	358	108	717	30.86	0.618	38.1	77.7	0.181	0.927	3.611	1.059	1.27	2	0.187	0.813	
5	111	469	166	883	40.43	0.761	49.95	89.55	0.239	1.166	3.85	1.495	0.79	2	0.091	0.909	
6	5	474	210	1093	40.862	0.942	50.48	90.1	0.185	1.35	4.04	42.0	0.05	10	0.080	0.920	
7	0.5		150									300	0.223	10			

TABLE B1: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 1)

Initial Oil Saturation	= .8095
Connate Water Saturation	= .1905
Pore Volume	= 1160 cc
Initial Oil in Place	= 939 cc

TABLE B2: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 2)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	171	171	5	5	14.74	0.0043	17.33	0.152	0.152	0.029	0.052	4	0.7034	0.297	
2	76	247	243	248	21.29	0.214	25.03	0.275	0.427	3.197	0.335	13	0.638	0.362	
3	44	291	345	593	25.09	0.511	29.48	0.335	0.762	7.84	0.372	12	0.60	0.4	
4	25	316	355	948	27.24	0.817	32.02	0.328	1.09	14.2	0.355	8	0.578	0.422	
5	19	335	367	1315	28.88	1.134	33.94	0.333	1.422	19.32	0.325	8	0.562	0.438	
6	17	352	385	1700	30.34	1.466	35.66	0.347	1.769	22.65	0.329	8	0.5474	0.453	
7	16	368	445	2145	31.72	1.849	37.28	0.397	2.166	27.81	0.357	9	0.534	0.466	
8	13	381	430	2575	32.84	2.22	38.60	0.382	2.548	33.08	0.392	8	0.522	0.478	7.47

TABLE B2 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 2)
NaOH (1 gm/ℓ)-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	95	95	470	470	8.19	0.405	9.63	48.23	0.487	0.487	3.04	4.95	0.095	2	0.441	0.559	8.73
2	62	157	148	618	13.53	0.533	15.91	54.51	0.181	0.668	3.22	2.39	0.135	5	0.387	0.613	9.87
3	72	229	158	776	19.74	0.669	23.2	61.8	0.198	0.866	3.42	2.19	0.053	2	0.325	0.675	9.50
4	100	329	128	904	28.36	0.779	33.33	71.93	0.197	1.063	3.62	1.28	0.514	3	0.239	0.761	11.05
5	80	409	148	1052	35.26	0.907	41.44	80.04	0.197	1.259	3.82	1.85	0.105	2	0.170	0.83	11.49
6	53	462	178	1230	39.83	1.06	46.81	85.41	0.199	1.459	4.02	3.36	0.105	2	0.124	0.876	11.65
7	37	499	202	1432	43.02	1.234	50.56	89.16	0.206	1.665	4.23	5.46	0.128	3	0.092	0.908	11.48
8	35	534	205	1637	46.03	1.411	54.1	92.7	0.207	1.872	4.44	5.86	0.219	2	0.062	0.938	11.48
9	31	565	198	1835	48.71	1.582	57.24	95.84	0.197	2.069	4.64	6.39	0.185	2	0.035	0.965	11.53
10	15	580	225	2060	50.0	1.776	58.76	97.36	0.207	2.276	4.85	15.0	0.236	4	0.022	0.978	10.93
11	12	592	232	2292	51.03	1.976	59.98	98.58	0.210	2.486	5.06	19.33	0.256	8	0.012	0.988	11.08
12	5	597	231	2523	51.47	2.175	60.49	99.09	0.203	2.69	5.26	46.20	0.450	9	0.008	0.992	11.56

TABLE B2: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 2)

