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May 10, 2005

Mr. Jun Anli
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Dear Jun:

An email copy of the Warner alkaline-surfactant-polymer laboratory evaluation report is attached. We are preparing 8 bound and 1 unbound hard copies. They will be mailed out in the next day or two.

Sincerely,

Malcolm J. Pitts, Ph.D.
Director - Petroleum Technology

**Laboratory Design of an
Alkaline-Surfactant-Polymer System
for the Warner Field, Alberta**

Prepared for
Husky Oil

May 2005

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Appendix A	Phase Behavior Nomenclature	after table and figures
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I. Purpose of Evaluation

The feasibility of implementing an alkaline-polymer or alkaline-surfactant-polymer flood in Warner was studied. Fluid-fluid evaluations included interfacial tension screening, phase behavior screening, and the effect of unsoftened produced water dilution on interfacial tension and phase behavior. Polymer rheology, intrinsic viscosity, and mercury injection capillary pressure studies were performed to estimate appropriate polymers for the Warner rock and to estimate the interfacial tension reduction required to produce a significant volume of incremental oil.

Six linear Corefloods were performed to define relative permeability, polymer rheology, and chemical retention of an alkaline-surfactant-polymer solution flowing through Warner cores. Four were performed treating the core oil-wet and two performed treating the core water-wet. Coreflood data are then used to determine an appropriate polymer for injection into Warner core and an injected concentration.

Fourteen radial corefloods were performed to evaluate the incremental oil recovery due to injection of field proportioned volumes of alkaline-surfactant-polymer solutions. Six radial cores were treated oil-wet and eight radial cores were treated water-wet. Radial corefloods help differentiate between optimum chemical systems, allow for economic calculations, and provide an estimate of oil cut change as a function of fluid injected.

II. Summary of Results

Fluid-Fluid

Warner produced and injection waters have low total dissolved solids, 5,070 and 4,400 mg/L, respectively, and low divalent cation content of less than 60 mg/L. Water softening is recommended for Warner injection water even with the low divalent ion content. Dead oil viscosity is 119 cp with an API gravity of 19 degrees. Crude oil characteristics agree with prior results, so the sample is representative of the reservoir.

Sodium hydroxide (NaOH) reduced the interfacial tension 85 fold while sodium carbonate (Na_2CO_3) only reduced interfacial tension 3 fold. Addition of surfactant to alkaline solutions resulted in interfacial tension reductions of up to 15,000 fold. Of fourteen surfactants tested, eleven developed 15,000 fold interfacial tension reduction when blended with alkali. NaOH produced lower interfacial tension values with surfactants than did Na_2CO_3 . Mercury injection calculations indicate interfacial tension reductions of 1,100 fold are necessary to produce significant quantities of incremental oil.

Alkali-surfactant combinations developed optimum phase types (type III and type II-) while alkali alone developed type II. Phase behavior testing showed less discrimination between NaOH and Na_2CO_3 solutions. When the two alkalis were blended in the same solution and mixed with surfactant, an interfacial tension reduction improvement was observed with two additional surfactants. Mixing the two alkalis did not alter ultra low interfacial tension values observed with single alkali. Optimum phase type was observed with mixed alkali solutions. Interfacial tension reductions of 1000 fold or greater after diluting with produced

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water were maintained for 20 to 30% dilutions on average with the best chemical solution maintaining interfacial tension reductions for 60% dilution. 100 fold interfacial tension reductions were maintained to more than 80% dilution with most solutions. Optimum phase types were maintained to 40% for type III and 80% for type II-.

Intrinsic viscosity/radius of gyration and mercury injection evaluations indicate that large molecular weight polymers should inject into Warner rock. Rheology data indicates comparable molecular weight polymers from different manufacturers should develop similar viscosities in the rock assuming rock-polymer interaction characteristics are similar.

Chemical adsorption was low, less than 5,000 lb/acre-ft for all chemicals. Cation exchange capacity was also low at 0.61 meq/100 g rock.

Linear Corefloods

Linear Coreflood evaluations indicate that Warner is a good candidate for alkaline-surfactant-polymer flooding. A mobility ratio for produced water displacing crude oil is 10.9 in oil-wet treated core and 12.4 in water-wet treated core, indicating that water is a poor displacing agent and that polymer inclusion will improve oil recovery performance. Waterflood oil recovery averaged 41.9% OOIP with 33 Vp produced water injection in oil-wet treated core. Waterflood oil recovery from water-wet treated core was 57.6% OOIP after injection of 39 Vp of produced water. Chemical injection brought the total average oil recovery up to 78.3% OOIP for an increase of 36.4% OOIP in oil-wet treated core and 16.1% OOIP for a total recovery of 73.6% OOIP in water-wet treated core. Warner cores showed some sensitivity to alkali but none to surfactant or polymer. Chemical solutions injected into and flowed through Warner rock. Injection of either a NaOH-surfactant or Na₂CO₃-surfactant solution improved injectivity up to 280% with injectivity improvement persisting upon subsequent unsoftened injection water injection. Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, and Cyantrol 770 injected into the core dissolved in either alkaline-surfactant solution or softened injection water regardless of core treatment. Both pseudoplastic and dilatant behavior was observed with all high molecular weight polymers. Recommended injected concentration for polymers are 2,650 mg/L for Flopaam 3530S, 1200 mg/L for Flopaam 3630S, 3,750 mg/L for Alcoflood 1275A, and 2,700 mg/L for Cyantrol 770 when the core was handled oil-wet. When core is treated water-wet, Flopaam 3630S recommended polymer concentration increases to 1800 mg/L and Alcoflood 1275A decreases to 2,375 mg/L. Alkalis, surfactants, and polymers retention by Warner core is acceptable for field application. Average chemical retention by oil-wet treated core was 15,872 lb/acre-ft for alkali, 5,270 lb/acre-ft for surfactant, and 850 lb/acre-ft for polymer dissolved with alkali plus surfactant, and 1,305 lb/acre-ft for polymer dissolved in softened injection water. Handling the core water-wet decreased average chemical retention values to 11,096 lb/acre-ft for alkali, 3,895 lb/acre-ft for surfactant and 478 lb/acre-ft for polymer. Effluent analysis indicates the chemical systems used in the linear Corefloods could be over designed, suggesting that alkali concentrations should be reduced for optimum radial coreflood oil recovery.

Radial Corefloods

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Radial coreflood data indicates that an alkaline-surfactant-polymer flood should be implemented in the Warner field. Incremental oil recoveries ranged from 17.7 to 35.8% OOIP (0.302 pore volumes). Oil-wet and water-wet treated core recovered similar volumes of incremental oil, averaging 0.214 and 0.190 pore volumes of incremental oil, respectively. Incremental oil banks were developed with chemical injection with peak tertiary oil cuts of 22 to 58%. Waterflood plus alkaline-surfactant-polymer flood oil recoveries ranged from 44.9 to 72.1% OOIP with final oil saturations ranging from 0.238 to 0.402 pore volumes. Resistance factor and effluent analyses indicate that 1200 mg/L of either Flopaam 3630S or Alcoflood 1275A blended in the alkaline-surfactant-polymer solution will provide adequate mobility control. Chemical retention is low for all chemicals regardless of how the core was handled. NaOH retention averaged 758 and 1,098 lb/acre-ft in oil-wet and water-wet treated core, respectively. Na_2CO_3 retention in oil-wet treated core was 1,535 lb/acre-ft. Surfactant retention averaged 124 and 212 lb/acre-ft in oil-wet and water-wet treated core, respectively. Polymer retention averaged 134 and 159 lb/acre-ft in oil-wet and water-wet treated core, respectively.

Alkaline-surfactant-polymer flooding is applicable to the Warner Field and should produce significant quantities of incremental oil. An alkaline-surfactant-polymer flood is recommended.

III. Discussion of Evaluation

1. Materials Received by Surtek, Inc.

Fluid samples received from Husky for the Warner evaluation are summarized below.

Fluids Used for Warner Field Alkaline-Surfactant-Polymer Design

<u>Description</u>	<u>Date Received</u>	<u>Quantity</u>
Warner Injection Water	4/30/2004	30 gal.
Warner Produced Water*	4/30/2004	30 gal.
Warner Crude Oil*	4/30/2004	30 gal.

*- A mixture of fluid from various B Pool producers.

Approximately fifteen feet of core from various wells was received as outlined in the following table.

Core Received for Warner Field Alkaline-Surfactant-Polymer Design

<u>Well Description</u>	<u>Depth (ft)</u>	<u>Length (inches)</u>
CPOG Tabers 4-21-16W4	3,196	9
	3,199-3,200.6	23
	3,215.5	5
Empire State Taber Unit 1 02/9-20-7-16W4	3,222.7	5
	3,226.0	5
	3,230.9	4
	3,232.4	5
	3,233.5-3,235.8	28.5
	3,237.1-3,237.7	9
	3,238.5	4
	3,238.9	4
CPOG Tabers 16-20-7-16W4	3,220.5	6
	3,222.2	11
	3,226.1	9
	3,227.1	9
	3,228	11
	3,234	10
	3,236	11
	3,238.5	6
	3,246.2	7.25

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Core was received dry. Core handled oil-wet were treated according to the following procedure. Oil-wet cores were trimmed and saturated prior to beginning the fluid-fluid work.

1. a. - Cut 4 - 1 inch diameter linear core plugs for the Warner design evaluation.
b. - Cut 6 - 2-inch high by full diameter radial disks for the Warner design evaluation.
2. Extract core
3. Saturate core with crude oil in the core holder by initial evacuation followed by injection.
4. Remove core from core holder and weigh to determine porosity and pore volume.
5. Place core back in core holder and inject produced water to residual oil saturation.
6. Immerse cores in reservoir oil and age at room temperature until the fluid design evaluations are complete.
7. Conduct corefloods with aged cores. Initial injected fluid after aging will be crude oil followed by a waterflood and then the chemical sequence.

Core handled water-wet were handled according the following procedure. Water-wet cores were trimmed and saturated prior to beginning the fluid-fluid work.

1. a. - Cut 2- 1 inch diameter linear core plugs for the Warner design evaluation.
b. - Cut 8 - 2 inch high by full diameter radial disks for the Warner design evaluation.
2. Extract core
3. Saturate core with produced water by evaluation and weigh to determine porosity and pore volume.
4. Place core in core holder and inject produced water and determine the absolute permeability to produced water.
5. Inject viscosity adjusted crude oil to an initial oil saturation.
6. Age for a minimum of four days at 95°F.

All chemicals used in the evaluation were provided by the manufacturers to Surtek.

2. Fluid Analysis

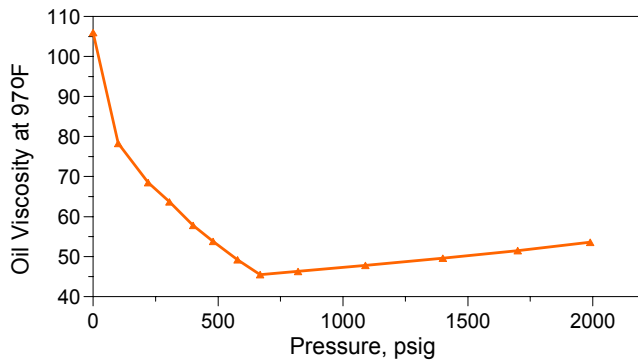
2.1. Water Analysis - The waters were 0.45 microns filtered and analyzed for total dissolved solids, pH, resistivity, viscosity, density, and the following ions: calcium, magnesium, barium, strontium, iron, sodium, potassium, chloride, sulfate, carbonate and bicarbonate.

Results of the analysis are presented in Table 2.1.1. Injection and produced water total dissolved solids are similar with total dissolved solids of 4,400 mg/L and 5,070 mg/L, respectively. Hardness is low for both waters with a total divalent cation content of 70 mg/L for injection water and 30 mg/L for produced water. Injection water needs to be softened to dissolve alkali. Hardness ions will precipitate if mixed with alkaline agents

and may cause pore plugging. In addition, the presence of calcium and magnesium ions is intolerable for many surfactants, greatly reduces the polymer solution viscosity, and accelerates the rate of polymer degradation. Softening requirements for the injection water should be minimal. Composition of both waters is acceptable for an alkaline-polymer or an alkaline-surfactant-polymer flood.

Warner injection and produced waters stability indices are negative and should not produce a calcium carbonate precipitate, according to the method of Stiff and Davis.¹ No sulfate scales should form with either water.

2.2. Crude Oil Analysis - Warner crude oil analysis is listed in Table 2.2.1. Crude oil samples were characterized by measuring API gravity and Brookfield viscosity. API



gravity is 19.4° with a dead oil viscosity of 119 cp at 35°C. Crude oil was 1.0 microns filtered before use. Interfacial tension between oil and injection water of 15 dyne/cm is low but still suggests that the oil is free of treating chemicals. Crude oil characteristics are consistent with earlier reports.^{2,3} Reservoir oil viscosity as a function of pressure is shown on the adjacent plot.

3. Fluid-Fluid Interactions: Alkali and Alkali-Surfactant Technology Potential

Oil recovery from porous media by flooding can be defined by the following equation:

$$N_p = \frac{E_D E_V E_A S_{oi} V_p}{B_o}$$

where N_p is the cumulative oil recovery, E_D is the unit displacement efficiency, E_V is the volumetric displacement efficiency, S_{oi} is the initial oil saturation, V_p is the pore volume, and B_o is the oil formation volume factor. The total recovery efficiency E_{total} is the product of E_D and E_V . Altering either the characteristics of the injected fluid or the placement of the injected fluid affects E_V , since E_V is the fraction of total reservoir volume contacted by the displacing fluid. E_V can be split into the product of areal sweep efficiency (E_A) and vertical sweep efficiency (E_{V1}) or $E_V = E_A \times E_{V1}$. Cross-linking polymer for conformance control will affect E_{V1} and a mobility control polymer flood will affect both factors.

E_D is a measure of the effectiveness of injected fluid to displace oil from contacted rock. An E_D of 90% means that 90% of the oil in the contacted rock is displaced. One reason chemicals are added to the injected fluids is to reduce the forces trapping the oil, allowing a shift in the oil saturation end point of the relative permeability curve. This can be accomplished by reducing the interfacial tension between the injected aqueous fluid and

crude oil in the reservoir. Interfacial tension and phase behavior evaluations provide a means to determine whether chemicals have the potential to increase E_D .

Interfacial tension between crude oil and water is high. As a result, crude oil globules form spheres in water to minimize the surface contact with water. In a petroleum reservoir, crude oil globules exist in the pores of porous media. For an ellipsoid oil globule, a sphere has the maximum average cross-sectional area and, as a result, may have difficulty passing through a pore throat or a restriction of a pore throat. When this happens, the reservoir reaches the oil saturation end point of the relative permeability curve.

To allow passage of a crude oil globule through a pore throat, the drop shape must change. Crude oil globule configuration can be changed by applying force with a pressure gradient. Decreasing the interfacial tension between crude oil and water reduces the differential pressure required to distort the drop configuration and allows the drop to move through the pore throat.⁴

Capillary number is a unitless relationship which has been developed to describe the interdependence between viscous forces (differential pressure) and surface forces (interfacial tension) and capillary flow. Capillary number as defined by Taber⁵ is:

$$N_{ca} = \frac{\text{Viscous Forces}}{\text{Surface Forces}} = \frac{(\Delta P/L)}{\sigma}$$

where N_{ca} is the capillary number, ΔP is the differential pressure across a given length (L), and σ is the interfacial tension between the crude oil and the aqueous phase.

Typical waterflood capillary numbers are 10^{-7} . Taber⁵ reported that an increase in capillary number is necessary to improve oil recovery. This increase must exceed a critical capillary number which is dependent upon various rock properties.

Mungan⁶ reported that additional oil recovery can be achieved by alkali addition to injection water independent of interfacial tension reduction. In this case, additional oil recovery is a result of the alkali reacting with reservoir rock and making the rock more water-wet.

Interfacial tension reduction is achieved in an oil reservoir by addition of a variety of chemical agents; alkali,⁵⁻⁷ and surfactant addition to the injection water^{8,9} and carbon dioxide injection.¹⁰ Nine papers discussing the co-injection of alkali plus surfactant and alkali plus surfactant plus polymer have been published.^{11,12,13,14,15,16,17,18,19} The performance of two full-field alkaline-surfactant-polymer projects,^{16,20} five alkaline-surfactant-polymer pilots,^{17,21,22,23,24} an alkaline-surfactant-polymer field test at 100% water-cut,²⁵ and an alkaline-surfactant pilot²⁶ have been published. Evaluations performed in this section investigate interfacial tension reduction through the addition of alkali, surfactant, and alkali plus surfactant to the injection water.

3.1. Alkali Interfacial Tension Screening - Two alkaline salts were dissolved in softened injection water, and the interfacial tension between Warner crude oil and the aqueous alkaline solutions were determined at 35°C. Ideally, alkali reacts with components of the oil to form in-situ surfactants. The alkaline salts used were sodium hydroxide (NaOH) and sodium carbonate (Na₂CO₃).

Polyacrylamide polymer at a concentration of 1,000 mg/L was added to all solutions, because it would be included in any low interfacial tension flooding fluid. Added polymer may slightly increase interfacial tension.

Interfacial tension measurements between Warner crude oil and NaOH and Na₂CO₃ solutions are listed in Table 3.1.1 and depicted in Figure 3.1.1. Warner crude oil shows interfacial tension reduction with NaOH but not Na₂CO₃. Maximum interfacial tension reduction with NaOH was 85 fold.

3.2. Surfactant Addition to Alkaline Solutions - A small quantity of surfactant added to alkaline solutions will further reduce interfacial tension between Warner crude oil and aqueous solutions. The combination of alkali and surfactant can have additional benefits not expressed by either agent alone.^{11,12,13, 27,28} Fourteen surfactants of varying structure and molecular weight were evaluated after determining stability in water. Surfactants used are listed below.

Surfactant Characteristics

<u>Name of Surfactant</u>	<u>Structure</u>	<u>Supplier</u>
Stepantan AS-1216	alpha olefin sulfonate	Stepan
Peterostep B-100	alkyl aryl sulfonate	Stepan
Petro AA	alkyl naphthalene sulfonate	Crompton
Petro P	alkyl naphthalene sulfonate	Crompton
Petronate EOR 2037	alkyl aryl sulfonate	Crompton
Petronate EOR 2094	alkyl aryl sulfonate	Crompton
Petronate EOR 2095	alkyl aryl sulfonate	Crompton
ORS-41HF	di or mono alkyl aryl sulfonate	OCT
ORS-60HF	di or mono alkyl aryl sulfonate	OCT
ORS-62HF	di or mono alkyl aryl sulfonate	OCT
ORS-64HF	di or mono alkyl aryl sulfonate	OCT
ORS-66HF	di or mono alkyl aryl sulfonate	OCT
ORS-97HF	di or mono alkyl aryl sulfonate	OCT
ORS-162HF	di or mono alkyl aryl sulfonate	OCT
ORS-164HF	di or mono alkyl aryl sulfonate	OCT
ORS-166	di or mono alkyl aryl sulfonate	OCT

Surfactants were blended with each alkali type at alkali concentrations from zero to 2.00 wt.%. Total surfactant concentration was 0.10 wt% active. Low surfactant concentrations were selected for economic viability of the chemical flood. The interfacial tension between the aqueous alkaline-surfactant-polymer solutions and Warner

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crude oil was determined at 35°C. Results are compiled in Tables 3.2.1 through 3.2.13 and depicted in Figures 3.2.1 through 3.2.10. NaOH and Na₂CO₃ were mixed with all surfactants in softened injection water. A number of surfactants were mixed with a combination of NaOH and Na₂CO₃. Where the two alkalis were blended, 0.25 and 0.50 wt% Na₂CO₃ were mixed with 0.5 to 1.0 wt% NaOH.

A number of surfactants without alkali reduced interfacial tension to values sufficient to produce incremental oil. Surfactants lowering the interfacial tension to less than 0.600 dyne/cm without alkali were Petrostep B-100 plus Stepantan AS-1216 at varying ratios and all the ORS products (41HF, 60HF, 62HF, 64HF, 66HF, 97HF, 162HF, 164HF and 166HF). The best interfacial tension reduction with surfactant alone was 0.024 dyne/cm observed with 0.67 wt% Petrostep B-100 plus 0.033 wt% Stepantan AS-1216, a 625 fold interfacial tension reduction.

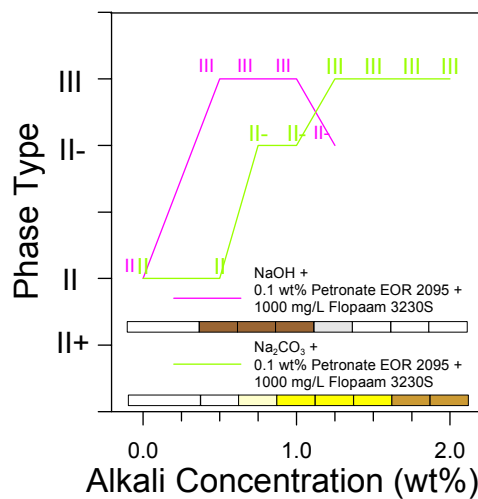
Addition of a single alkali to the surfactant solutions lowered interfacial tension values to 0.007 dyne/cm, a 2,142 fold reduction, with every surfactant or surfactant combination. Nine of the thirteen surfactant blends provided interfacial tension reductions of 10,000 fold or more when blended with alkali. NaOH was more effective at reducing interfacial tension when combined with surfactant than Na₂CO₃ as shown in the following table.

Alkali-Surfactant Solutions Interfacial Tension Reduction

<u>Surfactant</u>	<u>Maximum Interfacial Tension Reduction (fold)</u>		
	<u>NaOH</u>	<u>Na₂CO₃</u>	<u>Na₂CO₃-NaOH mix</u>
Petro AA	3,750	555	---
Petro P	15,000	134	---
Petronate 2037	15,000	1,071	15,000
Petronate 2094	15,000	1,250	5,000
Petronate 2095	15,000	1,875	15,000
ORS-41HF	15,000	576	15,000
ORS-60HF	15,000	429	---
ORS-62HF	15,000	385	---
ORS-64HF	15,000	242	---
ORS-66HF	15,000	179	---
ORS-97HF	3,000	2,142	2,142
ORS-162HF	9,750	5,000	15,000
ORS-164HF	15,000	3,000	15,000
ORS-166HF	15,000	500	15,000
1:1 B-100:AS 1216	2,143	30	15,000
1:2 B-100:AS 1216	306	75	---
2:1 B-100:AS 1216	405	1,500	---

Mixed alkali solutions were blended with nine surfactants. With the exception of an equal blend of Petrostep B-100 and Stepantan AS 1216, mixing the two alkaline agents did not reduce interfacial tension to values lower than a single alkaline agent.

3.3. Phase Behavior Evaluations - To help define which alkaline-surfactant-polymer solutions have the best potential to recover additional oil beyond a waterflood in the Warner reservoir, phase behavior evaluations were performed.²⁹ A phase behavior evaluation can be considered a long term interfacial tension measurement. A favorable phase behavior observed over the duration of the evaluation suggests that the interfacial tension between Warner crude oil and the chemical mixture has remained low throughout the elapsed time. Phase behavior evaluations involved blending the crude oil with equal volumes of the chemical solution and mixing. After approximately two weeks of equilibration at 35°C, phase type, appearance, and phase volume observed were recorded. From the phase type, a better estimate as to which chemical solution will have potential to recover incremental oil can be made. In addition, the ability of alkali to react with crude oil to produce in-situ surfactant is observed by discoloration of the aqueous phase.



The results of the phase behavior tests are listed in Tables 3.3.1 through 3.3.24. Appendix A contains an explanation of phase behavior types. The data is plotted in Figures 3.3.1 through 3.3.16. Figures 3.3.11 through 3.3.16 depict the mixed alkali solutions and Tables 3.3.19 through 3.3.24 list the data. Phase behaviors with just alkali were not favorable in that only type II was observed. When surfactant was added to alkali solutions, phase types III, II-, and II were observed. Phase behavior with NaOH, Na₂CO₃, and Petronate EOR 2095 shown to the left is typical of a number of alkaline-surfactant systems. Both alkalis develop type III phase behavior with NaOH solutions forming type III at lower alkali concentration and the Na₂CO₃ solutions transitioning through type II- before developing type III.

Interfacial tension reduction and phase type for solutions displaying either ultra low interfacial tension or optimum phase type are listed in the following table.

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Alkali-Surfactant Solutions with Type II- or Type III Phase Behavior and Interfacial Tension Reduction of 1,000 fold or greater

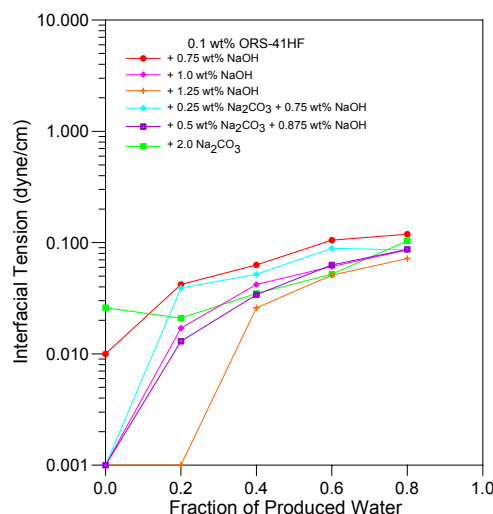
<u>Alkali + 0.1 wt.% Surfactant*</u>	Alkali Concentration <u>wt. %</u>	Interfacial Tension Reduction Ratio <u>IFT_{initial}/IFT</u>	Phase <u>type</u>
NaOH+Petro AA	0.50 to 0.75	1,500 to 3,750	II
NaOH+Petro P	0.75 to 2.00	1,500 to 15,000	II- to III to II
NaOH+Petronate EOR 2037	0.50 to 1.25	3,750 to 15,000	II- to III to II-
Na ₂ CO ₃ +Petronate EOR 2037	2.00	1,071	III
NaOH+0.25 wt% Na ₂ CO ₃ + Petronate EOR 2037	0.50 to 1.00	3,000 to 15,000	III to II
NaOH+0.50 wt% Na ₂ CO ₃ + Petronate EOR 2037	0.50 to 1.00	3,750 to 15,000	III to II
NaOH+Petronate EOR 2094	0.50 to 1.25	1,500 to 15,000	III to II
Na ₂ CO ₃ +Petronate EOR 2094	2.00	1,250	III
NaOH+0.25 wt% Na ₂ CO ₃ + Petronate EOR 2094	0.50 to 1.00	2,143 to 5,000	III
NaOH+0.50 wt% Na ₂ CO ₃ + Petronate EOR 2094	0.50 to 1.00	1,500 to 5,000	III
NaOH+Petronate EOR 2095	0.50 to 1.25	1,500 to 15,000	III to II-
Na ₂ CO ₃ +Petronate EOR 2095	1.75 to 2.00	1,364 to 1,875	III
NaOH+0.25 wt% Na ₂ CO ₃ + Petronate EOR 2095	0.50 to 1.00	2,143 to 15,000	III
NaOH+0.50 wt% Na ₂ CO ₃ + Petronate EOR 2095	0.50 to 1.00	3,750 to 15,000	III to II
NaOH+ORS-41HF	0.75 to 1.25	1,500 to 15,000	III to II
NaOH+0.25 wt% Na ₂ CO ₃ + ORS-41HF	0.50 to 1.00	1,071 to 15,000	III
NaOH+0.50 wt% Na ₂ CO ₃ + ORS-41HF	0.50 to 1.00	1,000 to 15,000	III to II
NaOH+ORS-60HF	0.75 to 1.25	1,875 to 15,000	III to II
NaOH+ORS-62HF	0.75 to 1.25	1,071 to 15,000	III
NaOH+ORS-64HF	1.00 to 1.25	2,500 to 3,000	III
	Alkali	Interfacial Tension	

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<u>Alkali + 0.1 wt.% Surfactant*</u>	Concentration <u>wt. %</u>	Reduction Ratio <u>IFT_{initial}/IFT</u>	Phase <u>type</u>
NaOH+ORS-66HF	1.00 to 1.25	2,142 to 3,750	III to II-
NaOH+ORS-97HF	0.30 to 1.00	1,071 to 7,500	II- to III
Na ₂ CO ₃ +ORS-97HF	1.00 to 2.00	1,250 to 2,142	III
NaOH+0.25 wt% Na ₂ CO ₃ + ORS-97HF	0.50	1,500	III
NaOH+0.50 wt% Na ₂ CO ₃ + ORS-97HF	0.50 to 0.625	1,667 to 2,143	III
NaOH+ORS-162HF	0.50 to 1.25	1,000 to 3,750	III
Na ₂ CO ₃ +ORS-162HF	1.75 to 2.00	1,667 to 5,000	III
NaOH+0.25 wt% Na ₂ CO ₃ + ORS-162HF	0.50 to 1.00	1,364 to 5,000	III to II
NaOH+0.50 wt% Na ₂ CO ₃ + ORS-162HF	0.50 to 1.00	2,143 to 15,000	III to II
NaOH+ORS-164HF	0.75 to 1.25	1,364 to 15,000	III to II
Na ₂ CO ₃ +ORS-164HF	1.75 to 2.00	1,364 to 3,000	III
NaOH+0.25 wt% Na ₂ CO ₃ + ORS-164HF	0.50 to 1.00	1,364 to 15,000	III to II
NaOH+0.50 wt% Na ₂ CO ₃ + ORS-164HF	0.50 to 1.00	2,143 to 15,000	III to II
NaOH+ORS-166HF	0.75 to 1.75	1,071 to 15,000	III to II-
NaOH+0.25 wt% Na ₂ CO ₃ + ORS-166HF	0.50 to 1.00	2,143 to 15,000	III to II
NaOH+0.50 wt% Na ₂ CO ₃ + ORS-166HF	0.50 to 1.00	1,000 to 15,000	III to II
NaOH+Petrostep B-100+ Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	0.75 to 1.75	1,000 to 2,143	III
NaOH+0.25 wt% Na ₂ CO ₃ +Petrostep B-100+ Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	0.50 to 0.625	5,000 to 15,000	II to III
Na ₂ CO ₃ +Petrostep B-100+ Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	0.75 to 1.00	1,071 to 1,500	III

* - surfactant concentration is active and is the total surfactant (sum of any surfactant blends)

3.4. Interfacial Tension of Optimum Solutions - A number of solutions with low interfacial tension values and favorable phase behavior were diluted with unsoftened produced water to 80%, 60%, 40% and 20% of their original concentration and the interfacial tension between the aqueous solutions and Warner crude oil determined at 35°C. Besides the effect of reducing the chemical concentration, this evaluation shows the effect of the hardness in the produced water.



Results of the effect of unsoftened produced water dilution on the interfacial tension are presented in Tables 3.4.1 through 3.4.32 and depicted in Figures 3.4.1 through 3.4.17. Produced water dilution changed interfacial tension values in a consistent manner whether the surfactant was dissolved in NaOH, Na_2CO_3 , or a mixture of the two alkalis. Generally with higher alkali concentrations, lower interfacial tension values persist as the solution is diluted with produced water. The adjacent figure for ORS-41HF-alkaline solutions is typical. The approximate percentage of produced water at which interfacial tension reduction drops below 1,000 fold and 100 fold are detailed in the following table for each solution.

**Fraction of Produced Water Maintaining
High Interfacial Tension Reduction
of Alkaline-Surfactant-Polymer Solutions**

<u>Alkali+ 0.1 wt.% Surfactant</u>	Alkali Concentration <u>wt. %</u>	Initial IFT <u>dyne/cm</u>	% Produced Water Resulting in IFT Reduction	
			<u>>1000</u>	<u>>100</u>
NaOH+Petro P	0.75	0.010	1	8
NaOH+Petro P	1.25	0.001	20	30
NaOH+Petro P	1.50	0.001	30	31
NaOH+Petronate EOR2037	0.50	0.004	10	25
NaOH+Petronate EOR2037	1.00	0.001	22	62
NaOH+Petronate EOR2037	1.25	<0.001	35	74
Na_2CO_3 +Petronate EOR 2037	2.00	0.014	1	65
0.25 wt% Na_2CO_3 +NaOH+ Petronate EOR 2037	0.625	0.001	15	70
0.50 wt% Na_2CO_3 +NaOH+ Petronate EOR 2037	0.75	0.001	22	72

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Alkali+ 0.1 wt.% Surfactant	Alkali Concentration wt. %	Initial IFT dyne/cm	% Produced Water Resulting in IFT Reduction	
			>1000	>100
NaOH+Petronate EOR2094	0.75	0.004	8	63
NaOH+Petronate EOR2094	1.00	0.001	23	73
NaOH+Petronate EOR2094	1.25	<0.001	28	69
Na ₂ CO ₃ +Petronate EOR 2094	2.00	0.012	4	>80
NaOH+Petronate EOR 2095	0.75	0.002	19	64
NaOH+Petronate EOR 2095	1.00	0.001	29	72
NaOH+Petronate EOR 2095	1.25	0.001	37	72
Na ₂ CO ₃ +Petronate EOR 2095	1.75	0.011	8	>80
Na ₂ CO ₃ +Petronate EOR 2095	2.00	0.008	18	>80
0.25 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2095	0.50	0.001	9	>80
0.50 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2095	0.75	0.001	28	74
NaOH+ORS-41HF	0.75	0.010	3	>80
NaOH+ORS-41HF	1.00	0.001	18	>80
NaOH+ORS-41HF	1.25	0.001	31	>80
Na ₂ CO ₃ +ORS-41HF	2.00	0.026	0	>80
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-41HF	0.75	0.001	7	>80
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-41HF	0.875	0.001	22	>80
NaOH+ORS-60HF	0.75	0.008	2	>80
NaOH+ORS-60HF	1.00	0.001	15	>80
NaOH+ORS-60HF	1.25	<0.001	37	>80
Na ₂ CO ₃ +ORS-60HF	2.00	0.035	0	>80
NaOH+ORS-62HF	1.25	0.001	25	>80
NaOH+ORS-64HF	1.00	0.006	6	>80
NaOH+ORS-64HF	1.25	0.005	22	>80
NaOH+ORS-66HF	1.00	0.007	12	>80
NaOH+ORS-66HF	1.25	0.004	14	>80
NaOH+ORS-97HF	0.50	0.002	27	>80
NaOH+ORS-97HF	0.75	0.010	60	>80
Na ₂ CO ₃ +ORS-97HF	1.00	0.007	48	53
Na ₂ CO ₃ +ORS-97HF	1.25	0.009	41	55
Na ₂ CO ₃ +ORS-97HF	1.50	0.011	59	76

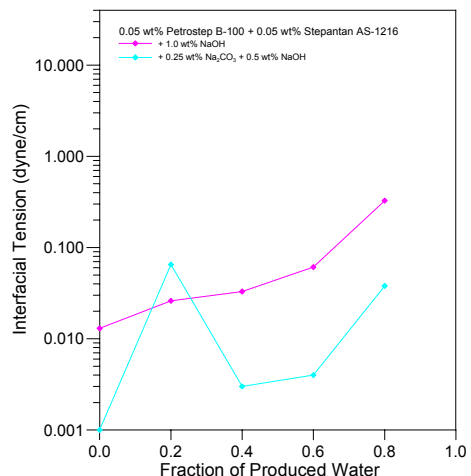
% Produced Water

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<u>Alkali+ 0.1 wt.% Surfactant</u>	Alkali Concentration <u>wt. %</u>	Initial IFT <u>dyne/cm</u>	Resulting in IFT Reduction	
			<u>>1000</u>	<u>>100</u>
NaOH+ORS-162HF	0.75	0.007	21	68
NaOH+ORS-162HF	1.00	0.004	47	68
Na ₂ CO ₃ +ORS-162HF	1.50	0.016	32	>80
Na ₂ CO ₃ +ORS-162HF	2.00	0.003	61	>80
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-162HF	0.625	0.001	15	>80
NaOH+ORS-164HF	0.75	0.002	15	62
NaOH+ORS-164HF	1.00	0.001	27	73
Na ₂ CO ₃ +ORS-164HF	1.75	0.011	25	68
Na ₂ CO ₃ +ORS-164HF	2.00	0.005	55	>80
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-164HF	0.625	0.001	11	>80
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-164HF	0.75	0.001	20	>80
NaOH+ORS-166HF	1.00	0.001	11	70
NaOH+ORS-166HF	1.50	0.004	34	>80
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-166HF	0.875	0.001	13	>80
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-166HF	0.875	0.001	15	71
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.00	0.013	3	67
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.50	0.007	12	73
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.25	0.071	0	78
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.75	0.055	0	84
0.25 wt% Na ₂ CO ₃ +NaOH +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	0.50	0.001	4	>80
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	0.50	0.019	46	78
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	1.25	0.037	61	71
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	0.75	0.010	6	65
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	1.25	0.024	0	77

* - surfactant concentration is active and is the total surfactant (sum of any surfactant blends)

The effect of alkali concentration is very noticeable with all surfactant plus alkali systems. Higher concentrations of alkali result in persistence of lower interfacial tension values. Na_2CO_3 and NaOH solutions produced water dilution change of interfacial tension is similar within no clear advantage of one alkali over another.



The benefit of mixing the two alkalis is demonstrated by the produced water dilution. Mixing the two alkalis results in low interfacial tension values continuing to higher produced water dilutions. Petronate 2037 (Tables 3.4.9 and 3.4.27), Petronate 2095 (Tables 3.4.8 and 3.4.28), and Petrostep B-100 (Tables 3.4.23 and 3.4.32) provides the best examples of the enhancement caused by mixing the two alkalis. The figure to the left shows the comparison of Petrostep B-100 plus AS-1216 with NaOH and a mix of NaOH and Na_2CO_3 .

3.5. Phase Behavior of Optimum Solutions - Alkaline-surfactant-polymer solutions diluted with produced water also had phase behavior determined. Results are compiled in Tables 3.5.1 through 3.5.30 with 3.5.26 through 3.5.30 being the mixed alkali. Data are depicted in Figures 3.5.1 through 3.5.19, the last three figures showing the mixed alkali solutions. The dilution at which type II- and type III phase behavior was lost for each of the solutions is listed in the following table.

**Fraction of Produced Water Maintaining
Optimum Phase Behavior
of Alkaline-Surfactant-Polymer Solutions**

			% Produced Water Resulting in Loss of phase type	
<u>Alkali+ 0.1 wt.% Surfactant</u>	<u>Alkali Concentration wt.%</u>	<u>Initial phase type</u>	<u>III</u>	<u>II-</u>
NaOH+Petro P	0.75	III	20	---
NaOH+Petro P	1.25	II-	20	---
NaOH+Petro P	1.50	II	20	40
NaOH+Petronate EOR2037	0.50	II-	20	---
NaOH+Petronate EOR2037	1.00	III	40	60
NaOH+Petronate EOR2037	1.25	II-	40	60
Na ₂ CO ₃ +Petronate EOR 2037	2.00	III	0	40
0.25 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2037	0.625	III	40	60

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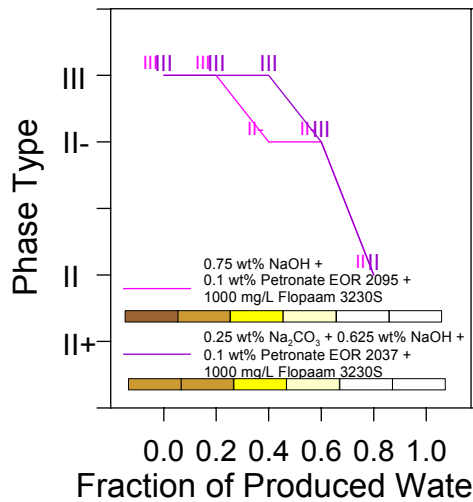
<u>Alkali+ 0.1 wt.% Surfactant</u>	<u>Alkali Concentration wt.%</u>	<u>Initial phase type</u>	<u>% Produced Water Resulting in Loss of phase type</u>	
			<u>III</u>	<u>II-</u>
0.50 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2037	0.75	III	60	---
NaOH+Petronate EOR2094	0.75	III	40	---
NaOH+Petronate EOR2094	1.00	III	60	---
NaOH+Petronate EOR2094	1.25	II	60	---
Na ₂ CO ₃ +Petronate EOR 2094	2.00	III	20	60
NaOH+Petronate EOR 2095	0.75	III	20	60
NaOH+Petronate EOR 2095	1.00	III	60	---
NaOH+Petronate EOR 2095	1.25	II-	60	---
Na ₂ CO ₃ +Petronate EOR 2095	1.75	III	20	40
Na ₂ CO ₃ +Petronate EOR 2095	2.00	III	40	60
0.25 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2095	0.50	III	40	60
0.50 wt% Na ₂ CO ₃ +NaOH+ Petronate EOR 2095	0.75	III	40	60
NaOH+ORS-41HF	0.75	III	40	60
NaOH+ORS-41HF	1.00	III	60	---
NaOH+ORS-41HF	1.25	II	60	---
Na ₂ CO ₃ +ORS-41HF	2.00	III	20	40
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-41HF	0.75	III	40	60
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-41HF	0.875	II	40	60
NaOH+ORS-60HF	0.75	III	40	60
NaOH+ORS-60HF	1.00	III	40	60
NaOH+ORS-60HF	1.25	II	40	60
Na ₂ CO ₃ +ORS-60HF	2.00	III	20	40
NaOH+ORS-62HF	1.25	III	60	80
NaOH+ORS-64HF	1.00	III	20	60
NaOH+ORS-64HF	1.25	III	40	60
NaOH+ORS-66HF	1.00	III	20	60
NaOH+ORS-66HF	1.25	II-	40	60
NaOH+ORS-97HF	0.50	III	20	40
NaOH+ORS-97HF	0.75	III	40	60
Na ₂ CO ₃ +ORS-97HF	1.00	III	0	20
Na ₂ CO ₃ +ORS-97HF	1.25	III	0	20
Na ₂ CO ₃ +ORS-97HF	1.50	III	0	20

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<u>Alkali+ 0.1 wt.% Surfactant</u>	Alkali Concentration wt.%	Initial phase type	% Produced Water Resulting in Loss of phase type	
			III	II-
NaOH+ORS-162HF	0.75	III	20	60
NaOH+ORS-162HF	1.00	III	40	60
Na ₂ CO ₃ +ORS-162HF	1.50	III	0	20
Na ₂ CO ₃ +ORS-162HF	2.00	II	20	40
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-162HF	0.625	III	60	---
NaOH+ORS-164HF	0.75	III	40	60
NaOH+ORS-164HF	1.00	III	40	60
Na ₂ CO ₃ +ORS-164HF	1.50	III	20	40
Na ₂ CO ₃ +ORS-164HF	2.00	III	40	60
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-164HF	0.625	III	40	---
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-164HF	0.75	II	60	20
NaOH+ORS-166HF	1.00	II-	---	60
NaOH+ORS-166HF	1.50	II-	40	60
0.25 wt% Na ₂ CO ₃ +NaOH+ORS-166HF	0.875	II	60	---
0.50 wt% Na ₂ CO ₃ +NaOH+ORS-166HF	0.875	II	60	---
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.00	III	20	60
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.50	III	20	60
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.25	II	---	---
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	1.75	II	---	---
0.25 wt% Na ₂ CO ₃ +NaOH +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.05:0.05 wt.%)	0.50	II	60	---
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	0.50	III	40	60
NaOH+Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	1.25	III	0	20
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	0.75	II-	---	0
Na ₂ CO ₃ +Petrostep B-100+Stepantan AS-1216 (B-100:AS-1216, 0.067:0.033 wt.%)	1.25	III	0	---

* - surfactant concentration is active and is the total surfactant (sum of any surfactant blends)

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Dilution of the NaOH solutions with produced water sustained optimum phase types (III and II-) to greater dilutions than did Na₂CO₃ solutions. Optimum phase type either upgraded (type II- to type III) or persisted longer with mixed alkalis solution for most solutions as shown in the figure to the left for Petronate EOR 2095.

The top ten chemical systems for future testing based on Surtek's in-house rating system are:

- 0.625 wt% NaOH plus 0.50 wt% Na₂CO₃ plus 0.1 wt% ORS-162HF
- 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.1 wt% Petronate EOR 2095
- 0.75 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.10 wt% ORS-41HF
- 1.00 wt.% NaOH plus 0.10 wt% Petronate EOR 2095
- 1.00 wt.% NaOH plus 0.10 wt% ORS-62HF
- 0.75 wt.% NaOH plus 0.50 wt% Na₂CO₃ plus 0.1 wt% Petronate EOR 2037
- 2.00 wt.% Na₂CO₃ plus 0.10 wt% ORS-164HF
- 1.00 wt.% NaOH plus 0.1 w.% Petronate EOR 2094
- 1.00 wt.% NaOH plus 0.1 wt% ORS-162HF
- 0.50 wt.% NaOH plus 0.25 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan AS-1216

Solutions for coreflooding initially will be taken from this list with polymer added to all solutions when used in corefloods. Cost of injected solutions will be a key factor for oil recovery corefloods.

3.6. Polymer Rheology

Apparent viscosity and screen factor of eight polymers were determined dissolved in softened injection water, 1.0 wt% NaOH plus 0.1 wt% Petronate EOR 2095, and 2.0 wt% Na₂CO₃ plus 0.1 wt% ORS-162HF. Table 3.6.1 through 3.6.3 list the data. Apparent viscosity versus polymer concentration and screen factor versus polymer concentration are plotted in the upper and lower plots of Figures 3.6.1 through 3.6.8. Polymers evaluated are listed in the following table.

<u>Polymer</u>	<u>Supplier</u>	<u>Weight</u>	<u>Hydrolysis</u>	<u>Description</u>
		<u>Dalton x 10⁶</u>	<u>%</u>	
Alcoflood 1285	Ciba	22	30	Polyacrylamide
Alcoflood 1275	Ciba	20	30	Polyacrylamide
Alcoflood 1235	Ciba	13.5	30	Polyacrylamide
Flopaam 3630S	SNF	19	28	Polyacrylamide
Flopaam 3530S	SNF	15.5	28	Polyacrylamide
Flopaam 3430S	SNF	12	32	Polyacrylamide
Cyanatrol 1266D	Cytec	30	30	Polyacrylamide
Cyanatrol 750	Cytec	15	35	Polyacrylamide

Apparent viscosity and screen factor generally varied with molecular weight with the exception of Cyanatrol 1266D. Cyanatrol 1266D viscosity and screen factor behaves like a much lower molecular weight polymer than reported. Other inter-manufacturers' polymers are comparable on a molecular weight basis.

3.7. Correlation of Polymer Hydrodynamic Radius with Pore Throat Radii

3.7.1 Intrinsic Viscosity - One can use rheological data to estimate the size of the polymer molecule. At a low, fixed shear rate one calculates the relative viscosity as:

$$\mu_r = \frac{\mu}{\mu_s}$$

where: μ_r = relative viscosity, μ_s = solvent viscosity, and μ = measured polymer viscosity or apparent viscosity. Polymer viscosity is extrapolated to one sec^{-1} .

The specific viscosity is: $\mu_{sp} = \mu_r - 1$

Reduced viscosity is: $\mu_R = \frac{\mu_{sp}}{c}$ where c = concentration, g/cm^3 .

Finally, the intrinsic viscosity is: $[\mu] = \lim_{c \rightarrow 0} \mu_R$. Radius of gyration of polymer is then calculated from intrinsic viscosity data as:

$$(R_G)^3 = \frac{[\mu] \times MW}{6.308 \times 10^{24} \times \xi}$$

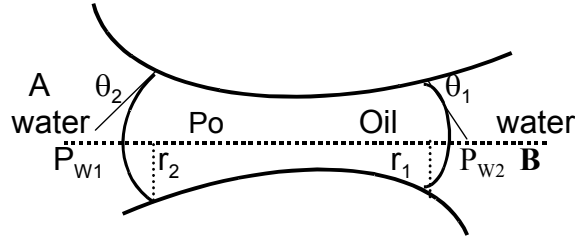
where MW is molecular weight in daltons and ξ is a parameter dependant on size and shape of the polymer molecule and of the hydration sphere taken as 0.875. Molecular weight is provided by the polymer manufactures.

Intrinsic viscosity and estimated radius of gyration data are tabulated and listed in Table 3.7.1.1. Radius of gyration varied from 0.220 to 0.440 microns when dissolved with alkali and surfactant. Dissolved in softened injection water, the radius of gyration increased by 46% for the 1.0 wt% NaOH solution and 36% for the 2.0 wt% Na_2CO_3 solution. Radius of gyration dissolved in softened injection water ranged from 0.343 to 0.560 microns.

3.7.2 Mercury Injection Capillary Pressure - Polymer Correlation - Mercury injection capillary pressure data from three Warner wells are summarized in Table 3.7.2.1. Ninety percent of the pore throats are between five and fifteen microns. Correlating radius of gyration with pore throat diameter, Cyanatrol 1266D is the only polymer dissolved in softened injection water that could be too large.

3.8. Interfacial Tension Reduction Calculations

3.8.1 Mercury Injection Capillary Pressure Calculation - In a reservoir, the pore throats are not uniform, capillary tubes and, therefore, the radius of the capillaries will vary. Schematically, this can be illustrated as follows.



Capillary pressure across the pore throat can be calculated using

$$P_B - P_A = 2\sigma_{ow} \cos \theta \left(\frac{1}{r_1} - \frac{1}{r_2} \right)$$

If $r_1 < r_2$, then $P_A < P_B$ and a static pressure gradient exists from A to B. This gradient has to be exceeded to induce flow. What is the pressure gradient required to move the drop of oil through a pore throat constriction? Assume the core is completely oil-wet, so $\Theta = 180^\circ$ and the capillaries are small so the interfaces are spherical. Interfacial tension between Warner oil and water is 15.0 dyne/cm, σ_{ow} . Mercury injection capillary pressure data suggests $r_1 = 10 \times 10^{-4}$ cm (on average 67% of pore throats are larger) and $r_2 = 17.5 \times 10^{-4}$ cm (on average 17% of pore throats are larger). Assume an oil drop length of 15×10^{-4} cm (1.50 times small pore throat diameter). Capillary pressure calculates to be

$$\frac{\Delta P}{L} = \frac{2(15.0) \left[\frac{1}{10 \times 10^{-4}} - \frac{1}{17.5 \times 10^{-4}} \right]}{15 \times 10^{-4}} K = 3,771 \text{ psi / ft}$$

where K is 0.00044 to convert units. The average pressure gradient in the Warner Field is 13,000 KPa or 1885 psi (injection well bottom hole pressure), with an estimated down hole pressure of 3260 psi over 300 m or 984 ft (average distance between injection well and production well) or 3.31 psi/ft. To calculate the interfacial tension reduction required to produce incremental oil based on pressure gradient calculations, the calculated pressure gradient is divided by the actual pressure gradient or:

$$\frac{3,771 \text{ psi / ft}}{3.31 \text{ psi / ft}} = 1,140 \text{ fold}.$$

Therefore, reduction of the interfacial tension to 0.013 dyne/cm (15.0 dyne/cm/1,140) should produce incremental oil according to capillary number calculation.