Initial Oil Saturation = .8508

Connate Water Saturation = .149

Pore Volume = 1160 cc

Initial Oil in Place = 987 cc

TABLE B3: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 3)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	112	112	0	0	9.66	0	13.3	0.097	0.097	0	0.135	10	0.629	0.371	
2	70	182	425	425	15.69	0.366	21.62	0.427	0.523	6.07	0.251	20	0.569	0.431	
3	42	224	458	883	19.31	0.761	26.60	0.431	0.954	10.9	0.395	20	0.533	0.467	
4	25	249	473	1356	21.47	1.169	29.57	0.429	1.38	18.92	0.435	27	0.511	0.489	
5	15	264	491	1847	22.76	1.592	31.35	0.436	1.82	32.73	0.352	17	0.412	0.588	
6	11	275	489	2336	23.71	2.013	32.66	0.431	2.25	44.45	0.330	15	0.399	0.601	
7	8	283	455	2791	24.40	2.406	33.61	0.399	2.65	56.88	0.337	17	0.390	0.61	7.26

TABLE B3 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 3)
NaOH (1.5 gm/ℓ)-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	5	5	497	497	0.431	0.428	0.59	34.2	0.433	0.433	3.08	99.4	0.147	6	0.385	0.615	9.14
2	1	6	501	998	0.517	0.860	0.713	34.32	0.433	0.866	3.51	501	0.206	5	0.385	0.615	11.13
3	1	7	246	1244	0.603	1.072	0.83	34.44	0.213	1.078	3.72	246	0.328	4	0.384	0.616	10.87
4	1	8	243	1487	0.69	1.282	0.95	34.56	0.21	1.289	3.93	243	0.126	5	0.383	0.617	11.04
5	10	18	988	2475	1.55	2.134	2.14	35.75	0.86	2.149	4.79	98.8	0.258	6	0.374	0.626	11.49
6	5	23	1028	3503	1.98	3.02	2.73	36.34	0.89	3.04	5.68	205.6	0.314	2	0.370	0.63	11.65
7	52	75	930	4433	6.47	3.822	8.9	42.51	0.85	3.87	6.53	17.88	0.385	2	0.325	0.675	11.48
8	60	135	838	5271	11.64	4.544	16.03	49.64	0.774	4.66	7.3	13.97	0.397	2	0.273	0.727	11.48
9	27	162	201	5472	13.97	4.717	19.24	52.85	0.197	4.86	7.5	7.44	0.097	1	0.25	0.75	11.53
10	10	170	238	5710	14.66	4.922	20.19	53.8	0.214	5.07	7.71	23.8	0.277	2	0.243	0.757	10.93
11	20	192	228	5938	16.55	5.12	22.8	56.4	0.214	5.28	7.92	11.4	0.245	2	0.224	0.776	11.08
12	3	195	213	6151	16.81	5.303	23.16	56.76	0.186	5.47	8.11	71.0	0.049	1	0.222	0.778	11.56

TABLE B3: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 3)

Initial Oil Saturation	= 0.7259
Connate Water Saturation	= 0.274
Pore Volume	= 1160 cc
Initial Oil in Place	= 842 cc

TABLE B4: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 4)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	130	130	11	11	11.21	0.0095	13.33	0.121	0.122	0.085	.088	12	0.728	0.272	
2	60	190	108	119	16.38	0.103	19.49	0.145	0.266	1.8	.105	15.5	0.677	0.323	
3	35	225	129	248	19.40	0.214	23.08	0.141	0.408	3.69	.119	16	0.647	0.353	
4	60	285	391	639	24.57	0.551	29.23	0.389	0.797	6.52	.248	12	0.595	0.405	
5	45	330	450	1089	28.45	0.939	33.85	0.427	1.223	10.0	.185	8	0.556	0.444	
6	30	360	469	1558	31.03	1.343	36.92	0.430	1.653	15.63	.179	6	0.530	0.470	
7	25	385	476	2034	33.19	1.75	39.49	0.432	2.09	19.04	.185	5	0.509	0.491	
8	13	398	306	2340	34.31	2.02	40.82	0.275	2.36	23.54	.24	5	0.497	0.503	7.51