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3.8.2 Taber Number Calculation - Interfacial tension reduction is the ratio of the interfacial tension between oil and water divided by the final interfacial tension. Interfacial tension reduction is equivalent to the increase in capillary number. Taber's⁵ estimated average critical capillary number change required to reduce the residual oil saturation is approximately 4 to 5 for a 1000 md air permeability rock, like Warner. Taber used a modified form of capillary number, N_{CA} , to help determine the force change required to reduce oil saturation reduction. N_{CA} is defined as the ratio of viscous forces in the reservoir divided by the surface forces and is an estimate of the parameters at which either residual oil will be displaced or at which better oil displacement will occur. Taber's number is proportional to N_{CA} but is not dimensionless. From Darcy's law, viscous forces of fluid flowing in a reservoir as can be represented as

$$v\mu = k \frac{\Delta P}{L}$$

substitution into N_{CA}

$$N_{CA} = \frac{\text{Viscous Forces}}{\text{Surface Forces}} = \frac{k\Delta P}{L\sigma}$$

Surface forces are the interfacial tension between oil and water (σ). Taber ignored k , yielding:

$$N_T = \frac{\Delta P}{L\sigma}$$

The result of Taber's work was that no residual oil is produced from a core unless a specific critical value of $\Delta P/L\sigma$ was exceeded. Log of critical capillary number is inversely proportional to log permeability, permeability being considered a reflection of capillary dimensions. Critical capillary number is thus defined as that capillary number that must be exceeded before oil de-saturation begins. For Warner's average permeability of 1000 md, the critical Taber Number is 4 to 5.

$$\frac{\Delta P}{L\sigma} = 5 \text{ psi} / \text{ft} / \text{dyne/cm} = \frac{3,260 \text{ psi}}{984 \text{ ft} * \sigma}$$

Therefore, $N_{CA_{critical}} = 0.66 \text{ dyne/cm}$ or an interfacial tension reduction of 22 (15 dyne/cm/0.66 dyne/cm) is required to begin to mobilize residual oil.

Low concentrations of NaOH will begin to mobilize oil according to Taber's theory. Mercury injection capillary pressure data indicates greater interfacial tension reduction is necessary to produce larger quantities of incremental oil in Section 3.8.1.

4. Fluid-Rock Evaluations

4.1. Static Chemical Consumption - Static consumption tests are a method to estimate chemical losses that may occur due to adsorption onto reservoir rock. These tests used crushed, extracted reservoir core. As a consequence, values are generally high compared with a field application. Crushed rock has more exposed surface area than would normally be available for adsorption. The primary purpose of these tests is to compare consumption of various chemicals and classes of surfactants over time rather than for absolute values. Changes in interfacial tension due to prolonged solution/rock exposure are also evaluated.

Twelve chemical systems consisting of various combinations of alkali, surfactant, and polymer were selected. These solutions were mixed on a 1:1 ratio by weight with crushed, extracted Warner core and incubated at 35°C. Aliquot samples were taken at 0, 1, 4, 7 and 20 days and were analyzed for alkali, surfactant and polymer concentration in order to determine the mass of chemical consumed by the rock. The interfacial tension between the aqueous solutions and Warner crude oil was also measured.

Results are listed in Table 4.1.1 and shown in Figures 4.1.1 through 4.1.12. The average static consumption of NaOH was 76.2 mg/100 gm rock, representing approximately 3,000 lb/acre-ft assuming an average reservoir porosity of 25%. Average static consumption of Na₂CO₃ was 156.0 mg/100gm rock, or approximately 6,150 lb/acre-ft. Consumption of NaOH was not affected by addition of surfactant and polymer to the solution. NaOH and Na₂CO₃ static consumption is low with a preference shown toward NaOH. Alkali retention values are close to those of Etzikom which were NaOH at 7,910 lb/acre-ft and Na₂CO₃ at 4,290 lb/acre-ft.

The average static consumption of surfactant was 69.3 mg/100 gm rock, or approximately 2,750 lb./acre-ft. Surfactant consumption ranged from 440 lb/acre-ft to 3,320 lb/acre-ft. The majority of surfactants consumption values were in the 2,500 to 3,300 lb/acre-ft range. Petro P class surfactants showed very low adsorption at 440 lb/acre-ft. All surfactant classes' static adsorption values are low for a field application. A slight distinction could be made between the consumption of surfactant in the presence of NaOH (2,730 lb/acre-ft) and Na₂CO₃ (3,140lb/acre-ft).

Static polymer consumption is low. In the presence of alkali and surfactant, polymer static consumption was essentially zero with the laboratory data showing slightly negative consumption. With only polymer dissolved in injection water, static adsorption is 4.6 mg/100 g rock or 180 lb/acre-ft.

Interfacial tension values stayed low over the 20-day test for the majority of solutions. Optimum solutions maintained interfacial tension values of 0.004 dyne/cm.

Adsorption of chemical onto Warner rock will not be a detriment to incremental oil recovery based on static adsorption results.

4.2. Cation Exchange Capacity - Cation exchange results from altering the ionic makeup of the water in contact with the reservoir rock. The cation exchange mechanism depends upon the fraction of clays in the multivalent form. This can be expressed as:

$$\frac{[Na]^2}{[Ca]_{clay}} = K \frac{[Na]^2}{[Ca]_{water}}$$

The source for cation exchange is the equilibrium between clays and reservoir water. Thus, as one increases the Na/Ca ratio by adding a sodium alkaline salt, the rock reacts to maintain the equilibrium by releasing calcium if available. Unfortunately, this released calcium will precipitate some alkali and will make the surfactant more oil soluble, which affects IFT and phase behavior.

To estimate the amount of calcium and magnesium which could be released from the rock and precipitate injected alkali and/or surfactant, a column chromatographic cation exchange capacity test using the Warner core was performed. Extracted, crushed core from the three Warner wells at various depths was flushed with 2N sodium chloride (NaCl) until the calcium concentration of the produced fluid was low and the concentration was asymptotic. The column was then flushed with 0.05N calcium chloride (CaCl₂) until the effluent calcium concentration was equal to that being injected. Cation exchange capacity is defined as the point at which no additional calcium is re-adsorbed onto the rock. The measured cation exchange capacity represents the maximum amount of exchange sites available for consumption, since all of the clay is forced into the multivalent form during the test.

The cation exchange capacity of Warner core was 0.61 milliequivalent/100g rock, a low value. Cation exchange capacity of the Etzikom core is 0.79 milliequivalents/100g rock, supporting the Warner value. Both are close to the cation exchange capacity for Berea Sandstone of 0.5 meq/100 g rock.³⁰ Cation exchange capacity of fields in which alkaline, alkaline-surfactant or alkaline-surfactant-polymer solutions have been injected is as high as 7.0 meq/100g sand for the Wilmington project.³¹

5.0 Linear Corefloods

Six polymer rheology linear corefloods were performed in the Warner Alkaline-Surfactant-Polymer feasibility study; four treating the core oil-wet and two treating the core water-wet. Linear coreflood were performed for the following reasons:

- To determine relative permeability characteristics.
- To determine chemical-rock incompatibilities.
- To determine the injection capabilities of different polymers dissolved in alkaline-surfactant solution into reservoir core.
- To determine the injection capabilities of different polymers dissolved in injection water into reservoir core.
- To determine the rheological characteristics of different polymers dissolved in alkaline-surfactant solution as solution flows through polymer satiated Warner rock.

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- To estimate the concentration of polymer dissolved in alkaline-surfactant solution that is required to give a unit mobility ratio for that solution flowing through polymer satiated rock.
- To define amount of alkali, surfactant and polymer retained by Warner core.
- To define the oil saturation changes after injection of water and chemical solutions.

Chemical solutions injected in linear corefloods were selected from the preliminary fluid-fluid evaluations³² and the well and depth of the core are listed below.

- **Fluid** - 1.00 wt% NaOH + 0.1 wt% Petronate EOR 2095+ Flopaam 3630S
Core - 00/04-21-007-16W4, 3196.5 ft
- **Fluid** - 2.00 wt% Na₂CO₃ + 0.1 wt.% ORS-162HF + Flopaam 3530S
Core - 00/04-21-007-16W4, 3200.9 ft
- **Fluid** - 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ + 0.1 wt.% Petronate EOR 2095 + Alcoflood 1275A
Core - 02/09-007-16W4, 3233.7 ft
- **Fluid** - 0.75 wt% NaOH + 0.1 wt.% ORS-97HF + Cyantrol 770
Core - 00/16-20-007-16W4, 3226.8 ft
- **Fluid** - 0.75 wt% NaOH + 0.1 wt.% ORS-97HF + Alcoflood 1275A
Core - 00/04-21-007-16W4, 3199.3 ft
- **Fluid** - 1.00 wt% NaOH + 0.1 wt.% ORS-97HF + Flopaam 3630S
Core - 00/16-20-007-16W4, 3236.1 ft

Polymers selected were all high molecular weight polymer with polymer radius of gyration ranging from 0.37 to 0.45 microns when dissolved in softened injection water and 0.24 to 0.29 micron when dissolved with alkali and surfactant. Intrinsic viscosity and radius of gyration calculations are discussed in Section 3.7 of the fluid-fluid report. Flopaam 3530S and Flopaam 3630S are solid polyacrylamide polymers manufactured by SNF Floerge. Alcoflood 1275A is a dry polyacrylamide polymer manufactured by Ciba Speciality Chemicals. Cyantrol 770 is a dry polyacrylamide polymer manufactured by Cytec. Linear coreflood procedures are detailed in Appendix B and the equations used in coreflood data analysis are found in Appendix C.

5.1 Relative Permeability - Unsteady-state oil-water relative permeabilities were determined at 35°C using four linear core plugs handled oil-wet from well 00/04-007-16W4 at a depth of 3,196.5 and 3,200.9 ft and from wells 02/09-20-007-16W4 and 00/16-20-007-16W4 at a depth of 3233.7 and 3226.8 ft and two linear core plugs handled water-wet from well 00/04-21-007-16W4 at a depth of 3199.3 ft and well 00/16-20-007-16W4 at a depth of 3236.1 ft. Relative permeabilities were determined using a computer adaptation of a standard graphical technique.³³ Warner reservoir crude oil diluted with 7.3% white gas so the injected viscosity was 52 cp at 35°C and actual produced water was used in the determination. Oil and water viscosities are listed in Table 5.2.1. Oil-wet relative permeability data are compiled in Tables 5.1.1.1 through 5.1.1.4 and depicted in Figures 5.1.1.1 and 5.1.1.4. Water-wet relative permeability data are compiled in Tables 5.1.1.5 through 5.1.1.6 and depicted in Figures 5.1.1.5 and 5.1.1.6. Fractional flow data are shown in Figures 5.1.2.1 and 5.1.2.6.

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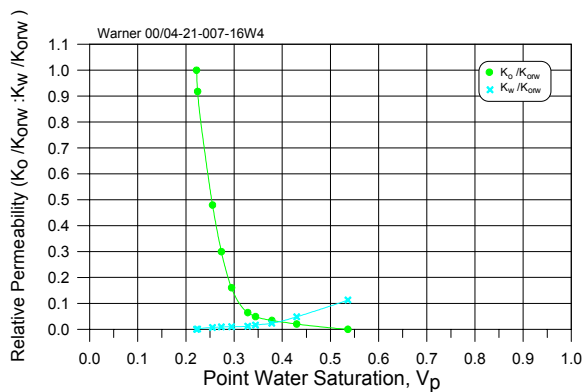
Injection rate for relative permeability determinations was calculated according to Batycky.³⁴ This methodology requires high injection rates to overcome end effects.

Relative permeability curves suggest an oil-wet to intermediate wetting nature for these core samples.³⁵ The criteria that define core as water-wet or oil-wet are:

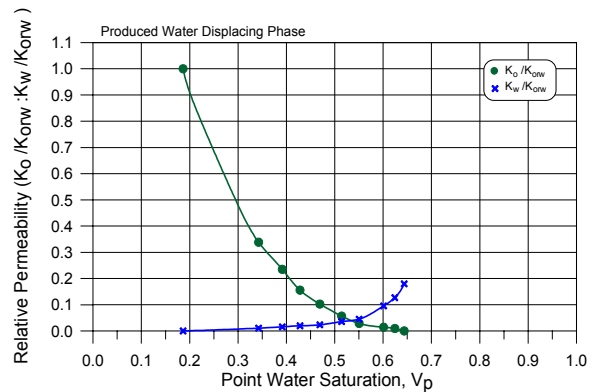
		----- Core Handling-----	
		Oil-Wet	Water-Wet
		Average	Average
		Warner	Warner
Initial Water Saturation S_{wi}	Literature Description <u>Water-wet</u> $> 20\% V_p$ <u>Oil-wet</u> $< 15\% V_p$	19.8%	18.8%
Relative Permeability crossover point ($k_{ro} = k_{rw}$)	$S_w > 50\% V_p$ $S_w < 50\% V_p$	37% V_p	53% V_p
Relative Permeability to Water at Residual Oil (k_{wro})	< 0.3 > 0.3	0.139	0.165
Final Oil Saturation, S_{or}	-----	0.501	0.344

Characteristics that suggest an oil-wet nature are: 1) 0.802 V_p average initial oil saturation for oil-wet core and 0.812 V_p for water-wet core is greater than 0.80 V_p , and 2) the relative permeability crossover point, where $k_{ro} = k_{rw}$, is 0.37 V_p water saturation for oil-wet core which less than 0.50 V_p - the dividing point separating oil-wet and water-wet core. Water-wet core shows water-wet nature for this parameter, where $k_{ro} = k_{rw}$, is 0.53 V_p . Relative permeability property suggesting water-wet nature is that the average relative permeability to water at residual oil saturation, k_w/k_{wro} , of 0.139 for oil-wet core and 0.165 for water-wet core is less than 0.300. What is interesting is when the core was treated water-wet, the effective permeability show more oil-wet characteristic than when the core was treated oil-wet. Relative permeability curves using core from 02/09-20-007-16W4 handled oil-wet and core from 00/04-021-007-16W4 handled water-wet are shown by the two plots below.

Oil-Wet, 02/09-20-007-16W4



Water-Wet, 00/04-021-007-16W4



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The major differences between the two curves are:

- volume of oil produced by injection of produced water
- relative oil permeability curve of core 02/09-20-007-16W4 displays greater oil-wet character.

Initial oil saturation and effective water permeability curves are similar.

Mobility ratio is calculated according to Smith³⁶ for produced water displacing Warner crude oil. Mobility ratio ranges from 8.1 to 13.5 for an average of 10.9 for oil-wet treated core and range from 11.4 to 13.5 for an average of 12.4 for water-wet treated core. Water is a poor displacing agent for removing Warner crude oil from the reservoir regardless of how the core is treated.

Relative Permeability Waterflood Oil Recovery - Waterflood oil displacement efficiency is shown in the cumulative oil recovery and incremental oil cut versus cumulative produced fluids curves shown in Figures 5.1.3.1 through 5.1.3.6. Tables 5.1.3.1 through 5.1.3.6 list the data. Both tables and figures 5.1.3.1 through 5.1.3.4 are water-wet treated core and 5.1.3.5 and 5.1.3.6 are oil-wet handled core. Oil recovered in this portion of the linear corefloods represents oil displaced in the field during primary recovery and waterflood operations. The following table summarizes average waterflood performance.

Average Warner Linear Coreflood Waterflood Performance

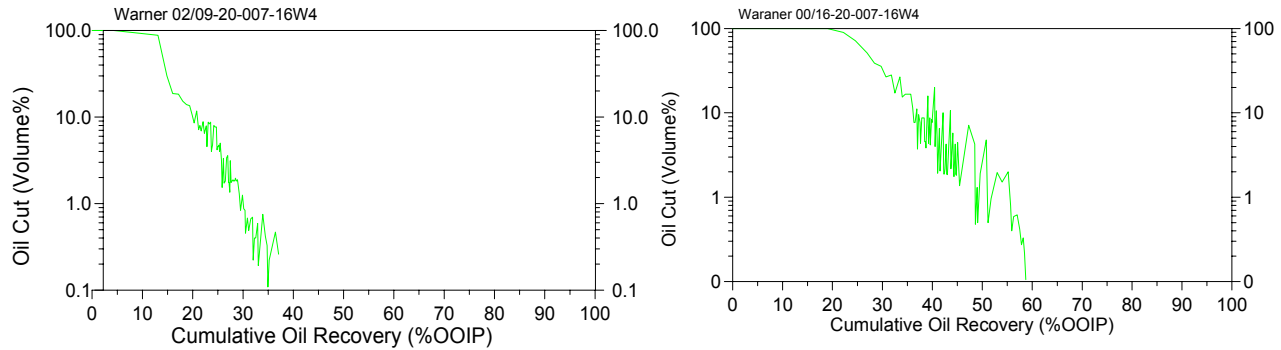
-----Oil-Wet Core-----				-----Water-Wet Core-----			
Fluids	Average	Average	Percent	Fluids	Average	Average	Percent
Produced (V _p)	Oil Cut, %	Oil Recovery	Cumulative	Produced (V _p)	Oil Cut%	Oil Recovery	Cumulative
		%OOIP	of Oil			% OOIP	of oil
0.05*	---	6.2	16.4	0.19	---	22.7	39.5
0.07	88.0	8.0	21.2	0.30	33.2	29.8	51.7
0.10	62.0	10.2	26.9	0.40	20.8	33.1	57.5
0.20	24.8	13.8	36.5	0.50	14.2	35.2	61.1
0.30	14.3	15.9	42.1	1.00	4.6	40.3	70.0
0.40	9.4	17.2	45.5	2.00	3.9	45.0	78.3
0.50	6.4	18.0	47.6	3.00	2.6	48.2	83.8
1.00	5.1	21.6	57.1	4.00	1.1	49.6	86.2
2.00	1.9	25.6	67.7	5.00	0.8	50.7	88.2
3.00	1.2	27.9	73.8	24.1**	0.0	57.5	100.0
4.00	1.2	29.4	77.8				
5.00	1.0	31.0	81.9				
27.5**	0.1	37.8	100.0				

* - water break through, ** - end of waterflood

Waterflood performance of coreflood 3L treated oil-wet is shown below in the left hand figure while the right hand figure depicts the waterflood performance of the water-wet handled coreflood 6L. Primary differences seen in both the figures and the above table are:

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- water break through occurs much earlier with oil-wet treated core
- oil cut decline as a function of cumulative oil recovery is greater for oil -wet treated core
- oil recovery of oil-wet handled core is 20% OOIP less than water-wet treated core



5.2 Brookfield Rheology of Polymer Solutions - High molecular weight polyacrylamide polymers from SNF Floerger, Ciba Speciality Chemicals, and Cytec were dissolved in an alkali plus surfactant solution, and in softened injection water. Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, and Cyanatrol 770 were tested. Table 5.2.1 lists the viscosity and screen factor data for solutions injected into the corefloods. Figures 5.2.1 through 5.2.6 depict the data. Alcoflood 1275A develops the largest apparent viscosity but the smallest screen factor when dissolved in alkaline-surfactant solutions. Both Flopaam polymers dissolved in alkaline-surfactant solutions develop larger screen factors but the lower apparent viscosities. When dissolved in softened injection water, Alcoflood 1275A develops the lowest apparent viscosity and the lowest screen factor. When Figures 5.2.1 and 5.2.6 (Flopaam 3630S), and Figures 5.2.3 and 5.2.5 (Alcoflood 1275A) are compared, the data suggest that a slight change in the alkaline-surfactant-polymer solution composition will result in a minimal change of apparent viscosity. Changing the surfactant type as in the 3630S comparison and changing the alkali mixture as well as the surfactant type resulted in similar apparent viscosities. Screen factors were close for the Alcoflood 1275A comparison but not for the Flopaam 3630S comparison.

5.3 Polymer Solution Flowing Rheology and Fluid-Rock Compatibility - Primary purpose of the linear corefloods is to provide polymer rheology data as solutions flow through reservoir core. This is complicated by the fact that polymer solutions are shear thinning fluids (pseudoplastic) and can be shear thickening (thixotropic) depending on shear rate. Polymer solutions exhibit lower viscosity near an injection well where flow rate is greatest with solution viscosity increasing as the solution moves away from the well into the formation.

Tables 5.3.1.1 through 5.3.1.6 are end point summaries listing injection sequence, rate of fluid injection, volume of fluid produced, and ending values for the following parameters: oil saturation, pressure, resistance factor, permeability, permeability reduction, and effective viscosity of the injected solution. Effective viscosity is the viscosity of a flowing polymer solution as calculated from Darcy's Law, assuming

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permeability to water during polymer flow is identical to that in the subsequent water flush step. Tables 5.3.2.1 through 5.3.2.6 list the incremental resistance factors and pressures. Incremental data are depicted in Figures 5.3.2.1 through 5.3.2.6. As before, both tables and figures 5.1.3.1 through 5.1.3.4 are water-wet treated core and 5.1.3.5 and 5.1.3.6 are oil-wet handled core. Please refer to these tables and figures throughout the discussion of the linear corefloods.

Produced Water Injection - Produced water injection was used as the baseline for calculation of resistance factor, effective permeability reduction, and all comparisons. Produced water injected into and flowed through Warner either oil-wet or water-wet core without problems. Cores from the three wells behaved identically.

Unsoftened Injection Water Injection - Unsoftened injection water injected into and flowed through Warner core from each of the three wells without problems regardless of core treatment.

Alkali Injection - NaOH, Na₂CO₃ and a blend of NaOH plus Na₂CO₃ were injected in respective corefloods. NaOH and Na₂CO₃ injected into and flowed through oil-wet core from well 00/04-21-007-16W4 with little change in effective water permeability. Injection of NaOH plus Na₂CO₃ into 02/09-007-16W4 oil-wet core and NaOH into 00/16-20-007-16W4 oil-wet core showed a reduction in permeability throughout the core. The two water-wet core, 00/04-21-007-16W4 and 00/16-20-007-16W4 both showed reduction of effective water permeability when NaOH was injected. Alkali injected and flowed through both core at higher resistance factors which translates to lower injection rate in the field.

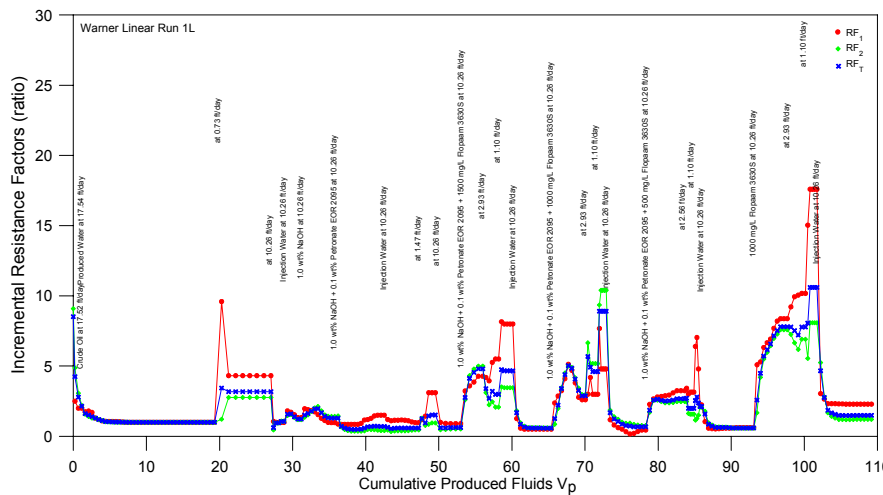
Alkali-Surfactant Injection - Alkaline-surfactant solution improved injectivity in all corefloods. Resistance factors declined to values below produced water injection regardless of whether the core was treated oil-wet or water-wet. Injectivity improvement was maintained with the subsequent injection water injection as shown the following table.

Alkaline-Surfactant Injectivity Improvement in Warner Core

oil-wet	Injectivity Improvement Relative
<u>Alkaline-Surfactant Solution Injected</u>	<u>Initial Produced Water %</u>
1L - 1.00 wt% NaOH+0.1 wt% Petronate EOR 2095	69.9%
2L - 2.00 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF	282%
3L - 0.50 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR-2095	28.5%
4L - 0.75 wt% NaOH + 0.1 wt% ORS-97HF	-15.6%
water-wet	
5L - 0.75 wt% NaOH + 0.1 wt% ORS-97HF	121.3%
6L - 1.0 wt% NaOH + 0.1 wt% ORS-97HF.	21.6%

Observed injectivity improvement is the result of chemical rock interaction as evident by maintenance of low resistance factors. Oil saturation reduction is a contributing factor in that oil saturations are reduced by 0.075 to 0.150 Vp.

Alkali-Surfactant-Polymer Injection - Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, and Cyanatrol 770 were added to alkaline-surfactant solutions. No injectivity or flow problems were seen for either Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, or Cyanatrol 770 when injected with alkali and surfactant with either oil-wet or water-wet treated core. Similar resistance factors were measured for all polymer types. Tables 5.3.2.1 through 5.3.2.6, and Figures 5.3.2.1 through 5.3.2.6 show typical resistance factors behavior for ultra high molecular weight polymer. Resistance factors increase with injection rates of 3 ft per day or lower, in a manner consistent with the pseudoplastic solution. However, resistance factors at 10 ft/day are greater, consistent with dilatant

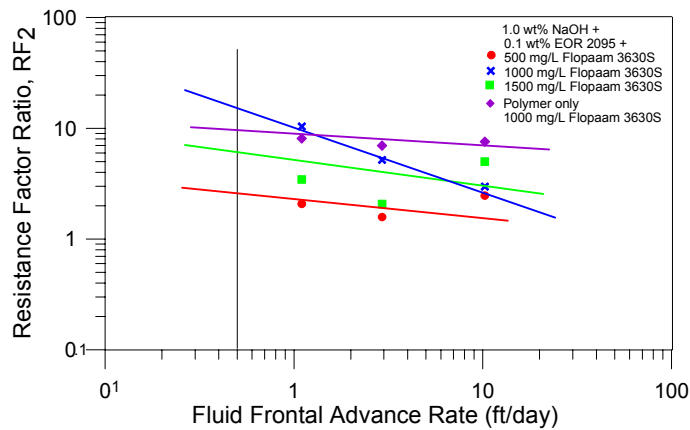


behavior. For injected polymer concentration calculations, emphasis was place on the pseudoplastic behavior.

Polymer dissolved in softened injection water showed pseudoplastic and dilatant characteristics. No injectivity or flow problems were seen for either Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, or Cyanatrol 770 when injected into either water-wet or oil-

wet treated core. These can be seen for Flopaam 3630S in Figure 5.3.2.1, reproduced to the left. Other polymers performances are shown in Figures 5.3.2.1 through 5.3.2.6 where resistance factors increase to stable values with changes in an injection rate or changes of injected fluids.

5.4 Concentration of Polymer Required for Mobility Control - Resistance factor data is used to estimate the concentration of polymer required to give a unit mobility ratio. A discussion of the relationship between a resistance factor, effective viscosity, and mobility ratio, and how the data are used to calculate the required polymer concentration is found in Appendix D and is discussed by Manji and Stasiuk.³⁷ A simplified way to think about resistance factors relationship to polymer concentration is that resistance factor is normalized flowing viscosity. In this case, resistance factors are normalized to produced water. So a resistance factor of 10 indicates the flowing viscosity of the injected fluid is ten times that of produced water. Figures 5.4.1 and 5.4.4 show resistance factor versus a fluid frontal advance rate in the upper plots for the water-wet treated core and Figure 5.4.5. and 5.4.6 depict the data for the oil-wet treated core. The lower plot is used to determine concentration of polymer required to develop the necessary resistance factor at an average fluid frontal advance rate of 0.5 ft/day.



Flopaam 3630S displayed pseudoplastic and dilatant characteristics in the upper plot of Figure 5.4.5.1 displayed to left. Similar behavior was displayed by Flopaam 3530S, Alcoflood 1275A, and Cyanatrol 770. Water-wet treated core show more pseudoplastic characteristics and less dilatant behavior.

Polymer concentration required for mobility control based on resistance factor data are Flopaam 3603S - 1100 mg/L Flopaam 3530S - 1300 mg/L, Alcoflood 1275A - 1,250 mg/L, and Cyanatrol 770 - 1,500 mg/L for injection into oil-wet treated core. When water-wet treated core is used, required polymer concentration are Flopaam 3630S - 1,300 mg/L and Alcoflood 1275A - 1,850 mg/L. The higher polymer concentration required for the water-wet treated core is consistent with the higher effective water permeability and increased mobility ratio.

5.5 Effluent Analysis of Polymer Rheology Linear Corefloods - Alkali, surfactant, and polymer effluent concentration for the four linear corefloods, as well as the calculated consumptive losses, are presented in Tables 5.5.1 through 5.5.4 for oil-wet handled core and Tables 5.5.5 and 5.5.6 for water-wet treated core. Consumption of alkali is similar for the two core handling procedures. Consumption of NaOH onto oil-wet treated core in Coreflood 1L was 24,447 lb/acre-ft while in coreflood 4L 36,104 lb/acre-ft of NaOH was retained. Water-wet handled core consumed 21,118 lb/acre-ft in coreflood 5L and 1,074 lb/acre-ft in coreflood 6L. All core, whether treated oil-wet or water-wet, produced significant quantities of Na_2CO_3 when NaOH was injected. An average of 163,100 lb/acre-ft of Na_2CO_3 was produced. Na_2CO_3 retention in coreflood 2L was 4,623 lb/acre-ft. Injection of a mixed NaOH and Na_2CO_3 resulted in a retention of 8,926 lb/acre-ft for NaOH and 5,264 lb/acre-ft for Na_2CO_3 . Etzikom retention of alkali was 16,827 lb/acre-ft for NaOH and 17,471 lb/acre-ft for Na_2CO_3 , comparable to Warner. Consumption values are acceptable and are of lower magnitude than the West Kiehl and Cambridge Minnelusa core. Comparative values for successful field projects are the West Kiehl and Cambridge projects, where Na_2CO_3 retention values in Corefloods were 77,000 lb/acre-ft and 109,000 lb/acre-ft, respectively.^{38,39,40} Alkali consumption values for the Warner core are low and acceptable for a field project.

Surfactant consumption by Warner sand was in the range observed for most field applications, ranging from 2,831 lb/acre-ft for Petronate EOR 2095 mixed with the two alkalis to 7,321 lb/acre-ft for Petronate EOR-2095 mixed with NaOH with oil-wet treated core. Surfactant retention was similar in water-wet handled core, averaging 3,895 lb/acre-ft for ORS-97HF dissolved with NaOH. Note in Tables 5.5.1 through 5.5.6 that the produced surfactant concentrations increase significantly with each unsoftened injection water flush. This suggests that even at 0.75 wt% alkali, alkaline-surfactant

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solutions might be over designed and that some surfactant was trapped in the oil phase during chemical injection. Average surfactant retention at Etzikom was 4,880 lb/acre-ft.

Polymer retention value for Flopaam 3630S, Flopaam 3530S, Alcoflood 1275A, and Cyanatrol 770 were in the 75 to 1,594 lb/acre-ft range for oil-wet treated core during alkaline-surfactant-polymer solution injection. Flopaam 3630S and Alcoflood 1275A retention onto water-wet treated core were 105 and 851 lb/acre-ft, respectively, similar to the oil-wet case. Polymer consumption onto water-wet treated core increased from an average of 853 lb/acre-ft with alkali + surfactant to 1,300 lb/acre-ft range for polymer dissolved in softened injection water. Oil-wet handled core results were mixed when the dissolution fluid was switch from alkali + surfactant to softened injection water. Alcoflood 1275A retention declined from 851 to 379 lb/acre-ft while Flopaam 3630S retention increased from 105 to 354 lb/acre-ft.

Linear coreflood retention of polymer in Etzikom rock was similar, 572 lb/acre-ft for Alcoflood 1275L with ORS-41 plus NaOH and 633 lb/acre-ft for Alcoflood 1285 with Petronate EOR 2095 plus Na₂CO₃. Retention of polymer alone was 682 lb/acre-ft for Alcoflood 1275L and 1,137 lb/acre-ft for Alcoflood 1285.

Chemical retention by Warner core does not vary significantly with core handling. Retention of all chemicals by Warner core is acceptable for a field application.

Retentive consumption of polymer in linear Corefloods is required to distinguish the quantity of polymer that provides resistance through viscosity increases from that amount that provides resistance through adsorption or entrapment. To define retention requirements for the polymer concentration necessary to give a mobility ratio of one, calculated concentrations for adsorption requirements are based on injection of 0.60 V_p total pore volume. These values are provided below.

Polymer Concentration Requirements

<u>Injected Fluid Composition</u>	<u>Polymer Concentration (mg/L)</u>		
	<u>Resistance</u>	<u>Adsorption</u>	<u>Total</u>
oil-wet			
Flopaam 3530S in Alkaline-Surfactant	1300	1350	2650
Flopaam 3630S in Alkaline-Surfactant	1100	105	1200
Alcoflood 1275A in Alkaline-Surfactant	1250	2500	3750
Cyanatrol 770 in Alkaline-Surfactant	1500	1200	2700
water-wet			
Flopaam 3630S in Alkaline-Surfactant	1300	515	1810
Alcoflood 1275A in Alkaline-Surfactant	1850	525	2375

These calculated values are for large volumes of chemical injection. Recommended field injected concentrations will be made after the oil recovery corefloods in which field appropriate volumes are injected.

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5.6 Oil Recovery of Polymer Rheology Linear Corefloods - Oil recovery for each injected solution in the linear corefloods and oil saturation changes are detailed in the end point summaries contained in Tables 5.3.1.1 through 5.3.1.4. Oil recovery resulting from alkaline-surfactant-polymer injection was encouraging. Recoveries at each step are detailed in the following table.

Oil Recovery in Linear Corefloods

	-----oil-wet-----				-----water-wet----	
<u>Injection Step</u>	<u>Coreflood 1L</u>	<u>Coreflood 2L</u>	<u>Coreflood 3L</u>	<u>Coreflood 4L</u>	<u>Coreflood 5L</u>	<u>Coreflood 6L</u>
Well	00/04-21	00/04-21	02/09-21	00/16-20	00/4-21	00/16-20
Crude Oil (initial Oil Sat), V_p	0.788	0.804	0.840	0.796	0.813	0.807
Produced Water Oil Recovery, V_p	0.362	0.388	0.322	0.250	0.457	0.475
%OOIP	45.9	48.2	38.3	31.4	58.4	58.8
Residual Oil Saturation, V_p	0.426	0.416	0.518	0.536	0.356	0.332
Injection Water Oil Recovery, V_p	0.000	0.000	0.000	0.000	0.000	0.000
Residual Oil Saturation, V_p	0.426	0.416	0.518	0.536	0.356	0.332
Alkali Injection Oil Recovery, V_p	0.028	0.032	0.002	0.060	0.002	0.015
%OOIP	3.6	4.0	0.2	7.5	0.2	1.9
Residual Oil Saturation, V_p	0.398	0.384	0.516	0.476	0.354	0.317
Alkaline-Surfactant Oil Recovery, V_p	0.122	0.043	0.090	0.026	0.048	0.014
%OOIP	15.5	5.3	10.7	3.3	5.9	1.7
Residual Oil Saturation, V_p	0.276	0.341	0.426	0.450	0.306	0.303
Alkaline-Surfactant-Polymer						
Oil Recovery, V_p	0.134	0.132	0.258	0.261	0.089	0.082
%OOIP	17.2	16.4	30.7	33.2	10.9	10.2
Residual Oil Saturation, V_p	0.142	0.209	0.168	0.189	0.217	0.221
Polymer Oil Recovery, V_p	0.001	0.001	0.004	0.005	0.003	0.008
%OOIP	0.1	0.1	0.4	0.6	0.4	1.0
Final Residual Oil Saturation, V_p	0.141	0.208	0.164	0.184	0.214	0.213
Total Oil Recovery, V_p	0.647	0.596	0.676	0.612	0.599	0.594
%OOIP	82.1	74.1	80.5	76.9	73.8	73.6

Average total recovery from oil-wet handled core was 78.4% OOIP with injection of 33.5 V_p of produced water recovering 41.0% OOIP and subsequent chemical injection producing 37.4% OOIP. Average total recovery from water-wet treated core was 73.7% OOIP after injection of 39.2 V_p of produced water recovering 58.6% OOIP and

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subsequent chemical injection producing 15.1% OOIP. The prior comparison evinces a startling difference between oil-wet and water-wet treated core. Waterflood oil recovery is considerably better with water-wet treated core leaving a lower oil target for alkaline-surfactant-polymer oil recovery. Average final residual oil saturation is slightly higher for the two water-wet handled core as well, 0.214 Vp compared to 0.174 Vp.

6.0 Radial Corefloods

Radial corefloods provide a physical simulation of the alkaline-surfactant-polymer process and a realistic measure of the oil recovery in the flooded portion of the field. Radial corefloods use field-proportioned volumes of chemicals. Thus, results from radial corefloods generally are a reflection of what may be expected in the field. In essence, radial corefloods take into account all of the following criteria: interfacial tension reduction, phase behavior, chemical adsorption, thinning of the chemical banks, and mobility control. Specific reasons for performing this series of radial corefloods are:

- To estimate the amount of oil produced by waterflooding and to define the oil saturation end points of the relative permeability curve.
- To estimate the amount of oil produced by alkaline-surfactant-polymer flooding and to define oil saturation end points of the relative permeability curve after chemical injection.
- To determine the mass of chemical retained by Warner core.
- To determine if potential injection and flow problems exist with injection of an alkaline-surfactant-polymer solution and a polymer solution.
- To look for potential scale problems as a result of chemical injection.⁴¹

Procedures for the radial corefloods are listed in Appendix E. Equations used are summarized in Appendix C. Physical properties of the injected fluids are listed in Table 6.0.1. Table 6.0.2 is a summary of core properties, volumes and sequence of fluids injected into the radial corefloods, and oil saturation changes and oil recovery during the waterflood and chemical flood. Oil-wet and water-wet treated cores were used for the radial corefloods. Incremental oil cut and cumulative oil recovery are listed in Tables and Figures 6.1.1-6.1.14.

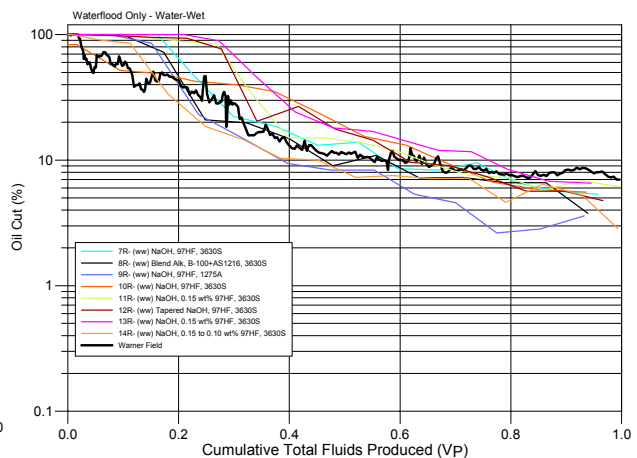
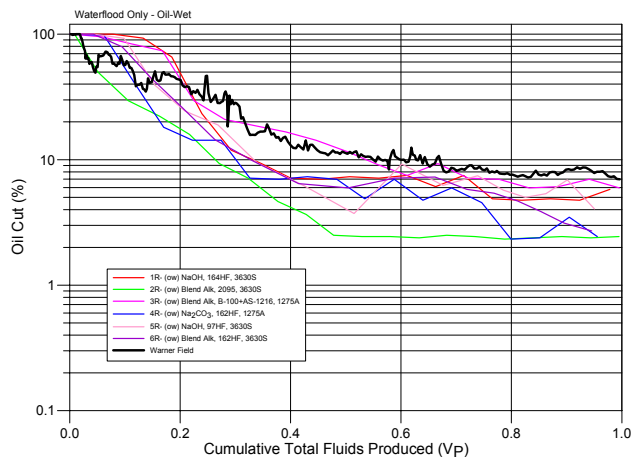
6.1 Waterflood Oil Recovery Data - Waterflood performances varied with the two core handling procedures. Oil-wet core water break through was early and oil production was lower. Oil cuts of 0.5% or less were being produced at the end of waterflood production, so differences were due to relative permeability characteristics. The waterflood performance of the radial corefloods is summarized in the following table.

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Waterflood Performance: Warner Radial Corefloods

Coreflood	Permeability	Initial Oil	Water	Final*	Waterflood		Waterflood
	To Oil	Saturation	Breakthrough	Oil Cut	Cumulative	Residual	
	md	V _P	V _P	%	Oil Recovery	Oil Saturation	
					V _P	%OOIP	V _P
oil-wet							
1R	274	0.836	0.12	0.5	0.289	34.5	0.548
2R	431	0.834	0.03	0.2	0.136	16.3	0.698
3R	337	0.781	0.05	0.5	0.304	39.0	0.476
4R	474	0.709	0.05	1.0	0.175	24.6	0.534
5R	145	0.811	0.09	0.3	0.220	27.1	0.591
6R	<u>127</u>	<u>0.795</u>	<u>0.07</u>	<u>0.3</u>	<u>0.206</u>	<u>25.9</u>	<u>0.589</u>
Average	298	0.794	0.07	0.5	0.222	27.9	0.573
water-wet							
7R	875	0.762	0.18	0.2	0.326	42.8	0.435
8R	530	0.864	0.15	0.9	0.292	33.8	0.572
9R	333	0.811	0.14	0.0	0.231	28.5	0.579
10R	481	0.812	0.01	0.1	0.309	38.1	0.503
11R	1180	0.821	0.13	0.2	0.400	48.7	0.421
12R	837	0.838	0.09	1.8	0.395	47.2	0.443
13R	1041	0.878	0.25	0.2	0.470	53.5	0.409
14R	<u>1294</u>	<u>0.842</u>	<u>0.05</u>	<u>0.5</u>	<u>0.233</u>	<u>27.7</u>	<u>0.609</u>
Average	821	0.828	0.12	0.5	0.332	40.0	0.496

Initial oil saturation of water-wet treated core is higher than oil-wet handled core perhaps due to the higher effective permeability to oil. However, no clear trend of oil saturation and effective oil permeability is evident. Waterflood oil recoveries of corefloods vary within each group with water-wet treated core having significantly greater waterflood oil recovery than oil-wet handled core. As in the linear corefloods, this results in a lower average waterflood residual oil saturation and, therefore, a lower oil target for chemical recovery. Water breakthrough occurs after producing 0.07 V_p of oil with oil-wet treated core compared to 0.12 V_p with water-wet handled core. The delayed water breakthrough is a contributor to the higher water flood oil recoveries of the water-wet treated core.



Waterflood recovery in oil-wet and water-wet treated core are compared to the field in the two figures on the subsequent page. Oil-wet treated corefloods to the left and Water-wet treated corefloods to the right. Waterflood oil recoveries were truncated at 1.0 V_p because of field injected volumes. Oil cut is plotted as a function of cumulative total fluids produced. A field pore volume of 57,200,000 bbls was used. Oil-wet treated core waterflood results mimic the field performance better early in the field performance than the water-wet handled core due to where water breaks through. However, later in the life of the field project, water-wet handled core correlates to field performance better.

6.2 Chemical Flood Oil Recovery Data - Chemical solutions injected in the radial corefloods are listed in Table 6.0.1. Figure 6.0.1 shows ASP solution viscosity versus temperature. Procedures for the radial corefloods are detailed in Appendix E. Chemical formulations were selected based on fluid-fluid evaluation ranking and linear corefloods. Table 6.0.2 summarizes the performance of the radial corefloods. Incremental oil cut and cumulative oil recovery are listed in Tables and Figures 6.1.1 to 6.1.14. Figure 6.1.15 and 6.1.18 compare the oil-wet and water-wet treated corefloods, respectively, on a normalized basis. The following table summarizes the response to chemical injection.

Chemical Flood Performance: Warner Radial Corefloods

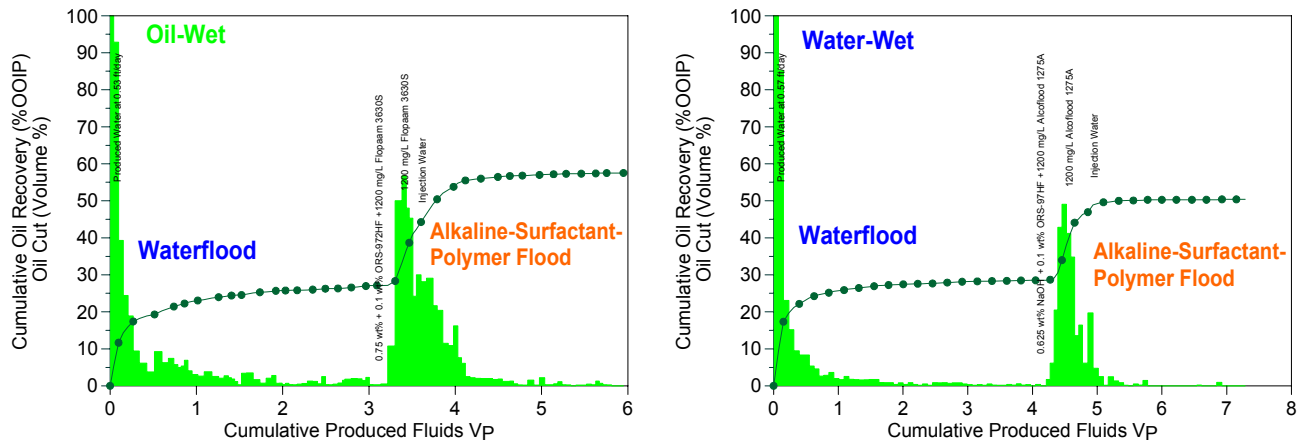
Coreflood	Surfactant and Concentration wt%	Alkali and Concentration wt%	Polymer and Concentration mg/L	Waterflood Residual Oil Saturation V _p	Peak Tertiary Oil Cut %	Volume Injected to Peak Oil Cut V _p	Volume Injected to Oil Cut <1% V _p	Tertiary Oil Produced @ >1% Oil Cut %OOIP
oil-wet								
1R	ORS-164HF 0.1	NaOH 0.75	Flopaam 3630S 1200	0.548	31.4	0.25	2.80	21.8
2R	EOR-2095 0.1	NaOH/Na ₂ CO ₃ 0.50/0.25	Flopaam 3630S 1200	0.698	48.7	0.19	2.70	37.8
3R	Petrostep B-100 Stepantan AS-1216 0.05/0.05	NaOH/Na ₂ CO ₃ 0.50/0.25	Alcoflood 1275A 1200	0.476	30.0	0.28	1.55	19.7
4R	ORS-162HF 0.1	Na ₂ CO ₃ 0.50/0.25	Alcoflood 1275A 1200	0.534	32.6	0.10	1.01	20.0
5R	ORS-97HF 0.1	NaOH 0.75	Flopaam 3630S 1200	0.591	56.8	0.25	1.53	29.7
6R	EOR-2095 0.1	NaOH/Na ₂ CO ₃ 0.50/0.25	Flopaam 3630S 1200	0.589	48.0	0.27	1.52	28.8
average				0.573	41.2	0.22	1.85	26.3

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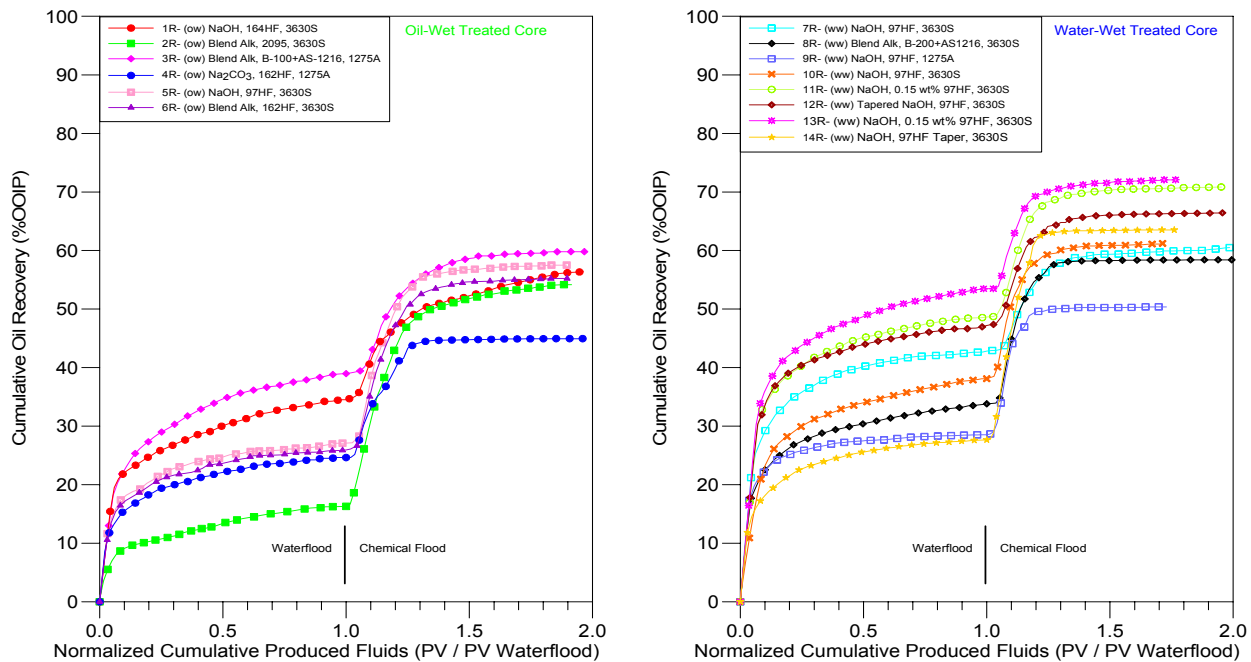
Coreflood	Surfactant and Concentration wt%	Alkali and Concentration wt%	Polymer and Concentration mg/L	Waterflood Residual Oil Saturation V_p	Peak Tertiary Oil Cut %	Volume Injected to Peak Oil Cut V_p	Volume Injected to Oil Cut <1% V_p	Tertiary Oil Produced @ >1% Oil Cut %OOIP
water-wet								
7R	ORS-97HF 0.1	NaOH 0.75	Flopaam 3630S 1200	0.435	22.5	0.39	1.32	16.0
8R	Petrostep B-100 Stepantan AS-1216 0.05/0.05	NaOH/Na ₂ CO ₃ 0.50/0.25	Flopaam 3630S 1200	0.572	46.7	0.21	1.16	24.1
9R	ORS-97HF 0.1	NaOH 0.625	Alcoflood 1275A 1200	0.579	49.1	0.25	1.12	21.5
10R	ORS-97HF 0.1	NaOH 0.625	Flopaam 3630S 1200	0.503	40.0	0.27	1.65	22.5
11R	ORS-97HF 0.15	NaOH 0.75	Flopaam 3630S 1200	0.421	35.3	0.35	1.86	21.5
12R	ORS-97HF 0.1	NaOH 1.00/0.75	Flopaam 3630S 1200	0.443	30.4	0.30	1.17	17.6
13R	ORS-97HF 0.15	NaOH 0.75	Flopaam 3630S 1200	0.409	34.5	0.26	1.86	18.0
14R	ORS-97HF 0.15/0.1	NaOH 0.75	Flopaam 3630S 1200	0.609	58.0	0.21	1.23	35.6
average				0.496	39.6	0.28	1.42	22.1

The above table and data in referenced tables and figures show some interesting features for the ASP corefloods:

- Oil-wet and water-wet core performed similarly. Peak oil cuts, time to develop the oil bank, the volume to produce the economic oil, and the volume of incremental oil produced were close. Oil-wet treated core produced a slightly greater volume of incremental oil over a larger volume.
- Oil cuts as a result of chemical injection were substantial in with either water-wet or oil-wet treated core. Two figures below show the performance. The oil cut and oil recovery performance of radial coreflood 5R is reproduced to the left and that of radial coreflood 9R to the right. Oil cut increased from less than 1% after injection 3 to 4 V_p of water to over 40% with a NaOH plus ORS-97HF-Flopaam 3630S solution.



- All corefloods developed and produced a substantial oil bank indicating that injected alkaline-surfactant-polymer solution will produce more oil than water.
- Oil saturation difference observed after waterflood was maintained after chemical flooding. Oil-wet treated core final oil saturation averaged 0.359 Vp and water-wet treated core averaged 0.306 Vp.



- Normalized figures (Figures 6.1.16 and 6.1.18) above compare oil-wet treated core with water-wet treated core. Water-wet treated core shows the most total oil recovery. However, the difference is primarily due to greater waterflood recovery not greater incremental oil recovery.

6.3 Resistance Factor Data - Incremental differential pressures, resistance factors and cumulative produced fluids are listed in Tables 6.2.1 through 6.2.14 and depicted in Figures 6.2.1 through 6.2.14.

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The average mobility ratio for water displacing Warner crude oil for all the radial corefloods was 6.3 for oil-wet treated core and 1.8 with water-wet handled core. Average mobility ratio for the linear corefloods was 10.9 with oil-wet treated core and 12.4 for water-wet handled core. A similar difference in mobility ratio between the core handling technique is seen.

The following table lists mobility ratios during chemical injection for the resistance factor data over the entire core, RF_T .

Mobility Ratio During Chemical Injection: Warner Radial Corefloods

Coreflood	Polymer	Polymer Concentration mg/L	Solution Viscosity cp	Water Mobility Ratio From RF_1	ASP Injection Mobility Ratio From RF_1	Polymer Injection Mobility Ratio From RF_1
oil-wet		<u>ASP/ flush</u>	<u>ASP / flush</u>			
1R	Flopaam 3630S	1,200/1200	25.1 / 29.3	4.1	1.1	1.1
2R	Flopaam 3630S	1,200/1200	20.6 / 29.3	6.3	1.0	0.9
3R	Alcoflood 1275A	1,200/1500	22.8 / 30.5	3.3	2.0	1.8
4R	Alcoflood 1275A	1,200/1500	17.8 / 30.5	4.0	2.1	2.1
5R	Flopaam 3630S	1,200/1200	23.2 / 30.6	7.8	1.5	1.7
6R	Flopaam 3630S	1,200/1200	20.3 / 30.6	12.5	1.7	1.8
average				6.3	1.6	1.6
water-wet						
7R	Flopaam 3630S	1,200/1200	19.4 / 31.8	1.4	0.5	0.4
8R	Flopaam 3630S	1,200/1200	19.5 / 31.8	2.0	0.7	0.3
9R	Alcoflood 1275A	1,200/1200	15.9 / 20.2	1.5	0.3	0.2
10R	Flopaam 3630S	1,200/1200	22.2 / 30.6	2.7	0.5	0.4
11R	Flopaam 3630S	1,200/1200	22.8 / 31.1	1.5	0.4	0.2
12R	Flopaam 3630S	1,200/1200	18.2 / 31.1	1.7	0.4	0.2
13R	Flopaam 3630S	1,200/1200	19.6 / 32.6	2.8	0.7	0.8
14R	Flopaam 3630S	1,200/1200	20.5 / 33.1	2.2	0.9	0.8
average				1.8	0.5	0.4

Mobility control with 1200 mg/L is very good with water-wet treated core during chemical injection. With oil-wet treated core, mobility is still good with 1200 mg/L polymer. Flopaam 3630S mobility control was consistently better than Alcoflood 1275 A in oil-wet treated core. This data indicates that the alkaline-surfactant-polymer chemical injection sequence had high enough polymer concentration to provide good mobility control.

Evaluation of the front resistance factor data, RF_1 , indicates Flopaam 3630S and Alcoflood 1275A dissolved in all solutions injected into the Warner core. RF_T indicates the Flopaam 3630S and Alcoflood 1275A flowed through the Warner rock. Both polymers are appropriate for use in the Warner alkaline-surfactant-polymer flood.

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6.4 Effluent Analysis - The concentrations of alkali, surfactant and polymer in the aqueous portion of the produced fluid samples for radial corefloods are listed in Tables 6.3.1 through 6.3.14. The incremental oil cut and incremental chemical concentration are plotted against cumulative total produced fluids in Figures 6.3.1 through 6.3.14. Chemical consumption is low as shown in the following table.

Average Chemical Retention - Warner Radial Corefloods

Average Chemical Retention		
	lb/acre-ft	
	<u>Oil-Wet</u>	<u>Water-Wet</u>
NaOH	759	1044
Na ₂ CO ₃	1,535	----
Na ₂ CO ₃ (co-inject with NaOH)	(344)	(1,005)
NaOH (co-injected with Na ₂ CO ₃)	725	729
Surfactant	124	222
with NaOH	147	231
with Na ₂ CO ₃	124	---
with NaOH + Na ₂ CO ₃	109	163
Polymer	134	167
with NaOH	33	167
with Na ₂ CO ₃	274	---
with NaOH + Na ₂ CO ₃	155	168
Flopaam 3630S	69	170
Alcoflood 1275A	264	149

Chemical retention by Warner core is lower in oil-wet treated core than water-wet treated core. NaOH retention appears to be lower than that of Na₂CO₃, the later with a single data point, Mixing the two alkalis reduce both chemicals' retention. Polymer retention appears to be considerably lower with NaOH than Na₂CO₃ in oil-wet treated core. However, the data may be skewed since the single data point with Na₂CO₃ was with Alcoflood 1275A. Little difference in retention between Flopaam 3630S and Alcoflood 1275A was observed with water-wet treated core a significant difference was seen in oil-wet treated core.

The position of produced chemical peaks indicates that mobility control was good for all corefloods. Chemical banks follow the oil bank. Produced alkali, surfactant, and polymer concentrations show that all chemicals move as a unit. Therefore, the interfacial tension reducing capacity of the injected chemical solution will be maintained as the solution moves through the reservoir.

V. Conclusions

Fluid-Fluid

Interfacial tension and phase behavior work suggests Alkaline-Surfactant-Polymer flooding potential is very high for the Warner Reservoir. A number of alkaline-surfactant solutions were formulated that provided sufficient interfacial tension reduction and optimum phase behavior to mobilize waterflood residual oil, based on capillary number theory. Chemical adsorption by the rock is low. Warner is an excellent candidate for chemical flooding based on the fluid-fluid evaluations.

Linear Corefloods

Alkaline-surfactant-polymer flooding potential in the Warner field is excellent. Alkaline-surfactant-polymer injection produced an equivalent volume of oil as did water injection, this being an upper value due to the large volumes of chemical injected.

Mobility ratio for produced water displacing crude oil from higher permeability Warner core was 10.9 for oil-wet treated core and 12.4 for water-wet treated core. Water is an inefficient fluid for displacing crude oil from Warner rock. Core displays intermediate wetting characteristics regardless of handling. Water injection recovered an average of 41.0% OOIP after injection of more than 39 pore volumes and in oil-wet treated core and an average of 57.6% OOIP in water-wet treated core after injection of 36 pore volumes of produced water.

When handled oil-wet, Warner core from 00/04-21-007-16W4 showed no change in effective water permeability due to alkali injection while cores from 02/09-007-16W4 core and 00/16-20-007-16W4 did show some alkali sensitivity. Treating 00/04-21-007-16W4 and 00/16-20-007-16W4 core water-wet, both showed reduction of effective water permeability when NaOH was injected. All cores, regardless of treatment, showed an increase in effective permeability from alkali-surfactant injection in part due to a decrease in oil saturation. Alkali and surfactant inject into Warner core without problem.

Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, and Cyanatrol 770 injected into and flowed through Warner core whether treated oil-wet or water-wet. All high molecular weight polymers tested showed both pseudoplastic and dilatant behavior.

Retention of NaOH, Na_2CO_3 , Petronate EOR 2095, ORS-162HF, and ORS-97HF, Flopaam 3530S, Flopaam 3630S, Alcoflood 1275A, and Cyanatrol 770 are acceptable for a field application. Polymer retention was lower when dissolved with alkali and surfactant than when dissolved in unsoftened injection water. Polymer concentration requirements calculated from oil-wet treated core are 2,650 mg/L for Flopaam 3530S, 1200 mg/L for Flopaam 3630S, 3,650 mg/L for Alcoflood 1275A, and 2,700 mg/L for Cyanatrol 770. When water-wet treated core data is used, Flopaam 3630S requirements increase to 1800 mg/L and Alcoflood 1275A requirements increase to 2375 mg/L.

Radial Corefloods

Radial coreflood evaluations indicate that the alkaline-surfactant-polymer technology will recover incremental oil from the Warner field. Total oil recoveries of over 70% OOIP with peak oil cut of up to 50% were observed in water-wet treated core. Incremental oil was produced in all radial corefloods with the maximum doubling the waterflood oil recovery.

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Resistance factor and effluent analysis indicates that 1200 mg/L polymer provides good mobility control using either Flopaam 3630S or Alcoflood 1275A. Core handling did not alter results. Chemical retention by Warner rock is low for all chemicals and acceptable of a field application. All chemicals injected and flowed through the Warner core. Neither oil recovery nor chemical retention showed a preference for alkali type.

VI. Recommendations

Fluid-fluid, linear coreflood, and radial coreflood data indicate that the following solution will produce incremental oil from the Warner Field.

- 0.75 wt% NaOH plus 0.15 wt% ORS-97HF plus 1200 mg/L Flopaam 3630S or Alcoflood 1275A

Consideration of using an alkali taper should be made. Increasing the NaOH concentration to 1.0 wt% for the first 5% pore volume is recommended.

Radial corefloods to match using the numerical simulator are 12R and 13R. An alkali gradient is matched in 12R. A gradient forecast should be made with 13R as well.

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Warner
Water Analysis

ION	Injection Water	Produced Water
	43-04	44-04
	Ion Concentration mg/L	
Calcium	55	15
Magnesium	15	15
Barium	<10	<10
Strontium	<10	<10
Sodium	1,300	1,475
Potassium	35	30
Iron	<10	<10
Chloride	1,160	1,295
Sulfate	15	5
Carbonate	85	110
Bicarbonate	1,975	2,025
Total Dissolved Solids	4,405	5,070
pH	8.15	8.70
Resistivity at 26°C ohm-m	1.45	1.53
Viscosity at 35°C cp	0.69	0.69
Density at 35°C g/mL	0.9972	0.9973

Warner
Oil Analysis

API Gravity* at 26°C	19.4	degree
Density at 15°C	0.9367	g/mL
Density at 35°C	0.9238	g/mL
Water Content** (used in evaluation)	0.2	vol%
Viscosity+ at 35°C	119	cp
Interfacial Tension*** between oil and softened injection water	15.0	dynes/cm

+ - viscosity is a Brookfield viscosity, UL adaptor at 6 rpm

** - water content is by Karl Fisher ASTM E-203

* - API gravity is by ASTM D287

*** - interfacial tension is by DuNouy ring

Interfacial Tension Between Alkali + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	15.0 D	15.0 D
0.30	0.241 s	---
0.50	0.176 s	8.983 s
0.75	0.432 s	8.955 s
1.00	0.496 s	8.915 s
1.25	0.566 s	6.336 s
1.50	0.708 s	6.018 s
1.75	0.729 s	5.698 s
2.00	0.749 s	5.380 s

* Interfacial tension values with an s are spinning drop measurements.
Interfacial tension values with a D are by DuNouy ring tensiometer.
ppt = precipitate, wg = wets glass

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% Petro AA

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	6.373 s	6.373 s
0.30	0.019 s	---
0.50	0.004 s	1.661 s
0.75	0.010 s	1.015 s
1.00	0.027 s	0.310 s
1.25	0.036 s	0.256 s
1.50	0.053 s	0.182 s
1.75	0.055 s	0.052 s
2.00	0.057 s	0.027 s

0.1 wt% Petro P

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.855 s	0.855 s
0.50	0.019 s	0.264 s
0.75	0.010 s	0.210 s
1.00	0.004 s	0.188 s
1.25	0.001 s	0.167 s
1.50	0.001 s	0.136 s
1.75	0.001 s	0.129 s
2.00	0.001 s	0.112 s

* Interfacial tension values are spinning drop measurements.
ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% Petronate EOR 2037

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	1.673 s	1.673 s
0.50	0.004 s	0.111 s
0.75	0.002 s	0.060 s
1.00	0.001 s	0.045 s
1.25	<0.001 s	0.036 s
1.50	--- ppt	0.025 s
1.75	--- ppt	0.019 s
2.00	--- ppt	0.014 s

0.1 wt% Petronate EOR 2037

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.004 s	0.004 s
0.625	0.001 s	0.003 s
0.75	0.003 s	0.001 s
0.875	0.003 s	0.001 s
1.00	0.005 s	0.001 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% Petronate EOR 2094

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	1.597 s	1.597 s
0.50	0.010 s	0.153 s
0.75	0.004 s	0.081 s
1.00	0.001 s	0.056 s
1.25	<0.001 s	0.036 s
1.50	--- ppt	0.022 s
1.75	--- ppt	0.016 s
2.00	--- ppt	0.012 s

0.1 wt% Petronate EOR 2094

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.004 s	0.010 s
0.625	0.006 s	0.004 s
0.75	0.007 s	0.005 s
0.875	0.003 s	0.003 s
1.00	0.003 s	0.003 s

* Interfacial tension values are spinning drop measurements.
ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% Petronate EOR 2095

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	1.918 s	1.918 s
0.50	0.010 s	0.131 s
0.75	0.002 s	0.081 s
1.00	0.001 s	0.056 s
1.25	0.001 s	0.028 s
1.50	---	0.021 s
1.75	---	0.011 s
2.00	---	0.008 s

0.1 wt% Petronate EOR 2095

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.001 s	0.004 s
0.625	0.003 s	0.003 s
0.75	0.003 s	<0.001 s
0.875	0.003 s	0.001 s
1.00	0.007 s	0.001 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-41HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.587 s	0.587 s
0.50	0.033 s	0.203 s
0.75	0.010 s	0.158 s
1.00	0.001 s	0.109 s
1.25	0.001 s	0.086 s
1.50	--- ppt	0.059 s
1.75	--- ppt	0.038 s
2.00	--- ppt	0.026 s

0.1 wt% Petronate ORS-41HF

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.014 s	0.015 s
0.625	0.004 s	0.011 s
0.75	0.001 s	0.003 s
0.875	0.007 s	0.001 s
1.00	<0.001 s	0.001 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-60HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.484 s	0.484 s
0.50	0.033 s	0.204 s
0.75	0.008 s	0.158 s
1.00	0.001 s	0.109 s
1.25	<0.001 s	0.086 s
1.50	--- ppt	0.059 s
1.75	--- ppt	0.043 s
2.00	--- ppt	0.035 s

0.1 wt% ORS-62HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.414 s	0.414 s
0.50	0.042 s	0.203 s
0.75	0.014 s	0.158 s
1.00	0.004 s	0.118 s
1.25	0.001 s	0.103 s
1.50	--- ppt	0.073 s
1.75	--- ppt	0.054 s
2.00	--- ppt	0.039 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-64 HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.437 s	0.437 s
0.50	0.047 s	0.233 s
0.75	0.020 s	0.183 s
1.00	0.006 s	0.139 s
1.25	0.005 s	0.122 s
1.50	--- ppt	0.106 s
1.75	--- ppt	0.082 s
2.00	--- ppt	0.062 s

0.1 wt% ORS-66 HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.483 s	0.483 s
0.50	0.053 s	0.264 s
0.75	0.020 s	0.210 s
1.00	0.007 s	0.162 s
1.25	0.004 s	0.143 s
1.50	--- ppt	0.115 s
1.75	--- ppt	0.099 s
2.00	--- ppt	0.084 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-97 HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.587 s	0.587 s
0.30	0.014 s	--- s
0.50	0.002 s	0.052 s
0.75	0.010 s	0.020 s
1.00	0.035 s	0.007 s
1.25	--- ppt	0.009 s
1.50	--- ppt	0.011 s
1.75	--- ppt	0.016 s
2.00	--- ppt	0.012 s

0.1 wt% Petronate ORS-97HF

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.010 s	0.007 s
0.625	0.020 s	0.009 s
0.75	0.035 s	0.021 s
0.875	0.046 s	0.029 s
1.00	0.071 s	0.048 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-162HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.247 s	0.247 s
0.50	0.014 s	0.111 s
0.75	0.007 s	0.081 s
1.00	0.004 s	0.045 s
1.25	0.015 s	0.028 s
1.50	0.048 s	0.016 s
1.75	---	0.009 s
2.00	---	0.003 s

0.1 wt% ORS-162HF

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.007 s	0.004 s
0.625	0.007 s	0.001 s
0.75	0.003 s	0.001 s
0.875	0.011 s	0.001 s
1.00	0.011 s	0.007 s

* Interfacial tension values are spinning drop measurements.
ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-164HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.218 s	0.218 s
0.50	0.022 s	0.131 s
0.75	0.002 s	0.081 s
1.00	0.001 s	0.062 s
1.25	0.011 s	0.036 s
1.50	0.022 s	0.029 s
1.75	0.039 s	0.011 s
2.00	--- ppt	0.005 s

0.1 wt% ORS-164HF

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.005 s	0.007 s
0.625	0.001 s	0.003 s
0.75	<0.001 s	0.001 s
0.875	0.003 s	0.001 s
1.00	0.011 s	0.005 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.1 wt% ORS-166HF

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.333 s	0.333 s
0.50	0.042 s	0.177 s
0.75	0.008 s	0.157 s
1.00	0.001 s	0.118 s
1.25	0.002 s	0.085 s
1.50	0.004 s	0.065 s
1.75	0.014 s	0.048 s
2.00	0.031 s	0.030 s

0.1 wt% ORS-166HF

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.007 s	0.015 s
0.625	0.007 s	0.007 s
0.75	0.003 s	0.004 s
0.875	0.001 s	0.001 s
1.00	0.001 s	0.001 s

* Interfacial tension values are spinning drop measurements.
ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.05 wt% Petrostep B-100 + 0.05 wt% Stepantan AS-1216

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.144 s	0.144 s
0.50	0.026 s	0.079 s
0.75	0.015 s	0.074 s
1.00	0.013 s	0.069 s
1.25	0.011 s	0.071 s
1.50	0.007 s	0.059 s
1.75	0.012 s	0.055 s
2.00	--- ppt	0.050 s

0.05 wt% Petrostep B-100 + 0.05 wt% Stepantan AS-1216

NaOH Concentration wt %	Interfacial Tension (dynes/cm)*	
	0.25 wt% Na ₂ CO ₃	0.5 wt% Na ₂ CO ₃
0.50	0.001 s	0.069 s
0.625	0.003 s	0.085 s
0.75	0.027 s	0.087 s
0.875	0.028 s	0.016 s
1.00	0.028 s	0.016 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Interfacial Tension Between Alkali-Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C

0.033 wt% Petrostep B-100 + 0.067 wt% Stepantan AS-1216

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.534 s	0.534 s
0.50	0.094 s	0.233 s
0.75	0.074 s	0.240 s
1.00	0.069 s	0.247 s
1.25	0.058 s	0.223 s
1.50	0.054 s	0.199 s
1.75	0.049 s	0.205 s
2.00	0.051 s	0.210 s

0.067 wt% Petrostep B-100 + 0.033 wt% Stepantan AS-1216

Alkali Concentration wt %	Interfacial Tension (dynes/cm)*	
	NaOH	Na ₂ CO ₃
0.00	0.024 s	0.024 s
0.50	0.019 s	0.014 s
0.75	0.030 s	0.010 s
1.00	0.045 s	0.017 s
1.25	0.037 s	0.024 s
1.50	--- ppt	0.037 s
1.75	--- ppt	0.029 s
2.00	--- ppt	0.039 s

* Interfacial tension values are spinning drop measurements.

ppt = precipitate, wg = wets glass, ns = not stable

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	15.0
	0.30	50.0	0.0	50.0	II	C,C	0.241
	0.50	50.0	0.0	50.0	II	C,C	0.176
	0.75	50.0	0.0	50.0	II	C,C	0.432
	1.00	50.0	0.0	50.0	II	C,C	0.496
	1.25	50.0	0.0	50.0	II	C,C	0.566
	1.50	50.0	0.0	50.0	II	C,C	0.708
	1.75	50.0	0.0	50.0	II	C,C	0.729
	2.00	50.0	0.0	50.0	II	C,C	0.749
Na ₂ CO ₃ + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	15.0
	0.50	50.0	0.0	50.0	II	C,C	8.983
	0.75	50.0	0.0	50.0	II	C,C	8.955
	1.00	50.0	0.0	50.0	II	C,C	8.915
	1.25	50.0	0.0	50.0	II	C,C	6.336
	1.50	50.0	0.0	50.0	II	C,C	6.018
	1.75	50.0	0.0	50.0	II	C,C	5.698
	2.00	50.0	0.0	50.0	II	C,C	5.380

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% Petro AA + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	6.373
	0.30	50.0	0.0	50.0	II	C,C	0.019
	0.50	50.0	0.0	50.0	II	C,C	0.004
	0.75	50.0	0.0	50.0	II	C,C	0.010
	1.00	50.0	0.0	50.0	II	C,C	0.027
	1.25	50.0	0.0	50.0	II	C,C	0.036
	1.50	50.0	0.0	50.0	II	C,C	0.053
	1.75	50.0	0.0	50.0	II	C,C	0.055
	2.00	50.0	0.0	50.0	II	C,C	0.057
Na ₂ CO ₃ + 0.1 wt% Petro AA + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	6.373
	0.50	50.0	0.0	50.0	II	C,C	1.661
	0.75	50.0	0.0	50.0	II	C,C	1.015
	1.00	50.0	0.0	50.0	II	C,C	0.310
	1.25	50.0	0.0	50.0	II	C,C	0.256
	1.50	50.0	0.0	50.0	II	C,C	0.182
	1.75	50.0	0.0	50.0	II	C,C	0.052
	2.00	50.0	0.0	50.0	II	C,C	0.027

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% Petro P + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.855
	0.50	50.0	0.0	50.0	II-	Y,T	0.019
	0.75	50.0	0.5	49.5	III	LY,C	0.010
	1.00	50.0	0.0	50.0	II-	LY,C	0.004
	1.25	50.0	0.0	50.0	II-	LY,C	0.001
	1.50	50.0	0.0	50.0	II	C,C	0.001
	1.75	50.0	0.0	50.0	II	C,C	0.001
	2.00	50.0	0.0	50.0	II	C,C	0.001
Na ₂ CO ₃ + 0.1 wt% Petro P + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.855
	0.50	50.0	0.0	50.0	II	C,C	0.264
	0.75	50.0	0.0	50.0	II	C,C	0.210
	1.00	50.0	0.0	50.0	II	C,C	0.188
	1.25	50.0	0.0	50.0	II	C,C	0.167
	1.50	50.0	0.0	50.0	II-	LY,C	0.136
	1.75	50.0	0.0	50.0	II-	LY,C	0.129
	2.00	50.0	0.0	50.0	II-	LY,C	0.112

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% Petronate EOR 2037 + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.673
	0.50	50.0	0.0	50.0	II-	B,C	0.004
	0.75	49.5	1.0	49.5	III	B,T	0.002
	1.00	50.0	0.5	49.5	III	LB,T	0.001
	1.25	50.0	0.0	50.0	II-	LY,T	<0.001
Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2037 + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.673
	0.50	50.0	0.0	50.0	II-	LY,C	0.111
	0.75	50.0	0.0	50.0	II-	LY,T	0.060
	1.00	50.0	0.0	50.0	II-	LY,T	0.045
	1.25	50.0	0.0	50.0	II-	LY,T	0.036
	1.50	50.0	0.2	49.8	III	LY,T	0.025
	1.75	50.0	0.2	49.8	III	Y,T	0.019
	2.00	50.0	0.2	49.8	III	LB,T	0.014

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% Petronate EOR 2094 + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.597
	0.50	50.0	1.0	49.0	III	B,C	0.010
	0.75	49.5	0.5	50.0	III	B,O	0.004
	1.00	50.0	0.2	49.8	III	B,T	0.001
	1.25	50.0	0.0	50.0	II	C,C	<0.001
Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2094 + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.597
	0.50	50.0	0.0	50.0	II	C,C	0.153
	0.75	50.0	0.0	50.0	II-	LY,C	0.081
	1.00	50.0	0.0	50.0	II-	LY,C	0.056
	1.25	50.0	0.1	49.9	III	Y,C	0.036
	1.50	50.0	0.1	49.9	III	Y,T	0.022
	1.75	50.0	0.2	49.8	III	LB,T	0.016
	2.00	50.0	0.2	49.8	III	LB,T	0.012

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.918
	0.50	50.0	1.0	49.0	III	B,T	0.010
	0.75	49.5	1.5	49.0	III	B,O	0.002
	1.00	50.0	0.5	49.5	III	B,T	0.001
	1.25	50.0	0.0	50.0	II-	M,T	0.001
Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095+ 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	1.918
	0.50	50.0	0.0	50.0	II	C,C	0.131
	0.75	50.0	0.0	50.0	II-	LY,C	0.081
	1.00	50.0	0.0	50.0	II-	Y,C	0.056
	1.25	50.0	0.1	49.9	III	Y,C	0.028
	1.50	50.0	0.1	49.9	III	Y,C	0.021
	1.75	50.0	0.2	49.8	III	LB,C	0.011
	2.00	50.0	0.2	49.8	III	LB,C	0.008

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-41 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.587
	0.50	50.0	1.5	48.5	III	DB,T	0.033
	0.75	50.0	1.0	49.0	III	LY,T	0.010
	1.00	50.0	0.2	49.8	III	C,C	0.001
	1.25	50.0	0.0	50.0	II	C,C	0.001
Na ₂ CO ₃ + 0.1 wt% ORS-41 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.587
	0.50	50.0	0.0	50.0	II-	LY,C	0.203
	0.75	50.0	0.2	49.8	III	LY,T	0.158
	1.00	50.0	0.2	49.8	III	LY,T	0.109
	1.25	50.0	0.2	49.8	III	LY,T	0.086
	1.50	50.0	1.0	49.0	III	LY,T	0.059
	1.75	50.0	0.5	49.5	III	M,T	0.038
	2.00	50.0	0.5	49.5	III	M,T	0.026

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-60 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.484
	0.50	50.0	0.1	49.9	III	B,C	0.033
	0.75	50.0	1.5	48.5	III	B,T	0.008
	1.00	50.0	0.1	49.9	III	C,C	0.001
	1.25	50.0	0.0	50.0	II	C,C	<0.001
Na ₂ CO ₃ + 0.1 wt% ORS-60 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.484
	0.50	50.0	0.0	50.0	II-	M,T	0.204
	0.75	50.0	0.0	50.0	II-	LY,C	0.158
	1.00	50.0	0.1	49.9	III	LY,T	0.109
	1.25	50.0	0.2	49.8	III	LY,T	0.086
	1.50	50.0	0.2	49.8	III	Y,T	0.059
	1.75	50.0	0.2	49.8	III	Y,T	0.043
	2.00	50.0	0.6	49.4	III	Y,O	0.035

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-62 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.414
	0.50	50.0	1.0	49.0	III	DB,T	0.042
	0.75	50.0	1.0	49.0	III	DB,O	0.014
	1.00	50.0	0.2	49.8	III	LY,C	0.004
	1.25	50.0	0.1	49.9	III	LY,C	0.001
Na ₂ CO ₃ + 0.1 wt% ORS-62 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.414
	0.50	50.0	0.0	50.0	II-	LY,C	0.203
	0.75	50.0	0.0	50.0	II-	LY,C	0.158
	1.00	50.0	0.0	50.0	II-	LY,T	0.118
	1.25	50.0	0.0	50.0	II-	LY,T	0.103
	1.50	50.0	0.1	49.9	III	LY,T	0.073
	1.75	50.0	0.2	49.8	III	LY,T	0.054
	2.00	50.0	0.4	49.6	III	Y,T	0.039

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-64 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.437
	0.50	49.5	1.5	49.0	III	DB,T	0.047
	0.75	50.0	1.0	49.0	III	DB,T	0.020
	1.00	50.0	0.1	49.9	III	LY,T	0.006
	1.25	50.0	0.1	49.9	III	M,T	0.005
Na ₂ CO ₃ + 0.1 wt% ORS-64 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.437
	0.50	50.0	0.0	50.0	II-	LY,C	0.233
	0.75	50.0	0.0	50.0	II-	LY,C	0.183
	1.00	50.0	0.0	50.0	II-	LY,T	0.139
	1.25	50.0	0.0	50.0	II-	LY,T	0.122
	1.50	50.0	0.0	50.0	II-	LY,T	0.106
	1.75	50.0	0.0	50.0	II-	Y,T	0.082
	2.00	50.0	0.1	49.9	III	Y,T	0.062

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-66 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.483
	0.50	50.0	0.0	50.0	II-	B,C	0.053
	0.75	49.5	1.0	49.5	III	B,T	0.020
	1.00	50.0	1.0	49.0	III	B,T	0.007
	1.25	50.0	0.0	50.0	II-	Y,T	0.004
Na ₂ CO ₃ + 0.1 wt% ORS-66 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.483
	0.50	50.0	0.0	50.0	II-	LY,C	0.264
	0.75	50.0	0.0	50.0	II-	LY,T	0.210
	1.00	50.0	0.0	50.0	II-	LY,T	0.162
	1.25	50.0	0.0	50.0	II-	LY,T	0.143
	1.50	50.0	0.0	50.0	II-	LY,T	0.115
	1.75	50.0	0.1	49.9	III	LY,T	0.099
	2.00	50.0	0.1	49.9	III	LY,T	0.084

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH +	0.00	50.0	0.0	50.0	II	C,C	0.587
0.1 wt% ORS-97 HF +	0.30	50.0	0.0	50.0	II-	LY,T	0.014
1000 mg/L Flopaam 3230S	0.50	50.0	0.2	49.8	III	C,C	0.002
	0.75	50.0	0.2	49.8	III	C,C	0.010
	1.00	50.0	0.2	49.8	III	C,C	0.035
Na ₂ CO ₃ +	0.00	50.0	0.0	50.0	II	C,C	0.587
0.1 wt% ORS-97 HF +	0.50	50.0	0.0	50.0	II-	M,T	0.052
1000 mg/L Flopaam 3230S	0.75	50.0	0.1	49.9	III	M,T	0.020
	1.00	50.0	0.2	49.8	III	M,T	0.007
	1.25	50.0	0.2	49.8	III	M,T	0.009
	1.50	50.0	0.2	49.8	III	C,C	0.011
	1.75	50.0	0.1	49.9	III	C,C	0.016
	2.00	50.0	0.1	49.9	III	C,C	0.012

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-162 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.247
	0.50	50.0	0.1	49.9	III	M,T	0.014
	0.75	50.0	0.1	49.9	III	M,T	0.007
	1.00	50.0	0.1	49.9	III	C,C	0.004
	1.25	50.0	0.4	49.6	III	C,C	0.015
	1.50	50.0	0.1	49.9	III	C,C	0.048
Na ₂ CO ₃ + 0.1 wt% ORS-162 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.247
	0.50	50.0	0.0	50.0	II-	M,T	0.111
	0.75	50.0	0.0	50.0	II-	M,T	0.081
	1.00	50.0	0.0	50.0	II-	LY,T	0.045
	1.25	50.0	0.1	49.9	III	LY,T	0.028
	1.50	50.0	0.1	49.9	III	LY,T	0.016
	1.75	50.0	0.1	49.9	III	LY,T	0.009
	2.00	50.0	0.0	50.0	II	C,C	0.003

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-164 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.218
	0.50	50.0	0.1	49.9	III	B,T	0.022
	0.75	50.0	0.6	49.4	III	LY,T	0.002
	1.00	50.0	0.0	50.0	II	C,C	0.001
	1.25	50.0	0.0	50.0	II	C,C	0.011
	1.50	50.0	0.0	50.0	II	C,C	0.022
	1.75	50.0	0.0	50.0	II	C,C	0.039
Na ₂ CO ₃ + 0.1 wt% ORS-164 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.218
	0.50	50.0	0.0	50.0	II-	LY,C	0.131
	0.75	50.0	0.0	50.0	II-	LY,T	0.081
	1.00	50.0	0.0	50.0	II-	LY,T	0.062
	1.25	50.0	0.0	50.0	II-	LY,T	0.036
	1.50	50.0	0.1	49.9	III	LY,T	0.029
	1.75	50.0	0.2	49.8	III	LY,T	0.011
	2.00	50.0	0.2	49.8	III	M,T	0.005

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH + 0.1 wt% ORS-166 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.333
	0.50	50.0	0.0	50.0	II-	DB,T	0.042
	0.75	49.5	1.0	49.5	III	LY,T	0.008
	1.00	50.0	0.0	50.0	II-	LY,C	0.001
	1.25	50.0	0.0	50.0	II-	LY,C	0.002
	1.50	50.0	0.0	50.0	II-	LY,C	0.004
	1.75	50.0	0.0	50.0	II	C,C	0.014
	2.00	50.0	0.0	50.0	II	C,C	0.031
Na ₂ CO ₃ + 0.1 wt% ORS-166 HF + 1000 mg/L Flopaam 3230S	0.00	50.0	0.0	50.0	II	C,C	0.333
	0.50	50.0	0.0	50.0	II-	LY,T	0.177
	0.75	50.0	0.0	50.0	II-	LY,T	0.157
	1.00	50.0	0.0	50.0	II-	LY,T	0.118
	1.25	50.0	0.0	50.0	II-	LY,T	0.085
	1.50	50.0	0.0	50.0	II-	LY,T	0.065
	1.75	50.0	0.1	49.9	III	Y,T	0.048
	2.00	50.0	0.2	49.8	III	LY,T	0.030

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH +	0.00	50.0	0.0	50.0	II	C,C	0.534
0.033 wt% Petrostep B-100 +	0.50	50.0	0.1	49.9	III	LB,C	0.094
0.067 wt% Stepantan AS-1216 +	0.75	50.0	0.4	49.6	III	Y,C	0.074
1000 mg/L Flopaam 3230S	1.00	50.0	0.1	49.9	III	Y,C	0.069
	1.25	50.0	0.6	49.4	III	Y,C	0.058
	1.50	50.0	1.0	49.0	III	LY,C	0.054
	1.75	50.0	0.2	49.8	III	LY,C	0.049
	2.00	50.0	0.2	49.8	III	LY,C	0.051
Na ₂ CO ₃ +	0.00	50.0	0.0	50.0	II	C,C	0.534
0.033 wt% Petrostep B-100 +	0.50	50.0	0.0	50.0	II	C,C	0.233
0.067 wt% Stepantan AS-1216 +	0.75	50.0	0.0	50.0	II	C,C	0.240
1000 mg/L Flopaam 3230S	1.00	50.0	0.0	50.0	II	C,C	0.247
	1.25	50.0	0.0	50.0	II	C,C	0.223
	1.50	50.0	0.0	50.0	II	C,C	0.199
	1.75	50.0	0.0	50.0	II	C,C	0.205
	2.00	50.0	0.0	50.0	II	C,C	0.210

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH +	0.00	50.0	0.0	50.0	II	C,C	0.144
0.05 wt% Petrostep B-100 +	0.50	50.0	0.1	49.9	III	LY,T	0.026
0.05 wt% Stepantan AS-1216 +	0.75	50.0	0.2	49.8	III	Y,T	0.015
1000 mg/L Flopaam 3230S	1.00	49.0	1.0	50.0	III	DB,T	0.013
	1.25	49.0	1.0	50.0	III	DB,T	0.011
	1.50	49.0	1.0	50.0	III	B,T	0.007
	1.75	49.0	1.0	50.0	III	B,T	0.012
Na ₂ CO ₃ +	0.00	50.0	0.0	50.0	II	C,C	0.144
0.05 wt% Petrostep B-100 +	0.50	50.0	0.0	50.0	II	C,C	0.079
0.05 wt% Stepantan AS-1216 +	0.75	50.0	0.0	50.0	II	C,C	0.074
1000 mg/L Flopaam 3230S	1.00	50.0	0.0	50.0	II	C,C	0.069
	1.25	50.0	0.0	50.0	II	C,C	0.071
	1.50	50.0	0.0	50.0	II	C,C	0.059
	1.75	50.0	0.0	50.0	II	C,C	0.055
	2.00	50.0	0.0	50.0	II	C,C	0.050

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	Alkali Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
NaOH +	0.00	50.0	0.0	50.0	II	C,C	0.024
0.067 wt% Petrostep B-100 +	0.50	50.0	0.1	49.9	III	C,C	0.019
0.033 wt% Stepantan AS-1216 +	0.75	50.0	0.5	49.5	III	C,C	0.030
1000 mg/L Flopaam 3230S	1.00	50.0	0.4	49.6	III	C,C	0.045
	1.25	50.0	0.2	49.8	III	C,C	0.037
Na ₂ CO ₃ +	0.00	50.0	0.0	50.0	II	C,C	0.024
0.067 wt% Petrostep B-100 +	0.50	50.0	0.0	50.0	II	C,C	0.014
0.033 wt% Stepantan AS-1216 +	0.75	50.0	0.0	50.0	II-	M,T	0.010
1000 mg/L Flopaam 3230S	1.00	50.0	0.1	49.9	III	M,T	0.017
	1.25	50.0	0.4	49.6	III	M,T	0.024
	1.50	50.0	0.1	49.9	III	C,C	0.037
	1.75	50.0	0.1	49.9	III	C,C	0.029
	2.00	50.0	0.1	49.9	III	C,C	0.039

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
0.25 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2037 + 1000 mg/L Flopaam 3230S	0.50	49.5	1.0	49.5	III	B,T	0.004
	0.625	50.0	0.4	49.6	III	LB,T	0.001
	0.75	50.0	0.4	49.6	III	C,C	0.003
	0.875	50.0	0.2	49.8	III	C,C	0.003
	1.0	50.0	0.0	50.0	II	C,C	0.005
0.5 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2037 + 1000 mg/L Flopaam 3230S	0.50	49.0	1.0	50.0	III	B,T	0.004
	0.625	49.3	0.7	50.0	III	Y,T	0.003
	0.75	50.0	0.4	49.6	III	LY,T	0.001
	0.875	50.0	0.1	49.9	III	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.001
0.25 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2094 + 1000 mg/L Flopaam 3230S	0.50	50.0	0.5	49.5	III	DB,C	0.004
	0.625	50.0	0.8	49.2	III	DB,T	0.006
	0.75	49.0	2.0	49.0	III	DB,T	0.007
	0.875	50.0	0.2	49.8	III	LY,T	0.003
	1.0	50.0	0.1	49.9	III	C,C	0.003
0.5 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2094 + 1000 mg/L Flopaam 3230S	0.50	50.0	0.2	49.8	III	B,C	0.010
	0.625	50.0	1.2	48.8	III	B,T	0.004
	0.75	50.0	1.0	49.0	III	LB,T	0.005
	0.875	50.0	0.1	49.9	III	C,C	0.003
	1.0	50.0	0.1	49.9	III	C,C	0.003

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
0.25 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	0.50	50.0	1.0	49.0	III	DB,O	0.001
	0.625	50.0	1.0	49.0	III	LB,T	0.003
	0.75	50.0	0.2	49.8	III	LY,T	0.003
	0.875	50.0	0.1	49.9	III	C,C	0.003
	1.0	50.0	0.1	49.9	III	C,C	0.007
0.5 wt% Na ₂ CO ₃ + 0.01 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	0.50	50.0	0.6	49.4	III	B,C	0.004
	0.625	50.0	1.0	49.0	III	LB,T	0.003
	0.75	50.0	0.2	49.8	III	LY,T	<0.001
	0.875	50.0	0.1	49.9	III	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.001

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
0.25 wt% Na ₂ CO ₃ + 0.01 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	0.50	50.0	2.0	48.0	III	LY,T	0.014
	0.625	50.0	1.0	49.0	III	C,C	0.004
	0.75	50.0	0.2	49.8	III	C,C	0.001
	0.875	50.0	0.1	49.9	III	C,C	0.007
	1.0	50.0	0.1	49.9	III	C,C	<0.001
0.5 wt% Na ₂ CO ₃ + 0.01 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	0.50	50.0	1.0	49.0	III	Y,T	0.015
	0.625	50.0	0.2	49.8	III	LY,T	0.011
	0.75	50.0	0.1	49.9	III	C,C	0.003
	0.875	50.0	0.0	50.0	II	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.001
0.25 wt% Na ₂ CO ₃ + 0.01 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.2	49.8	III	C,C	0.010
	0.625	50.0	0.2	49.8	III	C,C	0.020
	0.75	50.0	0.1	49.9	III	C,C	0.035
	0.875	50.0	0.1	49.9	III	C,C	0.046
	1.0	50.0	0.1	49.9	III	C,C	0.071
0.5 wt% Na ₂ CO ₃ + 0.01 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.1	49.9	III	C,C	0.007
	0.625	50.0	0.1	49.9	III	C,C	0.009
	0.75	50.0	0.0	50.0	II	C,C	0.021
	0.875	50.0	0.0	50.0	II	C,C	0.029
	1.0	50.0	0.0	50.0	II	C,C	0.048

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
0.25 wt% Na ₂ CO ₃ + 0.01 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.6	49.4	III	C,C	0.007
	0.625	50.0	0.4	49.6	III	C,C	0.007
	0.75	50.0	0.2	49.8	III	C,C	0.003
	0.875	50.0	0.0	50.0	II	C,C	0.011
	1.0	50.0	0.0	50.0	II	C,C	0.011
0.5 wt% Na ₂ CO ₃ + 0.01 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.2	49.8	III	C,C	0.004
	0.625	50.0	0.1	49.9	III	C,C	0.001
	0.75	50.0	0.1	49.9	III	C,C	0.001
	0.875	50.0	0.0	50.0	II	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.007
0.25 wt% Na ₂ CO ₃ + 0.01 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.6	49.4	III	LY,T	0.005
	0.625	50.0	0.2	49.8	III	C,C	0.001
	0.75	50.0	0.1	49.9	III	C,C	<0.001
	0.875	50.0	0.0	50.0	II	C,C	0.003
	1.0	50.0	0.0	50.0	II	C,C	0.011
0.5 wt% Na ₂ CO ₃ + 0.01 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	0.50	50.0	0.2	49.8	III	C,C	0.007
	0.625	50.0	0.1	49.9	III	C,C	0.003
	0.75	50.0	0.0	50.0	II	C,C	0.001
	0.875	50.0	0.0	50.0	II	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.005

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
0.25 wt% Na ₂ CO ₃ + 0.01 wt% ORS-166HF + 1000 mg/L Flopaam 3230S	0.50	49.5	1.0	49.5	III	LB,T	0.007
	0.625	49.5	1.0	49.5	III	LY,T	0.007
	0.75	50.0	0.5	49.5	III	C,C	0.003
	0.875	50.0	0.0	50.0	II	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.001
0.5 wt% Na ₂ CO ₃ + 0.01 wt% ORS-166HF + 1000 mg/L Flopaam 3230S	0.50	49.5	1.0	49.5	III	Y,T	0.015
	0.625	50.0	0.5	49.5	III	LY,T	0.007
	0.75	50.0	0.1	49.9	III	C,C	0.004
	0.875	50.0	0.0	50.0	II	C,C	0.001
	1.0	50.0	0.0	50.0	II	C,C	0.001

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Blended Alkali Concentrations
Alkaline-Surfactant-Polymer Solutions Dissolved in Softened Injection Water and Warner Crude Oil at 35°C

Chemical Combination	NaOH Concentration weight %	Equilibrated Phase Volumes %			Phase type	Phase Description code	Interfacial Tension dyne/cm
		bottom	middle	top			
0.25 wt% Na ₂ CO ₃ +	0.50	50.0	0.0	50.0	II	C,C	0.001
0.05 wt% Petrostep B-100 +	0.625	49.8	0.2	50.0	III	C,C	0.003
0.05 wt% Stepantan AS-1216 +	0.75	49.0	1.0	50.0	III	DB,T	0.027
1000 mg/L Flopaam 3230S	0.875	49.4	0.6	50.0	III	B,T	0.028
	1.0	49.6	0.4	50.0	III	B,T	0.028
0.5 wt% Na ₂ CO ₃ +	0.50	50.0	1.0	49.0	III	B,T	0.069
0.05 wt% Petrostep B-100 +	0.625	50.0	0.6	49.4	III	LB,T	0.085
0.05 wt% Stepantan AS-1216 +	0.75	50.0	0.2	49.8	III	LB,T	0.087
1000 mg/L Flopaam 3230S	0.875	50.0	0.0	50.0	II	C,C	0.016
	1.0	50.0	0.0	50.0	II	C,C	0.016

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% NaOH
+ 1000 mg/L Flopaam 3230S

Alkali-Polymer to Produced Water ratio AP : PW	Interfacial Tension (dynes/cm)*
100 : 0	0.176 s
80 : 20	0.833 s
60 : 40	1.247 s
40 : 60	1.395 s
20 : 80	0.794 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% NaOH + 0.1 wt% Petro AA
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial Tension (dynes/cm)*
ASP : PW		
100	: 0	0.004 s
80	: 20	1.738 s
60	: 40	1.097 s
40	: 60	4.528 s
20	: 80	1.058 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% Petro P
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.010 s
80	20	0.381 s
60	40	2.307 s
40	60	0.821 s
20	80	4.110 s

1.25 wt% NaOH + 0.1 wt% Petro P
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.001 s
80	20	0.010 s
60	40	1.307 s
40	60	2.499 s
20	80	3.195 s

1.5 wt% NaOH + 0.1 wt% Petro P
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.001 s
80	20	0.001 s
60	40	0.273 s
40	60	2.045 s
20	80	2.787 s

DuNouy ring tensiometer determinations. Those with
an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% NaOH + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.004 s
80	: 20	0.070 s
60	: 40	0.541 s
40	: 60	0.170 s
20	: 80	0.556 s

1.0 wt% NaOH + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.010 s
60	: 40	0.064 s
40	: 60	0.106 s
20	: 80	0.565 s

DuNouy ring tensiometer determinations. Those with
an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% NaOH + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	<0.001 s
80	: 20	0.007 s
60	: 40	0.019 s
40	: 60	0.069 s
20	: 80	0.268 s

2.0 wt% Na₂CO₃ + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.014 s
80	: 20	0.059 s
60	: 40	0.076 s
40	: 60	0.064 s
20	: 80	0.370 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% Petronate EOR 2094
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.004 s
80	: 20	0.033 s
60	: 40	0.076 s
40	: 60	0.133 s
20	: 80	0.264 s

1.0 wt% NaOH + 0.1 wt% Petronate EOR 2094
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.010 s
60	: 40	0.042 s
40	: 60	0.106 s
20	: 80	0.173 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% NaOH + 0.1 wt% Petronate EOR 2094
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	<0.001 s
80	: 20	0.007 s
60	: 40	0.026 s
40	: 60	0.083 s
20	: 80	0.226 s

2.0 wt% Na₂CO₃ + 0.1 wt% Petronate EOR 2094
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.012 s
80	: 20	0.025 s
60	: 40	0.045 s
40	: 60	0.064 s
20	: 80	0.018 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.002 s
80	: 20	0.016 s
60	: 40	0.051 s
40	: 60	0.081 s
20	: 80	0.467 s

1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.007 s
60	: 40	0.025 s
40	: 60	0.075 s
20	: 80	0.272 s

1.25 wt% NaOH + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.003 s
60	: 40	0.017 s
40	: 60	0.062 s
20	: 80	0.268 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.75 wt% Na₂CO₃ + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.011 s
80	: 20	0.021 s
60	: 40	0.044 s
40	: 60	0.054 s
20	: 80	0.099 s

2.0 wt% Na₂CO₃ + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.008 s
80	: 20	0.016 s
60	: 40	0.058 s
40	: 60	0.077 s
20	: 80	0.085 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.010 s
80 : 20		0.042 s
60 : 40		0.063 s
40 : 60		0.105 s
20 : 80		0.119 s

1.0 wt% NaOH + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.001 s
80 : 20		0.017 s
60 : 40		0.042 s
40 : 60		0.061 s
20 : 80		0.086 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% NaOH + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.001 s
60	: 40	0.026 s
40	: 60	0.051 s
20	: 80	0.072 s

2.0 wt% Na₂CO₃ + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.026 s
80	: 20	0.021 s
60	: 40	0.035 s
40	: 60	0.052 s
20	: 80	0.104 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% ORS-60HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.008 s
80 : 20		0.053 s
60 : 40		0.063 s
40 : 60		0.073 s
20 : 80		0.119 s