TABLE B4 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 4)
Na_2CO_3-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	38	38	460	460	3.28	0.396	3.89	44.71	0.429	3.89	44.71	12.10	0.275	3	0.465	0.535	8.28
2	35	73	261	721	6.29	0.225	7.49	48.31	0.255	7.49	48.31	7.45	0.217	5	0.435	0.565	9.36
3	18	91	211	932	7.84	0.182	9.35	50.15	0.197	9.33	50.15	11.72	0.25	7	0.419	0.581	10.82
4	17	108	213	1145	9.31	0.184	11.03	51.85	0.198	11.03	51.85	12.53	0.226	5	0.404	0.596	10.62
5	18	126	212	1357	10.86	0.183	12.92	53.74	0.198	12.92	53.74	11.78	0.22	6	0.388	0.612	10.54
6	17	143	213	1570	12.33	0.184	14.67	55.49	0.198	14.67	55.49	12.53	0.22	6	0.374	0.626	10.59
7	18	161	211	1781	13.88	0.182	16.51	57.33	0.197	16.51	57.33	11.72	0.23	7	0.359	0.641	10.50
8	19	180	209	1990	15.52	0.180	18.46	59.28	0.196	18.46	59.28	11.0	0.24	6	0.342	0.658	10.36
9	26	206	194	2184	17.76	0.167	21.13	61.95	0.190	21.13	61.95	7.46	0.356	4	0.320	0.680	10.18
10	65	271	710	2894	23.36	0.162	27.79	68.61	0.668	27.79	68.61	10.92	0.39	3	0.263	0.737	9.92
11	36	307	594	3488	26.47	0.512	31.49	72.31	0.543	31.49	72.31	16.50	0.45	2	0.233	0.767	10.16
12	25	332	435	3923	28.62	0.375	34.05	74.87	0.397	34.05	74.87	17.4	0.496	10	0.211	0.789	10.1
13	25	357	457	4380	30.78	0.394	36.62	77.44	0.416	36.62	77.44	18.28	0.485	12	0.190	0.810	10.2
14	27	384	468	4848	33.10	0.403	39.38	80.2	0.427	39.38	80.2	17.33	0.622	11	0.166	0.834	10.18
15	6	390	234	5082	33.62	0.201	40.0	80.82	0.207	40.0	80.82	39.0	0.822	11	0.161	0.839	10.13
16	6	396	240	5322	34.138	0.207	40.61	81.43	0.212	40.61	81.43	40.0	0.714	11	0.156	0.841	10.15
17	41	437	481	5803	37.67	0.415	44.82	85.64	0.45	44.82	85.64	11.73	0.718	10	0.121	0.879	10.0

TABLE B4: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 4)

Initial Oil Saturation	= 0.8405
Connate Water Saturation	= 0.1595
Pore Volume	= 1160 cc
Initial Oil in Place	= 975 cc

TABLE B5: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 5)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	176	176	5	5	15.17	0.004	18.26	0.156	0.156	0.028	.047	20	0.679	0.321	
2	92	268	235	240	23.10	0.207	27.8	0.282	0.438	2.55	.107	24	0.60	0.4	
3	54	322	410	650	27.76	0.560	33.4	0.40	0.838	7.59	.284	29	0.553	0.447	
4	27	349	322	972	30.09	0.838	36.2	0.30	1.139	11.93	.357	32	0.53	0.47	
5	15	364	310	1282	31.38	1.105	37.76	.28	1.419	20.66	.28	26	0.517	0.483	
6	22	386	330	1612	33.28	1.39	40.04	0.30	1.722	15.0	.123	23	0.498	0.502	
7	7	393	344	1956	33.88	1.69	40.77	0.30	2.025	49.14	.125	21	0.492	0.508	
8	5	398	218	2174	34.31	1.874	41.29	0.192	2.217	43.6	.129	24	0.488	0.512	7.28