1.0 wt% NaOH + 0.1 wt% ORS-60HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.001 s
80 : 20		0.020 s
60 : 40		0.047 s
40 : 60		0.089 s
20 : 80		0.129 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% NaOH + 0.1 wt% ORS-60HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	<0.001 s
80	: 20	0.002 s
60	: 40	0.017 s
40	: 60	0.052 s
20	: 80	0.063 s

2.0 wt% Na₂CO₃ + 0.1 wt% ORS-60HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.035 s
80	: 20	0.029 s
60	: 40	0.045 s
40	: 60	0.058 s
20	: 80	0.104 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% NaOH + 0.1 wt% ORS-62HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.001 s
80 : 20		0.010 s
60 : 40		0.029 s
40 : 60		0.076 s
20 : 80		0.102 s

1.0 wt% NaOH + 0.1 wt% ORS-64HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.006 s
80 : 20		0.034 s
60 : 40		0.078 s
40 : 60		0.125 s
20 : 80		0.139 s

1.25 wt% NaOH + 0.1 wt% ORS-64HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.005 s
80 : 20		0.012 s
60 : 40		0.042 s
40 : 60		0.083 s
20 : 80		0.102 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.0 wt% NaOH + 0.1 wt% ORS-66HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.007 s
80 : 20		0.020 s
60 : 40		0.078 s
40 : 60		0.125 s
20 : 80		0.129 s

1.25 wt% NaOH + 0.1 wt% ORS-66HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100 : 0		0.004 s
80 : 20		0.020 s
60 : 40		0.079 s
40 : 60		0.126 s
20 : 80		0.140 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% NaOH + 0.1 wt% ORS-97HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.002 s
80	20	0.010 s
60	40	0.024 s
40	60	0.031 s
20	80	0.047 s

0.75 wt% NaOH + 0.1 wt% ORS-97HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.010 s
80	20	0.002 s
60	40	0.004 s
40	60	0.015 s
20	80	0.085 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.0 wt% Na₂CO₃ + 0.1 wt% ORS-97HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.007 s
80 : 20		0.002 s
60 : 40		0.004 s
40 : 60		0.031 s
20 : 80		0.212 s

1.25 wt% Na₂CO₃ + 0.1 wt% ORS-97HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.009 s
80 : 20		0.001 s
60 : 40		0.008 s
40 : 60		0.195 s
20 : 80		0.213 s

1.5 wt% Na₂CO₃ + 0.1 wt% ORS-97HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.011 s
80 : 20		0.004 s
60 : 40		0.014 s
40 : 60		0.016 s
20 : 80		0.188 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% ORS-162HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.007 s
80	: 20	0.014 s
60	: 40	0.041 s
40	: 60	0.049 s
20	: 80	0.293 s

1.0 wt% NaOH + 0.1 wt% ORS-162HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.004 s
80	: 20	0.002 s
60	: 40	0.010 s
40	: 60	0.024 s
20	: 80	0.397 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.5 wt% Na₂CO₃ + 0.1 wt% ORS-162HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.016 s
80	: 20	0.007 s
60	: 40	0.020 s
40	: 60	0.025 s
20	: 80	0.149 s

2.0 wt% Na₂CO₃ + 0.1 wt% ORS-162HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.003 s
80	: 20	0.003 s
60	: 40	0.010 s
40	: 60	0.012 s
20	: 80	0.132 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% NaOH + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.002 s
80	: 20	0.019 s
60	: 40	0.046 s
40	: 60	0.061 s
20	: 80	0.890 s

1.0 wt% NaOH + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.005 s
60	: 40	0.033 s
40	: 60	0.045 s
20	: 80	0.213 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.75 wt% Na₂CO₃ + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.011 s
80 : 20		0.007 s
60 : 40		0.034 s
40 : 60		0.046 s
20 : 80		0.301 s

2.0 wt% Na₂CO₃ + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.005 s
80 : 20		0.003 s
60 : 40		0.004 s
40 : 60		0.025 s
20 : 80		0.099 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.0 wt% NaOH + 0.1 wt% ORS-166HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.001 s
80	20	0.026 s
60	40	0.042 s
40	60	0.061 s
20	80	0.238 s

1.5 wt% NaOH + 0.1 wt% ORS-166HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	0	0.004 s
80	20	0.003 s
60	40	0.020 s
40	60	0.041 s
20	80	0.106 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.0 wt% NaOH + 0.05 wt% B-100 + 0.05 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.013 s
80	: 20	0.026 s
60	: 40	0.033 s
40	: 60	0.061 s
20	: 80	0.327 s

1.5 wt% NaOH + 0.05 wt% B-100 + 0.05 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.007 s
80	: 20	0.020 s
60	: 40	0.025 s
40	: 60	0.031 s
20	: 80	0.213 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

1.25 wt% Na₂CO₃ + 0.05 wt% B-100 + 0.05 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.071 s
80 : 20		0.044 s
60 : 40		0.019 s
40 : 60		0.005 s
20 : 80		0.362 s

1.75 wt% Na₂CO₃ + 0.05 wt% B-100 + 0.05 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.055 s
80 : 20		0.036 s
60 : 40		0.020 s
40 : 60		0.008 s
20 : 80		0.217 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% NaOH + 0.067 wt% B-100 + 0.033 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.019 s
80	: 20	0.006 s
60	: 40	0.006 s
40	: 60	0.034 s
20	: 80	0.165 s

1.25 wt% NaOH + 0.067 wt% B-100 + 0.033 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio		Interfacial
ASP : PW		Tension (dynes/cm)*
100	: 0	0.037 s
80	: 20	0.027 s
60	: 40	0.007 s
40	: 60	0.006 s
20	: 80	0.268 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.75 wt% Na₂CO₃ + 0.067 wt% B-100 + 0.033 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.010 s
80 : 20		0.025 s
60 : 40		0.051 s
40 : 60		0.073 s
20 : 80		0.393 s

1.25 wt% Na₂CO₃ + 0.067 wt% B-100 + 0.033 wt% AS-1216
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.024 s
80 : 20		0.044 s
60 : 40		0.042 s
40 : 60		0.062 s
20 : 80		0.168 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.25 wt% Na₂CO₃ + 0.625 wt% NaOH + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.019 s
60 : 40		0.046 s
40 : 60		0.134 s
20 : 80		0.167 s

0.5 wt% Na₂CO₃ + 0.75 wt% NaOH + 0.1 wt% Petronate EOR 2037
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.010 s
60 : 40		0.053 s
40 : 60		0.136 s
20 : 80		0.268 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.25 wt% Na₂CO₃ + 0.5 wt% NaOH + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.033 s
60 : 40		0.076 s
40 : 60		0.143 s
20 : 80		0.059 s

0.5 wt% Na₂CO₃ + 0.75 wt% NaOH + 0.1 wt% Petronate EOR 2095
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		<0.001 s
80 : 20		0.007 s
60 : 40		0.026 s
40 : 60		0.108 s
20 : 80		0.168 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.25 wt% Na₂CO₃ + 0.75 wt% NaOH + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.039 s
60 : 40		0.052 s
40 : 60		0.089 s
20 : 80		0.086 s

0.5 wt% Na₂CO₃ + 0.875 wt% NaOH + 0.1 wt% ORS-41HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.013 s
60 : 40		0.034 s
40 : 60		0.063 s
20 : 80		0.087 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.5 wt% Na₂CO₃ + 0.625 wt% NaOH + 0.1 wt% ORS-162HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.020 s
60 : 40		0.042 s
40 : 60		0.062 s
20 : 80		0.102 s

0.25 wt% Na₂CO₃ + 0.625 wt% NaOH + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.026 s
60 : 40		0.041 s
40 : 60		0.074 s
20 : 80		0.059 s

0.5 wt% Na₂CO₃ + 0.75 wt% NaOH + 0.1 wt% ORS-164HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water		Interfacial
ratio		Tension (dynes/cm)*
ASP : PW		
100 : 0		0.001 s
80 : 20		0.015 s
60 : 40		0.048 s
40 : 60		0.076 s
20 : 80		0.130 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.25 wt% Na₂CO₃ + 0.875 wt% NaOH + 0.1 wt% ORS-166HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.023 s
60	: 40	0.058 s
40	: 60	0.107 s
20	: 80	0.030 s

0.5 wt% Na₂CO₃ + 0.875 wt% NaOH + 0.1 wt% ORS-166HF
+ 1000 mg/L Flopaam 3230S

Alkali-Surfactant-Polymer to Produced Water ratio ASP : PW		Interfacial Tension (dynes/cm)*
100	: 0	0.001 s
80	: 20	0.020 s
60	: 40	0.048 s
40	: 60	0.108 s
20	: 80	0.188 s

- * Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Effect of Produced Water Dilution on the
Interfacial Tension at 35°C between Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil

0.25 wt% Na ₂ CO ₃ + 0.5 wt% NaOH + 0.05 wt% Petrostep B-100 + 0.05 wt% Stepantan AS-1216 + 1000 mg/L Flopaam 3230S	
Alkali-Surfactant-Polymer to Produced Water	
ratio	Interfacial
ASP : PW	Tension (dynes/cm)*
100 : 0	0.001 s
80 : 20	0.065 s
60 : 40	0.003 s
40 : 60	0.004 s
20 : 80	0.038 s

* Interfacial tension values denoted with a "D" to the right are DuNouy ring tensiometer determinations. Those with an "s" are spinning drop measurements.
ppt. = precipitate wg = wets glass

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.5 wt% NaOH + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.176
	80	20	50.0	0.0	50.0	II	C,C	0.833
	60	40	50.0	0.0	50.0	II	C,C	1.247
	40	60	50.0	0.0	50.0	II	C,C	1.395
	20	80	50.0	0.0	50.0	II	C,C	0.794
0.5 wt% NaOH + 0.1 wt% Petro AA + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.004
	80	20	50.0	0.0	50.0	II	C,C	1.738
	60	40	50.0	0.0	50.0	II	C,C	1.097
	40	60	50.0	0.0	50.0	II	C,C	4.528
	20	80	50.0	0.0	50.0	II	C,C	1.058

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH + 0.1 wt% Petro P + 1000 mg/L Flopaam 3230S	100	0	50.0	0.5	49.5	III	LY,C	0.010
	80	20	50.0	0.1	49.9	III	LY,T	0.381
	60	40	50.0	0.0	50.0	II	C,C	2.307
	40	60	50.0	0.0	50.0	II	C,C	0.821
	20	80	50.0	0.0	50.0	II	C,C	4.110
1.25 wt% NaOH + 0.1 wt% Petro P + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II-	LY,C	0.001
	80	20	50.0	0.1	49.9	III	LY,T	0.010
	60	40	50.0	0.0	50.0	II	C,C	1.307
	40	60	50.0	0.0	50.0	II	C,C	2.499
	20	80	50.0	0.0	50.0	II	C,C	3.195
1.5 wt% NaOH + 0.1 wt% Petro P + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.001
	80	20	50.0	0.4	49.6	III	LY,T	0.001
	60	40	50.0	0.0	50.0	II-	M,T	0.273
	40	60	50.0	0.0	50.0	II	C,C	2.045
	20	80	50.0	0.0	50.0	II	C,C	2.787

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.5 wt% NaOH +	100	0	50.0	0.0	50.0	II-	B,C	0.004
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.1	49.9	III	Y,T	0.070
1000 mg/L Flopaam 3230S	60	40	50.0	0.0	50.0	II	C,C	0.541
	40	60	50.0	0.0	50.0	II	C,C	0.170
	20	80	50.0	0.0	50.0	II	C,C	0.556
1.0 wt% NaOH +	100	0	50.0	0.5	49.5	III	B,T	0.001
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.5	49.5	III	Y,T	0.010
1000 mg/L Flopaam 3230S	60	40	50.0	0.1	49.9	III	LY,T	0.064
	40	60	50.0	0.0	50.0	II-	LY,T	0.106
	20	80	50.0	0.0	50.0	II	C,C	0.565

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% NaOH +	100	0	50.0	0.0	50.0	II-	LY,T	<0.001
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.2	49.8	III	Y,T	0.007
1000 mg/L Flopaam 3230S	60	40	50.0	0.4	49.6	III	Y,T	0.019
	40	60	50.0	0.0	50.0	II-	LY,T	0.069
	20	80	50.0	0.0	50.0	II	C,C	0.268
2.0 wt% Na ₂ CO ₃ +	100	0	50.0	0.5	49.5	III	LB,T	0.014
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.0	50.0	II-	LY,T	0.059
1000 mg/L Flopaam 3230S	60	40	50.0	0.0	50.0	II-	LY,C	0.076
	40	60	50.0	0.0	50.0	II	C,C	0.064
	20	80	50.0	0.0	50.0	II	C,C	0.370

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH +	100	0	49.5	0.5	50.0	III	B,O	0.004
0.1 wt% Petronate EOR 2094 +	80	20	50.0	0.4	49.6	III	B,T	0.033
1000 mg/L Flopaam 3230S	60	40	50.0	0.2	49.8	III	Y,T	0.076
	40	60	49.0	0.0	51.0	II+	C,C	0.133
	20	80	50.0	0.0	50.0	II	C,C	0.264
1.0 wt% NaOH +	100	0	50.0	0.2	49.8	III	B,T	0.001
0.1 wt% Petronate EOR 2094 +	80	20	50.0	0.6	49.4	III	B,C	0.010
1000 mg/L Flopaam 3230S	60	40	49.0	1.0	50.0	III	Y,T	0.042
	40	60	50.0	0.5	49.5	III	C,C	0.106
	20	80	50.0	0.0	50.0	II	C,C	0.173

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% NaOH +	100	0	50.0	0.0	50.0	II	C,C	<0.001
0.1 wt% Petronate EOR 2094 +	80	20	50.0	0.4	49.6	III	B,T	0.007
1000 mg/L Flopaam 3230S	60	40	49.0	1.0	50.0	III	Y,C	0.026
	40	60	50.0	0.3	49.7	III	LY,C	0.083
	20	80	50.0	0.0	50.0	II	C,C	0.226
2.0 wt% Na ₂ CO ₃ +	100	0	50.0	0.2	49.8	III	LB,T	0.012
0.1 wt% Petronate EOR 2094 +	80	20	50.0	0.1	49.9	III	Y,C	0.025
1000 mg/L Flopaam 3230S	60	40	50.0	0.0	50.0	II-	Y,C	0.045
	40	60	50.0	0.0	50.0	II-	LY,C	0.064
	20	80	50.0	0.0	50.0	II	C,C	0.018

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH +	100	0	49.5	1.5	49.0	III	B,O	0.002
0.1 wt% Petronate EOR 2095 +	80	20	50.0	0.2	49.8	III	LB,T	0.016
1000 mg/L Flopaam 3230S	60	40	50.0	0.0	50.0	II-	Y,T	0.051
	40	60	50.0	0.0	50.0	II-	LY,T	0.081
	20	80	50.0	0.0	50.0	II	C,C	0.467
1.0 wt% NaOH +	100	0	50.0	0.5	49.5	III	B,T	0.001
0.1 wt% Petronate EOR 2095 +	80	20	50.0	1.0	49.0	III	LB,C	0.007
1000 mg/L Flopaam 3230S	60	40	48.5	1.5	50.0	III	LY,T	0.025
	40	60	49.0	0.1	50.0	III	LY,T	0.075
	20	80	50.0	0.0	50.0	II	C,C	0.272
1.25 wt% NaOH +	100	0	50.0	0.0	50.0	II-	M,T	0.001
0.1 wt% Petronate EOR 2095 +	80	20	49.6	0.4	50.0	III	LY,C	0.003
1000 mg/L Flopaam 3230S	60	40	49.0	1.0	50.0	III	LB,T	0.017
	40	60	48.4	1.6	50.0	III	LY,T	0.062
	20	80	50.0	0.0	50.0	II	C,C	0.268

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.75 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	LB,C	0.011
	80	20	50.0	0.1	49.9	III	Y,C	0.021
	60	40	50.0	0.0	50.0	II-	LY,C	0.044
	40	60	50.0	0.0	50.0	II	C,C	0.054
	20	80	50.0	0.0	50.0	II	C,C	0.099
2.0 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	LB,C	0.008
	80	20	50.0	0.2	49.8	III	Y,C	0.016
	60	40	50.0	0.1	49.9	III	LY,C	0.058
	40	60	50.0	0.0	50.0	II-	LY,C	0.077
	20	80	50.0	0.0	50.0	II	C,C	0.085

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	1.0	49.0	III	LY,T	0.010
	80	20	50.0	0.5	49.5	III	LB,T	0.042
	60	40	50.0	0.2	49.8	III	LY,T	0.063
	40	60	50.0	0.0	50.0	II-	LY,T	0.105
	20	80	50.0	0.0	50.0	II	C,C	0.119
1.0 wt% NaOH + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.001
	80	20	50.0	1.0	49.0	III	LY,T	0.017
	60	40	50.0	0.4	49.6	III	Y,T	0.042
	40	60	50.0	0.2	49.8	III	LY,T	0.061
	20	80	50.0	0.0	50.0	II	C,C	0.086

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% NaOH + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.001
	80	20	50.0	0.4	49.6	III	M,T	0.001
	60	40	50.0	1.2	48.8	III	Y,T	0.026
	40	60	50.0	0.2	49.8	III	LY,T	0.051
	20	80	50.0	0.0	50.0	II	C,C	0.072
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.5	49.5	III	M,T	0.026
	80	20	50.0	0.1	49.9	III	M,T	0.021
	60	40	50.0	0.0	50.0	II-	M,T	0.035
	40	60	50.0	0.0	50.0	II	C,C	0.052
	20	80	50.0	0.0	50.0	II	C,C	0.104

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH + 0.1 wt% ORS-60HF + 1000 mg/L Flopaam 3230S	100	0	50.0	1.5	48.5	III	B,T	0.008
	80	20	50.0	0.2	49.8	III	LB,T	0.053
	60	40	50.0	0.1	49.9	III	Y,T	0.063
	40	60	50.0	0.0	50.0	II-	LY,T	0.073
	20	80	50.0	0.0	50.0	II	C,C	0.119
1.0 wt% NaOH + 0.1 wt% ORS-60HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	C,C	0.001
	80	20	50.0	0.2	49.8	III	LB,T	0.020
	60	40	50.0	0.1	49.9	III	LB,T	0.047
	40	60	50.0	0.0	50.0	II-	Y,T	0.089
	20	80	50.0	0.0	50.0	II	C,C	0.129

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% NaOH + 0.1 wt% ORS-60HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	<0.001
	80	20	50.0	0.4	49.6	III	LB,T	0.002
	60	40	50.0	0.2	49.8	III	LB,T	0.017
	40	60	50.0	0.0	50.0	II-	Y,T	0.052
	20	80	50.0	0.0	50.0	II	C,C	0.063
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-60HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.6	49.4	III	Y,O	0.035
	80	20	50.0	0.1	49.9	III	Y,T	0.029
	60	40	50.0	0.0	50.0	II-	LY,T	0.045
	40	60	50.0	0.0	50.0	II	C,C	0.058
	20	80	50.0	0.0	50.0	II	C,C	0.104

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% NaOH + 0.1 wt% ORS-62HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	LY,C	0.001
	80	20	50.0	0.5	49.5	III	LB,T	0.010
	60	40	50.0	0.4	49.6	III	Y,T	0.029
	40	60	50.0	0.1	49.9	III	LY,T	0.076
	20	80	50.0	0.0	50.0	II-	M,T	0.102
1.0 wt% NaOH + 0.1 wt% ORS-64HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	LY,T	0.006
	80	20	50.0	0.1	49.9	III	Y,T	0.034
	60	40	50.0	0.0	50.0	II-	Y,T	0.078
	40	60	50.0	0.0	50.0	II-	M,T	0.125
	20	80	50.0	0.0	50.0	II	C,C	0.139
1.25 wt% NaOH + 0.1 wt% ORS-64HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	M,T	0.005
	80	20	49.6	0.4	50.0	III	LB,T	0.012
	60	40	49.2	0.8	50.0	III	Y,T	0.042
	40	60	50.0	0.0	50.0	II-	LY,T	0.083
	20	80	50.0	0.0	50.0	II	C,C	0.102

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.0 wt% NaOH + 0.1 wt% ORS-66HF + 1000 mg/L Flopaam 3230S	100	0	50.0	1.0	49.0	III	B,T	0.007
	80	20	49.8	0.2	50.0	III	LB,T	0.020
	60	40	50.0	0.0	50.0	II-	Y,T	0.078
	40	60	50.0	0.0	50.0	II-	Y,T	0.125
	20	80	50.0	0.0	50.0	II	C,C	0.129
1.25 wt% NaOH + 0.1 wt% ORS-66HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II-	Y,T	0.004
	80	20	49.8	0.2	50.0	III	Y,T	0.020
	60	40	49.6	0.4	50.0	III	Y,T	0.079
	40	60	50.0	0.0	50.0	II-	LY,T	0.126
	20	80	50.0	0.0	50.0	II	C,C	0.140

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.5 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.002
	80	20	50.0	0.1	49.9	III	LY,T	0.010
	60	40	50.0	0.0	50.0	II-	Y,T	0.024
	40	60	50.0	0.0	50.0	II	C,C	0.031
	20	80	50.0	0.0	50.0	II	C,C	0.047
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.010
	80	20	50.0	0.1	49.9	III	M,T	0.002
	60	40	50.0	0.1	49.9	III	M,T	0.004
	40	60	50.0	0.0	50.0	II-	M,T	0.015
	20	80	50.0	0.0	50.0	II	C,C	0.085

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	M,T	0.007
	80	20	50.0	0.0	50.0	II-	M,T	0.002
	60	40	50.0	0.0	50.0	II	C,C	0.004
	40	60	50.0	0.0	50.0	II	C,C	0.031
	20	80	50.0	0.0	50.0	II	C,C	0.212
1.25 wt% Na ₂ CO ₃ + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	M,T	0.009
	80	20	50.0	0.0	50.0	II-	LY,T	0.001
	60	40	50.0	0.0	50.0	II	C,C	0.008
	40	60	50.0	0.0	50.0	II	C,C	0.195
	20	80	50.0	0.0	50.0	II	C,C	0.213
1.5 wt% Na ₂ CO ₃ + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.011
	80	20	50.0	0.0	50.0	II-	M,T	0.004
	60	40	50.0	0.0	50.0	II	C,C	0.014
	40	60	50.0	0.0	50.0	II	C,C	0.016
	20	80	50.0	0.0	50.0	II	C,C	0.188

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	M,T	0.007
	80	20	50.0	0.2	49.8	III	Y,T	0.014
	60	40	50.0	0.0	50.0	II-	Y,T	0.041
	40	60	50.0	0.0	50.0	II-	LY,T	0.049
	20	80	50.0	0.0	50.0	II	C,C	0.293
1.0 wt% NaOH + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	C,C	0.004
	80	20	50.0	0.2	49.8	III	LY,T	0.002
	60	40	50.0	0.3	49.7	III	LY,T	0.010
	40	60	50.0	0.0	50.0	II-	LY,T	0.024
	20	80	50.0	0.0	50.0	II	C,C	0.397

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.5 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	LY,T	0.016
	80	20	50.0	0.0	50.0	II-	LY,T	0.007
	60	40	50.0	0.0	50.0	II	C,C	0.020
	40	60	50.0	0.0	50.0	II	C,C	0.025
	20	80	50.0	0.0	50.0	II	C,C	0.149
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.003
	80	20	50.0	0.1	49.9	III	LY,T	0.003
	60	40	50.0	0.0	50.0	II-	M,T	0.010
	40	60	50.0	0.0	50.0	II	C,C	0.012
	20	80	50.0	0.0	50.0	II	C,C	0.132

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% NaOH + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.6	49.4	III	LY,T	0.002
	80	20	50.0	0.4	49.6	III	Y,T	0.019
	60	40	50.0	0.1	49.9	III	LY,T	0.046
	40	60	50.0	0.0	50.0	II-	LY,T	0.061
	20	80	50.0	0.0	50.0	II	C,C	0.890
1.0 wt% NaOH + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	III	C,C	0.001
	80	20	50.0	0.2	49.8	III	Y,T	0.005
	60	40	50.0	0.4	49.6	III	LY,T	0.033
	40	60	50.0	0.0	50.0	II-	LY,T	0.045
	20	80	50.0	0.0	50.0	II	C,C	0.213

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.75 wt% Na ₂ CO ₃ + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	LY,T	0.011
	80	20	50.0	0.1	49.9	III	LY,T	0.007
	60	40	50.0	0.0	50.0	II-	LY,C	0.034
	40	60	50.0	0.0	50.0	II	C,C	0.046
	20	80	50.0	0.0	50.0	II	C,C	0.301
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	M,T	0.005
	80	20	50.0	0.4	49.6	III	M,T	0.003
	60	40	50.0	0.1	49.9	III	M,T	0.004
	40	60	50.0	0.0	50.0	II-	M,T	0.025
	20	80	50.0	0.0	50.0	II	C,C	0.099

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.0 wt% NaOH +	100	0	50.0	0.0	50.0	II-	LY,C	0.001
0.1 wt% ORS-166HF +	80	20	50.0	0.0	50.0	II-	B,T	0.026
1000 mg/L Flopaam 3230S	60	40	50.0	0.0	50.0	II-	Y,T	0.042
	40	60	50.0	0.0	50.0	II-	LY,T	0.061
	20	80	50.0	0.0	50.0	II	C,C	0.238
1.5 wt% NaOH +	100	0	50.0	0.0	50.0	II-	LY,C	0.004
0.1 wt% ORS-166HF +	80	20	50.0	0.1	49.9	III	C,C	0.003
1000 mg/L Flopaam 3230S	60	40	50.0	0.2	49.8	III	LB,T	0.020
	40	60	50.0	0.0	50.0	II-	LY,T	0.041
	20	80	50.0	0.0	50.0	II	C,C	0.106

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.0 wt% NaOH +	100	0	49.0	1.0	50.0	III	DB,T	0.013
0.05 wt% Petrostep B-100 +	80	20	49.9	0.1	50.0	III	LB,T	0.026
0.05 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II-	Y,T	0.033
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II-	LY,T	0.061
	20	80	50.0	0.0	50.0	II	C,C	0.327
1.5 wt% NaOH +	100	0	49.0	1.0	50.0	III	B,T	0.007
0.05 wt% Petrostep B-100 +	80	20	49.4	0.6	50.0	III	LB,T	0.020
0.05 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II-	Y,T	0.025
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II-	LY,T	0.031
	20	80	50.0	0.0	50.0	II	C,C	0.213

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
1.25 wt% Na ₂ CO ₃ +	100	0	50.0	0.0	50.0	II	C,C	0.071
0.05 wt% Petrostep B-100 +	80	20	50.0	0.0	50.0	II	C,C	0.044
0.05 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II	C,C	0.019
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II	C,C	0.005
	20	80	50.0	0.0	50.0	II	C,C	0.362
1.75 wt% Na ₂ CO ₃ +	100	0	50.0	0.0	50.0	II	C,C	0.055
0.05 wt% Petrostep B-100 +	80	20	50.0	0.0	50.0	II	C,C	0.036
0.05 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II	C,C	0.020
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II	C,C	0.008
	20	80	50.0	0.0	50.0	II	C,C	0.217

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.5 wt% NaOH +	100	0	50.0	0.1	49.9	III	C,C	0.019
0.067 wt% Petrostep B-100 +	80	20	50.0	0.1	49.9	III	LY,T	0.006
0.033 wt% Stepantan AS-1216 +	60	40	50.0	1.0	49.0	III	Y,T	0.006
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II-	LY,T	0.034
	20	80	50.0	0.0	50.0	II	C,C	0.165
1.25 wt% NaOH +	100	0	50.0	0.2	49.8	III	C,C	0.037
0.067 wt% Petrostep B-100 +	80	20	50.0	0.0	50.0	II-	M,T	0.027
0.033 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II-	M,T	0.007
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II-	M,T	0.006
	20	80	50.0	0.0	50.0	II	C,C	0.268

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.75 wt% Na ₂ CO ₃ +	100	0	50.0	0.0	50.0	II-	M,T	0.010
0.067 wt% Petrostep B-100 +	80	20	50.0	0.0	50.0	II	C,C	0.025
0.033 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II	C,C	0.051
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II	C,C	0.073
	20	80	50.0	0.0	50.0	II	C,C	0.393
1.25 wt% Na ₂ CO ₃ +	100	0	50.0	0.4	49.6	III	M,T	0.024
0.067 wt% Petrostep B-100 +	80	20	50.0	0.0	50.0	II	C,C	0.044
0.033 wt% Stepantan AS-1216 +	60	40	50.0	0.0	50.0	II	C,C	0.042
1000 mg/L Flopaam 3230S	40	60	50.0	0.0	50.0	II	C,C	0.062
	20	80	50.0	0.0	50.0	II	C,C	0.168

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Blended Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.25 wt% Na ₂ CO ₃ + 0.625 wt% NaOH + 100		0	50.0	0.4	49.6	III	LB,T	0.001
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.3	49.7	III	LB,T	0.019
1000 mg/L Flopaam 3230S	60	40	50.0	0.1	49.9	III	Y,T	0.046
	40	60	50.0	0.0	50.0	II-	LY,T	0.134
	20	80	50.0	0.0	50.0	II	C,C	0.167
0.5 wt% Na ₂ CO ₃ + 0.75 wt% NaOH +	100	0	50.0	0.4	49.6	III	LY,T	0.001
0.1 wt% Petronate EOR 2037 +	80	20	50.0	0.6	49.4	III	LB,T	0.010
1000 mg/L Flopaam 3230S	60	40	50.0	0.2	49.8	III	LY,T	0.053
	40	60	50.0	0.1	49.9	III	LY,T	0.136
	20	80	50.0	0.0	50.0	II	C,C	0.268

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Blended Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.25 wt% Na ₂ CO ₃ + 0.5 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	100	0	50.0	1.0	49.0	III	DB,O	0.001
	80	20	50.0	0.8	49.2	III	LY,T	0.033
	60	40	50.0	0.1	49.9	III	LY,T	0.076
	40	60	50.0	0.0	50.0	II-	M,T	0.143
	20	80	50.0	0.0	50.0	II	C,C	0.059
0.5 wt% Na ₂ CO ₃ + 0.75 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	LY,T	<0.001
	80	20	50.0	0.2	49.8	III	LB,T	0.007
	60	40	50.0	0.2	49.8	III	LB,T	0.026
	40	60	50.0	0.0	50.0	II-	LY,T	0.108
	20	80	50.0	0.0	50.0	II	C,C	0.168

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Blended Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.25 wt% Na ₂ CO ₃ + 0.75 wt% NaOH + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.001
	80	20	50.0	0.8	49.2	III	B,T	0.039
	60	40	50.0	0.2	49.8	III	LB,T	0.052
	40	60	50.0	0.0	50.0	II-	Y,T	0.089
	20	80	50.0	0.0	50.0	II	C,C	0.086
0.5 wt% Na ₂ CO ₃ + 0.875 wt% NaOH + 0.1 wt% ORS-41HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.001
	80	20	55.0	0.5	44.5	III	C,C	0.013
	60	40	51.0	0.2	48.8	III	LB,T	0.034
	40	60	56.0	0.0	44.0	II-	LY,T	0.063
	20	80	50.0	0.0	50.0	II	C,C	0.087

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Blended Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.5 wt% Na ₂ CO ₃ + 0.625 wt% NaOH + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.1	49.9	III	C,C	0.001
	80	20	50.0	0.1	49.9	III	M,T	0.020
	60	40	50.0	0.3	49.7	III	LB,T	0.042
	40	60	50.0	0.8	49.2	III	Y,T	0.062
	20	80	50.0	0.0	50.0	II	C,C	0.102
0.25 wt% Na ₂ CO ₃ + 0.625 wt% NaOH + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.2	49.8	III	C,C	0.001
	80	20	50.0	0.2	49.8	III	LY,T	0.026
	60	40	50.0	0.4	49.6	III	LB,T	0.041
	40	60	50.0	0.0	50.0	II	C,C	0.074
	20	80	50.0	0.0	50.0	II	C,C	0.059
0.5 wt% Na ₂ CO ₃ + 0.75 wt% NaOH + 0.1 wt% ORS-164HF + 1000 mg/L Flopaam 3230S	100	0	50.0	0.0	50.0	II	C,C	0.001
	80	20	50.0	0.0	50.0	II-	LY,T	0.015
	60	40	50.0	0.2	49.8	III	B,T	0.048
	40	60	50.0	0.1	49.9	III	LY,T	0.076
	20	80	50.0	0.0	50.0	II	C,C	0.130

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Phase Behaviors with Varying Produced Water and Blended Alkaline-Surfactant-Polymer Ratios
Chemicals Dissolved in Softened Injection Water

Chemical Combination	Ratio of ASP to Water		Equilibrated Phase			Phase type	Phase Description code	Interfacial Tension dyne/cm
	ASP volume %	Produced Water volume %	bottom	middle	upper			
0.25 wt% Na ₂ CO ₃ + 0.875 wt% NaOH + 100		0	50.0	0.0	50.0	II	C,C	0.001
0.1 wt% ORS-166HF +	80	20	50.0	0.2	49.8	III	M,T	0.023
1000 mg/L Flopaam 3230S	60	40	50.0	0.2	49.8	III	LB,T	0.058
	40	60	50.0	0.2	49.8	III	Y,T	0.107
	20	80	50.0	0.0	50.0	II	C,C	0.030
0.5 wt% Na ₂ CO ₃ + 0.875 wt% NaOH + 100		0	50.0	0.0	50.0	II	C,C	0.001
0.1 wt% ORS-166HF +	80	20	50.0	0.1	49.9	III	B,T	0.020
1000 mg/L Flopaam 3230S	60	40	50.0	0.2	49.8	III	LB,T	0.048
	40	60	50.0	0.2	49.8	III	Y,T	0.108
	20	80	50.0	0.0	50.0	II	C,C	0.188
0.25 wt% Na ₂ CO ₃ + 0.5 wt% NaOH + 100		0	50.0	0.0	50.0	II	C,C	0.001
0.05 wt% Petrostep B-100 +	80	20	50.0	1.0	49.0	III	LB,T	0.065
0.05 wt% Stepantan AS-1216 +	60	40	50.0	0.4	49.6	III	Y,T	0.003
1000 mg/L Flopaam 3230S	40	60	50.0	1.5	48.5	III	LB,T	0.004
	20	80	50.0	0.0	50.0	II	C,C	0.038

Lower Phase Description Codes

B = brown, C = clear, G = grey, M = milky, W = White, Y = yellow, L = light, D = dark, T = translucent, O = opaque, PPT = precipitate

- initial conditions : 50% oil and 50% alkali-surfactant-polymer

- interfacial tension values with one digit to the right of the decimal place are DuNouy ring tensiometer measurements (ASTM D-970) and those with three digits to the right of the decimal point are spinning drop measurements. The interfacial tension measurements were performed at 35°C.

Warner Polymer Viscosity and Screen Factor at 35°C

Flopaam 3430S, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	5.6	24.5
1000	Softened Injection	15.8	38.2
1500	Softened Injection	30.9	47.8
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Flopaam 3430S, mg/L			
500	Softened Injection	3.2	21.8
1000	Softened Injection	7.3	34.0
1500	Softened Injection	13.9	44.2
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Flopaam 3430S, mg/L			
500	Softened Injection	3.3	22.0
1000	Softened Injection	7.1	33.5
1500	Softened Injection	13.3	42.7
Flopaam 3530S, mg/L			
500	Softened Injection	8.6	28.2
1000	Softened Injection	20.4	39.5
1500	Softened Injection	39.9	50.4
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Flopaam 3530S 1235, mg/L			
500	Softened Injection	4.0	21.4
1000	Softened Injection	9.8	35.9
1500	Softened Injection	19.3	45.0
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Flopaam 3530S, mg/L			
500	Softened Injection	4.2	24.1
1000	Softened Injection	9.6	36.6
1500	Softened Injection	18.6	47.5
Flopaam 3630S, mg/L			
500	Softened Injection	9.0	37.1
1000	Softened Injection	22.1	51.6
1500	Softened Injection	43.4	68.9
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Flopaam 3630S, mg/L			
500	Softened Injection	4.2	32.9
1000	Softened Injection	10.8	43.3
1500	Softened Injection	22.1	55.1
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Flopaam 3630S, mg/L			
500	Softened Injection	4.6	33.2
1000	Softened Injection	11.2	45.1
1500	Softened Injection	22.0	56.7

Warner Polymer Viscosity and Screen Factor at 35°C

Alcoflood 1235, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	2.7	5.5
1000	Softened Injection	6.1	7.9
1500	Softened Injection	11.1	9.5
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Alcoflood 1235, mg/L			
500	Softened Injection	2.3	4.8
1000	Softened Injection	4.0	7.3
1500	Softened Injection	7.6	8.2
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Alcoflood 1235, mg/L			
500	Softened Injection	2.0	4.6
1000	Softened Injection	3.3	7.1
1500	Softened Injection	5.3	8.0
Alcoflood 1275, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	5.7	19.7
1000	Softened Injection	15.4	24.1
1500	Softened Injection	30.8	31.3
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Alcoflood 1275, mg/L			
500	Softened Injection	4.3	17.4
1000	Softened Injection	10.4	22.6
1500	Softened Injection	21.0	28.5
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Alcoflood 1275, mg/L			
500	Softened Injection	4.2	17.3
1000	Softened Injection	10.0	22.1
1500	Softened Injection	20.3	27.4
Alcoflood 1285, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	7.4	30.0
1000	Softened Injection	20.6	42.8
1500	Softened Injection	38.5	51.4
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Alcoflood 1285, mg/L			
500	Softened Injection	4.6	24.2
1000	Softened Injection	11.2	34.7
1500	Softened Injection	23.5	41.6
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Alcoflood 1285, mg/L			
500	Softened Injection	4.1	23.6
1000	Softened Injection	11.0	33.8
1500	Softened Injection	22.6	40.1

Warner Polymer Viscosity and Screen Factor at 35°C

Cyanatrol 750, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	7.6	32.5
1000	Softened Injection	20.6	46.9
1500	Softened Injection	39.0	58.0
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Cyanatrol 750, mg/L			
500	Softened Injection	3.7	28.0
1000	Softened Injection	8.5	43.8
1500	Softened Injection	18.0	54.3
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Cyanatrol 750, mg/L			
500	Softened Injection	3.5	27.7
1000	Softened Injection	8.2	43.0
1500	Softened Injection	17.5	53.1
Cyanatrol 1266D, mg/L	Water	Viscosity (cp)	Screen Factor
500	Softened Injection	7.5	19.7
1000	Softened Injection	20.6	27.6
1500	Softened Injection	43.0	35.7
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + Cyanatrol 1266D, mg/L			
500	Softened Injection	4.0	17.4
1000	Softened Injection	9.5	22.9
1500	Softened Injection	19.3	31.2
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + Cyanatrol 1266D, mg/L			
500	Softened Injection	4.1	17.5
1000	Softened Injection	9.9	23.2
1500	Softened Injection	21.0	32.4

Intrinsic Viscosity of Polymers at 35°C

Polymer	Type	Molecular Weight	Degree of Hydrolysis	Intrinsic Viscosity, dl/g			Radius of Gyration, microns		
				injection water	1.0 wt% NaOH	2.00 wt% Na2CO3	injection water	1.0 wt% NaOH	2.00 wt% Na2CO3
Flopaam 3430S	polyacrylamide	12,000,000	32%	0.0142	0.0038	0.0050	0.343	0.220	0.242
Flopaam 3530S	polyacrylamide	17,000,000	28%	0.0160	0.0033	0.0050	0.401	0.238	0.272
Flopaam 3630S	polyacrylamide	19,000,000	28%	0.0159	0.0047	0.0069	0.415	0.277	0.314
Alcoflood 1235	polyacrylamide	13,500,000	30%	0.0139	0.0055	0.0064	0.354	0.260	0.273
Alcoflood 1275	polyacrylamide	20,000,000	30%	0.0189	0.0054	0.0060	0.447	0.295	0.306
Alcoflood 1285	polyacrylamide	22,000,000	30%	0.0166	0.0056	0.0062	0.442	0.308	0.319
Cyantrol 750	polyacrylamide	15,000,000	35%	0.0166	0.0089	0.0093	0.389	0.316	0.320
Cyantrol 770	polyacrylamide	18,000,000	35%	0.0122			0.373		
Cyanatrol 1266D	polyacrylamide	30,000,000	30%	0.0247	0.0091	0.0120	0.560	0.401	0.440

Warner Mercury Injection Capillary Pressure Data

Well	Core ID	Depth, m	Porosity	K _{irr}	Max Hg Sat, Vp	Initial H ₂ O Sat, Vp	Percent of Pore Throats with micron listed						Mean Radius
							50	25	17.5	10	5	1	
Empire State Taber 9-20-7-16	A	981.06	0.236	648	0.965	0.035	0	0	1	50	75	87	10.2
	B	982.49	0.246	1160	0.974	0.026	0	2	8	68	82	92	13.8
	C	985.42	0.238	810	no								
	D	986.79	0.247	1010	no								
	E	987.52	0.24	1030	0.975	0.025	0	0.8	4	67	81	91	12.5
CPOG Taber S 4-21-7-16	A	975.57	0.240	1170	no								
	B	975.65	0.249	1200	0.973	0.027	0	0.5	6	66	80	90	12.9
	C	976.30	0.255	1520	no								
	D	976.70	0.234	1300	0.979	0.021	0	0	3	66	82	90	12.6
	E	977.04	0.243	1440	0.970	0.030	0	0	7	67	81	90	12.8
	F	978.26	0.269	2090	no								
	G	978.62	0.262	2110	0.971	0.029	0	0	13	75	85	92	15.0
	H	979.38	0.263	2670	0.967	0.033	0	0	50	75	83	89	17.1
	I	980.97	0.241	1490	no								
	J	981.33	0.242	1690	no								
Empire State Taber 16-20-7-16	A	981.33	0.269	2340	0.968	0.032	0	4	45	70	79	87	16.3
	B	984.38	0.272	2850	no								
	C	985.14	0.256	2030	0.972	0.028	0	3	40	75	84	91	16.2
	D	987.28	0.275	4134	no								

Static Alkali, Surfactant, and Polymer Adsorption

Well: Warner - Various Depth: Various

Chemical Solution	Days	Interfacial Tension dynes/cm	Alkali Consumption				Surfactant Consumption				Polymer Consumption			
			mg/L	mg/100g rock	% of initial	C/C ₀	mg/L	mg/100g rock	% of initial	C/C ₀	mg/L	mg/100g rock	% of initial	C/C ₀
1000 mg/L Flopaam 3430S	initial										Flopaam 3430S			
	0										966	0.0	0.0	1.000
	1										926	4.0	4.1	0.959
	4										941	2.6	2.9	0.974
	7										906	5.6	6.8	0.938
	20										899	6.1	8.1	0.931
											920	4.6	6.8	0.952
0.5 wt% NaOH + 1000 mg/L Flopaam 3430S	initial			NaOH							Flopaam 3430S			
	0	0.176	3280	0.0	0.0	1.000					970	0.0	0.0	1.000
	1	1.258	2977	30.3	9.2	0.908					980	-1.0	-1.0	1.010
	4	2.031	2854	41.6	13.7	0.870					1029	-5.5	-6.2	1.061
	7	2.265	2845	42.4	15.1	0.867					1081	-9.9	-12.2	1.114
	20	3.363	2509	68.1	26.2	0.765					1042	-6.9	-9.5	1.074
		4.776	2280	83.9	34.8	0.695					1062	-8.3	-12.7	1.095
1.0 wt% NaOH + 0.1 wt% Petro P + 1000 mg/L Flopaam 3430S	initial			NaOH				Petro P			Flopaam 3430S			
	0	0.004	8856	0.0	0.0	1.000	1000	0.0	0.0	1.000	961	0.0	0.0	1.000
	1	0.039	8577	27.9	3.2	0.968	913	8.7	8.7	0.913	1025	-6.4	-6.7	1.067
	4	0.055	8192	63.2	7.8	0.925	911	8.9	9.6	0.911	1125	-15.6	-17.8	1.171
	7	0.082	8044	75.6	10.1	0.908	911	8.9	10.4	0.911	1074	-11.3	-14.4	1.118
	20	0.116	7995	79.4	11.5	0.903	880	11.2	14.4	0.880	1085	-12.1	-17.2	1.129
		0.136	7733	97.4	15.5	0.873	880	11.2	15.7	0.880	1091	-12.6	-20.2	1.135
0.75 wt% NaOH + 0.1 wt% Petronate EOR 2037 + 1000 mg/L Flopaam 3430S	initial			NaOH				Petronate EOR 2037			Flopaam 3430S			
	0	0.002	6068	0.0	0.0	1.000	1000	0.0	0.0	1.000	973	0.0	0.0	1.000
	1	0.007	5633	43.5	7.2	0.928	565	43.5	43.5	0.565	989	-1.6	-1.6	1.016
	4	0.007	5609	45.7	8.2	0.924	507	48.8	51.2	0.507	1005	-3.1	-3.4	1.033
	7	0.008	5264	74.6	14.5	0.868	187	75.6	82.8	0.187	1040	-6.0	-7.4	1.069
	20	0.026	5191	80.1	16.8	0.855	183	75.9	84.5	0.183	1054	-7.1	-9.6	1.083
		0.065	4863	102.7	23.5	0.801	90	83.7	93.1	0.090	1082	-1.1	-1.5	1.112

Static Alkali, Surfactant, and Polymer Adsorption

Well: Warner - Various Depth: Various

Chemical Solution	Days	Interfacial Tension dynes/cm	Alkali Consumption				Surfactant Consumption				Polymer Consumption			
			mg/100g		% of	C/C ₀	mg/100g		% of	C/C ₀	mg/100g		% of	C/C ₀
			mg/L	rock	initial		mg/L	rock	initial		mg/L	rock	initial	
			NaOH				Petronate EOR 2095				Flopaam 3430S			
0.75 wt% NaOH +	initial	0.002	5929	0.0	0.0	1.000	1000	0.0	0.0	1.000	987	0.0	0.0	1.000
0.1 wt% Petronate EOR 2095 +	0	0.001	5740	18.9	3.2	0.968	733	26.7	26.7	0.733	975	1.2	1.2	0.988
1000 mg/L Flopaam 3430S	1	0.002	5691	23.4	4.3	0.960	678	31.8	33.8	0.678	990	-0.2	-0.2	1.003
	4	0.002	5387	49.0	9.7	0.909	300	63.6	71.6	0.300	1048	-5.1	-6.1	1.062
	7	0.002	5281	57.2	12.4	0.891	263	66.5	76.7	0.263	1044	-4.8	-6.3	1.058
	20	0.002	5117	68.5	16.2	0.863	159	73.7	87.0	0.159	1061	-5.9	-8.8	1.075
			Na ₂ CO ₃				Petronate EOR 2095				Flopaam 3430S			
2.0 wt% Na ₂ CO ₃ +	initial	0.008	22556	0.0	0.0	1.000	1000	0.0	0.0	1.000	979	0.0	0.0	1.000
0.1 wt% Petronate EOR 2095 +	0	0.008	22273	28.3	1.3	0.987	556	44.4	44.4	0.556	953	2.6	2.7	0.973
1000 mg/L Flopaam 3430S	1	0.008	21773	76.4	3.7	0.964	502	49.4	51.8	0.501	972	1.0	1.1	0.992
	4	0.012	21643	87.3	4.6	0.958	99	83.3	90.9	0.099	1005	-1.8	-2.2	1.025
	7	0.012	21513	97.2	5.6	0.953	96	83.5	91.9	0.096	1020	-3.0	-4.0	1.041
	20	0.062	21122	124.1	7.9	0.935	85	84.2	93.5	0.085	1047	-4.8	-7.2	1.068
			NaOH				ORS-60HF				Flopaam 3430S			
1.25 wt% NaOH +	initial	0.000	11218	0.0	0.0	1.000	1000	0.0	0.0	1.000	988	0.0	0.0	1.000
0.1 wt% ORS-60HF +	0	0.020	11103	11.5	1.0	0.990	304	69.6	69.6	0.304	1046	-5.8	-5.9	1.059
1000 mg/L Flopaam 3430S	1	0.003	11095	13.3	1.3	0.988	259	73.8	75.6	0.259	999	-1.4	-1.5	1.010
	4	0.003	10840	34.8	3.7	0.965	175	80.8	84.6	0.175	1032	-4.2	-5.0	1.043
	7	0.001	10512	60.0	6.9	0.936	171	81.1	86.1	0.171	1046	-5.2	-7.0	1.057
	20	0.001	10406	67.3	8.6	0.926	164	81.6	87.8	0.164	1037	-4.6	-6.9	1.048
			NaOH				ORS-62HF				Flopaam 3430S			
0.5 wt% NaOH +	initial	0.002	3157	0.0	0.0	1.000	1000	0.0	0.0	1.000	978	0.0	0.0	1.000
0.1 wt% ORS-97HF +	0	0.001	2788	36.9	11.7	0.883	272	72.8	72.8	0.272	1047	-6.9	-7.1	1.071
1000 mg/L Flopaam 3430S	1	0.002	2739	41.4	14.1	0.868	268	73.2	74.8	0.268	1063	-8.4	-9.4	1.087
	4	0.002	2599	53.2	19.5	0.823	223	77.0	80.4	0.223	1068	-8.8	-10.8	1.092
	7	0.002	2452	64.5	25.5	0.777	215	77.6	82.5	0.215	1066	-8.6	-11.8	1.090
	20	0.004	2280	76.4	32.6	0.722	215	79.2	84.2	0.215	1094	-2.6	-3.5	1.119

Static Alkali, Surfactant, and Polymer Adsorption

Well: Warner - Various Depth: Various

Chemical Solution	Days	Interfacial Tension dynes/cm	Alkali Consumption				Surfactant Consumption				Polymer Consumption			
			mg/100g		% of	C/C ₀	mg/100g		% of	C/C ₀	mg/100g		% of	C/C ₀
			mg/L	rock	initial		mg/L	rock	initial		mg/L	rock	initial	
			Na ₂ CO ₃				ORS-97HF				Flopaam 3430S			
1.0 wt% Na ₂ CO ₃ +	initial	0.007	12364	0.0	0.0	1.000	1000	0.0	0.0	1.000	981	0.0	0.0	1.000
0.1 wt% ORS-97HF +	0	0.556	11626	73.8	6.0	0.940	324	67.6	67.6	0.324	1080	-9.9	-10.1	1.101
1000 mg/L Flopaam 3430S	1	1.045	11278	106.9	9.4	0.911	285	71.2	73.2	0.285	1047	-6.8	-7.6	1.066
	4	1.195	10843	143.5	13.6	0.876	214	77.2	81.1	0.214	1082	-9.7	-11.9	1.102
	7	1.363	10669	156.8	16.1	0.862	210	77.5	82.8	0.210	1094	-10.6	-14.5	1.114
	20	1.449	10430	173.3	19.4	0.842	206	77.8	84.5	0.206	1097	-10.8	-16.7	1.117
			NaOH				ORS-162HF				Flopaam 3430S			
1.0 wt% NaOH +	initial	0.004	8430	0.0	0.0	1.000	1000	0.0	0.0	1.000	972	0.0	0.0	1.000
0.1 wt% ORS-162HF +	0	0.010	8397	3.3	0.4	0.996	464	53.6	53.6	0.464	985	-1.3	-1.3	1.013
1000 mg/L Flopaam 3430S	1	0.004	8225	19.1	2.5	0.976	460	54.0	56.1	0.460	1016	-4.1	-4.7	1.045
	4	0.003	8200	21.2	3.0	0.973	223	73.9	79.8	0.223	1043	-6.4	-7.9	1.073
	7	0.002	8077	30.6	4.7	0.958	215	74.5	81.9	0.215	1046	-6.6	-9.0	1.076
	20	0.001	7979	37.4	6.3	0.947	204	75.3	84.2	0.204	1061	-7.7	-11.7	1.092
			Na ₂ CO ₃				ORS-162HF				Flopaam 3430S			
2.0 wt% Na ₂ CO ₃ +	initial	0.003	24012	0.0	0.0	1.000	1000	0.0	0.0	1.000	964	0.0	0.0	1.000
0.1 wt% ORS-162HF +	0	0.004	23142	87.0	3.6	0.964	462	53.8	53.8	0.462	980	-1.6	-1.7	1.017
1000 mg/L Flopaam 3430S	1	0.005	23034	99.2	4.5	0.958	462	53.8	56.0	0.461	1009	-4.2	-4.7	1.046
	4	0.023	22621	133.9	6.6	0.941	208	75.2	81.1	0.208	1018	-4.9	-6.1	1.055
	7	0.035	22404	150.5	8.1	0.932	199	75.9	83.3	0.199	1019	-5.0	-6.8	1.056
	20	0.044	22056	174.5	10.3	0.917	192	76.4	85.2	0.192	1015	-4.7	-7.2	1.051
			Na ₂ CO ₃				B-100 and AS-1216				Flopaam 3430S			
1.25 wt% Na ₂ CO ₃ +	initial	0.071	15037	0.0	0.0	1.000	1000	0.0	0.0	1.000	953	0.0	0.0	1.000
0.05 wt% Petrostep B-100 +	0	0.106	14364	67.3	4.5	0.955	735	26.5	26.5	0.735	1064	-11.1	-11.6	1.116
0.05 wt% Stepantan AS-1216 +	1	0.103	13972	103.3	7.4	0.929	707	29.1	30.9	0.707	1045	-9.4	-10.8	1.097
1000 mg/L Flopaam 3430S	4	0.116	13407	151.0	11.8	0.892	530	44.0	49.6	0.530	1121	-15.8	-20.0	1.176
	7	0.116	13342	155.9	13.2	0.887	527	44.2	52.2	0.527	1103	-14.4	-20.5	1.157
	20	0.154	13147	169.4	15.7	0.874	501	50.0	59.0	0.501	1118	-7.1	-10.2	1.173

Warner
Relative Permeability #1

Field: Warner

Oil: Warner

Core Properties:

Well: 00/04-21-007-16W4

Depth (ft): 3196.5

Length (cm): 8.38

Diameter (cm): 2.48

Pore Volume (ml): 10.63

Porosity (frac): 0.263

Absolute Permeability to Oil (Kabs, o, md): 2,430

Effective Permeability to Oil (Korw, md): 325

Effective Permeability to Water (Kwro, md): 36.7

Mobility Ratio: 8.5

Point Water Saturation V_P	Relative Perm to Oil (Ko/Korw)	Relative Perm to Water (Kw/Korw)	Water-Oil Relative Perm Ratio (Kw/Ko)	Fractional Flow (fw)
Produced Water Displacing Phase				
0.222	1.000	0.000	0.000	0.000
0.224	0.918	0.001	0.001	0.070
0.255	0.480	0.007	0.015	0.524
0.274	0.300	0.009	0.030	0.694
0.295	0.161	0.010	0.063	0.826
0.328	0.065	0.012	0.186	0.933
0.345	0.049	0.016	0.332	0.962
0.378	0.034	0.023	0.677	0.981
0.430	0.020	0.048	2.375	0.994
0.536	0.000	0.113	---	1.000

Warner
Relative Permeability #2

Field: Warner

Oil: Warner

Core Properties:

Well: 00/04-21-007-16W4

Depth (ft): 3200.9

Length (cm): 7.67

Diameter (cm): 2.48

Pore Volume (ml): 9.41

Porosity (frac): 0.254

Absolute Permeability to Oil (Kabs, o, md); 1,000

Effective Permeability to Oil (Korw, md): 360

Effective Permeability to Water (Kwro, md): 38.5

Mobility Ratio: 8.1

Point Water Saturation V_P	Relative Perm to Oil (Ko/Korw)	Relative Perm to Water (Kw/Korw)	Water-Oil Relative Perm Ratio (Kw/Ko)	Fractional Flow (fw)
Produced Water Displacing Phase				
0.196	1.000	0.000	0.000	0.000
0.230	0.388	0.008	0.020	0.600
0.241	0.316	0.008	0.027	0.666
0.275	0.159	0.010	0.065	0.829
0.306	0.064	0.011	0.173	0.929
0.333	0.030	0.013	0.425	0.970
0.427	0.023	0.054	2.375	0.994
0.521	0.000	0.107	---	1.000

Warner
Relative Permeability #3

Field: Warner

Oil: Warner

Core Properties:

Well: 02/09-20-007-16W4

Depth (ft): 3233.7

Length (cm): 8.48

Diameter (cm): 2.48

Pore Volume (ml): 9.44

Porosity (frac): 0.231

Absolute Permeability to Oil (Kabs, o, md); 395

Effective Permeability to Oil (Korw, md): 204

Effective Permeability to Water (Kwro, md): 31.8

Mobility Ratio: 11.7

Point Water Saturation V_P	Relative Perm to Oil (Ko/Korw)	Relative Perm to Water (Kw/Korw)	Water-Oil Relative Perm Ratio (Kw/Ko)	Fractional Flow (fw)
Produced Water Displacing Phase				
0.160	1.000	0.000	0.000	0.000
0.162	0.942	0.001	0.001	0.057
0.167	0.882	0.002	0.002	0.119
0.235	0.297	0.009	0.031	0.702
0.254	0.183	0.011	0.058	0.813
0.254	0.178	0.011	0.059	0.816
0.267	0.119	0.010	0.082	0.860
0.269	0.112	0.010	0.085	0.865
0.289	0.068	0.010	0.142	0.914
0.300	0.056	0.010	0.179	0.931
0.318	0.039	0.011	0.279	0.955
0.325	0.036	0.012	0.319	0.960
0.358	0.025	0.019	0.743	0.982
0.440	0.005	0.064	12.194	0.999
0.455	0.006	0.085	15.644	0.999
0.464	0.003	0.099	31.037	1.000
0.482	0.000	0.156	---	1.000

Warner
Relative Permeability #4

Field: Warner

Oil: Warner

Core Properties:

Well: 00/16-20-007-16W4

Depth (ft): 3226.8

Length (cm): 8.42

Diameter (cm): 2.48

Pore Volume (ml): 10.10

Porosity (frac): 0.249

Absolute Permeability to Oil (Kabs, o, md); 514

Effective Permeability to Oil (Korw, md): 361

Effective Permeability to Water (Kwro, md): 64.8

Mobility Ratio: 13.5

Point Water Saturation V_P	Relative Perm to Oil (Ko/Korw)	Relative Perm to Water (Kw/Korw)	Water-Oil Relative Perm Ratio (Kw/Ko)	Fractional Flow (fw)
Produced Water Displacing Phase				
0.214	1.000	0.000	0.000	0.000
0.217	0.858	0.002	0.002	0.153
0.227	0.664	0.005	0.007	0.342
0.271	0.191	0.011	0.055	0.806
0.280	0.144	0.011	0.073	0.846
0.297	0.087	0.012	0.133	0.909
0.315	0.055	0.015	0.279	0.955
0.336	0.040	0.018	0.438	0.971
0.352	0.038	0.026	0.677	0.981
0.375	0.027	0.043	1.579	0.992
0.417	0.012	0.079	6.621	0.998
0.431	0.010	0.092	9.408	0.999
0.442	0.008	0.116	15.313	0.999
0.449	0.005	0.133	25.994	0.999
0.464	0.000	0.180	---	1.000

Warner
Relative Permeability #5

Field: Warner

Oil: Warner

Core Properties:

Well: 00/04-21-007-16W4

Depth (ft): 3199.3

Length (cm): 8.33

Diameter (cm): 2.46

Pore Volume (ml): 10.52

Porosity (frac): 0.266

Absolute Permeability to Water (Kabs, w, md); 923

Effective Permeability to Oil (Korw, md): 1389

Effective Permeability to Water (Kwro, md): 249

Mobility Ratio: 13.5

Point Water Saturation V_P	Relative Perm to Oil (Ko/Korw)	Relative Perm to Water (Kw/Korw)	Water-Oil Relative Perm Ratio (Kw/Ko)	Fractional Flow (fw)
Produced Water Displacing Phase				
0.186	1.000	0.000	0.000	0.000
0.343	0.338	0.011	0.031	0.700
0.392	0.235	0.016	0.066	0.833
0.428	0.156	0.020	0.126	0.905
0.469	0.103	0.023	0.226	0.944
0.514	0.057	0.035	0.624	0.979
0.550	0.029	0.045	1.579	0.992
0.601	0.014	0.096	6.754	0.998
0.624	0.009	0.127	13.455	0.999
0.644	0.000	0.180	---	1.000

Warner
Relative Permeability #6

Field: Warner

Oil: Warner

Core Properties:

Well: 00/16-20-007-16W4

Depth (ft): 3236.1

Length (cm): 8.26

Diameter (cm): 2.47

Pore Volume (ml): 10.17

Porosity (frac): 0.256

Absolute Permeability to Water (Kabs, w, md); 2,260

Effective Permeability to Oil (Korw, md): 1227

Effective Permeability to Water (Kwro, md): 185

Mobility Ratio: 11.4

Point Water Saturation V_P	Relative Perm to Oil (K_o/K_{orw})	Relative Perm to Water (K_w/K_{orw})	Water-Oil Relative Perm Ratio (K_w/K_o)	Fractional Flow (f_w)
Produced Water Displacing Phase				
0.193	1.000	0.000	0.000	0.000
0.209	0.844	0.001	0.002	0.102
0.422	0.168	0.024	0.139	0.913
0.472	0.103	0.033	0.319	0.960
0.543	0.045	0.045	1.004	0.987
0.582	0.033	0.055	1.645	0.992
0.622	0.019	0.076	4.012	0.997
0.658	0.005	0.116	24.933	0.999
0.668	0.000	0.151	---	1.000

Warner Run 1L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.63 ml
Initial Oil Saturation: 8.27 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.54 ft/day									
1	0.32	0.00	0.32	0.32	0.00	0.32	0.03	100.0	3.9
2	0.41	0.03	0.38	0.73	0.03	0.70	0.07	92.7	8.5
3	0.42	0.22	0.20	1.15	0.25	0.90	0.11	47.6	10.9
4	0.49	0.34	0.15	1.64	0.59	1.05	0.15	30.6	12.7
5	0.47	0.38	0.09	2.11	0.97	1.14	0.20	19.1	13.8
6	0.46	0.38	0.08	2.57	1.35	1.22	0.24	17.4	14.8
7	0.44	0.36	0.08	3.01	1.71	1.30	0.28	18.2	15.7
8	0.44	0.38	0.06	3.45	2.09	1.36	0.32	13.6	16.4
9	0.45	0.42	0.03	3.90	2.51	1.39	0.37	6.7	16.8
10	0.41	0.38	0.03	4.31	2.89	1.42	0.41	7.3	17.2
11	0.42	0.38	0.04	4.73	3.27	1.46	0.44	9.5	17.7
12	0.34	0.33	0.01	5.07	3.60	1.47	0.48	2.9	17.8
13	0.35	0.34	0.01	5.42	3.94	1.48	0.51	2.9	17.9
14	0.34	0.33	0.01	5.76	4.27	1.49	0.54	2.9	18.0
15	0.35	0.34	0.01	6.11	4.61	1.50	0.57	2.9	18.1
16	0.30	0.29	0.01	6.41	4.90	1.51	0.60	3.3	18.3
17	0.31	0.30	0.01	6.72	5.20	1.52	0.63	3.2	18.4
18	0.25	0.24	0.01	6.97	5.44	1.53	0.66	4.0	18.5
19	0.32	0.29	0.03	7.29	5.73	1.56	0.69	9.4	18.9
20	0.22	0.20	0.02	7.51	5.93	1.58	0.71	9.1	19.1
21	0.24	0.22	0.02	7.75	6.15	1.60	0.73	8.3	19.3
22	0.26	0.25	0.01	8.01	6.40	1.61	0.75	3.8	19.5
23	0.20	0.19	0.01	8.21	6.59	1.62	0.77	5.0	19.6
24	0.23	0.22	0.01	8.44	6.81	1.63	0.79	4.3	19.7
25	0.21	0.20	0.01	8.65	7.01	1.64	0.81	4.8	19.8
26	0.22	0.21	0.01	8.87	7.22	1.65	0.83	4.5	20.0
27	0.19	0.18	0.01	9.06	7.40	1.66	0.85	5.3	20.1
28	0.16	0.15	0.01	9.22	7.55	1.67	0.87	6.3	20.2
29	0.19	0.18	0.01	9.41	7.73	1.68	0.89	5.3	20.3
30	0.17	0.16	0.01	9.58	7.89	1.69	0.90	5.9	20.4
31	0.19	0.18	0.01	9.77	8.07	1.70	0.92	5.3	20.6
32	0.15	0.14	0.01	9.92	8.21	1.71	0.93	6.7	20.7
33	0.17	0.16	0.01	10.09	8.37	1.72	0.95	5.9	20.8
34	0.17	0.16	0.01	10.26	8.53	1.73	0.97	5.9	20.9
35	0.17	0.16	0.01	10.43	8.69	1.74	0.98	5.9	21.0
36	0.17	0.16	0.01	10.60	8.85	1.75	1.00	5.9	21.2
37	0.18	0.17	0.01	10.78	9.02	1.76	1.01	5.6	21.3
38	0.16	0.15	0.01	10.94	9.17	1.77	1.03	6.3	21.4
39	0.19	0.18	0.01	11.13	9.35	1.78	1.05	5.3	21.5
40	0.17	0.16	0.01	11.30	9.51	1.79	1.06	5.9	21.6

Warner Run 1L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.63 ml
Initial Oil Saturation: 8.27 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.54 ft/day									
41	0.19	0.18	0.01	11.49	9.69	1.80	1.08	5.3	21.8
42	0.19	0.18	0.01	11.68	9.87	1.81	1.10	5.3	21.9
43	0.19	0.18	0.01	11.87	10.05	1.82	1.12	5.3	22.0
44	0.19	0.18	0.01	12.06	10.23	1.83	1.13	5.3	22.1
45	0.19	0.18	0.01	12.25	10.41	1.84	1.15	5.3	22.2
46	0.53	0.51	0.02	12.78	10.92	1.86	1.20	3.8	22.5
47	0.51	0.49	0.02	13.29	11.41	1.88	1.25	3.9	22.7
48	0.53	0.51	0.02	13.82	11.92	1.90	1.30	3.8	23.0
49	0.53	0.52	0.01	14.35	12.44	1.91	1.35	1.9	23.1
50	0.53	0.52	0.01	14.88	12.96	1.92	1.40	1.9	23.2
51	0.53	0.52	0.01	15.41	13.48	1.93	1.45	1.9	23.3
52	0.54	0.52	0.02	15.95	14.00	1.95	1.50	3.7	23.6
53	0.54	0.52	0.02	16.49	14.52	1.97	1.55	3.7	23.8
54	0.57	0.56	0.01	17.06	15.08	1.98	1.60	1.8	23.9
55	0.51	0.49	0.02	17.57	15.57	2.00	1.65	3.9	24.2
56	0.57	0.56	0.01	18.14	16.13	2.01	1.71	1.8	24.3
57	0.50	0.49	0.01	18.64	16.62	2.02	1.75	2.0	24.4
58	0.50	0.49	0.01	19.14	17.11	2.03	1.80	2.0	24.5
59	0.52	0.51	0.01	19.66	17.62	2.04	1.85	1.9	24.7
60	0.46	0.44	0.02	20.12	18.06	2.06	1.89	4.3	24.9
61	0.50	0.50	0.00	20.62	18.56	2.06	1.94	0.0	24.9
62	0.50	0.48	0.02	21.12	19.04	2.08	1.99	4.0	25.2
63	0.48	0.46	0.02	21.60	19.50	2.10	2.03	4.2	25.4
64	2.00	1.92	0.08	23.60	21.42	2.18	2.22	4.0	26.4
65	2.10	2.07	0.03	25.70	23.49	2.21	2.42	1.4	26.7
66	1.90	1.84	0.06	27.60	25.33	2.27	2.60	3.2	27.4
67	2.10	2.06	0.04	29.70	27.39	2.31	2.79	1.9	27.9
68	1.90	1.88	0.02	31.60	29.27	2.33	2.97	1.1	28.2
69	2.00	1.96	0.04	33.60	31.23	2.37	3.16	2.0	28.7
70	2.00	1.97	0.03	35.60	33.20	2.40	3.35	1.5	29.0
71	2.30	2.28	0.02	37.90	35.48	2.42	3.57	0.9	29.3
72	1.80	1.79	0.01	39.70	37.27	2.43	3.73	0.6	29.4
73	4.90	4.81	0.09	44.60	42.08	2.52	4.20	1.8	30.5
74	4.90	4.82	0.08	49.50	46.90	2.60	4.66	1.6	31.4
75	5.10	5.04	0.06	54.60	51.94	2.66	5.14	1.2	32.2
76	5.50	5.42	0.08	60.10	57.36	2.74	5.65	1.5	33.1
77	6.10	6.04	0.06	66.20	63.40	2.80	6.23	1.0	33.9
78	4.70	4.68	0.02	70.90	68.08	2.82	6.67	0.4	34.1
79	5.80	5.78	0.02	76.70	73.86	2.84	7.22	0.3	34.3
80	9.10	9.02	0.08	85.80	82.88	2.92	8.07	0.9	35.3

Warner Run 1L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.63 ml
Initial Oil Saturation: 8.27 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.54 ft/day									
81	9.70	9.68	0.02	95.50	92.56	2.94	8.98	0.2	35.6
82	9.80	9.70	0.10	105.30	102.26	3.04	9.91	1.0	36.8
83	99.90	99.60	0.30	205.20	201.86	3.34	19.30	0.3	40.4

Warner Run 2L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.41 ml
Initial Oil Saturation: 7.57 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.15 ft/day									
1	0.14	0.00	0.14	0.14	0.00	0.14	0.01	100.0	1.8
2	0.40	0.00	0.40	0.54	0.00	0.54	0.06	100.0	7.1
3	0.62	0.37	0.25	1.16	0.37	0.79	0.12	40.3	10.4
4	0.40	0.24	0.16	1.56	0.61	0.95	0.17	40.0	12.5
5	0.42	0.28	0.14	1.98	0.89	1.09	0.21	33.3	14.4
6	0.41	0.34	0.07	2.39	1.23	1.16	0.25	17.1	15.3
7	0.49	0.43	0.06	2.88	1.66	1.22	0.31	12.2	16.1
8	0.44	0.40	0.04	3.32	2.06	1.26	0.35	9.1	16.6
9	0.38	0.34	0.04	3.70	2.40	1.30	0.39	10.5	17.2
10	0.42	0.39	0.03	4.12	2.79	1.33	0.44	7.1	17.6
11	0.33	0.30	0.03	4.45	3.09	1.36	0.47	9.1	18.0
12	0.29	0.27	0.02	4.74	3.36	1.38	0.50	6.9	18.2
13	0.31	0.28	0.03	5.05	3.64	1.41	0.54	9.7	18.6
14	0.32	0.29	0.03	5.37	3.93	1.44	0.57	9.4	19.0
15	0.32	0.29	0.03	5.69	4.22	1.47	0.60	9.4	19.4
16	0.33	0.32	0.01	6.02	4.54	1.48	0.64	3.0	19.6
17	0.27	0.26	0.01	6.29	4.80	1.49	0.67	3.7	19.7
18	0.30	0.28	0.02	6.59	5.08	1.51	0.70	6.7	19.9
19	0.29	0.28	0.01	6.88	5.36	1.52	0.73	3.4	20.1
20	0.24	0.23	0.01	7.12	5.59	1.53	0.76	4.2	20.2
21	0.28	0.26	0.02	7.40	5.85	1.55	0.79	7.1	20.5
22	0.28	0.27	0.01	7.68	6.12	1.56	0.82	3.6	20.6
23	0.22	0.21	0.01	7.90	6.33	1.57	0.84	4.5	20.7
24	0.27	0.26	0.01	8.17	6.59	1.58	0.87	3.7	20.9
25	0.22	0.20	0.02	8.39	6.79	1.60	0.89	9.1	21.1
26	0.27	0.26	0.01	8.66	7.05	1.61	0.92	3.7	21.3
27	0.20	0.19	0.01	8.86	7.24	1.62	0.94	5.0	21.4
28	0.26	0.24	0.02	9.12	7.48	1.64	0.97	7.7	21.7
29	0.21	0.19	0.02	9.33	7.67	1.66	0.99	9.5	21.9
30	0.21	0.20	0.01	9.54	7.87	1.67	1.01	4.8	22.1
31	0.20	0.19	0.01	9.74	8.06	1.68	1.04	5.0	22.2
32	0.22	0.20	0.02	9.96	8.26	1.70	1.06	9.1	22.5
33	0.21	0.20	0.01	10.17	8.46	1.71	1.08	4.8	22.6
34	0.21	0.20	0.01	10.38	8.66	1.72	1.10	4.8	22.7
35	0.19	0.18	0.01	10.57	8.84	1.73	1.12	5.3	22.9
36	0.19	0.18	0.01	10.76	9.02	1.74	1.14	5.3	23.0
37	0.16	0.15	0.01	10.92	9.17	1.75	1.16	6.3	23.1
38	0.24	0.22	0.02	11.16	9.39	1.77	1.19	8.3	23.4
39	0.19	0.18	0.01	11.35	9.57	1.78	1.21	5.3	23.5
40	0.17	0.16	0.01	11.52	9.73	1.79	1.22	5.9	23.6

Warner Run 2L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.41 ml
Initial Oil Saturation: 7.57 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.15 ft/day									
41	0.19	0.18	0.01	11.71	9.91	1.80	1.24	5.3	23.8
42	0.17	0.16	0.01	11.88	10.07	1.81	1.26	5.9	23.9
43	0.21	0.20	0.01	12.09	10.27	1.82	1.28	4.8	24.0
44	0.17	0.16	0.01	12.26	10.43	1.83	1.30	5.9	24.2
45	0.19	0.18	0.01	12.45	10.61	1.84	1.32	5.3	24.3
46	0.20	0.19	0.01	12.65	10.80	1.85	1.34	5.0	24.4
47	0.47	0.46	0.01	13.12	11.26	1.86	1.39	2.1	24.6
48	0.51	0.49	0.02	13.63	11.75	1.88	1.45	3.9	24.8
49	0.51	0.50	0.01	14.14	12.25	1.89	1.50	2.0	25.0
50	0.45	0.44	0.01	14.59	12.69	1.90	1.55	2.2	25.1
51	0.45	0.44	0.01	15.04	13.13	1.91	1.60	2.2	25.2
52	0.46	0.45	0.01	15.50	13.58	1.92	1.65	2.2	25.4
53	0.49	0.48	0.01	15.99	14.06	1.93	1.70	2.0	25.5
54	0.46	0.45	0.01	16.45	14.51	1.94	1.75	2.2	25.6
55	0.47	0.46	0.01	16.92	14.97	1.95	1.80	2.1	25.8
56	0.45	0.44	0.01	17.37	15.41	1.96	1.85	2.2	25.9
57	0.47	0.46	0.01	17.84	15.87	1.97	1.90	2.1	26.0
58	0.48	0.46	0.02	18.32	16.33	1.99	1.95	4.2	26.3
59	0.45	0.43	0.02	18.77	16.76	2.01	1.99	4.4	26.6
60	0.49	0.48	0.01	19.26	17.24	2.02	2.05	2.0	26.7
61	0.43	0.42	0.01	19.69	17.66	2.03	2.09	2.3	26.8
62	0.50	0.48	0.02	20.19	18.14	2.05	2.15	4.0	27.1
63	0.50	0.49	0.01	20.69	18.63	2.06	2.20	2.0	27.2
64	0.43	0.42	0.01	21.12	19.05	2.07	2.24	2.3	27.3
65	2.00	1.92	0.08	23.12	20.97	2.15	2.46	4.0	28.4
66	2.10	2.07	0.03	25.22	23.04	2.18	2.68	1.4	28.8
67	1.90	1.84	0.06	27.12	24.88	2.24	2.88	3.2	29.6
68	2.10	2.06	0.04	29.22	26.94	2.28	3.11	1.9	30.1
69	1.90	1.88	0.02	31.12	28.82	2.30	3.31	1.1	30.4
70	2.00	1.96	0.04	33.12	30.78	2.34	3.52	2.0	30.9
71	2.00	1.97	0.03	35.12	32.75	2.37	3.73	1.5	31.3
72	2.30	2.28	0.02	37.42	35.03	2.39	3.98	0.9	31.6
73	1.80	1.79	0.01	39.22	36.82	2.40	4.17	0.6	31.7
74	4.90	4.81	0.09	44.12	41.63	2.49	4.69	1.8	32.9
75	4.90	4.82	0.08	49.02	46.45	2.57	5.21	1.6	33.9
76	5.10	5.04	0.06	54.12	51.49	2.63	5.75	1.2	34.7
77	5.50	5.42	0.08	59.62	56.91	2.71	6.34	1.5	35.8
78	6.10	6.04	0.06	65.72	62.95	2.77	6.98	1.0	36.6
79	4.70	4.68	0.02	70.42	67.63	2.79	7.48	0.4	36.9
80	5.80	5.78	0.02	76.22	73.41	2.81	8.10	0.3	37.1

Warner Run 2L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.41 ml
Initial Oil Saturation: 7.57 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.15 ft/day									
81	9.10	9.02	0.08	85.32	82.43	2.89	9.07	0.9	38.2
82	9.70	9.68	0.02	95.02	92.11	2.91	10.10	0.2	38.4
83	9.80	9.70	0.10	104.82	101.81	3.01	11.14	1.0	39.8
84	98.00	97.95	0.05	202.82	199.76	3.06	21.55	0.1	40.4

Warner Run 3L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.44 ml
Initial Oil Saturation: 7.93 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 20.63 ft/day									
1	0.04	0.00	0.04	0.04	0.00	0.04	0.00	100.0	0.5
2	0.30	0.00	0.30	0.34	0.00	0.34	0.04	100.0	4.3
3	0.35	0.02	0.33	0.69	0.02	0.67	0.07	94.3	8.4
4	0.42	0.05	0.37	1.11	0.07	1.04	0.12	88.1	13.1
5	0.47	0.33	0.14	1.58	0.40	1.18	0.17	29.8	14.9
6	0.48	0.39	0.09	2.06	0.79	1.27	0.22	18.8	16.0
7	0.49	0.40	0.09	2.55	1.19	1.36	0.27	18.4	17.2
8	0.46	0.39	0.07	3.01	1.58	1.43	0.32	15.2	18.0
9	0.43	0.37	0.06	3.44	1.95	1.49	0.36	14.0	18.8
10	0.37	0.32	0.05	3.81	2.27	1.54	0.40	13.5	19.4
11	0.38	0.34	0.04	4.19	2.61	1.58	0.44	10.5	19.9
12	0.35	0.32	0.03	4.54	2.93	1.61	0.48	8.6	20.3
13	0.34	0.30	0.04	4.88	3.23	1.65	0.52	11.8	20.8
14	0.42	0.39	0.03	5.30	3.62	1.68	0.56	7.1	21.2
15	0.25	0.23	0.02	5.55	3.85	1.70	0.59	8.0	21.4
16	0.29	0.27	0.02	5.84	4.12	1.72	0.62	6.9	21.7
17	0.34	0.31	0.03	6.18	4.43	1.75	0.65	8.8	22.1
18	0.31	0.29	0.02	6.49	4.72	1.77	0.69	6.5	22.3
19	0.38	0.35	0.03	6.87	5.07	1.80	0.73	7.9	22.7
20	0.22	0.21	0.01	7.09	5.28	1.81	0.75	4.5	22.8
21	0.23	0.21	0.02	7.32	5.49	1.83	0.78	8.7	23.1
22	0.24	0.22	0.02	7.56	5.71	1.85	0.80	8.3	23.3
23	0.23	0.21	0.02	7.79	5.92	1.87	0.83	8.7	23.6
24	0.25	0.24	0.01	8.04	6.16	1.88	0.85	4.0	23.7
25	0.23	0.22	0.01	8.27	6.38	1.89	0.88	4.3	23.8
26	0.21	0.20	0.01	8.48	6.58	1.90	0.90	4.8	24.0
27	0.25	0.23	0.02	8.73	6.81	1.92	0.92	8.0	24.2
28	0.26	0.24	0.02	8.99	7.05	1.94	0.95	7.7	24.5
29	0.23	0.23	0.00	9.22	7.28	1.94	0.98	0.0	24.5
30	0.26	0.24	0.02	9.48	7.52	1.96	1.00	7.7	24.7
31	0.24	0.23	0.01	9.72	7.75	1.97	1.03	4.2	24.8
32	0.22	0.21	0.01	9.94	7.96	1.98	1.05	4.5	25.0
33	0.22	0.21	0.01	10.16	8.17	1.99	1.08	4.5	25.1
34	0.21	0.20	0.01	10.37	8.37	2.00	1.10	4.8	25.2
35	0.25	0.24	0.01	10.62	8.61	2.01	1.13	4.0	25.3
36	0.20	0.19	0.01	10.82	8.80	2.02	1.15	5.0	25.5
37	0.64	0.62	0.02	11.46	9.42	2.04	1.21	3.1	25.7
38	0.65	0.64	0.01	12.11	10.06	2.05	1.28	1.5	25.9
39	0.60	0.58	0.02	12.71	10.64	2.07	1.35	3.3	26.1
40	0.58	0.57	0.01	13.29	11.21	2.08	1.41	1.7	26.2

Warner Run 3L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.44 ml
Initial Oil Saturation: 7.93 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 20.63 ft/day									
41	0.57	0.56	0.01	13.86	11.77	2.09	1.47	1.8	26.4
42	0.55	0.54	0.01	14.41	12.31	2.10	1.53	1.8	26.5
43	0.59	0.57	0.02	15.00	12.88	2.12	1.59	3.4	26.7
44	0.56	0.54	0.02	15.56	13.42	2.14	1.65	3.6	27.0
45	0.57	0.56	0.01	16.13	13.98	2.15	1.71	1.8	27.1
46	0.57	0.56	0.01	16.70	14.54	2.16	1.77	1.8	27.2
47	0.74	0.73	0.01	17.44	15.27	2.17	1.85	1.4	27.4
48	0.32	0.31	0.01	17.76	15.58	2.18	1.88	3.1	27.5
49	0.57	0.56	0.01	18.33	16.14	2.19	1.94	1.8	27.6
50	0.55	0.54	0.01	18.88	16.68	2.20	2.00	1.8	27.7
51	0.55	0.54	0.01	19.43	17.22	2.21	2.06	1.8	27.9
52	0.53	0.52	0.01	19.96	17.74	2.22	2.11	1.9	28.0
53	0.55	0.54	0.01	20.51	18.28	2.23	2.17	1.8	28.1
54	0.54	0.53	0.01	21.05	18.81	2.24	2.23	1.9	28.2
55	0.55	0.54	0.01	21.60	19.35	2.25	2.29	1.8	28.4
56	0.51	0.50	0.01	22.11	19.85	2.26	2.34	2.0	28.5
57	0.54	0.53	0.01	22.65	20.38	2.27	2.40	1.9	28.6
58	0.55	0.54	0.01	23.20	20.92	2.28	2.46	1.8	28.8
59	0.50	0.50	0.00	23.70	21.42	2.28	2.51	0.0	28.8
60	0.53	0.52	0.01	24.23	21.94	2.29	2.57	1.9	28.9
61	2.30	2.27	0.03	26.53	24.21	2.32	2.81	1.3	29.3
62	2.40	2.38	0.02	28.93	26.59	2.34	3.06	0.8	29.5
63	2.40	2.37	0.03	31.33	28.96	2.37	3.32	1.2	29.9
64	2.30	2.28	0.02	33.63	31.24	2.39	3.56	0.9	30.1
65	2.40	2.38	0.02	36.03	33.62	2.41	3.82	0.8	30.4
66	2.20	2.19	0.01	38.23	35.81	2.42	4.05	0.5	30.5
67	4.40	4.37	0.03	42.63	40.18	2.45	4.52	0.7	30.9
68	4.10	4.08	0.02	46.73	44.26	2.47	4.95	0.5	31.1
69	4.50	4.47	0.03	51.23	48.73	2.50	5.43	0.7	31.5
70	4.30	4.27	0.03	55.53	53.00	2.53	5.88	0.7	31.9
71	4.50	4.49	0.01	60.03	57.49	2.54	6.36	0.2	32.0
72	5.00	4.98	0.02	65.03	62.47	2.56	6.89	0.4	32.3
73	5.00	4.98	0.02	70.03	67.45	2.58	7.42	0.4	32.5
74	5.10	5.07	0.03	75.13	72.52	2.61	7.96	0.6	32.9
75	5.20	5.19	0.01	80.33	77.71	2.62	8.51	0.2	33.0
76	9.30	9.23	0.07	89.63	86.94	2.69	9.49	0.8	33.9
77	9.50	9.46	0.04	99.13	96.40	2.73	10.50	0.4	34.4
78	9.20	9.17	0.03	108.33	105.57	2.76	11.48	0.3	34.8
79	9.20	9.19	0.01	117.53	114.76	2.77	12.45	0.1	34.9
80	9.00	8.98	0.02	126.53	123.74	2.79	13.40	0.2	35.2

Warner Run 3L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 9.44 ml
Initial Oil Saturation: 7.93 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 20.63 ft/day									
81	21.40	21.30	0.10	147.93	145.04	2.89	15.67	0.5	36.4
82	19.30	19.25	0.05	167.23	164.29	2.94	17.72	0.3	37.1
83	23.40	23.39	0.01	190.63	187.68	2.95	20.19	0.0	37.2
84	23.60	23.58	0.02	214.23	211.26	2.97	22.69	0.1	37.5
85	49.10	49.06	0.04	263.33	260.32	3.01	27.90	0.1	38.0
86	38.00	37.97	0.03	301.33	298.29	3.04	31.92	0.1	38.3
87	18.40	18.40	0.00	319.73	316.69	3.04	33.87	0.0	38.3
88	18.60	18.60	0.00	338.33	335.29	3.04	35.84	0.0	38.3

Warner Run 4L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.10 ml
Initial Oil Saturation: 7.94 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 19.15 ft/day									
1	0.23	0.00	0.23	0.23	0.00	0.23	0.02	100.0	2.9
2	0.26	0.04	0.22	0.49	0.04	0.45	0.05	84.6	5.7
3	0.38	0.13	0.25	0.87	0.17	0.70	0.09	65.8	8.8
4	0.45	0.34	0.11	1.32	0.51	0.81	0.13	24.4	10.2
5	0.38	0.29	0.09	1.70	0.80	0.90	0.17	23.7	11.3
6	0.27	0.21	0.06	1.97	1.01	0.96	0.20	22.2	12.1
7	0.36	0.29	0.07	2.33	1.30	1.03	0.23	19.4	13.0
8	0.39	0.33	0.06	2.72	1.63	1.09	0.27	15.4	13.7
9	0.29	0.27	0.02	3.01	1.90	1.11	0.30	6.9	14.0
10	0.33	0.30	0.03	3.34	2.20	1.14	0.33	9.1	14.4
11	0.34	0.32	0.02	3.68	2.52	1.16	0.36	5.9	14.6
12	0.29	0.27	0.02	3.97	2.79	1.18	0.39	6.9	14.9
13	0.27	0.25	0.02	4.24	3.04	1.20	0.42	7.4	15.1
14	0.32	0.31	0.01	4.56	3.35	1.21	0.45	3.1	15.2
15	0.24	0.23	0.01	4.80	3.58	1.22	0.48	4.2	15.4
16	0.37	0.36	0.01	5.17	3.94	1.23	0.51	2.7	15.5
17	0.23	0.22	0.01	5.40	4.16	1.24	0.53	4.3	15.6
18	0.24	0.23	0.01	5.64	4.39	1.25	0.56	4.2	15.7
19	0.23	0.22	0.01	5.87	4.61	1.26	0.58	4.3	15.9
20	0.27	0.25	0.02	6.14	4.86	1.28	0.61	7.4	16.1
21	0.27	0.27	0.00	6.41	5.13	1.28	0.63	0.0	16.1
22	0.26	0.25	0.01	6.67	5.38	1.29	0.66	3.8	16.2
23	0.21	0.19	0.02	6.88	5.57	1.31	0.68	9.5	16.5
24	0.19	0.18	0.01	7.07	5.75	1.32	0.70	5.3	16.6
25	0.30	0.28	0.02	7.37	6.03	1.34	0.73	6.7	16.9
26	0.21	0.20	0.01	7.58	6.23	1.35	0.75	4.8	17.0
27	0.18	0.17	0.01	7.76	6.40	1.36	0.77	5.6	17.1
28	0.24	0.22	0.02	8.00	6.62	1.38	0.79	8.3	17.4
29	0.22	0.21	0.01	8.22	6.83	1.39	0.81	4.5	17.5
30	0.21	0.20	0.01	8.43	7.03	1.40	0.83	4.8	17.6
31	0.14	0.13	0.01	8.57	7.16	1.41	0.85	7.1	17.8
32	0.23	0.21	0.02	8.80	7.37	1.43	0.87	8.7	18.0
33	0.19	0.18	0.01	8.99	7.55	1.44	0.89	5.3	18.1
34	0.51	0.50	0.01	9.50	8.05	1.45	0.94	2.0	18.3
35	0.50	0.49	0.01	10.00	8.54	1.46	0.99	2.0	18.4
36	0.48	0.46	0.02	10.48	9.00	1.48	1.04	4.2	18.6
37	0.59	0.54	0.05	11.07	9.54	1.53	1.10	8.5	19.3
38	0.58	0.56	0.02	11.65	10.10	1.55	1.15	3.4	19.5
39	0.57	0.56	0.01	12.22	10.66	1.56	1.21	1.8	19.6
40	0.55	0.53	0.02	12.77	11.19	1.58	1.26	3.6	19.9

Warner Run 4L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.10 ml
Initial Oil Saturation: 7.94 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 19.15 ft/day									
41	0.51	0.50	0.01	13.28	11.69	1.59	1.31	2.0	20.0
42	0.50	0.49	0.01	13.78	12.18	1.60	1.36	2.0	20.2
43	0.51	0.48	0.03	14.29	12.66	1.63	1.41	5.9	20.5
44	0.73	0.69	0.04	15.02	13.35	1.67	1.49	5.5	21.0
45	0.34	0.33	0.01	15.36	13.68	1.68	1.52	2.9	21.2
46	0.50	0.48	0.02	15.86	14.16	1.70	1.57	4.0	21.4
47	0.53	0.52	0.01	16.39	14.68	1.71	1.62	1.9	21.5
48	0.52	0.51	0.01	16.91	15.19	1.72	1.67	1.9	21.7
49	0.53	0.52	0.01	17.44	15.71	1.73	1.73	1.9	21.8
50	0.50	0.49	0.01	17.94	16.20	1.74	1.78	2.0	21.9
51	0.50	0.49	0.01	18.44	16.69	1.75	1.83	2.0	22.0
52	0.51	0.50	0.01	18.95	17.19	1.76	1.88	2.0	22.2
53	0.50	0.49	0.01	19.45	17.68	1.77	1.93	2.0	22.3
54	0.54	0.53	0.01	19.99	18.21	1.78	1.98	1.9	22.4
55	0.52	0.51	0.01	20.51	18.72	1.79	2.03	1.9	22.5
56	0.48	0.47	0.01	20.99	19.19	1.80	2.08	2.1	22.7
57	0.51	0.50	0.01	21.50	19.69	1.81	2.13	2.0	22.8
58	2.40	2.38	0.02	23.90	22.07	1.83	2.37	0.8	23.0
59	2.40	2.38	0.02	26.30	24.45	1.85	2.60	0.8	23.3
60	2.30	2.28	0.02	28.60	26.73	1.87	2.83	0.9	23.6
61	2.00	1.98	0.02	30.60	28.71	1.89	3.03	1.0	23.8
62	2.50	2.48	0.02	33.10	31.19	1.91	3.28	0.8	24.1
63	2.10	2.09	0.01	35.20	33.28	1.92	3.49	0.5	24.2
64	4.50	4.42	0.08	39.70	37.70	2.00	3.93	1.8	25.2
65	4.20	4.10	0.10	43.90	41.80	2.10	4.35	2.4	26.4
66	4.30	4.27	0.03	48.20	46.07	2.13	4.77	0.7	26.8
67	4.20	4.17	0.03	52.40	50.24	2.16	5.19	0.7	27.2
68	4.60	4.59	0.01	57.00	54.83	2.17	5.64	0.2	27.3
69	5.00	4.99	0.01	62.00	59.82	2.18	6.14	0.2	27.5
70	5.00	4.95	0.05	67.00	64.77	2.23	6.63	1.0	28.1
71	5.10	5.08	0.02	72.10	69.85	2.25	7.14	0.4	28.3
72	5.20	5.18	0.02	77.30	75.03	2.27	7.65	0.4	28.6
73	9.30	9.28	0.02	86.60	84.31	2.29	8.57	0.2	28.8
74	9.30	9.26	0.04	95.90	93.57	2.33	9.50	0.4	29.3
75	9.10	9.09	0.01	105.00	102.66	2.34	10.40	0.1	29.5
76	9.20	9.18	0.02	114.20	111.84	2.36	11.31	0.2	29.7
77	9.00	8.99	0.01	123.20	120.83	2.37	12.20	0.1	29.8
78	21.30	21.27	0.03	144.50	142.10	2.40	14.31	0.1	30.2
79	19.80	19.75	0.05	164.30	161.85	2.45	16.27	0.3	30.9
80	23.10	23.08	0.02	187.40	184.93	2.47	18.55	0.1	31.1

Warner Run 4L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.10 ml
Initial Oil Saturation: 7.94 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 19.15 ft/day									
81	23.20	23.18	0.02	210.60	208.11	2.49	20.85	0.1	31.4
82	47.40	47.38	0.02	258.00	255.49	2.51	25.54	0.0	31.6
83	39.20	39.18	0.02	297.20	294.67	2.53	29.43	0.1	31.9
84	18.70	18.70	0.00	315.90	313.37	2.53	31.28	0.0	31.9
85	18.60	18.60	0.00	334.50	331.97	2.53	33.12	0.0	31.9

Warner Run 5L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.52 ml
Initial Oil Saturation: 8.56 ml

Tube No.	----Produced----			-----Cumulative-----			V _p	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.58 ft/day									
1	0.11	0.00	0.11	0.11	0.00	0.11	0.01	100.0	1.3
2	0.24	0.00	0.24	0.35	0.00	0.35	0.03	100.0	4.1
3	0.21	0.00	0.21	0.56	0.00	0.56	0.05	100.0	6.5
4	0.22	0.00	0.22	0.78	0.00	0.78	0.07	100.0	9.1
5	0.22	0.00	0.22	1.00	0.00	1.00	0.10	100.0	11.7
6	0.20	0.00	0.20	1.20	0.00	1.20	0.11	100.0	14.0
7	0.20	0.00	0.20	1.40	0.00	1.40	0.13	100.0	16.4
8	0.24	0.00	0.24	1.64	0.00	1.64	0.16	100.0	19.2
9	0.20	0.00	0.20	1.84	0.00	1.84	0.17	100.0	21.5
10	0.21	0.00	0.21	2.05	0.00	2.05	0.19	100.0	23.9
11	0.21	0.04	0.17	2.26	0.04	2.22	0.21	81.0	25.9
12	0.25	0.14	0.11	2.51	0.18	2.33	0.24	44.0	27.2
13	0.26	0.12	0.14	2.77	0.30	2.47	0.26	53.8	28.9
14	0.21	0.14	0.07	2.98	0.44	2.54	0.28	33.3	29.7
15	0.25	0.18	0.07	3.23	0.62	2.61	0.31	28.0	30.5
16	0.26	0.18	0.08	3.49	0.80	2.69	0.33	30.8	31.4
17	0.20	0.14	0.06	3.69	0.94	2.75	0.35	30.0	32.1
18	0.21	0.16	0.05	3.90	1.10	2.80	0.37	23.8	32.7
19	0.21	0.16	0.05	4.11	1.26	2.85	0.39	23.8	33.3
20	0.24	0.18	0.06	4.35	1.44	2.91	0.41	25.0	34.0
21	0.23	0.20	0.03	4.58	1.64	2.94	0.44	13.0	34.3
22	0.24	0.19	0.05	4.82	1.83	2.99	0.46	20.8	34.9
23	0.23	0.20	0.03	5.05	2.03	3.02	0.48	13.0	35.3
24	0.17	0.15	0.02	5.22	2.18	3.04	0.50	11.8	35.5
25	0.21	0.19	0.02	5.43	2.37	3.06	0.52	9.5	35.7
26	0.22	0.18	0.04	5.65	2.55	3.10	0.54	18.2	36.2
27	0.24	0.20	0.04	5.89	2.75	3.14	0.56	16.7	36.7
28	0.20	0.17	0.03	6.09	2.92	3.17	0.58	15.0	37.0
29	0.24	0.20	0.04	6.33	3.12	3.21	0.60	16.7	37.5
30	0.41	0.35	0.06	6.74	3.47	3.27	0.64	14.6	38.2
31	0.24	0.21	0.03	6.98	3.68	3.30	0.66	12.5	38.6
32	0.20	0.18	0.02	7.18	3.86	3.32	0.68	10.0	38.8
33	0.20	0.19	0.01	7.38	4.05	3.33	0.70	5.0	38.9
34	0.22	0.20	0.02	7.60	4.25	3.35	0.72	9.1	39.1
35	0.23	0.20	0.03	7.83	4.45	3.38	0.74	13.0	39.5
36	0.18	0.16	0.02	8.01	4.61	3.40	0.76	11.1	39.7
37	0.23	0.21	0.02	8.24	4.82	3.42	0.78	8.7	40.0
38	0.20	0.18	0.02	8.44	5.00	3.44	0.80	10.0	40.2
39	0.21	0.20	0.01	8.65	5.20	3.45	0.82	4.8	40.3
40	0.26	0.24	0.02	8.91	5.44	3.47	0.85	7.7	40.5

Warner Run 5L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.52 ml
Initial Oil Saturation: 8.56 ml

Tube No.	----Produced----			-----Cumulative-----			V _p	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.58 ft/day									
41	0.18	0.17	0.01	9.09	5.61	3.48	0.86	5.6	40.7
42	0.18	0.17	0.01	9.27	5.78	3.49	0.88	5.6	40.8
43	0.28	0.26	0.02	9.55	6.04	3.51	0.91	7.1	41.0
44	0.14	0.13	0.01	9.69	6.17	3.52	0.92	7.1	41.1
45	0.20	0.19	0.01	9.89	6.36	3.53	0.94	5.0	41.2
46	0.21	0.20	0.01	10.10	6.56	3.54	0.96	4.8	41.4
47	0.21	0.20	0.01	10.31	6.76	3.55	0.98	4.8	41.5
48	0.20	0.20	0.00	10.51	6.96	3.55	1.00	0.0	41.5
49	0.21	0.19	0.02	10.72	7.15	3.57	1.02	9.5	41.7
50	0.22	0.20	0.02	10.94	7.35	3.59	1.04	9.1	41.9
51	0.48	0.45	0.03	11.42	7.80	3.62	1.09	6.2	42.3
52	0.48	0.46	0.02	11.90	8.26	3.64	1.13	4.2	42.5
53	0.49	0.47	0.02	12.39	8.73	3.66	1.18	4.1	42.8
54	0.52	0.50	0.02	12.91	9.23	3.68	1.23	3.8	43.0
55	0.50	0.48	0.02	13.41	9.71	3.70	1.27	4.0	43.2
56	0.49	0.46	0.03	13.90	10.17	3.73	1.32	6.1	43.6
57	0.51	0.49	0.02	14.41	10.66	3.75	1.37	3.9	43.8
58	0.48	0.47	0.01	14.89	11.13	3.76	1.42	2.1	43.9
59	0.48	0.47	0.01	15.37	11.60	3.77	1.46	2.1	44.0
60	0.49	0.47	0.02	15.86	12.07	3.79	1.51	4.1	44.3
61	0.51	0.48	0.03	16.37	12.55	3.82	1.56	5.9	44.6
62	0.48	0.47	0.01	16.85	13.02	3.83	1.60	2.1	44.7
63	0.53	0.52	0.01	17.38	13.54	3.84	1.65	1.9	44.9
64	0.46	0.45	0.01	17.84	13.99	3.85	1.70	2.2	45.0
65	0.49	0.48	0.01	18.33	14.47	3.86	1.74	2.0	45.1
66	0.43	0.41	0.02	18.76	14.88	3.88	1.78	4.7	45.3
67	0.58	0.57	0.01	19.34	15.45	3.89	1.84	1.7	45.4
68	0.50	0.48	0.02	19.84	15.93	3.91	1.89	4.0	45.7
69	0.46	0.45	0.01	20.30	16.38	3.92	1.93	2.2	45.8
70	0.51	0.49	0.02	20.81	16.87	3.94	1.98	3.9	46.0
71	0.49	0.48	0.01	21.30	17.35	3.95	2.02	2.0	46.1
72	0.48	0.47	0.01	21.78	17.82	3.96	2.07	2.1	46.3
73	2.30	2.25	0.05	24.08	20.07	4.01	2.29	2.2	46.8
74	2.40	2.38	0.02	26.48	22.45	4.03	2.52	0.8	47.1
75	2.40	2.36	0.04	28.88	24.81	4.07	2.75	1.7	47.5
76	2.30	2.28	0.02	31.18	27.09	4.09	2.96	0.9	47.8
77	2.40	2.38	0.02	33.58	29.47	4.11	3.19	0.8	48.0
78	2.20	2.19	0.01	35.78	31.66	4.12	3.40	0.5	48.1
79	4.40	4.36	0.04	40.18	36.02	4.16	3.82	0.9	48.6
80	4.10	4.08	0.02	44.28	40.10	4.18	4.21	0.5	48.8