TABLE B5 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 5)
Na_2SiO_3-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	8	8	223	223	0.6896	0.192	0.83	42.12	0.199	0.199	2.42	27.87	0.333	5	0.481	0.519	7.47
2	122	130	102	325	11.21	0.28	13.49	54.78	0.193	0.392	2.61	0.84	0.271	2	0.376	0.624	8.98
3	74	204	152	477	17.59	0.411	21.16	62.45	0.195	0.587	2.81	2.05	0.219	2	0.312	0.688	9.40
4	42	246	184	661	21.21	0.57	25.52	66.81	0.195	0.782	3.01	4.38	0.214	2	0.276	0.724	9.49
5	47	293	189	850	25.26	0.733	30.39	71.68	0.203	0.985	3.21	4.02	0.215	2	0.235	0.765	9.59
6	32	325	204	1054	28.02	0.909	33.71	75.0	0.203	1.189	3.41	6.38	0.217	2	0.208	0.792	9.93
7	30	355	206	1260	30.60	1.086	36.83	78.12	0.203	1.392	3.61	6.87	0.22	2	0.182	0.818	10.33
8	95	450	800	2060	38.79	1.776	46.68	87.97	0.772	2.164	4.38	8.42	0.206	2	0.1	0.9	10.65
9	17	467	218	2278	40.26	1.964	48.44	89.73	0.202	2.37	4.58	12.82	0.301	3	0.085	0.915	9.85
10	16	483	214	2492	41.64	2.15	50.1	91.39	0.198	2.57	4.78	13.38	0.429	3	0.072	0.928	10.33
11	49	532	890	3382	45.86	2.92	55.19	96.48	0.809	3.37	5.59	18.16	0.376	8	0.029	0.971	9.92
12	19	551	915	4297	47.50	3.704	57.16	98.45	0.805	4.18	6.4	48.16	0.595	10	0.013	0.987	10.65
13	8	559	214	4511	48.19	3.89	57.99	99.28	0.191	4.37	6.59	26.75	0.632	10	0.006	0.994	10.12

TABLE B5: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 5)

Initial Oil Saturation	= 0.831
Connate Water Saturation	= 0.169
Pore Volume	= 1160 cc
Initial Oil in Place	= 964 cc

TABLE B6: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 6)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	124	124	24	24	10.7	0.02	12.7	0.128	0.128	0.194	.092	10	0.733	0.267	
2	38	162	190	114	14.0	0.098	16.6	0.197	0.238	5.0	.371	20	0.70	0.30	
3	33	195	217	331	16.8	0.285	20.0	0.216	0.453	6.58	.446	25	0.672	0.328	
4	28	223	348	679	19.2	0.585	22.9	0.324	0.777	12.43	.151	15	0.648	0.352	
5	22	245	378	1057	21.1	0.911	25.2	0.345	1.122	17.18	.175	30	0.628	0.372	
6	12	257	220	1277	22.2	1.10	26.4	0.20	1.322	18.33	.221	25	0.618	0.372	
7	9	266	234	1511	22.9	1.303	27.3	0.209	1.532	26.0	.282	27	0.611	0.389	
8	14	280	438	1949	24.1	1.68	28.7	0.39	1.922	31.29	.347	30	0.599	0.401	
9	12	292	408	2357	25.2	2.032	30.0	0.362	2.283	34.0	.406	40	0.588	0.412	7.29

TABLE B6 (Cont): SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 6)
KOH-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	83	83	255	255	7.16	0.22	8.52	38.52	0.291	0.29	2.57	3.07	0.125	25	0.516	0.484	8.35
2	146	229	75	330	19.74	0.284	23.51	53.51	0.191	0.482	2.76	0.51	0.156	30	0.390	0.61	8.16
3	75	304	134	464	26.21	0.40	31.21	61.21	0.180	0.662	2.94	1.79	0.113	30	0.326	0.674	9.88
4	66	370	144	608	31.9	0.524	37.99	67.99	0.181	0.843	3.12	2.18	0.353	20	0.269	0.731	10.84
5	55	425	163	771	36.64	0.665	43.63	73.63	0.188	1.031	3.31	2.96	0.240	22	0.221	0.779	11.21
6	44	469	185	956	40.43	0.824	48.15	78.15	0.197	1.23	3.51	4.2	0.294	35	0.183	0.817	11.24
7	56	525	270	1226	45.26	1.057	53.9	83.9	0.281	1.51	3.79	4.82	0.370	30	0.135	0.865	11.43
8	33	558	204	1430	48.10	1.233	57.29	87.29	0.204	1.74	4.02	6.18	1.089	15	0.106	0.894	11.53
9	108	666	257	1687	57.41	1.454	68.38	98.33	0.315	2.03	4.31	2.38	0.318	10	0.014	0.986	11.18
10	1	667	189	1876	57.5	1.617	68.48	98.48	0.164	2.192	4.47	189	0.268	15	0.013	0.987	11.36