Warner Run 5L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.52 ml
Initial Oil Saturation: 8.56 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 17.58 ft/day									
81	4.50	4.47	0.03	48.78	44.57	4.21	4.64	0.7	49.2
82	4.30	4.27	0.03	53.08	48.84	4.24	5.05	0.7	49.5
83	4.50	4.49	0.01	57.58	53.33	4.25	5.47	0.2	49.6
84	5.00	4.98	0.02	62.58	58.31	4.27	5.95	0.4	49.9
85	5.00	4.98	0.02	67.58	63.29	4.29	6.42	0.4	50.1
86	5.10	5.07	0.03	72.68	68.36	4.32	6.91	0.6	50.5
87	5.20	5.14	0.06	77.88	73.50	4.38	7.40	1.2	51.2
88	9.30	9.23	0.07	87.18	82.73	4.45	8.29	0.8	52.0
89	9.50	9.41	0.09	96.68	92.14	4.54	9.19	0.9	53.0
90	9.20	9.17	0.03	105.88	101.31	4.57	10.06	0.3	53.4
91	10.20	10.18	0.02	116.08	111.49	4.59	11.03	0.2	53.6
92	9.40	9.30	0.10	125.48	120.79	4.69	11.93	1.1	54.8
93	11.20	11.17	0.03	136.68	131.96	4.72	12.99	0.3	55.1
94	9.40	9.38	0.02	146.08	141.34	4.74	13.89	0.2	55.4
95	9.40	9.38	0.02	155.48	150.72	4.76	14.78	0.2	55.6
96	20.30	20.28	0.02	175.78	171.00	4.78	16.71	0.1	55.8
97	20.00	19.98	0.02	195.78	190.98	4.80	18.61	0.1	56.1
98	19.40	19.39	0.01	215.18	210.37	4.81	20.45	0.1	56.2
99	24.00	24.00	0.00	239.18	234.37	4.81	22.74	0.0	56.2
100	24.00	24.00	0.00	263.18	258.37	4.81	25.02	0.0	56.2

Warner Run 6L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.17 ml
Initial Oil Saturation: 8.21 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.03 ft/day									
1	0.19	0.00	0.19	0.19	0.00	0.19	0.02	100.0	2.3
2	0.40	0.00	0.40	0.59	0.00	0.59	0.06	100.0	7.2
3	0.40	0.00	0.40	0.99	0.00	0.99	0.10	100.0	12.1
4	0.27	0.00	0.27	1.26	0.00	1.26	0.12	100.0	15.3
5	0.30	0.00	0.30	1.56	0.00	1.56	0.15	100.0	19.0
6	0.29	0.03	0.26	1.85	0.03	1.82	0.18	89.7	22.2
7	0.28	0.08	0.20	2.13	0.11	2.02	0.21	71.4	24.6
8	0.37	0.18	0.19	2.50	0.29	2.21	0.25	51.4	26.9
9	0.31	0.19	0.12	2.81	0.48	2.33	0.28	38.7	28.4
10	0.31	0.20	0.11	3.12	0.68	2.44	0.31	35.5	29.7
11	0.30	0.22	0.08	3.42	0.90	2.52	0.34	26.7	30.7
12	0.32	0.23	0.09	3.74	1.13	2.61	0.37	28.1	31.8
13	0.35	0.29	0.06	4.09	1.42	2.67	0.40	17.1	32.5
14	0.30	0.22	0.08	4.39	1.64	2.75	0.43	26.7	33.5
15	0.26	0.22	0.04	4.65	1.86	2.79	0.46	15.4	34.0
16	0.30	0.25	0.05	4.95	2.11	2.84	0.49	16.7	34.6
17	0.30	0.25	0.05	5.25	2.36	2.89	0.52	16.7	35.2
18	0.24	0.20	0.04	5.49	2.56	2.93	0.54	16.7	35.7
19	0.26	0.23	0.03	5.75	2.79	2.96	0.57	11.5	36.1
20	0.26	0.24	0.02	6.01	3.03	2.98	0.59	7.7	36.3
21	0.26	0.24	0.02	6.27	3.27	3.00	0.62	7.7	36.5
22	0.27	0.24	0.03	6.54	3.51	3.03	0.64	11.1	36.9
23	0.27	0.26	0.01	6.81	3.77	3.04	0.67	3.7	37.0
24	0.21	0.19	0.02	7.02	3.96	3.06	0.69	9.5	37.3
25	0.26	0.24	0.02	7.28	4.20	3.08	0.72	7.7	37.5
26	0.23	0.22	0.01	7.51	4.42	3.09	0.74	4.3	37.6
27	0.23	0.21	0.02	7.74	4.63	3.11	0.76	8.7	37.9
28	0.23	0.21	0.02	7.97	4.84	3.13	0.78	8.7	38.1
29	0.24	0.24	0.00	8.21	5.08	3.13	0.81	0.0	38.1
30	0.23	0.21	0.02	8.44	5.29	3.15	0.83	8.7	38.4
31	0.22	0.21	0.01	8.66	5.50	3.16	0.85	4.5	38.5
32	0.25	0.25	0.00	8.91	5.75	3.16	0.88	0.0	38.5
33	0.20	0.20	0.00	9.11	5.95	3.16	0.90	0.0	38.5
34	0.22	0.21	0.01	9.33	6.16	3.17	0.92	4.5	38.6
35	0.26	0.25	0.01	9.59	6.41	3.18	0.94	3.8	38.7
36	0.22	0.22	0.00	9.81	6.63	3.18	0.96	0.0	38.7
37	0.19	0.16	0.03	10.00	6.79	3.21	0.98	15.8	39.1
38	0.23	0.22	0.01	10.23	7.01	3.22	1.01	4.3	39.2
39	0.23	0.21	0.02	10.46	7.22	3.24	1.03	8.7	39.5
40	0.21	0.21	0.00	10.67	7.43	3.24	1.05	0.0	39.5

Warner Run 6L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.17 ml
Initial Oil Saturation: 8.21 ml

Tube No.	----Produced----			-----Cumulative-----			V _p	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.03 ft/day									
41	0.24	0.23	0.01	10.91	7.66	3.25	1.07	4.2	39.6
42	0.19	0.19	0.00	11.10	7.85	3.25	1.09	0.0	39.6
43	0.21	0.21	0.00	11.31	8.06	3.25	1.11	0.0	39.6
44	0.24	0.22	0.02	11.55	8.28	3.27	1.14	8.3	39.8
45	0.13	0.12	0.01	11.68	8.40	3.28	1.15	7.7	40.0
46	0.20	0.16	0.04	11.88	8.56	3.32	1.17	20.0	40.4
47	0.25	0.24	0.01	12.13	8.80	3.33	1.19	4.0	40.6
48	0.19	0.17	0.02	12.32	8.97	3.35	1.21	10.5	40.8
49	0.20	0.20	0.00	12.52	9.17	3.35	1.23	0.0	40.8
50	0.21	0.20	0.01	12.73	9.37	3.36	1.25	4.8	40.9
51	0.20	0.20	0.00	12.93	9.57	3.36	1.27	0.0	40.9
52	0.52	0.51	0.01	13.45	10.08	3.37	1.32	1.9	41.0
53	0.46	0.43	0.03	13.91	10.51	3.40	1.37	6.5	41.4
54	0.53	0.53	0.00	14.44	11.04	3.40	1.42	0.0	41.4
55	0.49	0.48	0.01	14.93	11.52	3.41	1.47	2.0	41.5
56	0.50	0.45	0.05	15.43	11.97	3.46	1.52	10.0	42.1
57	0.53	0.52	0.01	15.96	12.49	3.47	1.57	1.9	42.3
58	0.53	0.52	0.01	16.49	13.01	3.48	1.62	1.9	42.4
59	0.46	0.45	0.01	16.95	13.46	3.49	1.67	2.2	42.5
60	0.47	0.45	0.02	17.42	13.91	3.51	1.71	4.3	42.8
61	0.53	0.52	0.01	17.95	14.43	3.52	1.76	1.9	42.9
62	0.54	0.53	0.01	18.49	14.96	3.53	1.82	1.9	43.0
63	0.48	0.48	0.00	18.97	15.44	3.53	1.87	0.0	43.0
64	0.47	0.42	0.05	19.44	15.86	3.58	1.91	10.6	43.6
65	0.46	0.45	0.01	19.90	16.31	3.59	1.96	2.2	43.7
66	0.52	0.49	0.03	20.42	16.80	3.62	2.01	5.8	44.1
67	0.47	0.46	0.01	20.89	17.26	3.63	2.05	2.1	44.2
68	0.57	0.56	0.01	21.46	17.82	3.64	2.11	1.8	44.3
69	0.47	0.45	0.02	21.93	18.27	3.66	2.16	4.3	44.6
70	0.53	0.52	0.01	22.46	18.79	3.67	2.21	1.9	44.7
71	0.55	0.54	0.01	23.01	19.33	3.68	2.26	1.8	44.8
72	0.53	0.53	0.00	23.54	19.86	3.68	2.31	0.0	44.8
73	0.45	0.43	0.02	23.99	20.29	3.70	2.36	4.4	45.1
74	2.20	2.17	0.03	26.19	22.46	3.73	2.58	1.4	45.4
75	2.10	1.95	0.15	28.29	24.41	3.88	2.78	7.1	47.3
76	2.35	2.25	0.10	30.64	26.66	3.98	3.01	4.3	48.5
77	2.10	2.09	0.01	32.74	28.75	3.99	3.22	0.5	48.6
78	2.30	2.27	0.03	35.04	31.02	4.02	3.45	1.3	49.0
79	2.00	1.99	0.01	37.04	33.01	4.03	3.64	0.5	49.1
80	2.10	2.06	0.04	39.14	35.07	4.07	3.85	1.9	49.6

Warner Run 6L
Waterflood Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 10.17 ml
Initial Oil Saturation: 8.21 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 18.03 ft/day									
81	2.10	2.00	0.10	41.24	37.07	4.17	4.06	4.8	50.8
82	2.00	1.98	0.02	43.24	39.05	4.19	4.25	1.0	51.0
83	2.00	1.99	0.01	45.24	41.04	4.20	4.45	0.5	51.2
84	5.20	5.15	0.05	50.44	46.19	4.25	4.96	1.0	51.8
85	5.10	5.00	0.10	55.54	51.19	4.35	5.46	2.0	53.0
86	5.30	5.22	0.08	60.84	56.41	4.43	5.98	1.5	54.0
87	5.00	5.00	0.00	65.84	61.41	4.43	6.47	0.0	54.0
88	5.00	4.90	0.10	70.84	66.31	4.53	6.97	2.0	55.2
89	5.00	4.96	0.04	75.84	71.27	4.57	7.46	0.8	55.7
90	5.00	4.98	0.02	80.84	76.25	4.59	7.95	0.4	55.9
91	5.10	5.07	0.03	85.94	81.32	4.62	8.45	0.6	56.3
92	9.70	9.64	0.06	95.64	90.96	4.68	9.40	0.6	57.0
93	9.60	9.56	0.04	105.24	100.52	4.72	10.35	0.4	57.5
94	11.00	10.97	0.03	116.24	111.49	4.75	11.43	0.3	57.9
95	9.10	9.07	0.03	125.34	120.56	4.78	12.32	0.3	58.2
96	9.20	9.18	0.02	134.54	129.74	4.80	13.23	0.2	58.5
97	19.20	19.20	0.00	153.74	148.94	4.80	15.12	0.0	58.5
98	19.00	18.98	0.02	172.74	167.92	4.82	16.99	0.1	58.7
99	18.80	18.79	0.01	191.54	186.71	4.83	18.83	0.1	58.8
100	22.00	22.00	0.00	213.54	208.71	4.83	21.00	0.0	58.8
101	22.00	22.00	0.00	235.54	230.71	4.83	23.16	0.0	58.8

Injected Fluids Summary: Warner Linear Corefloods

Coreflood Number		1	2	3	4	5	6
<u>Warner Crude Oil</u>							
Viscosity at 35°C	cp	52	52	52	52	52	52
<u>Produced Water</u>							
Viscosity at 35°C	cp	0.69	0.69	0.69	0.69	0.69	0.69
<u>Injection Water</u>							
Viscosity at 35°C	cp	0.69	0.69	0.69	0.69	0.69	0.69
<u>Alkaline Solutions</u>							
Water		Softened Injection		Softened Injection		Softened Injection	
Alkaline Type		NaOH	Na ₂ CO ₃	NaOH	NaOH	NaOH	NaOH
Alkali Concentration	wt%	1.0	2.0	0.25	0.75	0.75	1.0
Alkaline Type		---	---	Na ₂ CO ₃	---	---	---
Alkali Concentration	wt%	---	---	0.5	---	---	---
Viscosity at 35°C	cp	0.71	0.70	0.71	0.71	0.72	0.72
<u>Alkaline-Surfactant Solutions</u>							
Water		Softened Injection		Softened Injection		Softened Injection	
Alkaline Type		NaOH	Na ₂ CO ₃	NaOH	NaOH	NaOH	NaOH
Alkali Concentration	wt%	1.0	2.0	0.25	0.75	0.75	1.0
Alkaline Type		---	---	Na ₂ CO ₃	---	---	---
Alkali Concentration	wt%	---	---	0.5	---	---	---
Surfactant Type		Petronate EOR 2095	ORS-162HF	Petronate EOR 2095	ORS-97HF	ORS-97HF	ORS-97HF
Surfactant Concentration	wt%	0.1	0.1	0.1	0.1	0.1	0.1
Viscosity at 35°C	cp	0.72	0.71	0.72	0.72	0.72	0.72
<u>Alkaline-Surfactant-Polymer Solutions</u>							
Water		Softened Injection		Softened Injection		Softened Injection	
Alkaline Type		NaOH	Na ₂ CO ₃	NaOH	NaOH	NaOH	NaOH
Alkali Concentration	wt%	1.0	2.0	0.25	0.75	0.75	1.0
Alkaline Type		---	---	Na ₂ CO ₃	---	---	---
Alkali Concentration	wt%	---	---	0.5	---	---	---
Surfactant Type		Petronate EOR 2095	ORS-162HF	Petronate EOR 2095	ORS-97HF	ORS-97HF	ORS-97HF
Surfactant Concentration	wt%	0.1	0.1	0.1	0.1	0.1	0.1
Polymer Type		Flopaam 3630S	Flopaam 3530S	Alcoflood 1275A	Cyanatrol 770	Alcoflood 1275A	Flopaam 3630S
Polymer Concentration	mg/L	1500	1500	1500	1500	1500	1500
Viscosity at 35°C	cp	22.1	18.6	28.8	24.9	28.3	22.0
Screen Factor at 35°C		55.1	47.5	29.9	38.8	29.6	54.8
Polymer Concentration	mg/L	1000	1000	1000	1000	1000	1000
Viscosity at 35°C	cp	10.8	9.6	13.5	12.0	13.3	10.9
Screen Factor at 35°C		43.3	36.6	23.0	31.6	22.7	43.1
Polymer Concentration	mg/L	500	500	500	500	500	500
Viscosity at 35°C	cp	4.2	4.2	5.1	4.8	4.8	4.4
Screen Factor at 35°C		32.9	24.1	18.0	21.5	17.6	33.0
<u>Polymer Solutions</u>							
Water		Softened Injection		Softened Injection		Softened Injection	
Polymer Type		Flopaam 3630S	Flopaam 3530S	Alcoflood 1275A	Cyanatrol 770	Alcoflood 1275A	Flopaam 3630S
Polymer Concentration	mg/L	1000	1000	1000	1000	1000	1000
Viscosity at 35°C	cp	22.1	20.4	15.4	22.1	15.2	20.3
Screen Factor at 35°C		51.6	39.5	24.2	44.1	23.8	39.1

END POINT SUMMARY: Warner Linear Coreflood 1L

Field: Warner				Diameter (cm): 2.48				Pore Volume (ml): 10.63											
Well: 00/04-21-007-16W4 Depth (ft): 3196.5				Length (cm): 8.38				Porosity (%): 26.3											
Fluid Injected	Injection		Oil		-----Incremental-----			-Resistance Factor (Ratio)-			--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-		
	Rate ft/day	Produced Volume V _p	Saturation V _p	-Differential Pressure (psid)- P ₁ P ₂ P _T	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T			
Warner Crude Oil dead crude - 119 cp	6.33	2.54	1.000	---	---	4.40	---	---	3.23	---	---	1960							
	10.33	1.58	1.000	---	---	5.40	---	---	2.43	---	---	2607							
	29.86	4.33	1.000	---	---	15.00	---	---	2.34	---	---	2711							
Produced Water	29.86	5.45	0.477	---	---	2.50	---	---	0.39	---	---	94.3							
Warner Crude Oil viscosity adjusted crude - 52 cp	8.77	14.68	0.778	3.32	10.68	14.00	6.64	7.71	7.43	477	340	373							
	23.35	4.16	0.778	5.50	17.00	22.50	4.13	4.61	4.48	766	570	618							
	17.54	13.36	0.778	6.90	25.20	32.10	6.90	9.10	8.51	459	289	325							
Produced Water	17.54	19.31	0.464	1.00	2.77	3.77	1.00	1.00	1.00	42.0	34.8	36.7	1.00	1.00	1.00				
	0.73	7.71	0.426	0.18	0.32	0.50	4.32	2.77	3.18	9.73	12.6	11.5	4.32	2.77	3.18				
	10.26	1.79	0.426	0.58	1.76	2.34	0.99	1.09	1.06	42.4	32.1	34.6	0.99	1.09	1.06				
Injection Water	10.26	2.37	0.426	0.78	1.92	2.70	1.33	1.18	1.22	31.5	29.4	30.0	1.33	1.18	1.22				
1.0 wt% NaOH	10.26	4.57	0.398	0.57	2.29	2.86	0.97	1.41	1.30	44.4	25.4	29.2	0.95	1.37	1.26				
1.0 wt% NaOH + 0.1 wt% EOR 2095	10.26	6.77	0.379	0.88	0.66	1.54	1.50	0.41	0.70	29.1	89.3	54.9	1.44	0.39	0.67				
Injection Water	10.26	4.70	0.285	0.57	0.73	1.30	0.97	0.45	0.59	43.1	77.4	62.3	0.97	0.45	0.59				
	1.47	2.30	0.276	0.26	0.22	0.48	3.11	0.95	1.52	13.5	36.7	24.2	3.11	0.95	1.52				
	10.26	3.46	0.276	0.53	0.85	1.38	0.91	0.52	0.63	46.4	66.4	58.7	0.91	0.52	0.63				
1.0 wt% NaOH + 0.1 wt% EOR 2095 + 1500 mg/L Flopaam 3630S	10.26	3.01	0.200	2.50	8.10	10.60	4.27	5.00	4.81							5.75	5.70	5.71	
	2.93	2.18	0.196	0.92	0.96	1.88	5.51	2.07	2.98							7.41	2.37	3.55	
	1.10	1.94	0.167	0.50	0.60	1.10	8.00	3.46	4.67							10.76	3.95	5.55	
Injection Water	10.26	5.25	0.149	0.30	0.98	1.28	0.51	0.60	0.58	81.9	57.6	63.3	0.51	0.60	0.58				
1.0 wt% NaOH + 0.1 wt% EOR 2095 + 1000 mg/L Flopaam 3630S	10.26	4.68	0.145	1.53	4.83	6.35	2.61	2.98	2.88							4.05	2.68	2.92	
	2.93	1.67	0.144	0.50	2.40	2.90	2.99	5.19	4.60							4.65	4.68	4.67	
	1.10	1.17	0.144	0.30	1.80	2.10	4.80	10.39	8.91							7.45	9.37	9.04	
Injection Water	10.26	5.40	0.143	0.26	1.24	1.50	0.44	0.77	0.68	94.5	45.5	54.0	0.44	0.77	0.68				
1.0 wt% NaOH + 0.1 wt% EOR 2095 + 500 mg/L Flopaam 3630S	10.26	5.34	0.142	1.90	4.00	5.90	3.25	2.47	2.68							3.64	2.94	3.13	
	2.56	1.24	0.142	0.46	0.64	1.10	3.15	1.58	2.00							3.53	1.88	2.34	
	1.10	1.05	0.142	0.14	0.36	0.50	2.24	2.08	2.12							2.51	2.47	2.48	
Injection Water	10.26	7.14	0.142	0.36	0.94	1.30	0.62	0.58	0.59	68.3	60.1	62.3	0.62	0.58	0.59				
1000 mg/L Flopaam 3630S	10.26	4.59	0.141	4.90	12.30	17.20	8.38	7.59	7.80							2.52	4.33	3.60	
	2.93	2.48	0.141	1.70	3.20	4.90	10.17	6.91	7.78							3.06	3.94	3.59	
	1.10	1.58	0.141	1.10	1.40	2.50	17.59	8.08	10.61							5.30	4.61	4.89	
Injection Water	10.26	7.45	0.141	1.34	1.96	3.30	2.29	1.21	1.50	18.3	28.8	24.6	2.29	1.21	1.50				

Field: Warner		Diameter (cm): 2.48										Pore Volume (ml): 9.41									
Well: 00/04-21-007-16W4		Depth (ft): 3200.9										Length (cm): 7.67									
												Porosity (%): 25.4									
Fluid Injected	Injection Rate ft/day	Produced Volume V _p	Oil Saturation V _p	-----Incremental-----			-Resistance Factor (Ratio)-			--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-					
				P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T			
Warner Crude Oil dead crude oil - 119 cp	6.55	2.69	1.000	---	---	9.75	---	---	8.18	---	---	811									
	10.70	1.81	1.000	---	---	10.75	---	---	5.53	---	---	1200									
	30.90	4.89	1.000	---	---	12.10	---	---	2.15	---	---	3081									
Produced Water	30.90	6.11	0.486	---	---	5.00	---	---	0.89	---	---	43.2									
Warner Crude Oil viscosity adjusted crude - 52 cp	9.07	16.26	0.804	3.32	10.68	14.00	8.74	8.41	8.49	477	300	342									
	24.17	4.55	0.804	6.00	16.50	22.50	5.93	4.88	5.12	703	517	566									
	18.15	14.88	0.804	8.00	18.60	26.60	10.53	7.32	8.06	396	344	360									
Produced Water	18.15	21.55	0.479	0.76	2.54	3.30	1.00	1.00	1.00	55.3	33.4	38.5	1.00	1.00	1.00						
	0.76	7.86	0.416	0.14	0.36	0.50	4.42	3.40	3.64	12.5	9.84	10.6	4.42	3.40	3.64						
	10.62	2.76	0.416	0.46	1.76	2.22	1.03	1.18	1.15	53.5	28.2	33.5	1.03	1.18	1.15						
Injection Water	10.62	2.81	0.416	0.58	1.72	2.30	1.30	1.16	1.19	42.4	28.9	32.3	1.30	1.16	1.19						
2.0 wt% Na ₂ CO ₃	10.62	5.31	0.384	0.50	2.00	2.50	1.12	1.35	1.30	49.9	25.2	30.1	1.11	1.33	1.28						
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF	10.62	7.65	0.352	0.22	0.46	0.68	0.49	0.31	0.35	115	111	112	0.48	0.30	0.34						
Injection Water	10.62	5.31	0.341	0.39	0.37	0.76	0.88	0.25	0.39	63.1	134	97.7	0.88	0.25	0.39						
	1.52	2.53	0.341	0.22	0.14	0.36	3.46	0.66	1.30	16.0	50.8	29.5	3.46	0.66	1.30						
	10.62	3.83	0.341	0.39	0.19	0.58	0.88	0.13	0.30	63.1	262	128	0.88	0.13	0.30						
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1500 mg/L Flopaam 3530S	10.62	3.51	0.320	1.56	4.50	6.06	3.51	3.03	3.14							2.45	3.61	3.22			
Injection Water	3.03	2.34	0.309	0.60	0.88	1.48	4.73	2.07	2.68							3.29	2.47	2.75			
	1.14	2.17	0.245	0.44	0.28	0.72	9.26	1.76	3.49							6.46	2.10	3.58			
	10.62	5.84	0.214	0.44	0.86	1.30	0.99	0.58	0.67	55.9	57.8	57.1	0.99	0.58	0.67						
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3530S	10.62	5.53	0.211	0.99	3.11	4.10	2.23	2.09	2.12							1.49	2.55	2.18			
Injection Water	3.03	1.85	0.210	0.40	0.20	0.60	3.15	0.47	1.09							2.10	0.58	1.11			
	1.14	1.43	0.209	0.16	0.34	0.50	3.37	2.14	2.42							2.25	2.61	2.48			
	10.62	6.16	0.209	0.46	0.84	1.30	1.03	0.57	0.67	53.5	59.2	57.1	1.03	0.57	0.67						
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 500 mg/L Flopaam 3530S	10.62	6.23	0.209	0.80	2.26	3.06	1.80	1.52	1.59							1.20	1.86	1.62			
Injection Water	2.65	1.30	0.209	0.40	0.30	0.70	3.60	0.81	1.45							2.40	0.99	1.49			
	1.14	1.15	0.209	0.26	0.02	0.28	5.47	0.13	1.36							3.65	0.15	1.39			
	10.62	7.97	0.209	0.46	0.84	1.30	1.03	0.57	0.67	53.5	59.2	57.1	1.03	0.57	0.67						
1000 mg/L Flopaam 3530S	10.62	4.97	0.208	1.70	5.98	7.68	3.82	4.02	3.98							3.91	3.50	3.58			
	3.03	2.61	0.208	0.36	1.54	1.90	2.84	3.63	3.45							2.90	3.15	3.10			
	1.14	1.76	0.208	0.06	0.64	0.70	1.26	4.03	3.39							1.29	3.50	3.05			
Injection Water	10.62	8.32	0.208	0.30	1.18	1.48	0.67	0.79	0.77	82.0	42.1	50.2	0.67	0.79	0.77						

END POINT SUMMARY: Warner Linear Coreflood 3L

Field: Warner		Diameter (cm): 2.48										Pore Volume (ml): 9.44									
Well: 02/09-007-16W4		Depth (ft): 3233.7										Length (cm): 8.48									
												Porosity (%): 23.1									
Fluid Injected	Injection Rate ft/day	Produced Volume V _p	Oil Saturation V _p	-----Incremental-----			-Resistance Factor (Ratio)-			--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-					
				P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T			
Warner Crude Oil dead crude - 119 cp	7.28	2.44	1.000	---	---	21.30	---	---	13.30	---	---	413									
	12.10	5.08	1.000	---	---	37.00	---	---	13.89	---	---	395									
Produced Water	12.10	6.46	0.783	---	---	3.50	---	---	1.31	---	---	24.2									
	8.31	16.53	0.840	5.10	22.90	28.00	31.65	13.73	15.31	258	134	157									
Warner Crude Oil viscosity adjusted crude - 52 cp	26.77	4.68	0.840	11.70	58.60	70.30	22.54	10.91	11.93	362	169	201									
	20.63	15.04	0.840	9.60	43.70	53.30	24.00	10.56	11.74	340	175	204									
Produced Water	20.63	35.84	0.518	0.40	4.14	4.54	1.00	1.00	1.00	108	24.5	31.8	1.00	1.00	1.00						
	12.01	2.12	0.518	0.12	2.58	2.70	0.52	1.07	1.02	210	22.8	31.2	0.52	1.07	1.02						
Injection Water	12.01	4.45	0.518	0.12	2.58	2.70	0.52	1.07	1.02	210	22.8	31.2	0.52	1.07	1.02						
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃	12.01	7.03	0.516	1.00	5.30	6.30	4.29	2.20	2.38	26.0	11.4	13.7	4.17	2.14	2.32						
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095	12.01	3.75	0.463	0.36	1.54	1.90	1.55	0.64	0.72	73.1	39.9	46.2	1.48	0.61	0.69						
Injection Water	12.01	8.07	0.426	0.21	1.89	2.10	0.90	0.78	0.79	120	31.2	40.1	0.90	0.78	0.79						
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095	12.01	4.11	0.288	2.20	10.20	12.40	9.45	4.23	4.69							6.60	7.82	7.57			
	3.43	1.36	0.267	0.56	2.35	2.91	8.42	3.41	3.85							5.88	6.31	6.22			
0.1 wt% Petronate EOR 2095 + 1500 mg/L Alcoflood 1275A	1.28	2.02	0.256	0.80	3.58	4.38	32.11	13.86	15.47							22.4	25.6	25.0			
Injection Water	12.01	6.46	0.203	0.23	0.90	1.13	0.99	0.37	0.43	110	65.5	74.5	0.99	0.37	0.43						
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095	12.01	3.88	0.182	1.05	4.70	5.75	4.51	1.95	2.18							3.54	4.01	3.92			
	3.43	2.25	0.181	0.40	1.18	1.58	6.01	1.71	2.09							4.72	3.52	3.77			
0.1 wt% Petronate EOR 2095 + 1000 mg/L Alcoflood 1275A	1.28	2.37	0.179	0.24	0.60	0.84	9.63	2.33	2.97							7.56	4.79	5.35			
Injection Water	1.28	4.46	0.179	0.09	0.13	0.22	3.61	0.50	0.78	30.0	48.5	40.9	3.61	0.50	0.78						
	11.73	2.97	0.179	0.20	0.79	0.99	0.88	0.34	0.38	123	72.9	83.1	0.88	0.34	0.38						
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095	11.73	2.42	0.179	1.15	4.98	6.13	5.05	2.11	2.37							2.27	1.60	1.69			
	3.35	2.08	0.179	0.28	0.97	1.25	4.31	1.44	1.69							1.93	1.09	1.21			
0.1 wt% Petronate EOR 2095 + 500 mg/L Alcoflood 1275A	1.25	2.29	0.168	0.24	0.66	0.90	9.91	2.63	3.27							4.44	1.99	2.33			
Injection Water	11.73	10.95	0.168	0.35	2.15	2.50	1.54	0.91	0.97	70.4	26.8	32.9	1.54	0.91	0.97						
1000 mg/L Alcoflood 1275A	11.73	3.26	0.167	1.60	6.95	8.55	7.03	2.95	3.31							2.76	3.00	2.95			
	3.35	2.22	0.167	0.35	2.15	2.50	1.54	0.91	0.97							0.60	0.93	0.86			
	1.25	1.97	0.165	0.50	0.53	1.03	20.64	2.09	3.73							8.10	2.13	3.32			
Injection Water	11.73	10.49	0.164	0.40	1.60	2.00	1.76	0.68	0.77	61.6	36.0	41.1	1.76	0.68	0.77						

END POINT SUMMARY: Warner Linear Coreflood 4L

Field: Warner				Diameter (cm): 2.48				Pore Volume (ml): 10.10											
Well: 00/16-20-007-16W4 Depth (ft): 3226.8				Length (cm): 8.42				Porosity (%): 24.9											
Fluid Injected	Injection		Oil		-----Incremental-----			-Resistance Factor (Ratio)-			--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-		
	Rate	Produced Volume	Saturation	-Differential Pressure (psid)-	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T			
ft/day	V _p	V _p	P ₁	P ₂	P _T														
Warner Crude Oil	10.97	2.67	1.000	---	---	33.00	---	---	25.96	---	---	428							
	dead crude - 119 cp	17.61	4.55	1.000	---	---	44.00	---	---	21.56	---	---	514						
Produced Water	17.61	8.99	0.728	---	---	2.36	---	---	1.16	---	---	55.7							
	Warner Crude Oil	7.71	15.45	0.796	5.10	15.60	20.70	29.44	21.64	23.15	258	196	211						
viscosity adjusted crude - 52 cp	24.85	4.38	0.786	9.90	36.00	45.90	17.74	15.50	15.93	429	273	307							
	19.15	14.06	0.786	6.75	23.30	30.05	15.70	13.02	13.54	485	325	361							
Produced Water	19.15	33.12	0.536	0.43	1.79	2.22	1.00	1.00	1.00	101	56.2	64.8	1.00	1.00	1.00				
	11.15	1.96	0.536	0.34	0.96	1.30	1.36	0.92	1.01	74.4	61.0	64.5	1.36	0.92	1.01				
Injection Water	11.15	4.18	0.536	0.35	0.95	1.30	1.40	0.91	1.01	72.2	61.6	64.5	1.40	0.91	1.01				
0.75 wt% NaOH +	11.15	6.50	0.476	0.91	3.39	4.30	3.64	3.25	3.33	28.6	17.8	20.1	3.53	3.16	3.23				
0.75 wt% NaOH +	11.15	3.47	0.474	0.37	0.81	1.18	1.48	0.78	0.91	71.3	75.4	74.1	1.42	0.74	0.88				
0.1 wt% ORS-97HF																			
Injection Water	11.15	7.64	0.450	0.35	1.19	1.54	1.40	1.14	1.19	72.2	49.2	54.4	1.40	1.14	1.19				
0.75 wt% NaOH +	11.15	3.83	0.331	3.10	12.30	15.40	12.38	11.80	11.92										
0.1 wt% ORS-97HF	3.19	1.27	0.321	0.75	2.33	3.08	10.49	7.83	8.34										
+ 1500 mg/L Cyanatrol 770	1.19	1.92	0.301	0.51	0.95	1.46	19.04	8.52	10.56										
Injection Water	11.15	6.02	0.202	0.39	1.47	1.86	1.56	1.41	1.44	64.8	39.8	45.1	1.56	1.41	1.44				
0.75 wt% NaOH +	11.15	3.52	0.200	1.60	6.48	8.08	6.39	6.22	6.25										
0.1 wt% ORS-97HF	3.19	2.22	0.199	0.54	0.96	1.50	7.55	3.22	4.06										
+ 1000 mg/L Cyanatrol 770	1.19	2.24	0.197	0.39	0.31	0.70	14.56	2.78	5.06										
Injection Water	1.19	4.20	0.195	0.31	0.05	0.36	11.57	0.45	2.60	8.73	125	24.9	11.6	0.45	2.60				
	10.89	2.67	0.195	0.35	1.39	1.74	1.43	1.37	1.38	70.6	41.1	47.1	1.43	1.37	1.38				
0.75 wt% NaOH +	10.89	2.36	0.194	0.51	2.15	2.66	2.09	2.11	2.11										
0.1 wt% ORS-97HF	3.11	1.90	0.193	0.35	0.39	0.74	5.01	1.34	2.05										
+ 500 mg/L Cyanatrol 770	1.16	2.16	0.191	0.33	0.15	0.48	12.67	1.38	3.57										
Injection Water	10.89	9.29	0.189	0.34	1.36	1.70	1.39	1.34	1.35	72.6	42.0	48.2	1.39	1.34	1.35				
1000 mg/L Cyanatrol 770																			
	10.89	2.97	0.187	2.10	7.30	9.40	8.59	7.17	7.44										
	3.11	2.12	0.186	0.34	1.36	1.70	1.39	1.34	1.35										
	1.16	1.86	0.185	0.55	0.35	0.90	21.12	3.23	6.69										
Injection Water	10.89	9.84	0.184	0.36	1.28	1.64	1.47	1.26	1.30	68.6	44.7	49.9	1.47	1.26	1.30				

END POINT SUMMARY: Warner Linear Coreflood 5L

Field: Warner			Diameter (cm): 2.46			Pore Volume (ml): 10.52												
Well: 00/04-21-007-16W4 Depth (ft): 3199.3			Length (cm): 8.33			Porosity (%): 26.6												
Fluid Injected	Injection Rate ft/day	Produced Volume V _p	Oil Saturation V _p	-----Incremental-----			-Resistance Factor (Ratio)-		--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-			
				P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T
Produced Water	11.61	4.09	0.000	0.01	0.09	0.10	0.08	0.38	0.27	2815	713	923						
	23.22	3.14	0.000	0.01	0.19	0.20	0.04	0.40	0.27	5631	675	923						
Warner Crude Oil viscosity adjusted crude - 52 cp	0.73	2.00	0.737	0.25	0.72	0.97	30.19	48.31	41.84	532	421	449						
	5.81	1.81	0.775	1.00	2.18	3.18	15.13	18.32	17.18	1061	1109	1094						
	11.65	1.71	0.794	1.90	3.90	5.80	14.33	16.35	15.63	1120	1244	1203						
	29.12	2.47	0.813	4.42	8.58	13.00	13.34	14.38	14.01	1204	1414	1342						
	17.58	9.89	0.813	2.67	4.91	7.58	13.35	13.64	13.54	1203	1490	1389						
Produced Water	17.58	25.02	0.356	0.20	0.36	0.56	1.00	1.00	1.00	213	270	249	1.00	1.00	1.00			
	10.22	12.02	0.356	0.11	0.20	0.31	0.95	0.96	0.95	225	282	262	0.95	0.96	0.95			
Injection Water	10.22	3.19	0.356	0.07	0.28	0.35	0.60	1.34	1.08	354	202	232	0.60	1.34	1.08			
0.75 wt% NaOH	10.22	3.86	0.354	0.26	0.31	0.57	2.24	1.48	1.75	99	190	149	2.14	1.42	1.68			
0.75 wt% NaOH + 0.1 wt% ORS-97HF	10.22	4.35	0.349	0.15	0.10	0.25	1.29	0.48	0.77	172	589	339	1.24	0.46	0.74			
Injection Water	10.22	6.59	0.306	0.07	0.07	0.14	0.60	0.33	0.43	354	806	580	0.60	0.33	0.43			
0.75 wt% NaOH + 0.1 wt% ORS-97HF	10.22	2.49	0.249	0.59	1.06	1.65	5.07	5.06	5.07							6.79	10.45	8.76
+ 1500 mg/L Alcoflood 1275A	3.64	3.04	0.221	0.25	0.50	0.75	6.03	6.70	6.46							8.06	13.82	11.16
	1.09	1.29	0.219	0.13	0.14	0.27	10.44	6.24	7.74							13.96	12.88	13.38
Injection Water	10.22	5.06	0.217	0.06	0.07	0.13	0.52	0.33	0.40	413	806	625	0.52	0.33	0.40			
0.75 wt% NaOH + 0.1 wt% ORS-97HF	10.22	2.78	0.215	0.44	0.53	0.97	3.78	2.53	2.98							6.07	2.29	3.19
+ 1000 mg/L Alcoflood 1275A	3.64	2.09	0.215	0.17	0.21	0.37	3.98	2.75	3.19							6.38	2.48	3.41
	1.09	2.55	0.215	0.05	0.05	0.10	4.01	2.23	2.87							6.44	2.01	3.07
Injection Water	10.22	5.29	0.214	0.05	0.16	0.21	0.43	0.76	0.65	496	353	387	0.43	0.76	0.65			
0.75 wt% NaOH + 0.1 wt% ORS-97HF	10.22	2.05	0.214	0.31	0.53	0.84	2.67	2.53	2.58							4.28	7.31	5.80
+ 500 mg/L Alcoflood 1275A	3.64	1.92	0.214	0.11	0.15	0.26	2.65	2.01	2.24							4.26	5.80	5.03
	1.09	2.30	0.214	0.05	0.03	0.08	4.01	1.34	2.29							6.44	3.86	5.15
Injection Water	10.22	4.71	0.214	0.05	0.05	0.10	0.43	0.24	0.31	496	1129	812	0.43	0.24	0.31			
1000 mg/L Alcoflood 1275A	10.22	2.28	0.214	0.50	0.72	1.22	4.30	3.44	3.75							6.90	9.94	8.42
Injection Water	3.64	1.39	0.214	0.17	0.23	0.40	4.10	3.08	3.44							6.58	8.90	7.74
	1.09	3.08	0.214	0.06	0.03	0.09	4.82	1.34	2.58							7.73	3.86	5.80
Injection Water	10.22	7.21	0.214	0.05	0.05	0.10	0.43	0.24	0.31	496	1129	812	0.43	0.24	0.31			

END POINT SUMMARY: Warner Linear Coreflood 6L

Field: Warner										Diameter (cm): 2.47			Pore Volume (ml): 10.17					
Well: 00/16-20-007-16W4 Depth (ft): 3236.1										Length (cm): 8.26			Porosity (%): 25.6					
Fluid Injected	Injection		Produced Volume V _p	Oil Saturation V _p	-----Incremental-----			-Resistance Factor (Ratio)-		--Permeability (md)--			-Permeability Reduction-			-Effective Viscosity-		
	Rate ft/day				-Differential Pressure (psid)- P ₁ P ₂ P _T	RF ₁	RF ₂	RF _T	K ₁	K ₂	K _T	K _{red1}	K _{red2}	K _{redT}	μ ₁	μ ₂	μ _T	
Produced Water	11.91		3.34	0.089	0.02	0.02	0.04	0.14	0.06	0.08	1390	3128	2259					
	23.82		3.68	0.089	0.02	0.06	0.08	0.07	0.09	0.08	2779	2085	2259					
Warner Crude Oil viscosity adjusted crude - 52 cp	0.75		2.85	0.778	0.13	0.25	0.38	14.27	11.61	12.40	1010	1182	1123					
	5.96		1.72	0.788	1.28	2.46	3.74	17.60	14.31	15.29	819	959	911					
	11.95		1.77	0.788	2.35	4.35	6.70	16.12	12.62	13.66	894	1087	1020					
	29.87		2.54	0.807	5.05	9.45	14.50	13.86	10.97	11.83	1040	1251	1178					
	18.03		10.42	0.807	3.10	5.30	8.40	14.09	10.19	11.35	1023	1347	1227					
Produced Water	18.03		23.16	0.332	0.22	0.52	0.74	1.00	1.00	1.00	191	182	185	1.00	1.00	1.00		
	10.48		12.07	0.332	0.13	0.26	0.39	1.02	0.86	0.91	188	212	204	1.02	0.86	0.91		
Injection Water	10.48		2.95	0.332	0.15	0.68	0.83	1.17	2.25	1.93	163	81.0	95.8	1.17	2.25	1.93		
1.0 wt% NaOH	10.48		3.93	0.317	0.62	1.03	1.65	4.85	3.41	3.84	40.6	55.0	49.6	4.71	3.31	3.73		
1.0 wt% NaOH + 0.1 wt% ORS-97HF	10.48		4.54	0.307	0.17	0.33	0.50	1.33	1.09	1.16	150	174	166	1.27	1.05	1.11		
Injection Water	10.48		6.99	0.303	0.10	0.22	0.32	0.78	0.73	0.74	245	250	248	0.78	0.73	0.74		
1.0 wt% NaOH + 0.1 wt% ORS-97HF	10.48		2.36	0.244	1.29	2.71	4.00	10.09	8.96	9.30						5.24	8.13	6.90
+ 1500 mg/L Flopaam 3630S	3.74		3.17	0.225	0.47	0.85	1.32	10.30	7.88	8.60						5.35	7.15	6.38
	1.12		1.34	0.223	0.19	0.41	0.60	13.87	12.66	13.02						7.20	11.48	9.66
Injection Water	10.48		5.29	0.221	0.17	0.23	0.40	1.33	0.76	0.93	144	239	199	1.33	0.76	0.93		
1.0 wt% NaOH + 0.1 wt% ORS-97HF	10.48		2.75	0.220	1.07	1.23	2.30	8.37	4.07	5.35						4.34	4.47	4.41
+ 1000 mg/L Flopaam 3630S	3.74		2.20	0.219	0.37	0.43	0.80	8.11	3.99	5.21						4.21	4.38	4.30
	1.12		2.64	0.218	0.17	0.18	0.35	12.41	5.56	7.59						6.44	6.10	6.26
Injection Water	10.48		5.68	0.217	0.17	0.19	0.36	1.33	0.63	0.84	144	290	221	1.33	0.63	0.84		
1.0 wt% NaOH + 0.1 wt% ORS-97HF	10.48		2.01	0.217	0.75	0.66	1.41	5.86	2.18	3.28						2.59	2.85	2.70
+ 500 mg/L Flopaam 3630S	3.74		2.06	0.217	0.25	0.20	0.45	5.48	1.85	2.93						2.42	2.42	2.42
	1.12		2.42	0.217	0.09	0.06	0.15	6.57	1.85	3.25						2.90	2.42	2.68
Injection Water	10.48		4.84	0.217	0.20	0.16	0.36	1.56	0.53	0.84	122	344	221	1.56	0.53	0.84		
1000 mg/L Flopaam 3630S	10.48		2.16	0.216	2.15	2.35	4.50	16.81	7.77	10.46						2.28	8.11	3.65
Injection Water	3.74		1.53	0.214	0.59	0.51	1.10	12.93	4.73	7.17						1.76	4.93	2.50
	1.12		3.21	0.213	0.51	0.24	0.75	37.22	7.41	16.27						5.05	7.73	5.68
Injection Water	10.48		7.43	0.213	0.65	0.20	0.85	5.08	0.66	1.98	37.6	275	93.5	5.08	0.66	1.98		

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 17.54 ft/day							
0	0.00	6.90	25.20	32.10	6.9	9.1	8.5
Produced Water at 17.54 ft/day							
1	0.22	2.50	13.50	16.00	2.5	4.9	4.2
2	0.69	2.00	8.50	10.50	2.0	3.1	2.8
3	1.15	2.00	6.10	8.10	2.0	2.2	2.1
4	1.62	1.75	4.35	6.10	1.8	1.6	1.6
5	2.08	1.80	3.90	5.70	1.8	1.4	1.5
6	2.55	1.70	3.60	5.30	1.7	1.3	1.4
7	3.02	1.30	3.58	4.88	1.3	1.3	1.3
8	3.48	1.19	3.31	4.50	1.2	1.2	1.2
9	3.95	1.10	3.10	4.20	1.1	1.1	1.1
10	4.41	1.07	2.87	3.94	1.1	1.0	1.0
11	4.88	1.06	2.84	3.90	1.1	1.0	1.0
12	5.34	1.06	2.82	3.88	1.1	1.0	1.0
13	5.81	1.05	2.79	3.84	1.1	1.0	1.0
14	6.27	1.04	2.78	3.82	1.0	1.0	1.0
15	6.74	1.02	2.78	3.80	1.0	1.0	1.0
16	7.21	1.00	2.78	3.78	1.0	1.0	1.0
17	7.67	1.00	2.77	3.77	1.0	1.0	1.0
18	8.14	1.00	2.77	3.77	1.0	1.0	1.0
19	8.60	1.00	2.77	3.77	1.0	1.0	1.0
20	9.07	1.00	2.77	3.77	1.0	1.0	1.0
21	9.53	1.00	2.77	3.77	1.0	1.0	1.0
22	10.00	1.00	2.77	3.77	1.0	1.0	1.0
23	10.47	1.00	2.77	3.77	1.0	1.0	1.0
24	10.93	1.00	2.77	3.77	1.0	1.0	1.0
25	11.40	1.00	2.77	3.77	1.0	1.0	1.0
26	11.86	1.00	2.77	3.77	1.0	1.0	1.0
27	12.33	1.00	2.77	3.77	1.0	1.0	1.0
28	12.79	1.00	2.77	3.77	1.0	1.0	1.0
29	13.26	1.00	2.77	3.77	1.0	1.0	1.0
30	13.73	1.00	2.77	3.77	1.0	1.0	1.0
31	14.19	1.00	2.77	3.77	1.0	1.0	1.0
32	14.66	1.00	2.77	3.77	1.0	1.0	1.0
33	15.12	1.00	2.77	3.77	1.0	1.0	1.0
34	15.59	1.00	2.77	3.77	1.0	1.0	1.0
35	16.05	1.00	2.77	3.77	1.0	1.0	1.0

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Produced Water at 17.54 ft/day							
36	16.52	1.00	2.77	3.77	1.0	1.0	1.0
37	16.98	1.00	2.77	3.77	1.0	1.0	1.0
38	17.45	1.00	2.77	3.77	1.0	1.0	1.0
39	17.92	1.00	2.77	3.77	1.0	1.0	1.0
40	18.38	1.00	2.77	3.77	1.0	1.0	1.0
41	18.85	1.00	2.77	3.77	1.0	1.0	1.0
42	19.31	1.00	2.77	3.77	1.0	1.0	1.0
Produced Water at 0.73 ft/day							
43	20.28	0.40	0.14	0.54	9.6	1.2	3.4
44	21.24	0.18	0.32	0.50	4.3	2.8	3.2
45	22.21	0.18	0.32	0.50	4.3	2.8	3.2
46	23.17	0.18	0.32	0.50	4.3	2.8	3.2
47	24.13	0.18	0.32	0.50	4.3	2.8	3.2
48	25.10	0.18	0.32	0.50	4.3	2.8	3.2
49	26.06	0.18	0.32	0.50	4.3	2.8	3.2
50	27.03	0.18	0.32	0.50	4.3	2.8	3.2
Produced Water at 10.26 ft/day							
51	27.38	0.62	0.74	1.36	1.1	0.5	0.6
52	27.74	0.58	1.52	2.10	1.0	0.9	1.0
53	28.10	0.58	1.52	2.10	1.0	0.9	1.0
54	28.46	0.58	1.76	2.34	1.0	1.1	1.1
55	28.81	0.58	1.76	2.34	1.0	1.1	1.1
Injection Water at 10.26 ft/day							
56	29.29	1.06	2.40	3.46	1.8	1.5	1.6
57	29.76	1.00	2.50	3.50	1.7	1.5	1.6
58	30.24	0.90	2.16	3.06	1.5	1.3	1.4
59	30.71	0.78	1.92	2.70	1.3	1.2	1.2
60	31.19	0.78	1.92	2.70	1.3	1.2	1.2
1.0 wt% NaOH at 10.26 ft/day							
61	31.64	1.15	2.19	3.34	2.0	1.4	1.5
62	32.10	1.11	2.47	3.58	1.9	1.5	1.6
63	32.56	1.08	2.86	3.94	1.8	1.8	1.8
64	33.01	1.02	3.28	4.30	1.7	2.0	1.9
65	33.47	0.90	3.44	4.34	1.5	2.1	2.0
66	33.93	0.75	2.95	3.70	1.3	1.8	1.7
67	34.39	0.66	2.48	3.14	1.1	1.5	1.4