TABLE B6: SUMMARY OF DISPLACEMENT TEST: SAND PACK (TEST NO. 6)

Initial Oil Saturation = 0.8397

Connate Water Saturation = 0.1603

Pore Volume = 1160 cc

Initial Oil in Place = 974 cc

TABLE B7: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 1)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	40	40	24	24	15.9	0.095	22.7	0.254	0.254	0.6	.096	934	0.54	0.46	
2	21	61	110	128	23.8	0.508	34.7	0.520	0.75	5.24	.27	100	0.46	0.54	
3	4	65	94	222	25.8	0.882	36.9	0.39	1.14	23.5	.44	100	0.441	0.56	
4	9	74	223	445	29.4	1.77	42.0	0.922	2.063	24.8	.21	900	0.406	0.59	

TABLE B7 (Cont): SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 1)
Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)		Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)
1	2	2	118	118	0.79	30.2	0.469	1.14	43.14	0.477	0.477	2.54	59	0.09	30	0.40	0.60
2	15	17	10	128	6.76	36.17	0.509	9.65	51.65	0.099	0.576	2.64	0.667	0.034	30	0.34	0.66
3	20	37	47	175	14.7	44.11	0.695	21.0	63.0	0.266	0.843	2.91	2.35	0.025	30	0.26	0.74
4	1	38	80	255	15.1	44.51	1.01	21.58	63.58	0.32	1.16	3.23	80.0	0.025	32	0.255	0.745
5	4	42	92	347	16.69	46.1	1.38	23.85	65.85	0.38	1.55	3.61	23.0	0.019	35	0.239	0.761
6	2	44	88	435	17.49	46.9	1.73	24.98	66.98	0.36	1.9	3.97	44.0	0.035	50	0.231	0.769
7	1	45	89	524	17.88	47.29	2.08	25.55	67.55	0.36	2.26	4.33	44.0	0.046	78	0.227	0.773
8	1	46	89	613	18.28	47.69	2.436	26.12	68.14	0.36	2.22	4.69	89.0	0.041	70	0.223	0.777

TABLE B7: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 1)

Initial Oil Saturation	= 0.70
Connate Water Saturation	= 0.30
Pore Volume	= 251.62 cc
Initial Oil in Place	= 176.12 cc

TABLE B8: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 2)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	15	15	1	1	5.96	0.004	8.3	.064	0.064	0.07	.063	468	0.656	0.344	
2	12	27	1	2	10.73	0.008	15.0	.052	0.12	0.08	.059	350	0.608	0.392	
3	6	36	3	5	14.307	0.02	20.0	.036	0.16	0.5	.066	310	0.572	0.428	
4	8	44	8	13	17.49	0.052	24.4	.064	0.23	1	.069	330	0.541	0.459	
5	7	51	10	23	20.27	0.09	28.3	.068	0.29	1.43	.065	380	0.513	0.487	
6	10	61	28	51	24.24	0.20	33.88	.11	0.45	2.8	.062	380	0.473	0.527	
7	4	65	45	96	25.83	0.38	36.11	.195	0.64	11.25	.064	390	0.457	0.543	
8	1	66	29	125	26.23	0.497	36.66	.12	0.76	0.03	.06	400	0.453	0.547	
9	5	71	88	213	28.22	0.847	39.44	.37	1.129	17.6	.061	500	0.433	0.567	
10	2	73	82	295	29.0	1.172	40.55	.33	1.46	41	.063	500	0.425	0.575	
11	1	74	140	435	29.4	1.729	41.11	.56	2.02	140	.067	495	0.421	0.579	7.28

TABLE B8 (Cont): SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 2)
NaOH(1 gm/ℓ)-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	8	8	123	123	3.2	0.49	4.4	45.51	0.52	0.52	2.54	15.38	0.02	350	0.389	0.611	9.66
2	25	33	450	573	13.1	2.28	18.33	59.44	1.89	2.4	4.43	18.0	0.06	400	0.29	0.71	11.33
3	10	43	473	1046	17.1	4.16	23.88	64.99	1.92	4.33	6.35	47.3	0.04	370	0.25	0.75	10.96
4	5	48	294	1340	19.0	5.33	26.66	67.77	1.19	5.52	7.54	58.8	0.05	380	0.231	0.769	10.91
5	16	64	200	1540	25.0	6.12	35.55	76.66	0.858	6.37	8.39	12.5	0.053	350	0.171	0.829	11.12
6	3	67	442	1982	26.6	7.88	37.22	78.33	1.77	8.14	10.16	147.33	0.051	350	0.155	0.845	11.10

TABLE B8: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 2)

Initial Oil Saturation	= 0.715
Connate Water Saturation	= 0.30
Pore Volume	= 251.62 cc
Initial Oil in Place	= 180.0 cc

TABLE B9: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 3)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	49	49	19	19	19.47	0.076	26.63	0.27	0.27	0.39	0.05	554	0.537	0.463	
2	7	56	62	81	22.25	0.322	30.43	0.274	0.54	8.89	0.034	470	0.509	0.491	
3	19	75	175	256	29.81	1.017	40.76	0.771	1.315	9.0	0.109	875	0.433	0.567	7.38

TABLE B9 (Cont): SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 3)
Na_2CO_3-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	16	16	336	336	6.36	1.45	8.7	49.5	1.399	1.399	2.71	21	0.027	1125	0.37	0.63	7.97
2	2	18	345	681	7.15	2.71	9.78	50.6	1.380	2.78	4.10	172.5	0.20	1650	0.362	0.638	8.41
3	6	24	224	905	9.54	3.6	13.0	53.86	0.91	3.69	5.01	37.33	0.018	1680	0.338	0.662	9.8
4	14	38	162	1067	15.1	4.24	20.65	61.47	0.70	4.39	5.71	11.57	0.027	1780	0.282	0.718	9.75
5	7	45	269	1336	17.88	5.309	24.46	65.28	1.097	5.49	6.81	38.43	0.067	1780	0.254	0.746	10.7

TABLE B9: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 3)

Initial Oil Saturation	= 0.731
Connate Water Saturation	= 0.269
Pore Volume	= 251.62 cc
Initial Oil in Place	= 184 cc

TABLE B10: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 4)
Waterflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP	Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water	Producing WOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	39	39	11	11	15.5	0.044	24.68	0.199	0.199	0.282	.075	1350	0.4729	0.5271	7.28
2	11	50	69	80	19.9	0.318	31.65	0.318	0.52	6.27	.103	950	0.4289	0.5711	
3	5	55	76	156	21.9	0.62	34.81	0.322	0.839	15.2	.107	950	0.4089	0.5911	
4	4	59	100	256	23.4	1.02	37.34	0.413	1.25	25.0	.106	950	0.3939	0.6061	
5	3	62	34	290	25.0	1.153	39.24	0.147	1.399	11.33	.116	950	0.3779	0.6221	7.33

TABLE B10 (Cont): SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 4)
Na_2SiO_3-Steamflood