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
1.0 wt% NaOH at 10.26 ft/day							
68	34.84	0.58	2.32	2.90	1.0	1.4	1.3
69	35.30	0.57	2.29	2.86	1.0	1.4	1.3
70	35.76	0.57	2.29	2.86	1.0	1.4	1.3
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 at 10.26 ft/day							
71	36.21	0.51	2.35	2.86	0.9	1.5	1.3
72	36.66	0.50	1.06	1.56	0.9	0.7	0.7
73	37.11	0.50	0.80	1.30	0.9	0.5	0.6
74	37.56	0.50	0.66	1.16	0.9	0.4	0.5
75	38.02	0.50	0.60	1.10	0.9	0.4	0.5
76	38.47	0.50	0.58	1.08	0.9	0.4	0.5
77	38.92	0.50	0.60	1.10	0.9	0.4	0.5
78	39.37	0.54	0.60	1.14	0.9	0.4	0.5
79	39.82	0.68	0.62	1.30	1.2	0.4	0.6
80	40.27	0.70	0.80	1.50	1.2	0.5	0.7
81	40.72	0.75	0.77	1.52	1.3	0.5	0.7
82	41.18	0.85	0.75	1.60	1.5	0.5	0.7
83	41.63	0.88	0.70	1.58	1.5	0.4	0.7
84	42.08	0.88	0.66	1.54	1.5	0.4	0.7
85	42.53	0.88	0.66	1.54	1.5	0.4	0.7
Injection Water at 10.26 ft/day							
86	43.00	0.70	0.72	1.42	1.2	0.4	0.6
87	43.47	0.65	0.55	1.20	1.1	0.3	0.5
88	43.94	0.67	0.61	1.28	1.1	0.4	0.6
89	44.41	0.67	0.63	1.30	1.1	0.4	0.6
90	44.88	0.68	0.62	1.30	1.2	0.4	0.6
91	45.35	0.67	0.63	1.30	1.1	0.4	0.6
92	45.82	0.65	0.65	1.30	1.1	0.4	0.6
93	46.29	0.60	0.70	1.30	1.0	0.4	0.6
94	46.76	0.57	0.73	1.30	1.0	0.5	0.6
95	47.23	0.57	0.73	1.30	1.0	0.5	0.6
Injection Water at 1.47 ft/day							
96	47.69	0.10	0.30	0.40	1.2	1.3	1.3
97	48.15	0.12	0.18	0.30	1.4	0.8	1.0
98	48.61	0.26	0.20	0.46	3.1	0.9	1.5
99	49.07	0.26	0.22	0.48	3.1	0.9	1.5
100	49.53	0.26	0.22	0.48	3.1	0.9	1.5

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.26 ft/day							
101	50.22	0.58	0.76	1.34	1.0	0.5	0.6
102	50.91	0.54	0.78	1.32	0.9	0.5	0.6
103	51.61	0.53	0.83	1.36	0.9	0.5	0.6
104	52.30	0.53	0.85	1.38	0.9	0.5	0.6
105	52.99	0.53	0.85	1.38	0.9	0.5	0.6
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Flopaam 3630S at 10.26 ft/day							
106	53.59	1.89	4.21	6.10	3.2	2.6	2.8
107	54.20	2.10	7.00	9.10	3.6	4.3	4.1
108	54.80	2.26	7.78	10.04	3.9	4.8	4.6
109	55.40	2.50	8.10	10.60	4.3	5.0	4.8
110	56.00	2.50	8.10	10.60	4.3	5.0	4.8
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Flopaam 3630S at 2.93 ft/day							
111	56.44	0.70	1.44	2.14	4.2	3.1	3.4
112	56.87	0.66	1.04	1.70	4.0	2.2	2.7
113	57.31	0.88	1.14	2.02	5.3	2.5	3.2
114	57.75	0.92	0.96	1.88	5.5	2.1	3.0
115	58.18	0.92	0.96	1.88	5.5	2.1	3.0
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Flopaam 3630S at 1.10 ft/day							
116	58.57	0.51	0.61	1.12	8.2	3.5	4.8
117	58.96	0.50	0.60	1.10	8.0	3.5	4.7
118	59.35	0.50	0.60	1.10	8.0	3.5	4.7
119	59.73	0.50	0.60	1.10	8.0	3.5	4.7
120	60.12	0.50	0.60	1.10	8.0	3.5	4.7
Injection Water at 10.26 ft/day							
121	60.65	0.74	2.96	3.70	1.3	1.8	1.7
122	61.17	0.34	1.56	1.90	0.6	1.0	0.9
123	61.70	0.30	1.18	1.48	0.5	0.7	0.7
124	62.22	0.30	1.02	1.32	0.5	0.6	0.6
125	62.75	0.30	1.00	1.30	0.5	0.6	0.6
126	63.27	0.30	1.00	1.30	0.5	0.6	0.6
127	63.80	0.30	1.00	1.30	0.5	0.6	0.6
128	64.32	0.30	0.98	1.28	0.5	0.6	0.6
129	64.85	0.30	0.98	1.28	0.5	0.6	0.6
130	65.37	0.30	0.98	1.28	0.5	0.6	0.6

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3630S at 10.26 ft/day							
131	65.84	1.39	1.39	2.78	2.4	0.9	1.3
132	66.31	1.68	3.22	4.90	2.9	2.0	2.2
133	66.78	1.90	5.60	7.50	3.2	3.5	3.4
134	67.25	2.40	7.30	9.70	4.1	4.5	4.4
135	67.71	3.00	8.10	11.10	5.1	5.0	5.0
136	68.18	2.75	7.95	10.70	4.7	4.9	4.9
137	68.65	2.23	6.78	9.00	3.8	4.2	4.1
138	69.12	1.63	5.58	7.20	2.8	3.4	3.3
139	69.59	1.53	4.83	6.35	2.6	3.0	2.9
140	70.06	1.53	4.83	6.35	2.6	3.0	2.9
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3630S at 2.56 ft/day							
141	70.39	0.50	3.08	3.58	3.0	6.7	5.7
142	70.73	0.70	2.40	3.10	4.2	5.2	4.9
143	71.06	0.50	2.40	2.90	3.0	5.2	4.6
144	71.40	0.50	2.40	2.90	3.0	5.2	4.6
145	71.73	0.50	2.40	2.90	3.0	5.2	4.6
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Flopaam 3630S at 1.10 ft/day							
146	71.96	0.48	1.62	2.10	7.7	9.4	8.9
147	72.20	0.30	1.80	2.10	4.8	10.4	8.9
148	72.43	0.30	1.80	2.10	4.8	10.4	8.9
149	72.66	0.30	1.80	2.10	4.8	10.4	8.9
150	72.90	0.30	1.80	2.10	4.8	10.4	8.9
Injection Water at 10.26 ft/day							
151	73.44	0.69	3.01	3.70	1.2	1.9	1.7
152	73.98	0.47	2.25	2.72	0.8	1.4	1.2
153	74.52	0.36	1.98	2.34	0.6	1.2	1.1
154	75.06	0.30	1.64	1.94	0.5	1.0	0.9
155	75.60	0.19	1.51	1.70	0.3	0.9	0.8
156	76.14	0.10	1.52	1.62	0.2	0.9	0.7
157	76.68	0.12	1.38	1.50	0.2	0.9	0.7
158	77.22	0.20	1.30	1.50	0.3	0.8	0.7
159	77.76	0.26	1.24	1.50	0.4	0.8	0.7
160	78.30	0.26	1.24	1.50	0.4	0.8	0.7
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 500 mg/L Flopaam 3630S at 10.26 ft/day							
161	78.83	1.33	2.77	4.10	2.3	1.7	1.9
162	79.37	1.56	4.14	5.70	2.7	2.6	2.6

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 500 mg/L Flopaam 3630S at 10.26 ft/day							
163	79.90	1.64	4.18	5.82	2.8	2.6	2.6
164	80.43	1.66	4.00	5.66	2.8	2.5	2.6
165	80.97	1.69	3.85	5.54	2.9	2.4	2.5
166	81.50	1.72	3.86	5.58	2.9	2.4	2.5
167	82.04	1.81	3.89	5.70	3.1	2.4	2.6
168	82.57	1.90	4.00	5.90	3.2	2.5	2.7
169	83.11	1.90	4.00	5.90	3.2	2.5	2.7
170	83.64	1.90	4.00	5.90	3.2	2.5	2.7
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 500 mg/L Flopaam 3630S at 2.56 ft/day							
171	83.89	0.50	1.00	1.50	3.4	2.5	2.7
172	84.14	0.44	0.66	1.10	3.0	1.6	2.0
173	84.39	0.46	0.64	1.10	3.1	1.6	2.0
174	84.63	0.46	0.64	1.10	3.1	1.6	2.0
175	84.88	0.46	0.64	1.10	3.1	1.6	2.0
1.0 wt% NaOH + 0.1 wt% Petronate EOR 2095 + 500 mg/L Flopaam 3630S at 1.10 ft/day							
176	85.09	0.40	0.20	0.60	6.4	1.2	2.5
177	85.30	0.44	0.22	0.66	7.0	1.3	2.8
178	85.51	0.30	0.26	0.56	4.8	1.5	2.4
179	85.73	0.14	0.36	0.50	2.2	2.1	2.1
180	85.94	0.14	0.36	0.50	2.2	2.1	2.1
Injection Water at 10.26 ft/day							
181	86.41	0.61	2.89	3.50	1.0	1.8	1.6
182	86.89	0.34	1.56	1.90	0.6	1.0	0.9
183	87.36	0.32	1.30	1.62	0.5	0.8	0.7
184	87.84	0.31	1.09	1.40	0.5	0.7	0.6
185	88.32	0.32	1.08	1.40	0.5	0.7	0.6
186	88.79	0.33	1.07	1.40	0.6	0.7	0.6
187	89.27	0.34	1.06	1.40	0.6	0.7	0.6
188	89.74	0.34	1.00	1.34	0.6	0.6	0.6
189	90.22	0.35	0.95	1.30	0.6	0.6	0.6
190	90.70	0.36	0.94	1.30	0.6	0.6	0.6
191	91.17	0.36	0.94	1.30	0.6	0.6	0.6
192	91.65	0.36	0.94	1.30	0.6	0.6	0.6
193	92.12	0.36	0.94	1.30	0.6	0.6	0.6
194	92.60	0.36	0.94	1.30	0.6	0.6	0.6
195	93.08	0.36	0.94	1.30	0.6	0.6	0.6

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
1000 mg/L Flopaam 3630S at 10.26 ft/day							
196	93.54	2.98	2.72	5.70	5.1	1.7	2.6
197	93.99	3.10	6.80	9.90	5.3	4.2	4.5
198	94.45	3.70	8.90	12.60	6.3	5.5	5.7
199	94.91	3.90	9.70	13.60	6.7	6.0	6.2
200	95.37	4.05	10.45	14.50	6.9	6.4	6.6
201	95.83	4.50	11.30	15.80	7.7	7.0	7.2
202	96.29	4.80	11.80	16.60	8.2	7.3	7.5
203	96.75	4.90	12.30	17.20	8.4	7.6	7.8
204	97.21	4.90	12.30	17.20	8.4	7.6	7.8
205	97.67	4.90	12.30	17.20	8.4	7.6	7.8
1000 mg/L Flopaam 3630S at 2.93 ft/day							
206	98.16	1.54	3.36	4.90	9.2	7.3	7.8
207	98.66	1.66	3.08	4.74	9.9	6.7	7.5
208	99.16	1.68	2.86	4.54	10.1	6.2	7.2
209	99.65	1.70	3.20	4.90	10.2	6.9	7.8
210	100.15	1.70	3.20	4.90	10.2	6.9	7.8
1000 mg/L Flopaam 3630S at 1.10 ft/day							
211	100.47	0.94	0.96	1.90	15.0	5.5	8.1
212	100.78	1.10	1.40	2.50	17.6	8.1	10.6
213	101.10	1.10	1.40	2.50	17.6	8.1	10.6
214	101.41	1.10	1.40	2.50	17.6	8.1	10.6
215	101.73	1.10	1.40	2.50	17.6	8.1	10.6
Injection Water at 10.26 ft/day							
216	102.23	1.78	8.51	10.29	3.0	5.3	4.7
217	102.72	1.55	4.55	6.10	2.6	2.8	2.8
218	103.22	1.36	2.72	4.08	2.3	1.7	1.9
219	103.72	1.36	2.32	3.68	2.3	1.4	1.7
220	104.21	1.36	2.09	3.45	2.3	1.3	1.6
221	104.71	1.35	1.95	3.30	2.3	1.2	1.5
222	105.21	1.35	1.93	3.28	2.3	1.2	1.5
223	105.70	1.34	1.92	3.26	2.3	1.2	1.5
224	106.20	1.34	1.92	3.26	2.3	1.2	1.5
225	106.70	1.34	1.94	3.28	2.3	1.2	1.5
226	107.19	1.34	1.96	3.30	2.3	1.2	1.5
227	107.69	1.34	1.96	3.30	2.3	1.2	1.5
228	108.19	1.34	1.96	3.30	2.3	1.2	1.5

Warner Linear Coreflood 1L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 10.26 ft/day							
229	108.68	1.34	1.96	3.30	2.3	1.2	1.5
230	109.18	1.34	1.96	3.30	2.3	1.2	1.5

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 18.15 ft/day							
0	0.00	8.00	18.60	26.60	10.5	7.3	8.1
Produced Water at 18.15 ft/day							
1	0.20	1.80	11.65	13.45	2.4	4.6	4.1
2	0.72	1.40	5.70	7.10	1.8	2.2	2.2
3	1.24	1.40	4.65	6.05	1.8	1.8	1.8
4	1.76	1.38	4.03	5.40	1.8	1.6	1.6
5	2.28	1.33	3.78	5.10	1.7	1.5	1.5
6	2.81	1.10	3.90	5.00	1.4	1.5	1.5
7	3.33	1.08	3.22	4.30	1.4	1.3	1.3
8	3.85	0.98	3.01	3.99	1.3	1.2	1.2
9	4.37	0.90	2.84	3.74	1.2	1.1	1.1
10	4.89	0.90	2.69	3.59	1.2	1.1	1.1
11	5.41	0.90	2.60	3.50	1.2	1.0	1.1
12	5.93	0.89	2.60	3.49	1.2	1.0	1.1
13	6.45	0.88	2.50	3.38	1.2	1.0	1.0
14	6.97	0.87	2.53	3.40	1.1	1.0	1.0
15	7.49	0.85	2.53	3.38	1.1	1.0	1.0
16	8.01	0.77	2.59	3.36	1.0	1.0	1.0
17	8.53	0.76	2.57	3.33	1.0	1.0	1.0
18	9.05	0.76	2.54	3.30	1.0	1.0	1.0
19	9.57	0.76	2.54	3.30	1.0	1.0	1.0
20	10.10	0.76	2.54	3.30	1.0	1.0	1.0
21	10.62	0.76	2.54	3.30	1.0	1.0	1.0
22	11.14	0.76	2.54	3.30	1.0	1.0	1.0
23	11.66	0.76	2.54	3.30	1.0	1.0	1.0
24	12.18	0.76	2.54	3.30	1.0	1.0	1.0
25	12.70	0.76	2.54	3.30	1.0	1.0	1.0
26	13.22	0.76	2.54	3.30	1.0	1.0	1.0
27	13.74	0.76	2.54	3.30	1.0	1.0	1.0
28	14.26	0.76	2.54	3.30	1.0	1.0	1.0
29	14.78	0.76	2.54	3.30	1.0	1.0	1.0
30	15.30	0.76	2.54	3.30	1.0	1.0	1.0
31	15.82	0.76	2.54	3.30	1.0	1.0	1.0
32	16.34	0.76	2.54	3.30	1.0	1.0	1.0
33	16.87	0.76	2.54	3.30	1.0	1.0	1.0
34	17.39	0.76	2.54	3.30	1.0	1.0	1.0
35	17.91	0.76	2.54	3.30	1.0	1.0	1.0

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Produced Water at 18.15 ft/day							
36	18.43	0.76	2.54	3.30	1.0	1.0	1.0
37	18.95	0.76	2.54	3.30	1.0	1.0	1.0
38	19.47	0.76	2.54	3.30	1.0	1.0	1.0
39	19.99	0.76	2.54	3.30	1.0	1.0	1.0
40	20.51	0.76	2.54	3.30	1.0	1.0	1.0
41	21.03	0.76	2.54	3.30	1.0	1.0	1.0
42	21.55	0.76	2.54	3.30	1.0	1.0	1.0
Produced Water at 0.76 ft/day							
43	22.53	0.18	0.52	0.70	5.7	4.9	5.1
44	23.52	0.14	0.76	0.90	4.4	7.2	6.5
45	24.50	0.14	0.56	0.70	4.4	5.3	5.1
46	25.48	0.14	0.36	0.50	4.4	3.4	3.6
47	26.47	0.14	0.36	0.50	4.4	3.4	3.6
48	27.45	0.14	0.36	0.50	4.4	3.4	3.6
49	28.43	0.14	0.36	0.50	4.4	3.4	3.6
50	29.42	0.14	0.36	0.50	4.4	3.4	3.6
Produced Water at 10.62 ft/day							
51	29.97	0.50	1.90	2.40	1.1	1.3	1.2
52	30.52	0.48	1.72	2.20	1.1	1.2	1.1
53	31.07	0.46	1.68	2.14	1.0	1.1	1.1
54	31.63	0.46	1.76	2.22	1.0	1.2	1.2
55	32.18	0.46	1.76	2.22	1.0	1.2	1.2
Injection Water at 10.62 ft/day							
56	32.74	1.02	1.82	2.84	2.3	1.2	1.5
57	33.30	0.90	1.82	2.72	2.0	1.2	1.4
58	33.86	0.82	1.68	2.50	1.8	1.1	1.3
59	34.42	0.58	1.72	2.30	1.3	1.2	1.2
60	34.98	0.58	1.72	2.30	1.3	1.2	1.2
2.0 wt% Na ₂ CO ₃ at 10.62 ft/day							
61	35.52	1.20	1.66	2.86	2.7	1.1	1.5
62	36.05	1.14	2.36	3.50	2.6	1.6	1.8
63	36.58	1.10	2.72	3.82	2.5	1.8	2.0
64	37.11	1.08	3.00	4.08	2.4	2.0	2.1
65	37.64	0.98	3.02	4.00	2.2	2.0	2.1
66	38.17	0.82	2.68	3.50	1.8	1.8	1.8
67	38.70	0.64	2.22	2.86	1.4	1.5	1.5

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
2.0 wt% Na_2CO_3 at 10.62 ft/day							
68	39.23	0.52	2.04	2.56	1.2	1.4	1.3
69	39.77	0.50	2.00	2.50	1.1	1.3	1.3
70	40.30	0.50	2.00	2.50	1.1	1.3	1.3
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF at 10.62 ft/day							
71	40.81	0.53	1.57	2.10	1.2	1.1	1.1
72	41.32	0.22	1.26	1.48	0.5	0.8	0.8
73	41.83	0.22	0.82	1.04	0.5	0.6	0.5
74	42.34	0.22	0.66	0.88	0.5	0.4	0.5
75	42.85	0.22	0.52	0.74	0.5	0.3	0.4
76	43.36	0.22	0.48	0.70	0.5	0.3	0.4
77	43.87	0.22	0.48	0.70	0.5	0.3	0.4
78	44.38	0.22	0.48	0.70	0.5	0.3	0.4
79	44.89	0.22	0.48	0.70	0.5	0.3	0.4
80	45.40	0.22	0.48	0.70	0.5	0.3	0.4
81	45.91	0.22	0.46	0.68	0.5	0.3	0.4
82	46.42	0.22	0.46	0.68	0.5	0.3	0.4
83	46.93	0.22	0.46	0.68	0.5	0.3	0.4
84	47.44	0.22	0.46	0.68	0.5	0.3	0.4
85	47.95	0.22	0.46	0.68	0.5	0.3	0.4
Injection Water at 10.62 ft/day							
86	48.48	0.30	0.42	0.72	0.7	0.3	0.4
87	49.01	0.39	0.47	0.86	0.9	0.3	0.4
88	49.54	0.40	0.48	0.88	0.9	0.3	0.5
89	50.07	0.40	0.44	0.84	0.9	0.3	0.4
90	50.61	0.40	0.36	0.76	0.9	0.2	0.4
91	51.14	0.40	0.34	0.74	0.9	0.2	0.4
92	51.67	0.40	0.36	0.76	0.9	0.2	0.4
93	52.20	0.39	0.37	0.76	0.9	0.2	0.4
94	52.73	0.39	0.37	0.76	0.9	0.2	0.4
95	53.26	0.39	0.37	0.76	0.9	0.2	0.4
Injection Water at 1.52 ft/day							
96	53.77	0.25	0.13	0.38	3.9	0.6	1.4
97	54.27	0.22	0.14	0.36	3.5	0.7	1.3
98	54.78	0.22	0.14	0.36	3.5	0.7	1.3
99	55.29	0.22	0.14	0.36	3.5	0.7	1.3
100	55.79	0.22	0.14	0.36	3.5	0.7	1.3

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.62 ft/day							
101	56.56	0.39	0.07	0.46	0.9	0.0	0.2
102	57.32	0.39	0.11	0.50	0.9	0.1	0.3
103	58.09	0.39	0.19	0.58	0.9	0.1	0.3
104	58.85	0.39	0.19	0.58	0.9	0.1	0.3
105	59.62	0.39	0.19	0.58	0.9	0.1	0.3
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1500 mg/L Flopaam 3530S at 10.62 ft/day							
106	60.32	1.48	2.58	4.06	3.3	1.7	2.1
107	61.02	1.59	3.93	5.52	3.6	2.6	2.9
108	61.72	1.58	4.22	5.80	3.6	2.8	3.0
109	62.42	1.56	4.50	6.06	3.5	3.0	3.1
110	63.12	1.56	4.50	6.06	3.5	3.0	3.1
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1500 mg/L Flopaam 3530S at 3.03 ft/day							
111	63.59	0.60	0.92	1.52	4.7	2.2	2.8
112	64.06	0.56	0.72	1.28	4.4	1.7	2.3
113	64.53	0.62	0.72	1.34	4.9	1.7	2.4
114	64.99	0.60	0.88	1.48	4.7	2.1	2.7
115	65.46	0.60	0.88	1.48	4.7	2.1	2.7
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1500 mg/L Flopaam 3530S at 1.14 ft/day							
116	65.90	0.46	0.44	0.90	9.7	2.8	4.4
117	66.33	0.44	0.36	0.80	9.3	2.3	3.9
118	66.76	0.44	0.30	0.74	9.3	1.9	3.6
119	67.20	0.44	0.28	0.72	9.3	1.8	3.5
120	67.63	0.44	0.28	0.72	9.3	1.8	3.5
Injection Water at 10.62 ft/day							
121	68.21	0.84	3.64	4.48	1.9	2.4	2.3
122	68.80	0.66	1.48	2.14	1.5	1.0	1.1
123	69.38	0.62	1.10	1.72	1.4	0.7	0.9
124	69.97	0.60	1.04	1.64	1.3	0.7	0.8
125	70.55	0.60	0.90	1.50	1.3	0.6	0.8
126	71.14	0.60	0.84	1.44	1.3	0.6	0.7
127	71.72	0.58	0.74	1.32	1.3	0.5	0.7
128	72.31	0.52	0.78	1.30	1.2	0.5	0.7
129	72.89	0.44	0.86	1.30	1.0	0.6	0.7
130	73.48	0.44	0.86	1.30	1.0	0.6	0.7

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3530S at 10.62 ft/day							
131	74.03	0.93	1.37	2.30	2.1	0.9	1.2
132	74.58	1.04	4.48	5.52	2.3	3.0	2.9
133	75.13	1.23	2.87	4.10	2.8	1.9	2.1
134	75.69	1.40	3.66	5.06	3.1	2.5	2.6
135	76.24	1.44	4.22	5.66	3.2	2.8	2.9
136	76.79	1.32	4.18	5.50	3.0	2.8	2.8
137	77.34	1.16	3.66	4.82	2.6	2.5	2.5
138	77.90	1.00	3.28	4.28	2.2	2.2	2.2
139	78.45	0.99	3.11	4.10	2.2	2.1	2.1
140	79.00	0.99	3.11	4.10	2.2	2.1	2.1
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3530S at 3.03 ft/day							
141	79.37	0.59	0.71	1.30	4.6	1.7	2.4
142	79.74	0.64	1.46	2.10	5.0	3.4	3.8
143	80.11	0.58	1.06	1.64	4.6	2.5	3.0
144	80.48	0.40	0.20	0.60	3.2	0.5	1.1
145	80.85	0.40	0.20	0.60	3.2	0.5	1.1
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 1000 mg/L Flopaam 3530S at 1.14 ft/day							
146	81.14	0.38	0.20	0.58	8.0	1.3	2.8
147	81.42	0.36	0.14	0.50	7.6	0.9	2.4
148	81.71	0.16	0.34	0.50	3.4	2.1	2.4
149	82.00	0.16	0.34	0.50	3.4	2.1	2.4
150	82.28	0.16	0.34	0.50	3.4	2.1	2.4
Injection Water at 10.62 ft/day							
151	82.90	0.70	2.50	3.20	1.6	1.7	1.7
152	83.52	0.73	1.91	2.64	1.6	1.3	1.4
153	84.13	0.66	1.52	2.18	1.5	1.0	1.1
154	84.75	0.62	1.38	2.00	1.4	0.9	1.0
155	85.37	0.60	1.18	1.78	1.3	0.8	0.9
156	85.98	0.58	1.08	1.66	1.3	0.7	0.9
157	86.60	0.52	0.96	1.48	1.2	0.6	0.8
158	87.22	0.48	0.84	1.32	1.1	0.6	0.7
159	87.83	0.46	0.84	1.30	1.0	0.6	0.7
160	88.45	0.46	0.84	1.30	1.0	0.6	0.7

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 500 mg/L Flopaam 3530S at 10.62 ft/day							
161	89.07	0.76	1.64	2.40	1.7	1.1	1.2
162	89.69	0.85	2.05	2.90	1.9	1.4	1.5
163	90.32	0.86	2.02	2.88	1.9	1.4	1.5
164	90.94	0.84	2.02	2.86	1.9	1.4	1.5
165	91.56	0.81	2.03	2.84	1.8	1.4	1.5
166	92.18	0.80	2.08	2.88	1.8	1.4	1.5
167	92.81	0.80	2.14	2.94	1.8	1.4	1.5
168	93.43	0.80	2.24	3.04	1.8	1.5	1.6
169	94.05	0.80	2.26	3.06	1.8	1.5	1.6
170	94.68	0.80	2.26	3.06	1.8	1.5	1.6
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 500 mg/L Flopaam 3530S at 2.65 ft/day							
171	94.94	0.41	0.41	0.82	3.7	1.1	1.7
172	95.19	0.40	0.30	0.70	3.6	0.8	1.5
173	95.45	0.40	0.30	0.70	3.6	0.8	1.5
174	95.71	0.40	0.30	0.70	3.6	0.8	1.5
175	95.97	0.40	0.30	0.70	3.6	0.8	1.5
2.0 wt% Na_2CO_3 + 0.1 wt% ORS-162HF + 500 mg/L Flopaam 3530S at 1.14 ft/day							
176	96.20	0.36	0.10	0.46	7.6	0.6	2.2
177	96.43	0.35	0.05	0.40	7.4	0.3	1.9
178	96.66	0.30	0.04	0.34	6.3	0.3	1.6
179	96.89	0.26	0.02	0.28	5.5	0.1	1.4
180	97.12	0.26	0.02	0.28	5.5	0.1	1.4
Injection Water at 10.62 ft/day							
181	97.65	0.61	1.87	2.48	1.4	1.3	1.3
182	98.18	0.60	1.62	2.22	1.3	1.1	1.2
183	98.71	0.58	1.30	1.88	1.3	0.9	1.0
184	99.25	0.56	1.12	1.68	1.3	0.8	0.9
185	99.78	0.54	1.04	1.58	1.2	0.7	0.8
186	100.31	0.50	1.02	1.52	1.1	0.7	0.8
187	100.84	0.50	1.00	1.50	1.1	0.7	0.8
188	101.37	0.48	0.98	1.46	1.1	0.7	0.8
189	101.90	0.47	0.93	1.40	1.1	0.6	0.7
190	102.43	0.46	0.88	1.34	1.0	0.6	0.7
191	102.96	0.46	0.84	1.30	1.0	0.6	0.7
192	103.50	0.46	0.84	1.30	1.0	0.6	0.7
193	104.03	0.46	0.84	1.30	1.0	0.6	0.7

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.62 ft/day							
194	104.56	0.46	0.84	1.30	1.0	0.6	0.7
195	105.09	0.46	0.84	1.30	1.0	0.6	0.7
1000 mg/L Flopaam 3530S at 10.62 ft/day							
196	105.59	1.32	1.78	3.10	3.0	1.2	1.6
197	106.09	1.47	4.43	5.90	3.3	3.0	3.1
198	106.58	1.50	5.12	6.62	3.4	3.4	3.4
199	107.08	1.50	5.18	6.68	3.4	3.5	3.5
200	107.58	1.54	5.32	6.86	3.5	3.6	3.6
201	108.07	1.67	5.67	7.34	3.8	3.8	3.8
202	108.57	1.70	5.92	7.62	3.8	4.0	3.9
203	109.07	1.70	6.00	7.70	3.8	4.0	4.0
204	109.57	1.70	5.98	7.68	3.8	4.0	4.0
205	110.06	1.70	5.98	7.68	3.8	4.0	4.0
1000 mg/L Flopaam 3530S at 3.03 ft/day							
206	110.59	0.39	1.51	1.90	3.1	3.6	3.4
207	111.11	0.38	1.66	2.04	3.0	3.9	3.7
208	111.63	0.35	1.41	1.76	2.8	3.3	3.2
209	112.16	0.36	1.54	1.90	2.8	3.6	3.4
210	112.68	0.36	1.54	1.90	2.8	3.6	3.4
1000 mg/L Flopaam 3530S at 1.14 ft/day							
211	113.03	0.06	0.70	0.76	1.3	4.4	3.7
212	113.38	0.06	0.64	0.70	1.3	4.0	3.4
213	113.74	0.06	0.64	0.70	1.3	4.0	3.4
214	114.09	0.06	0.64	0.70	1.3	4.0	3.4
215	114.44	0.06	0.64	0.70	1.3	4.0	3.4
Injection Water at 10.62 ft/day							
216	115.00	0.53	4.15	4.68	1.2	2.8	2.4
217	115.55	0.45	1.87	2.32	1.0	1.3	1.2
218	116.11	0.36	1.38	1.74	0.8	0.9	0.9
219	116.66	0.33	1.31	1.64	0.7	0.9	0.8
220	117.22	0.32	1.24	1.56	0.7	0.8	0.8
221	117.77	0.32	1.20	1.52	0.7	0.8	0.8
222	118.33	0.30	1.20	1.50	0.7	0.8	0.8
223	118.88	0.30	1.20	1.50	0.7	0.8	0.8
224	119.43	0.30	1.18	1.48	0.7	0.8	0.8
225	119.99	0.30	1.18	1.48	0.7	0.8	0.8

Warner Linear Coreflood 2L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 10.62 ft/day							
226	120.54	0.30	1.18	1.48	0.7	0.8	0.8
227	121.10	0.30	1.18	1.48	0.7	0.8	0.8
228	121.65	0.30	1.18	1.48	0.7	0.8	0.8
229	122.21	0.30	1.18	1.48	0.7	0.8	0.8
230	122.76	0.30	1.18	1.48	0.7	0.8	0.8

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 20.63 ft/day							
0	0.00	9.60	43.70	53.30	24.0	10.6	11.7
Produced Water at 20.63 ft/day							
1	0.44	2.90	22.24	25.14	7.3	5.4	5.5
2	1.16	2.10	12.74	14.84	5.3	3.1	3.3
3	1.88	2.00	10.14	12.14	5.0	2.4	2.7
4	2.60	2.00	9.24	11.24	5.0	2.2	2.5
5	3.33	2.00	8.64	10.64	5.0	2.1	2.3
6	4.05	2.00	7.84	9.84	5.0	1.9	2.2
7	4.77	1.00	8.30	9.30	2.5	2.0	2.0
8	5.49	0.96	7.64	8.60	2.4	1.8	1.9
9	6.22	0.90	7.40	8.30	2.3	1.8	1.8
10	6.94	0.82	7.18	8.00	2.1	1.7	1.8
11	7.66	0.80	7.12	7.92	2.0	1.7	1.7
12	8.38	0.78	6.96	7.74	2.0	1.7	1.7
13	9.11	0.76	6.78	7.54	1.9	1.6	1.7
14	9.83	0.68	6.64	7.32	1.7	1.6	1.6
15	10.55	0.62	6.52	7.14	1.6	1.6	1.6
16	11.27	0.60	6.32	6.92	1.5	1.5	1.5
17	12.00	0.60	6.02	6.62	1.5	1.5	1.5
18	12.72	0.58	5.94	6.52	1.5	1.4	1.4
19	13.44	0.58	5.80	6.38	1.5	1.4	1.4
20	14.16	0.56	5.76	6.32	1.4	1.4	1.4
21	14.89	0.55	5.63	6.18	1.4	1.4	1.4
22	15.61	0.53	5.61	6.14	1.3	1.4	1.4
23	16.33	0.52	5.42	5.94	1.3	1.3	1.3
24	17.05	0.50	5.30	5.80	1.3	1.3	1.3
25	17.78	0.48	5.24	5.72	1.2	1.3	1.3
26	18.50	0.46	5.16	5.62	1.2	1.2	1.2
27	19.22	0.45	5.11	5.56	1.1	1.2	1.2
28	19.94	0.44	5.10	5.54	1.1	1.2	1.2
29	20.67	0.43	5.09	5.52	1.1	1.2	1.2
30	21.39	0.42	4.90	5.32	1.1	1.2	1.2
31	22.11	0.41	4.76	5.17	1.0	1.1	1.1
32	22.83	0.41	4.73	5.14	1.0	1.1	1.1
33	23.56	0.41	4.71	5.12	1.0	1.1	1.1
34	24.28	0.41	4.61	5.02	1.0	1.1	1.1
35	25.00	0.40	4.56	4.96	1.0	1.1	1.1

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Produced Water at 20.63 ft/day							
36	25.72	0.40	4.54	4.94	1.0	1.1	1.1
37	26.44	0.40	4.52	4.92	1.0	1.1	1.1
38	27.17	0.40	4.50	4.90	1.0	1.1	1.1
39	27.89	0.40	4.45	4.85	1.0	1.1	1.1
40	28.61	0.40	4.36	4.76	1.0	1.1	1.0
41	29.33	0.40	4.33	4.73	1.0	1.0	1.0
42	30.06	0.40	4.23	4.63	1.0	1.0	1.0
43	30.78	0.40	4.15	4.55	1.0	1.0	1.0
44	31.50	0.40	4.14	4.54	1.0	1.0	1.0
45	32.22	0.40	4.14	4.54	1.0	1.0	1.0
46	32.95	0.40	4.14	4.54	1.0	1.0	1.0
47	33.67	0.40	4.14	4.54	1.0	1.0	1.0
48	34.39	0.40	4.14	4.54	1.0	1.0	1.0
49	35.11	0.40	4.14	4.54	1.0	1.0	1.0
50	35.84	0.40	4.14	4.54	1.0	1.0	1.0
Produced Water at 12.01 ft/day							
51	36.26	0.16	2.54	2.70	0.7	1.1	1.0
52	36.68	0.12	2.58	2.70	0.5	1.1	1.0
53	37.11	0.12	2.58	2.70	0.5	1.1	1.0
54	37.53	0.12	2.58	2.70	0.5	1.1	1.0
55	37.96	0.12	2.58	2.70	0.5	1.1	1.0
Injection Water at 12.01 ft/day							
56	38.40	0.16	2.70	2.86	0.7	1.1	1.1
57	38.85	0.16	2.74	2.90	0.7	1.1	1.1
58	39.29	0.16	2.74	2.90	0.7	1.1	1.1
59	39.74	0.16	2.67	2.83	0.7	1.1	1.1
60	40.18	0.17	2.55	2.72	0.7	1.1	1.0
61	40.63	0.17	2.53	2.70	0.7	1.0	1.0
62	41.07	0.14	2.56	2.70	0.6	1.1	1.0
63	41.51	0.12	2.58	2.70	0.5	1.1	1.0
64	41.96	0.12	2.58	2.70	0.5	1.1	1.0
65	42.40	0.12	2.58	2.70	0.5	1.1	1.0
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ at 12.01 ft/day							
66	43.11	1.00	5.50	6.50	4.3	2.3	2.5
67	43.81	1.20	6.10	7.30	5.2	2.5	2.8
68	44.51	1.20	5.90	7.10	5.2	2.4	2.7

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
0.5 wt% NaOH + 0.25 wt% Na_2CO_3 at 12.01 ft/day							
69	45.22	1.08	5.46	6.54	4.6	2.3	2.5
70	45.92	1.00	5.30	6.30	4.3	2.2	2.4
71	46.63	1.00	5.30	6.30	4.3	2.2	2.4
72	47.33	1.00	5.30	6.30	4.3	2.2	2.4
73	48.03	1.00	5.30	6.30	4.3	2.2	2.4
74	48.74	1.00	5.30	6.30	4.3	2.2	2.4
75	49.44	1.00	5.30	6.30	4.3	2.2	2.4
0.5 wt% NaOH + 0.25 wt% Na_2CO_3 + 0.1 wt% Petronate EOR 2095 at 12.01 ft/day							
76	50.19	0.42	4.40	4.82	1.8	1.8	1.8
77	50.94	0.40	2.50	2.90	1.7	1.0	1.1
78	51.69	0.38	1.78	2.16	1.6	0.7	0.8
79	52.44	0.36	1.54	1.90	1.5	0.6	0.7
80	53.19	0.36	1.54	1.90	1.5	0.6	0.7
Injection Water at 12.01 ft/day							
81	54.00	0.22	1.84	2.06	0.9	0.8	0.8
82	54.80	0.20	1.90	2.10	0.9	0.8	0.8
83	55.61	0.20	1.74	1.94	0.9	0.7	0.7
84	56.42	0.20	1.70	1.90	0.9	0.7	0.7
85	57.22	0.20	1.74	1.94	0.9	0.7	0.7
86	58.03	0.20	1.87	2.07	0.9	0.8	0.8
87	58.84	0.20	1.90	2.10	0.9	0.8	0.8
88	59.65	0.21	1.89	2.10	0.9	0.8	0.8
89	60.45	0.21	1.89	2.10	0.9	0.8	0.8
90	61.26	0.21	1.89	2.10	0.9	0.8	0.8
0.5 wt% NaOH + 0.25 wt% Na_2CO_3 + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Alcoflood 1275A at 12.01 ft/day							
91	61.67	1.59	5.71	7.30	6.8	2.4	2.8
92	62.08	1.81	10.89	12.70	7.8	4.5	4.8
93	62.49	1.95	12.23	14.18	8.4	5.1	5.4
94	62.90	2.15	11.25	13.40	9.2	4.7	5.1
95	63.32	2.00	10.60	12.60	8.6	4.4	4.8
96	63.73	2.00	10.40	12.40	8.6	4.3	4.7
97	64.14	2.00	10.40	12.40	8.6	4.3	4.7
98	64.55	2.05	10.35	12.40	8.8	4.3	4.7
99	64.96	2.20	10.20	12.40	9.4	4.2	4.7
100	65.37	2.20	10.20	12.40	9.4	4.2	4.7

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Alcoflood 1275A at 3.43 ft/day							
101	65.64	0.70	2.96	3.66	10.5	4.3	4.8
102	65.91	0.55	2.23	2.78	8.3	3.2	3.7
103	66.18	0.56	2.24	2.80	8.4	3.3	3.7
104	66.46	0.56	2.35	2.91	8.4	3.4	3.9
105	66.73	0.56	2.35	2.91	8.4	3.4	3.9
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1500 mg/L Alcoflood 1275A at 1.28 ft/day							
106	67.13	0.36	1.02	1.38	14.4	4.0	4.9
107	67.54	0.34	1.06	1.40	13.6	4.1	5.0
108	67.94	0.32	1.00	1.32	12.8	3.9	4.7
109	68.35	0.80	3.58	4.38	32.1	13.9	15.5
110	68.75	0.80	3.58	4.38	32.1	13.9	15.5
Injection Water at 12.01 ft/day							
111	69.40	0.77	6.51	7.28	3.3	2.7	2.8
112	70.04	0.36	1.78	2.14	1.5	0.7	0.8
113	70.69	0.25	1.28	1.53	1.1	0.5	0.6
114	71.33	0.24	1.07	1.31	1.0	0.4	0.5
115	71.98	0.23	0.95	1.18	1.0	0.4	0.4
116	72.63	0.23	0.92	1.15	1.0	0.4	0.4
117	73.27	0.23	0.90	1.13	1.0	0.4	0.4
118	73.92	0.23	0.90	1.13	1.0	0.4	0.4
119	74.57	0.23	0.90	1.13	1.0	0.4	0.4
120	75.21	0.23	0.90	1.13	1.0	0.4	0.4
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Alcoflood 1275A at 12.01 ft/day							
121	75.99	1.16	3.30	4.46	5.0	1.4	1.7
122	76.76	1.15	4.89	6.04	4.9	2.0	2.3
123	77.54	1.05	4.73	5.78	4.5	2.0	2.2
124	78.31	1.05	4.70	5.75	4.5	2.0	2.2
125	79.09	1.05	4.70	5.75	4.5	2.0	2.2
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Alcoflood 1275A at 3.43 ft/day							
126	79.54	0.36	1.02	1.38	5.4	1.5	1.8
127	79.99	0.38	1.04	1.42	5.7	1.5	1.9
128	80.44	0.38	1.14	1.52	5.7	1.7	2.0
129	80.89	0.40	1.18	1.58	6.0	1.7	2.1
130	81.33	0.40	1.18	1.58	6.0	1.7	2.1

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 1000 mg/L Alcoflood 1275A at 1.28 ft/day							
131	81.81	0.24	0.46	0.70	9.6	1.8	2.5
132	82.28	0.24	0.56	0.80	9.6	2.2	2.8
133	82.76	0.24	0.60	0.84	9.6	2.3	3.0
134	83.23	0.24	0.60	0.84	9.6	2.3	3.0
135	83.71	0.24	0.60	0.84	9.6	2.3	3.0
Injection Water at 1.28 ft/day							
136	84.60	0.16	0.10	0.26	6.4	0.4	0.9
137	85.49	0.10	0.10	0.20	4.0	0.4	0.7
138	86.38	0.09	0.09	0.18	3.6	0.3	0.6
139	87.28	0.09	0.13	0.22	3.6	0.5	0.8
140	88.17	0.09	0.13	0.22	3.6	0.5	0.8
Injection Water at 11.73 ft/day							
141	88.76	0.20	0.88	1.08	0.9	0.4	0.4
142	89.35	0.20	0.82	1.02	0.9	0.3	0.4
143	89.95	0.20	0.80	1.00	0.9	0.3	0.4
144	90.54	0.20	0.79	0.99	0.9	0.3	0.4
145	91.13	0.20	0.79	0.99	0.9	0.3	0.4
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 500 mg/L Alcoflood 1275A at 11.74 ft/day							
146	91.62	0.99	1.99	2.98	4.4	0.8	1.2
147	92.10	1.00	4.18	5.18	4.4	1.8	2.0
148	92.58	1.04	4.86	5.90	4.6	2.1	2.3
149	93.07	1.15	4.97	6.12	5.1	2.1	2.4
150	93.55	1.15	4.98	6.13	5.1	2.1	2.4
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 500 mg/L Alcoflood 1275A at 3.35 ft/day							
151	93.96	0.24	0.86	1.10	3.7	1.3	1.5
152	94.38	0.25	0.87	1.12	3.8	1.3	1.5
153	94.79	0.27	0.88	1.15	4.2	1.3	1.6
154	95.21	0.28	0.97	1.25	4.3	1.4	1.7
155	95.62	0.28	0.97	1.25	4.3	1.4	1.7

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% Petronate EOR 2095 + 500 mg/L Alcoflood 1275A at 1.25 ft/day							
156	96.08	0.19	0.43	0.62	7.8	1.7	2.3
157	96.54	0.36	0.74	1.10	14.9	3.0	4.0
158	97.00	0.25	0.65	0.90	10.3	2.6	3.3
159	97.46	0.24	0.66	0.90	9.9	2.6	3.3
160	97.91	0.24	0.66	0.90	9.9	2.6	3.3
Injection Water at 11.73 ft/day							
161	98.46	0.77	4.31	5.08	3.4	1.8	2.0
162	99.01	0.54	3.05	3.59	2.4	1.3	1.4
163	99.56	0.41	2.64	3.05	1.8	1.1	1.2
164	100.10	0.40	2.19	2.59	1.8	0.9	1.0
165	100.65	0.38	2.12	2.50	1.7	0.9	1.0
166	101.20	0.36	2.12	2.48	1.6	0.9	1.0
167	101.75	0.36	2.13	2.49	1.6	0.9	1.0
168	102.29	0.36	2.16	2.52	1.6	0.9	1.0
169	102.84	0.36	2.14	2.50	1.6	0.9	1.0
170	103.39	0.36	2.14	2.50	1.6	0.9	1.0
171	103.94	0.35	2.15	2.50	1.5	0.9	1.0
172	104.49	0.35	2.15	2.50	1.5	0.9	1.0
173	105.03	0.35	2.15	2.50	1.5	0.9	1.0
174	105.58	0.35	2.15	2.50	1.5	0.9	1.0
175	106.13	0.35	2.15	2.50	1.5	0.9	1.0
176	106.68	0.35	2.15	2.50	1.5	0.9	1.0
177	107.22	0.35	2.15	2.50	1.5	0.9	1.0
178	107.77	0.35	2.15	2.50	1.5	0.9	1.0
179	108.32	0.35	2.15	2.50	1.5	0.9	1.0
180	108.87	0.35	2.15	2.50	1.5	0.9	1.0
1000 mg/L Alcoflood 1275A at 11.73 ft/day							
181	109.52	2.24	7.98	10.22	9.8	3.4	4.0
182	110.17	2.63	12.28	14.90	11.5	5.2	5.8
183	110.82	2.00	8.85	10.85	8.8	3.8	4.2
184	111.48	1.60	7.05	8.65	7.0	3.0	3.3
185	112.13	1.60	6.95	8.55	7.0	3.0	3.3
1000 mg/L Alcoflood 1275A at 3.35 ft/day							
186	112.57	0.80	2.20	3.00	12.3	3.3	4.1
187	113.02	0.63	2.28	2.90	9.6	3.4	3.9
188	113.46	0.60	2.15	2.75	9.2	3.2	3.7

Warner Linear Coreflood 3L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
1000 mg/L Alcoflood 1275A at 3.35 ft/day							
189	113.91	0.58	2.28	2.85	8.8	3.4	3.9
190	114.35	0.58	2.28	2.85	8.8	3.4	3.9
1000 mg/L Alcoflood 1275A at 1.25 ft/day							
191	114.75	0.50	0.33	0.83	20.6	1.3	3.0
192	115.14	0.50	0.30	0.80	20.6	1.2	2.9
193	115.54	0.50	0.50	1.00	20.6	2.0	3.6
194	115.93	0.50	0.53	1.03	20.6	2.1	3.7
195	116.32	0.50	0.53	1.03	20.6	2.1	3.7
Injection Water at 11.73 ft/day							
196	116.85	0.56	3.86	4.42	2.5	1.6	1.7
197	117.37	0.41	2.05	2.46	1.8	0.9	1.0
198	117.90	0.40	1.80	2.20	1.8	0.8	0.9
199	118.42	0.40	1.72	2.12	1.8	0.7	0.8
200	118.95	0.40	1.71	2.11	1.8	0.7	0.8
201	119.47	0.40	1.70	2.10	1.8	0.7	0.8
202	119.99	0.40	1.70	2.10	1.8	0.7	0.8
203	120.52	0.40	1.70	2.10	1.8	0.7	0.8
204	121.04	0.40	1.69	2.09	1.8	0.7	0.8
205	121.57	0.40	1.68	2.08	1.8	0.7	0.8
206	122.09	0.40	1.66	2.06	1.8	0.7	0.8
207	122.62	0.40	1.64	2.04	1.8	0.7	0.8
208	123.14	0.40	1.62	2.02	1.8	0.7	0.8
209	123.67	0.40	1.62	2.02	1.8	0.7	0.8
210	124.19	0.40	1.60	2.00	1.8	0.7	0.8
211	124.71	0.40	1.60	2.00	1.8	0.7	0.8
212	125.24	0.40	1.60	2.00	1.8	0.7	0.8
213	125.76	0.40	1.60	2.00	1.8	0.7	0.8
214	126.29	0.40	1.60	2.00	1.8	0.7	0.8
215	126.81	0.40	1.60	2.00	1.8	0.7	0.8

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 19.15 ft/day							
0	0.00	6.75	23.30	30.05	15.7	13.0	13.5
Produced Water at 19.15 ft/day							
1	0.37	1.55	13.80	15.35	3.6	7.7	6.9
2	1.04	1.10	8.25	9.35	2.6	4.6	4.2
3	1.71	1.05	6.35	7.40	2.4	3.5	3.3
4	2.38	1.05	5.40	6.45	2.4	3.0	2.9
5	3.04	1.00	4.85	5.85	2.3	2.7	2.6
6	3.71	0.95	4.40	5.35	2.2	2.5	2.4
7	4.38	0.79	3.98	4.77	1.8	2.2	2.1
8	5.05	0.73	3.92	4.65	1.7	2.2	2.1
9	5.72	0.71	3.74	4.45	1.7	2.1	2.0
10	6.39	0.71	3.62	4.33	1.7	2.0	2.0
11	7.05	0.67	3.58	4.25	1.6	2.0	1.9
12	7.72	0.65	3.46	4.11	1.5	1.9	1.9
13	8.39	0.63	3.34	3.97	1.5	1.9	1.8
14	9.06	0.61	3.20	3.81	1.4	1.8	1.7
15	9.73	0.59	3.06	3.65	1.4	1.7	1.6
16	10.40	0.59	2.86	3.45	1.4	1.6	1.6
17	11.06	0.57	2.72	3.29	1.3	1.5	1.5
18	11.73	0.57	2.68	3.25	1.3	1.5	1.5
19	12.40	0.55	2.54	3.09	1.3	1.4	1.4
20	13.07	0.55	2.50	3.05	1.3	1.4	1.4
21	13.74	0.55	2.44	2.99	1.3	1.4	1.3
22	14.41	0.55	2.34	2.89	1.3	1.3	1.3
23	15.07	0.53	2.30	2.83	1.2	1.3	1.3
24	15.74	0.53	2.24	2.77	1.2	1.3	1.2
25	16.41	0.53	2.14	2.67	1.2	1.2	1.2
26	17.08	0.51	2.14	2.65	1.2	1.2	1.2
27	17.75	0.51	2.14	2.65	1.2	1.2	1.2
28	18.42	0.51	2.12	2.63	1.2	1.2	1.2
29	19.08	0.51	2.10	2.61	1.2	1.2	1.2
30	19.75	0.51	2.06	2.57	1.2	1.2	1.2
31	20.42	0.51	2.00	2.51	1.2	1.1	1.1
32	21.09	0.51	1.96	2.47	1.2	1.1	1.1
33	21.76	0.51	1.96	2.47	1.2	1.1	1.1
34	22.43	0.49	1.96	2.45	1.1	1.1	1.1
35	23.09	0.47	1.98	2.45	1.1	1.1	1.1