Sample No.	Vol. of Oil Prod. (cc)	Cum. Vol. of Oil Prod. (cc)	Vol. of Water Prod. (cc)	Cum. Vol. of Water Prod. (cc)	% Pore Vol. of Oil Prod. (cum)	Pore Vol. of Water Prod. (cum)	Oil Recovery %IOIP		Injected Pore Vol. Water	Cum. Inj. Pore Vol. of Water		Producing SOR	Injection Rate (cc/sec)	Differential Pressure (psia)	Oil Saturation (Fraction of PV)	Water Saturation (Fraction of PV)	pH
1	10	10	345	345	3.97	1.37	6.33	45.57	1.41	1.41	2.81	34.5	0.058	750	.3382	.6618	7.98
2	16	26	182	527	10.33	2.09	16.49	55.73	0.79	2.198	3.6	11.4	0.06	1000	.2746	.7254	8.5
3	30	56	95	622	22.26	2.47	35.44	74.68	0.497	2.69	4.09	3.17	0.059	1100	.1553	.8447	8.9
4	0.5	56.5	100	722	22.45	2.87	35.76	75	0.399	3.09	4.49	200	0.0455	1250	.1534	.8466	10.19

TABLE B10: SUMMARY OF DISPLACEMENT TEST: BEREA CORE (TEST NO. 4)

Initial Oil Saturation	= 0.628
Connate Water Saturation	= 0.372
Pore Volume	= 251.62 cc
Initial Oil in Place	= 158 cc

APPENDIX C

TEMPERATURE DISTRIBUTION IN THE SANDPACK DURING THE DURATION OF THE STEAM AND ALKALINE STEAM FLOODS

TABLE C1: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #1
(Steam Displacement in Sand Pack)

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	105	90	90	90	80	80	80	80	80	80	80	80	80	85	80	355
0.5	210	170	155	110	120	95	95	110	105	105	100	100	85	100	80	355
1.0	212	195	185	180	135	143	118	122	110	110	110	100	85	125	83	355
1.5	193	190	190	184	180	170	170	175	180	180	160	155	125	140	95	355
2.0	218	195	190	190	185	175	170	185	180	180	162	155	125	170	95	355
2.5	270	240	240	240	230	215	215	220	220	220	190	185	155	190	110	355
3.0	275	275	275	265	260	250	250	240	245	243	225	215	180	245	140	355
3.5	285	280	290	280	280	278	275	265	265	265	235	230	225	255	190	365
4.0	300	315	320	310	310	290	295	295	290	290	280	275	260	270	205	365
4.5	325	320	320	315	320	325	320	320	320	300	300	300	290	285	205	365

TABLE C2: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #2
(NaOH-Steam Displacement in Sand Pack)

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	100	85	100	80	80	80	80	80	80	90	90	90	80	80	80	
0.25	180	130	180	100	100	90	100	90	90	90	90	90	80	100	80	
0.5	215	180	180	130	120	100	120	100	100	100	95	90	85	100	85	
1.5	270	240	210	160	140	115	140	100	100	100	95	90	90	100	85	
2.0	285	260	260	185	170	130	170	110	100	100	100	95	90	103	87	
2.5	295	280	275	210	195	150	195	120	100	100	100	98	90	105	88	
3.0	290	280	295	270	295	290	295	265	135	190	150	110	95	110	88	
3.5	305	260	320	280	300	260	300	210	185	190	180	130	105	120	100	
4.0	315	265	325	295	310	265	310	213	205	200	150	148	115	130	1105	
4.5	310	315	330	310	330	310	330	255	220	210	170	165	130	145	120	
5.0	320	320	320	310	320	320	320	320	290	290	290	275	270	160	145	
5.5	315	308	315	310	320	315	320	290	310	300	300	280	270	180	160	
6.0	300	295	300	300	305	300	305	300	300	300	300	285	285	245	205	
6.5	285	280	280	280	280	280	280	280	280	280	280	285	280	245	205	

TABLE C3: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #3
[NaOH (1.5 gm/l)-Steam Displacement in the Sand Pack)

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	112	80	100	82	85	82	82	82	82	82	82	82	80	95	80	345
0.5	140	90	115	85	82	80	82	82	82	82	82	82	80	95	80	345
1.0	239	195	200	123	160	125	105	90	90	85	85	82	80	105	82	345
1.5	283	265	245	200	200	160	150	125	115	115	110	95	88	105	95	345
2.0	315	310	310	265	260	200	175	175	145	140	125	120	165	180	98	345
2.5	330	315	310	292	290	260	245	230	200	200	190	160	160	195	120	380
3.0	332	318	305	295	290	265	260	240	220	215	190	180	165	198	132	380
3.5	350	348	325	300	300	270	260	260	240	240	225	200	190	205	140	425
4.0	355	355	355	352	358	315	308	308	280	277	263	250	240	255	145	425
4.5	410	410	427	407	408	372	360	358	343	340	350	300	240	350	192	440
5.0	420	420	420	420	420	420	418	420	410	410	400	350	280	365	200	440
5.5	400	400	400	400	400	400	400	400	400	400	410	382	340	385	205	440

TABLE C4: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #4
(Na_2CO_3-Steam Displacement in the Sand Pack)

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	100	85	100	80	80	80	80	80	80	80	80	80	80	100	80	
0.5	210	190	210	170	180	155	140	130	130	130	125	125	102	120	95	
1.5	220	220	215	200	185	160	150	150	150	150	140	140	120	135	120	
2.0	270	250	225	210	190	170	170	170	160	160	150	150	125	140	123	
2.5	275	255	243	230	215	190	180	180	180	180	170	155	130	145	127	
3.0	280	270	270	255	240	220	210	215	200	200	200	200	230	150	130	
3.5	305	290	300	300	297	270	265	265	250	250	235	235	220	195	170	
4.0	305	290	300	295	300	292	290	280	275	275	260	255	255	225	203	
4.5	285	280	285	280	285	285	285	285	280	280	275	270	230	240	205	

TABLE C5: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #5
(Na_2SiO_3-Steam Displacement in the Sand Pack)

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	110	110	110	100	100	100	100	100	100	100	90	90	80	100	80	
0.5	200	198	160	137	120	115	102	102	100	100	100	95	90	100	90	
1.0	255	253	210	182	158	130	120	116	105	105	100	100	92	105	92	
1.5	282	282	250	222	200	165	150	140	120	120	110	108	100	110	95	
2.0	295	290	272	250	235	200	188	170	150	150	125	120	108	120	100	
2.5	310	300	280	260	250	225	215	200	180	180	150	140	120	135	115	
3.0	310	305	295	275	265	242	233	218	200	200	165	160	140	150	130	
3.5	310	310	310	300	290	270	260	250	235	235	200	195	160	180	160	
4.0	305	302	305	298	300	290	288	275	270	268	230	227	198	210	190	
4.5	300	298	300	290	292	290	287	280	280	280	260	250	218	228	205	
5.0	295	290	295	285	290	290	287	280	285	285	275	270	250	260	205	

TABLE C6: TEMPERATURE DISTRIBUTION WITH DISTANCE FOR TEST #6
[KOH (1 gm/l)-Steam Displacement in the Sand Pack]

Thermocouple #	2	6	7	9	8	3	11	10	12	14	13	4	0	1	5	15
Distance inches / Time hours	2	3	5.5	7	9	11	13.5	15	18	18.5	21	22	24	Axil	Outlet	Inlet
0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	310
0.5	80	112	98	80	85	98	80	80	80	80	80	80	80	88	80	310
1.0	232	188	150	105	95	100	80	80	80	80	80	80	80	90	80	310
1.5	250	210	165	128	112	92	82	85	80	87	80	80	80	90	80	310
2.0	315	263	212	165	140	110	100	95	87	87	80	80	80	92	80	345
2.5	300	283	295	200	190	135	118	115	100	100	95	85	82	120	80	345
3.0	308	300	310	290	310	285	238	188	145	135	115	103	90	104	87	345
3.5	301	308	295	295	300	300	290	262	218	218	200	175	147	155	132	345
4.0	300	309	270	268	270	285	270	270	270	270	265	265	255	260	240	345
4.5	275	280	288	270	280	270	270	270	270	270	265	262	225	250	200	345
4.88	300	295	300	278	300	290	270	260	265	265	265	255	238	250	207	345