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Produced Water at 19.15 ft/day							
36	23.76	0.45	2.00	2.45	1.0	1.1	1.1
37	24.43	0.45	1.98	2.43	1.0	1.1	1.1
38	25.10	0.45	1.98	2.43	1.0	1.1	1.1
39	25.77	0.45	1.96	2.41	1.0	1.1	1.1
40	26.44	0.43	1.88	2.31	1.0	1.1	1.0
41	27.10	0.43	1.84	2.27	1.0	1.0	1.0
42	27.77	0.43	1.82	2.25	1.0	1.0	1.0
43	28.44	0.43	1.82	2.25	1.0	1.0	1.0
44	29.11	0.43	1.82	2.25	1.0	1.0	1.0
45	29.78	0.43	1.82	2.25	1.0	1.0	1.0
46	30.45	0.43	1.82	2.25	1.0	1.0	1.0
47	31.11	0.43	1.79	2.22	1.0	1.0	1.0
48	31.78	0.43	1.79	2.22	1.0	1.0	1.0
49	32.45	0.43	1.79	2.22	1.0	1.0	1.0
50	33.12	0.43	1.79	2.22	1.0	1.0	1.0
Produced Water at 11.15 ft/day							
51	33.51	0.37	0.99	1.36	1.5	1.0	1.1
52	33.90	0.35	0.95	1.30	1.4	0.9	1.0
53	34.30	0.34	0.96	1.30	1.4	0.9	1.0
54	34.69	0.34	0.96	1.30	1.4	0.9	1.0
55	35.08	0.34	0.96	1.30	1.4	0.9	1.0
Injection Water at 11.15 ft/day							
56	35.50	0.34	0.98	1.32	1.4	0.9	1.0
57	35.91	0.35	0.97	1.32	1.4	0.9	1.0
58	36.33	0.35	0.99	1.34	1.4	1.0	1.0
59	36.75	0.35	0.99	1.34	1.4	1.0	1.0
60	37.17	0.35	0.97	1.32	1.4	0.9	1.0
61	37.59	0.35	0.95	1.30	1.4	0.9	1.0
62	38.00	0.35	0.95	1.30	1.4	0.9	1.0
63	38.42	0.35	0.95	1.30	1.4	0.9	1.0
64	38.84	0.35	0.95	1.30	1.4	0.9	1.0
65	39.26	0.35	0.95	1.30	1.4	0.9	1.0
0.75 wt% NaOH at 11.15 ft/day							
66	39.91	1.17	2.85	4.02	4.7	2.7	3.1
67	40.56	1.39	3.47	4.86	5.6	3.3	3.8
68	41.21	1.23	3.63	4.86	4.9	3.5	3.8

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
0.75 wt% NaOH at 11.15 ft/day							
69	41.86	1.11	3.41	4.52	4.4	3.3	3.5
70	42.50	0.97	3.49	4.46	3.9	3.3	3.5
71	43.15	0.95	3.39	4.34	3.8	3.3	3.4
72	43.80	0.95	3.37	4.32	3.8	3.2	3.3
73	44.45	0.93	3.37	4.30	3.7	3.2	3.3
74	45.10	0.91	3.39	4.30	3.6	3.3	3.3
75	45.75	0.91	3.39	4.30	3.6	3.3	3.3
0.75 wt% NaOH + 0.1 wt% ORS-97HF at 11.15 ft/day							
76	46.45	0.45	1.69	2.14	1.8	1.6	1.7
77	47.14	0.43	1.27	1.70	1.7	1.2	1.3
78	47.83	0.39	0.93	1.32	1.6	0.9	1.0
79	48.52	0.37	0.81	1.18	1.5	0.8	0.9
80	49.22	0.37	0.81	1.18	1.5	0.8	0.9
Injection Water at 11.15 ft/day							
81	49.98	0.40	0.80	1.20	1.6	0.8	0.9
82	50.75	0.51	0.79	1.30	2.0	0.8	1.0
83	51.51	0.45	0.91	1.36	1.8	0.9	1.1
84	52.28	0.41	1.05	1.46	1.6	1.0	1.1
85	53.04	0.38	1.12	1.50	1.5	1.1	1.2
86	53.80	0.35	1.15	1.50	1.4	1.1	1.2
87	54.57	0.35	1.15	1.50	1.4	1.1	1.2
88	55.33	0.35	1.17	1.52	1.4	1.1	1.2
89	56.10	0.35	1.19	1.54	1.4	1.1	1.2
90	56.86	0.35	1.19	1.54	1.4	1.1	1.2
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Cyanatrol 770 at 11.15 ft/day							
91	57.24	2.15	3.75	5.90	8.6	3.6	4.6
92	57.63	2.55	9.95	12.50	10.2	9.5	9.7
93	58.01	2.75	12.35	15.10	11.0	11.9	11.7
94	58.39	2.90	12.55	15.45	11.6	12.0	12.0
95	58.78	2.75	12.65	15.40	11.0	12.1	11.9
96	59.16	2.80	12.60	15.40	11.2	12.1	11.9
97	59.54	2.85	12.55	15.40	11.4	12.0	11.9
98	59.93	3.00	12.40	15.40	12.0	11.9	11.9
99	60.31	3.10	12.30	15.40	12.4	11.8	11.9
100	60.69	3.10	12.30	15.40	12.4	11.8	11.9

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Cyanatrol 770 at 3.19 ft/day							
101	60.95	1.03	3.87	4.90	14.4	13.0	13.3
102	61.20	0.77	2.31	3.08	10.8	7.8	8.3
103	61.45	0.75	2.15	2.90	10.5	7.2	7.9
104	61.71	0.75	2.33	3.08	10.5	7.8	8.3
105	61.96	0.75	2.33	3.08	10.5	7.8	8.3
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Cyanatrol 770 at 1.19 ft/day							
106	62.34	0.45	0.85	1.30	16.8	7.6	9.4
107	62.73	0.47	0.83	1.30	17.5	7.4	9.4
108	63.11	0.49	0.79	1.28	18.3	7.1	9.3
109	63.50	0.51	0.95	1.46	19.0	8.5	10.6
110	63.88	0.51	0.95	1.46	19.0	8.5	10.6
Injection Water at 11.15 ft/day							
111	64.48	1.14	6.76	7.90	4.6	6.5	6.1
112	65.09	0.59	3.51	4.10	2.4	3.4	3.2
113	65.69	0.43	2.35	2.78	1.7	2.3	2.2
114	66.29	0.39	1.67	2.06	1.6	1.6	1.6
115	66.89	0.37	1.47	1.84	1.5	1.4	1.4
116	67.49	0.37	1.33	1.70	1.5	1.3	1.3
117	68.10	0.37	1.33	1.70	1.5	1.3	1.3
118	68.70	0.39	1.43	1.82	1.6	1.4	1.4
119	69.30	0.39	1.47	1.86	1.6	1.4	1.4
120	69.90	0.39	1.47	1.86	1.6	1.4	1.4
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Cyanatrol 770 at 11.15 ft/day							
121	70.61	1.53	4.05	5.58	6.1	3.9	4.3
122	71.31	1.61	6.27	7.88	6.4	6.0	6.1
123	72.02	1.60	6.36	7.96	6.4	6.1	6.2
124	72.72	1.60	6.48	8.08	6.4	6.2	6.3
125	73.43	1.60	6.48	8.08	6.4	6.2	6.3
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Cyanatrol 770 at 3.19 ft/day							
126	73.87	0.55	0.99	1.54	7.7	3.3	4.2
127	74.31	0.53	0.97	1.50	7.4	3.3	4.1
128	74.76	0.51	0.99	1.50	7.1	3.3	4.1
129	75.20	0.54	0.96	1.50	7.6	3.2	4.1
130	75.64	0.54	0.96	1.50	7.6	3.2	4.1

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Cyanatrol 770 at 1.19 ft/day							
131	76.09	0.35	0.29	0.64	13.1	2.6	4.6
132	76.54	0.35	0.33	0.68	13.1	3.0	4.9
133	76.99	0.37	0.33	0.70	13.8	3.0	5.1
134	77.43	0.39	0.31	0.70	14.6	2.8	5.1
135	77.88	0.39	0.31	0.70	14.6	2.8	5.1
Injection Water at 1.19 ft/day							
136	78.72	0.31	0.29	0.60	11.6	2.6	4.3
137	79.56	0.31	0.09	0.40	11.6	0.8	2.9
138	80.40	0.31	0.09	0.40	11.6	0.8	2.9
139	81.24	0.31	0.05	0.36	11.6	0.4	2.6
140	82.08	0.31	0.05	0.36	11.6	0.4	2.6
Injection Water at 10.89 ft/day							
141	82.61	0.35	1.47	1.82	1.4	1.4	1.4
142	83.15	0.35	1.45	1.80	1.4	1.4	1.4
143	83.68	0.35	1.41	1.76	1.4	1.4	1.4
144	84.22	0.35	1.39	1.74	1.4	1.4	1.4
145	84.75	0.35	1.39	1.74	1.4	1.4	1.4
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Cyanatrol 770 at 10.89 ft/day							
146	85.22	0.53	1.89	2.42	2.2	1.9	1.9
147	85.70	0.51	2.39	2.90	2.1	2.3	2.3
148	86.17	0.51	2.17	2.68	2.1	2.1	2.1
149	86.64	0.51	2.15	2.66	2.1	2.1	2.1
150	87.11	0.51	2.15	2.66	2.1	2.1	2.1
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Cyanatrol 770 at 3.11 ft/day							
151	87.49	0.35	0.37	0.72	5.0	1.3	2.0
152	87.87	0.35	0.35	0.70	5.0	1.2	1.9
153	88.25	0.35	0.37	0.72	5.0	1.3	2.0
154	88.63	0.35	0.39	0.74	5.0	1.3	2.1
155	89.01	0.35	0.39	0.74	5.0	1.3	2.1
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Cyanatrol 770 at 1.16 ft/day							
156	89.44	0.33	0.17	0.50	12.7	1.6	3.7
157	89.87	0.34	0.32	0.66	13.1	3.0	4.9
158	90.30	0.34	0.16	0.50	13.1	1.5	3.7
159	90.74	0.33	0.15	0.48	12.7	1.4	3.6
160	91.17	0.33	0.15	0.48	12.7	1.4	3.6

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.89 ft/day							
161	91.63	0.42	2.60	3.02	1.7	2.6	2.4
162	92.10	0.39	2.09	2.48	1.6	2.1	2.0
163	92.56	0.36	1.92	2.28	1.5	1.9	1.8
164	93.03	0.35	1.69	2.04	1.4	1.7	1.6
165	93.49	0.35	1.55	1.90	1.4	1.5	1.5
166	93.95	0.35	1.49	1.84	1.4	1.5	1.5
167	94.42	0.35	1.39	1.74	1.4	1.4	1.4
168	94.88	0.35	1.39	1.74	1.4	1.4	1.4
169	95.35	0.35	1.37	1.72	1.4	1.3	1.4
170	95.81	0.35	1.35	1.70	1.4	1.3	1.3
171	96.28	0.35	1.35	1.70	1.4	1.3	1.3
172	96.74	0.35	1.35	1.70	1.4	1.3	1.3
173	97.20	0.35	1.35	1.70	1.4	1.3	1.3
174	97.67	0.34	1.36	1.70	1.4	1.3	1.3
175	98.13	0.34	1.36	1.70	1.4	1.3	1.3
176	98.60	0.34	1.36	1.70	1.4	1.3	1.3
177	99.06	0.34	1.36	1.70	1.4	1.3	1.3
178	99.53	0.34	1.36	1.70	1.4	1.3	1.3
179	99.99	0.34	1.36	1.70	1.4	1.3	1.3
180	100.46	0.34	1.36	1.70	1.4	1.3	1.3
1000 mg/L Cyanatrol 770 at 10.89 ft/day							
181	101.05	2.37	4.49	6.86	9.7	4.4	5.4
182	101.64	3.05	10.80	13.85	12.5	10.6	11.0
183	102.24	2.50	8.95	11.45	10.2	8.8	9.1
184	102.83	2.10	7.30	9.40	8.6	7.2	7.4
185	103.43	2.10	7.30	9.40	8.6	7.2	7.4
1000 mg/L Cyanatrol 770 at 3.11 ft/day							
186	103.85	0.75	2.10	2.85	10.7	7.2	7.9
187	104.27	0.70	1.30	2.00	10.0	4.5	5.5
188	104.70	0.65	1.40	2.05	9.3	4.8	5.7
189	105.12	0.65	1.75	2.40	9.3	6.0	6.7
190	105.54	0.65	1.75	2.40	9.3	6.0	6.7
1000 mg/L Cyanatrol 770 at 1.16 ft/day							
191	105.92	0.60	0.40	1.00	23.0	3.7	7.4
192	106.29	0.55	0.35	0.90	21.1	3.2	6.7
193	106.66	0.55	0.35	0.90	21.1	3.2	6.7
194	107.03	0.55	0.35	0.90	21.1	3.2	6.7
195	107.41	0.55	0.35	0.90	21.1	3.2	6.7

Warner Linear Coreflood 4L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 10.89 ft/day							
196	107.90	0.60	6.90	7.50	2.5	6.8	5.9
197	108.39	0.44	2.68	3.12	1.8	2.6	2.5
198	108.88	1.00	4.70	5.70	4.1	4.6	4.5
199	109.37	1.00	4.20	5.20	4.1	4.1	4.1
200	109.87	0.95	3.95	4.90	3.9	3.9	3.9
201	110.36	0.95	3.90	4.85	3.9	3.8	3.8
202	110.85	0.95	3.85	4.80	3.9	3.8	3.8
203	111.34	0.95	3.70	4.65	3.9	3.6	3.7
204	111.83	0.95	3.50	4.45	3.9	3.4	3.5
205	112.33	0.95	3.45	4.40	3.9	3.4	3.5
206	112.82	0.36	1.34	1.70	1.5	1.3	1.3
207	113.31	0.36	1.34	1.70	1.5	1.3	1.3
208	113.80	0.36	1.32	1.68	1.5	1.3	1.3
209	114.30	0.36	1.30	1.66	1.5	1.3	1.3
210	114.79	0.36	1.28	1.64	1.5	1.3	1.3
211	115.28	0.36	1.28	1.64	1.5	1.3	1.3
212	115.77	0.36	1.28	1.64	1.5	1.3	1.3
213	116.26	0.36	1.28	1.64	1.5	1.3	1.3
214	116.76	0.36	1.28	1.64	1.5	1.3	1.3
215	117.25	0.36	1.28	1.64	1.5	1.3	1.3

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 17.58 ft/day							
0	0.00	2.67	4.91	7.58	13.4	13.6	13.5
Produced Water at 17.58 ft/day							
1	0.20	0.79	3.81	4.60	4.0	10.6	8.2
2	0.70	0.53	1.77	2.30	2.7	4.9	4.1
3	1.21	0.42	1.28	1.70	2.1	3.6	3.0
4	1.72	0.38	1.02	1.40	1.9	2.8	2.5
5	2.22	0.33	0.86	1.19	1.7	2.4	2.1
6	2.73	0.30	0.79	1.09	1.5	2.2	1.9
7	3.23	0.29	0.71	1.00	1.5	2.0	1.8
8	3.74	0.29	0.67	0.96	1.5	1.9	1.7
9	4.24	0.28	0.63	0.91	1.4	1.8	1.6
10	4.75	0.27	0.61	0.88	1.4	1.7	1.6
11	5.26	0.27	0.58	0.85	1.4	1.6	1.5
12	5.76	0.27	0.54	0.81	1.4	1.5	1.4
13	6.27	0.26	0.54	0.80	1.3	1.5	1.4
14	6.77	0.26	0.53	0.79	1.3	1.5	1.4
15	7.28	0.26	0.51	0.77	1.3	1.4	1.4
16	7.78	0.25	0.50	0.75	1.3	1.4	1.3
17	8.29	0.25	0.47	0.72	1.3	1.3	1.3
18	8.80	0.24	0.46	0.70	1.2	1.3	1.3
19	9.30	0.24	0.45	0.69	1.2	1.3	1.2
20	9.81	0.23	0.45	0.68	1.2	1.3	1.2
21	10.31	0.23	0.44	0.67	1.2	1.2	1.2
22	10.82	0.22	0.44	0.66	1.1	1.2	1.2
23	11.32	0.22	0.43	0.65	1.1	1.2	1.2
24	11.83	0.22	0.42	0.64	1.1	1.2	1.1
25	12.34	0.22	0.41	0.63	1.1	1.1	1.1
26	12.84	0.22	0.40	0.62	1.1	1.1	1.1
27	13.35	0.21	0.40	0.61	1.1	1.1	1.1
28	13.85	0.21	0.40	0.61	1.1	1.1	1.1
29	14.36	0.21	0.39	0.60	1.1	1.1	1.1
30	14.86	0.21	0.39	0.60	1.1	1.1	1.1
31	15.37	0.21	0.39	0.60	1.1	1.1	1.1
32	15.88	0.21	0.39	0.60	1.1	1.1	1.1
33	16.38	0.21	0.39	0.60	1.1	1.1	1.1
34	16.89	0.21	0.39	0.60	1.1	1.1	1.1
35	17.39	0.21	0.39	0.60	1.1	1.1	1.1

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Produced Water at 17.58 ft/day							
36	17.90	0.21	0.39	0.60	1.1	1.1	1.1
37	18.40	0.21	0.38	0.59	1.1	1.1	1.1
38	18.91	0.21	0.38	0.59	1.1	1.1	1.1
39	19.42	0.21	0.37	0.58	1.1	1.0	1.0
40	19.92	0.20	0.38	0.58	1.0	1.1	1.0
41	20.43	0.20	0.37	0.57	1.0	1.0	1.0
42	20.93	0.20	0.37	0.57	1.0	1.0	1.0
43	21.44	0.20	0.36	0.56	1.0	1.0	1.0
44	21.94	0.20	0.36	0.56	1.0	1.0	1.0
45	22.45	0.20	0.36	0.56	1.0	1.0	1.0
46	22.96	0.20	0.36	0.56	1.0	1.0	1.0
47	23.46	0.20	0.36	0.56	1.0	1.0	1.0
48	23.97	0.20	0.36	0.56	1.0	1.0	1.0
49	24.47	0.20	0.36	0.56	1.0	1.0	1.0
50	25.02	0.20	0.36	0.56	1.0	1.0	1.0
Produced Water at 10.22 ft/day							
51	25.62	0.15	0.23	0.37	1.2	1.1	1.1
52	26.22	0.12	0.19	0.30	1.0	0.9	0.9
53	26.82	0.11	0.19	0.30	0.9	0.9	0.9
54	27.42	0.11	0.19	0.30	0.9	0.9	0.9
55	28.02	0.11	0.19	0.30	0.9	0.9	0.9
56	28.62	0.11	0.19	0.30	0.9	0.9	0.9
57	29.22	0.11	0.19	0.30	0.9	0.9	0.9
58	29.83	0.11	0.19	0.30	0.9	0.9	0.9
59	30.43	0.11	0.19	0.30	0.9	0.9	0.9
60	31.03	0.11	0.19	0.30	0.9	0.9	0.9
61	31.63	0.11	0.19	0.30	0.9	0.9	0.9
62	32.23	0.11	0.19	0.30	0.9	0.9	0.9
63	32.83	0.11	0.20	0.31	0.9	1.0	1.0
64	33.43	0.11	0.20	0.31	0.9	1.0	1.0
65	34.03	0.11	0.20	0.31	0.9	1.0	1.0
66	34.63	0.11	0.20	0.31	0.9	1.0	1.0
67	35.23	0.11	0.20	0.31	0.9	1.0	1.0
68	35.83	0.11	0.20	0.31	0.9	1.0	1.0
69	36.43	0.11	0.20	0.31	0.9	1.0	1.0
70	37.03	0.11	0.20	0.31	0.9	1.0	1.0

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Injection Water at 10.22 ft/day							
71	37.67	0.08	0.28	0.36	0.7	1.3	1.1
72	38.31	0.07	0.28	0.35	0.6	1.3	1.1
73	38.95	0.07	0.28	0.35	0.6	1.3	1.1
74	39.59	0.07	0.28	0.35	0.6	1.3	1.1
75	40.23	0.07	0.28	0.35	0.6	1.3	1.1
0.75 wt% NaOH at 10.22 ft/day							
76	40.61	0.27	0.78	1.05	2.3	3.7	3.2
77	41.00	0.26	0.82	1.08	2.2	3.9	3.3
78	41.39	0.26	0.68	0.94	2.2	3.2	2.9
79	41.77	0.26	0.57	0.83	2.2	2.7	2.5
80	42.16	0.26	0.48	0.74	2.2	2.3	2.3
81	42.54	0.26	0.39	0.65	2.2	1.9	2.0
82	42.93	0.26	0.38	0.64	2.2	1.8	2.0
83	43.32	0.26	0.33	0.59	2.2	1.6	1.8
84	43.70	0.26	0.31	0.57	2.2	1.5	1.8
85	44.09	0.26	0.31	0.57	2.2	1.5	1.8
0.75 wt% NaOH + 0.1 wt% ORS-97HF at 10.22 ft/day							
86	44.52	0.16	0.28	0.44	1.4	1.3	1.4
87	44.96	0.15	0.17	0.32	1.3	0.8	1.0
88	45.39	0.15	0.10	0.25	1.3	0.5	0.8
89	45.83	0.15	0.10	0.25	1.3	0.5	0.8
90	46.26	0.15	0.10	0.25	1.3	0.5	0.8
91	46.70	0.15	0.10	0.25	1.3	0.5	0.8
92	47.13	0.15	0.10	0.25	1.3	0.5	0.8
93	47.57	0.15	0.10	0.25	1.3	0.5	0.8
94	48.01	0.15	0.10	0.25	1.3	0.5	0.8
95	48.44	0.15	0.10	0.25	1.3	0.5	0.8
Injection Water at 10.22 ft/day							
96	48.88	0.13	0.08	0.21	1.1	0.4	0.6
97	49.32	0.11	0.08	0.19	0.9	0.4	0.6
98	49.76	0.09	0.06	0.15	0.8	0.3	0.5
99	50.20	0.08	0.07	0.15	0.7	0.3	0.5
100	50.64	0.07	0.08	0.15	0.6	0.4	0.5
101	51.08	0.07	0.07	0.14	0.6	0.3	0.4
102	51.52	0.07	0.07	0.14	0.6	0.3	0.4
103	51.95	0.07	0.07	0.14	0.6	0.3	0.4

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.22 ft/day							
104	52.39	0.07	0.07	0.14	0.6	0.3	0.4
105	52.83	0.07	0.07	0.14	0.6	0.3	0.4
106	53.27	0.07	0.07	0.14	0.6	0.3	0.4
107	53.71	0.07	0.07	0.14	0.6	0.3	0.4
108	54.15	0.07	0.07	0.14	0.6	0.3	0.4
109	54.59	0.07	0.07	0.14	0.6	0.3	0.4
110	55.03	0.07	0.07	0.14	0.6	0.3	0.4
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Alcoflood 1275A at 10.22 ft/day							
111	55.53	0.57	0.64	1.21	4.9	3.1	3.7
112	56.02	0.60	0.97	1.57	5.2	4.6	4.8
113	56.52	0.59	1.05	1.64	5.1	5.0	5.0
114	57.02	0.59	1.06	1.65	5.1	5.1	5.1
115	57.52	0.59	1.06	1.65	5.1	5.1	5.1
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Alcoflood 1275A at 3.64 ft/day							
116	58.13	0.24	0.42	0.66	5.8	5.6	5.7
117	58.74	0.25	0.42	0.67	6.0	5.6	5.8
118	59.34	0.25	0.47	0.72	6.0	6.3	6.2
119	59.95	0.25	0.50	0.75	6.0	6.7	6.5
120	60.56	0.25	0.50	0.75	6.0	6.7	6.5
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Alcoflood 1275A at 1.09 ft/day							
121	60.82	0.11	0.14	0.25	8.8	6.2	7.2
122	61.08	0.12	0.13	0.25	9.6	5.8	7.2
123	61.34	0.13	0.13	0.26	10.4	5.8	7.5
124	61.60	0.13	0.14	0.27	10.4	6.2	7.7
125	61.85	0.13	0.14	0.27	10.4	6.2	7.7
Injection Water at 10.22 ft/day							
126	62.36	0.21	0.59	0.80	1.8	2.8	2.5
127	62.87	0.15	0.29	0.44	1.3	1.4	1.4
128	63.37	0.12	0.17	0.29	1.0	0.8	0.9
129	63.88	0.10	0.11	0.21	0.9	0.5	0.6
130	64.38	0.07	0.09	0.16	0.6	0.4	0.5
131	64.89	0.07	0.08	0.15	0.6	0.4	0.5
132	65.39	0.07	0.08	0.14	0.6	0.4	0.4
133	65.90	0.06	0.07	0.13	0.5	0.3	0.4
134	66.40	0.06	0.07	0.13	0.5	0.3	0.4
135	66.91	0.06	0.07	0.13	0.5	0.3	0.4

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Alcoflood 1275A at 10.22 ft/day							
136	67.47	0.38	0.39	0.77	3.3	1.9	2.4
137	68.02	0.41	0.47	0.88	3.5	2.2	2.7
138	68.58	0.44	0.51	0.95	3.8	2.4	2.9
139	69.13	0.44	0.53	0.97	3.8	2.5	3.0
140	69.69	0.44	0.53	0.97	3.8	2.5	3.0
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Alcoflood 1275A at 3.64 ft/day							
141	70.10	0.15	0.20	0.35	3.6	2.7	3.0
142	70.52	0.15	0.21	0.36	3.6	2.8	3.1
143	70.94	0.16	0.21	0.37	3.9	2.8	3.2
144	71.36	0.17	0.21	0.37	4.0	2.7	3.2
145	71.78	0.17	0.21	0.37	4.0	2.7	3.2
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Alcoflood 1275A at 1.09 ft/day							
146	72.29	0.05	0.01	0.06	4.0	0.4	1.7
147	72.80	0.05	0.03	0.08	4.0	1.3	2.3
148	73.31	0.05	0.04	0.09	4.0	1.8	2.6
149	73.82	0.05	0.05	0.10	4.0	2.2	2.9
150	74.33	0.05	0.05	0.10	4.0	2.2	2.9
Injection Water at 10.22 ft/day							
151	74.85	0.53	0.67	1.20	4.6	3.2	3.7
152	75.38	0.21	0.45	0.66	1.8	2.2	2.0
153	75.91	0.14	0.26	0.40	1.2	1.2	1.2
154	76.44	0.08	0.22	0.30	0.7	1.1	0.9
155	76.97	0.07	0.18	0.25	0.6	0.9	0.8
156	77.50	0.05	0.20	0.25	0.4	1.0	0.8
157	78.02	0.05	0.18	0.23	0.4	0.9	0.7
158	78.55	0.05	0.16	0.21	0.4	0.8	0.6
159	79.08	0.05	0.16	0.21	0.4	0.8	0.6
160	79.61	0.05	0.16	0.21	0.4	0.8	0.6
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Alcoflood 1275A at 10.22 ft/day							
161	80.02	0.31	0.36	0.67	2.7	1.7	2.1
162	80.43	0.33	0.42	0.75	2.8	2.0	2.3
163	80.84	0.32	0.51	0.83	2.8	2.4	2.5
164	81.25	0.31	0.53	0.84	2.7	2.5	2.6
165	81.66	0.31	0.53	0.84	2.7	2.5	2.6

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Alcoflood 1275A at 3.64 ft/day							
166	82.05	0.10	0.15	0.25	2.4	2.0	2.2
167	82.43	0.11	0.14	0.25	2.7	1.9	2.2
168	82.82	0.11	0.15	0.26	2.7	1.9	2.2
169	83.20	0.11	0.15	0.26	2.7	2.0	2.2
170	83.58	0.11	0.15	0.26	2.7	2.0	2.2
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Alcoflood 1275A at 1.09 ft/day							
171	84.04	0.05	0.05	0.10	4.0	2.2	2.9
172	84.50	0.05	0.05	0.10	4.0	2.2	2.9
173	84.96	0.05	0.04	0.09	4.0	1.8	2.6
174	85.42	0.05	0.03	0.08	4.0	1.3	2.3
175	85.88	0.05	0.03	0.08	4.0	1.3	2.3
Injection Water at 10.22 ft/day							
176	86.20	0.15	0.40	0.55	1.3	1.9	1.7
177	86.51	0.13	0.33	0.46	1.1	1.6	1.4
178	86.83	0.11	0.36	0.47	0.9	1.7	1.4
179	87.14	0.09	0.35	0.44	0.8	1.7	1.4
180	87.45	0.07	0.28	0.35	0.6	1.3	1.1
181	87.77	0.06	0.19	0.25	0.5	0.9	0.8
182	88.08	0.05	0.14	0.19	0.4	0.7	0.6
183	88.39	0.05	0.11	0.16	0.4	0.5	0.5
184	88.71	0.05	0.10	0.15	0.4	0.5	0.5
185	89.02	0.05	0.07	0.12	0.4	0.3	0.4
186	89.33	0.05	0.05	0.10	0.4	0.2	0.3
187	89.65	0.05	0.05	0.10	0.4	0.2	0.3
188	89.96	0.05	0.05	0.10	0.4	0.2	0.3
189	90.28	0.05	0.05	0.10	0.4	0.2	0.3
190	90.59	0.05	0.05	0.10	0.4	0.2	0.3
1000 mg/L Alcoflood 1275A at 10.22 ft/day							
191	91.05	0.45	0.49	0.94	3.9	2.3	2.9
192	91.50	0.48	0.73	1.20	4.1	3.5	3.7
193	91.96	0.49	0.72	1.21	4.2	3.4	3.7
194	92.41	0.50	0.72	1.22	4.3	3.4	3.7
195	92.87	0.50	0.72	1.22	4.3	3.4	3.7

Warner Linear Coreflood 5L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
1000 mg/L Alcoflood 1275A at 3.64 ft/day							
196	93.15	0.18	0.23	0.41	4.3	3.1	3.5
197	93.43	0.17	0.23	0.40	4.1	3.1	3.4
198	93.70	0.17	0.23	0.40	4.1	3.1	3.4
199	93.98	0.17	0.23	0.40	4.1	3.1	3.4
200	94.26	0.17	0.23	0.40	4.1	3.1	3.4
1000 mg/L Alcoflood 1275A at 1.09 ft/day							
201	94.87	0.06	0.04	0.10	4.8	1.8	2.9
202	95.49	0.06	0.02	0.08	4.8	0.9	2.3
203	96.11	0.06	0.03	0.09	4.8	1.3	2.6
204	96.72	0.06	0.03	0.09	4.8	1.3	2.6
205	97.34	0.06	0.03	0.09	4.8	1.3	2.6
Injection Water at 10.22 ft/day							
206	97.82	0.11	0.44	0.55	0.9	2.1	1.7
207	98.30	0.07	0.14	0.21	0.6	0.7	0.6
208	98.78	0.06	0.09	0.15	0.5	0.4	0.5
209	99.26	0.06	0.08	0.13	0.5	0.4	0.4
210	99.74	0.06	0.06	0.11	0.5	0.3	0.3
211	100.22	0.05	0.04	0.09	0.4	0.2	0.3
212	100.71	0.05	0.04	0.09	0.4	0.2	0.3
213	101.19	0.05	0.04	0.09	0.4	0.2	0.3
214	101.67	0.05	0.04	0.09	0.4	0.2	0.3
215	102.15	0.05	0.05	0.10	0.4	0.2	0.3
216	102.63	0.05	0.05	0.10	0.4	0.2	0.3
217	103.11	0.05	0.05	0.10	0.4	0.2	0.3
218	103.59	0.05	0.05	0.10	0.4	0.2	0.3
219	104.07	0.05	0.05	0.10	0.4	0.2	0.3
220	104.55	0.05	0.05	0.10	0.4	0.2	0.3

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
Warner Crude Oil (Viscosity Adjusted = 52 cp) at 18.03 ft/day							
0	0.00	3.10	5.30	8.40	14.1	10.2	11.4
Produced Water at 18.03 ft/day							
1	0.13	1.10	4.41	5.51	5.0	8.5	7.4
2	0.60	0.58	2.20	2.78	2.6	4.2	3.8
3	1.07	0.48	1.62	2.10	2.2	3.1	2.8
4	1.54	0.42	1.48	1.90	1.9	2.8	2.6
5	2.01	0.40	1.23	1.63	1.8	2.4	2.2
6	2.48	0.40	1.18	1.58	1.8	2.3	2.1
7	2.95	0.39	1.11	1.50	1.8	2.1	2.0
8	3.42	0.38	1.07	1.45	1.7	2.1	2.0
9	3.89	0.36	1.04	1.40	1.6	2.0	1.9
10	4.36	0.34	0.98	1.32	1.5	1.9	1.8
11	4.83	0.33	0.94	1.27	1.5	1.8	1.7
12	5.30	0.32	0.91	1.23	1.5	1.8	1.7
13	5.77	0.32	0.88	1.20	1.5	1.7	1.6
14	6.24	0.31	0.85	1.16	1.4	1.6	1.6
15	6.71	0.31	0.80	1.11	1.4	1.5	1.5
16	7.18	0.30	0.79	1.09	1.4	1.5	1.5
17	7.65	0.30	0.77	1.07	1.4	1.5	1.4
18	8.12	0.30	0.72	1.02	1.4	1.4	1.4
19	8.59	0.30	0.71	1.01	1.4	1.4	1.4
20	9.06	0.30	0.70	1.00	1.4	1.3	1.4
21	9.53	0.30	0.69	0.99	1.4	1.3	1.3
22	10.00	0.29	0.69	0.98	1.3	1.3	1.3
23	10.47	0.29	0.68	0.97	1.3	1.3	1.3
24	10.94	0.28	0.68	0.96	1.3	1.3	1.3
25	11.41	0.28	0.66	0.94	1.3	1.3	1.3
26	11.88	0.28	0.64	0.92	1.3	1.2	1.2
27	12.35	0.27	0.64	0.91	1.2	1.2	1.2
28	12.82	0.27	0.63	0.90	1.2	1.2	1.2
29	13.29	0.26	0.63	0.89	1.2	1.2	1.2
30	13.76	0.26	0.61	0.87	1.2	1.2	1.2
31	14.23	0.26	0.59	0.85	1.2	1.1	1.1
32	14.70	0.26	0.58	0.84	1.2	1.1	1.1
33	15.17	0.25	0.58	0.83	1.1	1.1	1.1
34	15.64	0.25	0.56	0.81	1.1	1.1	1.1
35	16.11	0.25	0.55	0.80	1.1	1.1	1.1

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 18.03 ft/day							
36	16.58	0.24	0.56	0.80	1.1	1.1	1.1
37	17.05	0.24	0.56	0.80	1.1	1.1	1.1
38	17.52	0.23	0.57	0.80	1.0	1.1	1.1
39	17.99	0.23	0.57	0.80	1.0	1.1	1.1
40	18.46	0.23	0.56	0.79	1.0	1.1	1.1
41	18.93	0.23	0.56	0.79	1.0	1.1	1.1
42	19.40	0.23	0.55	0.78	1.0	1.1	1.1
43	19.87	0.23	0.55	0.78	1.0	1.1	1.1
44	20.34	0.23	0.54	0.77	1.0	1.0	1.0
45	20.81	0.23	0.52	0.75	1.0	1.0	1.0
46	21.28	0.23	0.51	0.74	1.0	1.0	1.0
47	21.75	0.22	0.52	0.74	1.0	1.0	1.0
48	22.22	0.22	0.52	0.74	1.0	1.0	1.0
49	22.69	0.22	0.52	0.74	1.0	1.0	1.0
50	23.16	0.22	0.52	0.74	1.0	1.0	1.0
Produced Water at 10.48 ft/day							
51	23.76	0.18	0.25	0.43	1.4	0.8	1.0
52	24.37	0.17	0.26	0.43	1.3	0.9	1.0
53	24.97	0.16	0.27	0.43	1.3	0.9	1.0
54	25.58	0.15	0.27	0.42	1.2	0.9	1.0
55	26.18	0.14	0.28	0.42	1.1	0.9	1.0
56	26.78	0.14	0.28	0.42	1.1	0.9	1.0
57	27.39	0.14	0.27	0.41	1.1	0.9	1.0
58	27.99	0.14	0.27	0.41	1.1	0.9	1.0
59	28.59	0.13	0.28	0.41	1.0	0.9	1.0
60	29.20	0.13	0.27	0.40	1.0	0.9	0.9
61	29.80	0.12	0.28	0.40	0.9	0.9	0.9
62	30.41	0.12	0.28	0.40	0.9	0.9	0.9
63	31.01	0.12	0.28	0.40	0.9	0.9	0.9
64	31.61	0.12	0.28	0.40	0.9	0.9	0.9
65	32.22	0.12	0.28	0.40	0.9	0.9	0.9
66	32.82	0.12	0.28	0.40	0.9	0.9	0.9
67	33.42	0.12	0.28	0.40	0.9	0.9	0.9
68	34.03	0.13	0.26	0.39	1.0	0.9	0.9
69	34.63	0.13	0.26	0.39	1.0	0.9	0.9
70	35.24	0.13	0.26	0.39	1.0	0.9	0.9

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.48 ft/day							
71	35.83	0.12	0.53	0.65	0.9	1.8	1.5
72	36.42	0.15	0.70	0.85	1.2	2.3	2.0
73	37.01	0.15	0.69	0.84	1.2	2.3	2.0
74	37.60	0.15	0.68	0.83	1.2	2.2	1.9
75	38.19	0.15	0.68	0.83	1.2	2.2	1.9
1.0 wt% NaOH at 10.48 ft/day							
76	38.58	0.72	1.12	1.84	5.6	3.7	4.3
77	38.97	0.73	1.04	1.77	5.7	3.4	4.1
78	39.37	0.70	1.06	1.76	5.5	3.5	4.1
79	39.76	0.67	1.08	1.75	5.2	3.6	4.1
80	40.15	0.59	1.13	1.72	4.6	3.7	4.0
81	40.55	0.61	1.13	1.74	4.8	3.7	4.0
82	40.94	0.62	1.12	1.74	4.8	3.7	4.0
83	41.33	0.62	1.08	1.70	4.8	3.6	4.0
84	41.73	0.62	1.03	1.65	4.8	3.4	3.8
85	42.12	0.62	1.03	1.65	4.8	3.4	3.8
1.0 wt% NaOH + 0.1 wt% ORS-97HF at 10.48 ft/day							
86	42.57	0.24	0.69	0.93	1.9	2.3	2.2
87	43.03	0.18	0.42	0.60	1.4	1.4	1.4
88	43.48	0.17	0.38	0.55	1.3	1.3	1.3
89	43.94	0.17	0.34	0.51	1.3	1.1	1.2
90	44.39	0.17	0.33	0.50	1.3	1.1	1.2
91	44.84	0.17	0.33	0.50	1.3	1.1	1.2
92	45.30	0.17	0.33	0.50	1.3	1.1	1.2
93	45.75	0.17	0.33	0.50	1.3	1.1	1.2
94	46.21	0.17	0.33	0.50	1.3	1.1	1.2
95	46.66	0.17	0.33	0.50	1.3	1.1	1.2
Injection Water at 10.48 ft/day							
96	47.13	0.16	0.28	0.44	1.3	0.9	1.0
97	47.59	0.15	0.25	0.40	1.2	0.8	0.9
98	48.06	0.14	0.25	0.39	1.1	0.8	0.9
99	48.53	0.13	0.25	0.38	1.0	0.8	0.9
100	48.99	0.12	0.25	0.37	0.9	0.8	0.9
101	49.46	0.12	0.24	0.36	0.9	0.8	0.8
102	49.92	0.12	0.23	0.35	0.9	0.8	0.8
103	50.39	0.11	0.24	0.35	0.9	0.8	0.8

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 10.48 ft/day							
104	50.86	0.11	0.24	0.35	0.9	0.8	0.8
105	51.32	0.11	0.24	0.35	0.9	0.8	0.8
106	51.79	0.10	0.24	0.34	0.8	0.8	0.8
107	52.25	0.10	0.23	0.33	0.8	0.8	0.8
108	52.72	0.10	0.22	0.32	0.8	0.7	0.7
109	53.19	0.10	0.22	0.32	0.8	0.7	0.7
110	53.65	0.10	0.22	0.32	0.8	0.7	0.7
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Flopaam 3630S at 10.48 ft/day							
111	54.12	0.95	1.55	2.50	7.4	5.1	5.8
112	54.60	1.27	2.63	3.90	9.9	8.7	9.1
113	55.07	1.29	2.86	4.15	10.1	9.5	9.6
114	55.54	1.29	2.71	4.00	10.1	9.0	9.3
115	56.01	1.29	2.71	4.00	10.1	9.0	9.3
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Flopaam 3630S at 3.74 ft/day							
116	56.65	0.40	0.70	1.10	8.8	6.5	7.2
117	57.28	0.45	0.75	1.20	9.9	7.0	7.8
118	57.91	0.47	0.83	1.30	10.3	7.7	8.5
119	58.55	0.47	0.85	1.32	10.3	7.9	8.6
120	59.18	0.47	0.85	1.32	10.3	7.9	8.6
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1500 mg/L Flopaam 3630S at 1.12 ft/day							
121	59.45	0.19	0.37	0.56	13.9	11.4	12.2
122	59.71	0.19	0.39	0.58	13.9	12.0	12.6
123	59.98	0.19	0.41	0.60	13.9	12.7	13.0
124	60.25	0.19	0.41	0.60	13.9	12.7	13.0
125	60.52	0.19	0.41	0.60	13.9	12.7	13.0
Injection Water at 10.48 ft/day							
126	61.05	0.61	2.19	2.80	4.8	7.2	6.5
127	61.57	0.37	0.59	0.96	2.9	2.0	2.2
128	62.10	0.27	0.33	0.60	2.1	1.1	1.4
129	62.63	0.22	0.28	0.50	1.7	0.9	1.2
130	63.16	0.18	0.26	0.44	1.4	0.9	1.0
131	63.69	0.17	0.25	0.42	1.3	0.8	1.0
132	64.22	0.17	0.25	0.42	1.3	0.8	1.0
133	64.75	0.17	0.24	0.41	1.3	0.8	1.0
134	65.28	0.17	0.23	0.40	1.3	0.8	0.9
135	65.81	0.17	0.23	0.40	1.3	0.8	0.9

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum V_p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3630S at 10.48 ft/day							
136	66.36	0.95	0.75	1.70	7.4	2.5	4.0
137	66.91	1.04	1.21	2.25	8.1	4.0	5.2
138	67.46	1.07	1.19	2.26	8.4	3.9	5.3
139	68.01	1.07	1.23	2.30	8.4	4.1	5.3
140	68.56	1.07	1.23	2.30	8.4	4.1	5.3
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3630S at 3.74 ft/day							
141	69.00	0.37	0.37	0.74	8.1	3.4	4.8
142	69.44	0.37	0.42	0.79	8.1	3.9	5.1
143	69.88	0.37	0.43	0.80	8.1	4.0	5.2
144	70.32	0.37	0.43	0.80	8.1	4.0	5.2
145	70.76	0.37	0.43	0.80	8.1	4.0	5.2
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1000 mg/L Flopaam 3630S at 1.12 ft/day							
146	71.29	0.17	0.16	0.33	12.4	4.9	7.2
147	71.82	0.17	0.17	0.34	12.4	5.2	7.4
148	72.34	0.17	0.18	0.35	12.4	5.6	7.6
149	72.87	0.17	0.18	0.35	12.4	5.6	7.6
150	73.40	0.17	0.18	0.35	12.4	5.6	7.6
Injection Water at 10.48 ft/day							
151	73.97	0.25	0.90	1.15	2.0	3.0	2.7
152	74.53	0.88	1.54	2.42	6.9	5.1	5.6
153	75.10	0.43	0.52	0.95	3.4	1.7	2.2
154	75.67	0.34	0.31	0.65	2.7	1.0	1.5
155	76.24	0.25	0.29	0.54	2.0	1.0	1.3
156	76.81	0.24	0.23	0.47	1.9	0.8	1.1
157	77.38	0.22	0.23	0.45	1.7	0.8	1.0
158	77.94	0.19	0.21	0.40	1.5	0.7	0.9
159	78.51	0.17	0.20	0.37	1.3	0.7	0.9
160	79.08	0.17	0.19	0.36	1.3	0.6	0.8
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Flopaam 3630S at 10.48 ft/day							
161	79.48	0.76	0.38	1.14	5.9	1.3	2.6
162	79.88	0.75	0.73	1.48	5.9	2.4	3.4
163	80.28	0.75	0.69	1.44	5.9	2.3	3.3
164	80.69	0.75	0.66	1.41	5.9	2.2	3.3
165	81.09	0.75	0.66	1.41	5.9	2.2	3.3

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _p	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Flopaam 3630S at 3.74 ft/day							
166	81.50	0.25	0.18	0.43	5.5	1.7	2.8
167	81.91	0.25	0.20	0.45	5.5	1.9	2.9
168	82.33	0.25	0.20	0.45	5.5	1.9	2.9
169	82.74	0.25	0.20	0.45	5.5	1.9	2.9
170	83.15	0.25	0.20	0.45	5.5	1.9	2.9
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 500 mg/L Flopaam 3630S at 1.12 ft/day							
171	83.64	0.08	0.08	0.16	5.8	2.5	3.5
172	84.12	0.09	0.06	0.15	6.6	1.9	3.3
173	84.60	0.09	0.06	0.15	6.6	1.9	3.3
174	85.09	0.09	0.06	0.15	6.6	1.9	3.3
175	85.57	0.09	0.06	0.15	6.6	1.9	3.3
Injection Water at 10.48 ft/day							
176	85.89	0.62	0.67	1.29	4.8	2.2	3.0
177	86.22	0.68	0.87	1.55	5.3	2.9	3.6
178	86.54	0.46	0.65	1.11	3.6	2.2	2.6
179	86.86	0.36	0.47	0.83	2.8	1.6	1.9
180	87.18	0.33	0.32	0.65	2.6	1.1	1.5
181	87.51	0.25	0.31	0.56	2.0	1.0	1.3
182	87.83	0.25	0.28	0.53	2.0	0.9	1.2
183	88.15	0.25	0.23	0.48	2.0	0.8	1.1
184	88.47	0.24	0.21	0.45	1.9	0.7	1.0
185	88.80	0.23	0.21	0.44	1.8	0.7	1.0
186	89.12	0.22	0.20	0.42	1.7	0.7	1.0
187	89.44	0.21	0.18	0.39	1.6	0.6	0.9
188	89.76	0.20	0.17	0.37	1.6	0.6	0.9
189	90.09	0.20	0.16	0.36	1.6	0.5	0.8
190	90.41	0.20	0.16	0.36	1.6	0.5	0.8
1000 mg/L Flopaam 3630S at 10.48 ft/day							
191	90.84	1.85	0.70	2.55	14.5	2.3	5.9
192	91.27	2.00	1.87	3.87	15.6	6.2	9.0
193	91.71	2.14	2.31	4.45	16.7	7.6	10.3
194	92.14	2.15	2.35	4.50	16.8	7.8	10.5
195	92.57	2.15	2.35	4.50	16.8	7.8	10.5

Warner Linear Coreflood 6L
Incremental Resistance Factors

Sample No.	Cum V _p	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
1000 mg/L Flopaam 3630S at 3.74 ft/day							
196	92.88	0.57	0.47	1.04	12.5	4.4	6.8
197	93.18	0.55	0.50	1.05	12.1	4.6	6.8
198	93.49	0.57	0.50	1.07	12.5	4.6	7.0
199	93.80	0.59	0.51	1.10	12.9	4.7	7.2
200	94.11	0.59	0.51	1.10	12.9	4.7	7.2
1000 mg/L Flopaam 3630S at 1.12 ft/day							
201	94.75	0.27	0.19	0.46	19.7	5.9	10.0
202	95.39	0.35	0.19	0.54	25.5	5.9	11.7
203	96.03	0.41	0.23	0.64	29.9	7.1	13.9
204	96.67	0.50	0.23	0.73	36.5	7.1	15.8
205	97.31	0.51	0.24	0.75	37.2	7.4	16.3
Injection Water at 10.48 ft/day							
206	97.81	1.26	2.09	3.35	9.9	6.9	7.8
207	98.30	0.86	0.55	1.41	6.7	1.8	3.3
208	98.80	0.75	0.29	1.04	5.9	1.0	2.4
209	99.29	0.71	0.24	0.95	5.6	0.8	2.2
210	99.79	0.68	0.24	0.92	5.3	0.8	2.1
211	100.28	0.66	0.22	0.88	5.2	0.7	2.0
212	100.78	0.65	0.22	0.87	5.1	0.7	2.0
213	101.28	0.65	0.21	0.86	5.1	0.7	2.0
214	101.77	0.65	0.20	0.85	5.1	0.7	2.0
215	102.27	0.65	0.20	0.85	5.1	0.7	2.0
216	102.76	0.65	0.20	0.85	5.1	0.7	2.0
217	103.26	0.65	0.20	0.85	5.1	0.7	2.0
218	103.75	0.65	0.20	0.85	5.1	0.7	2.0
219	104.25	0.65	0.20	0.85	5.1	0.7	2.0
220	104.74	0.65	0.20	0.85	5.1	0.7	2.0

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 1L

Fluid Injected	Cumulative Effluent V _p	Aqueous Volume mL	NaOH wt%	Na ₂ CO ₃ wt%	Petronate EOR 2095 wt%	Flopaam 3630S mg/L
Injection Water	31.19	327.76	0.000	0.000	0.000	0
1.0 wt% NaOH	35.76	48.30	0.646	0.044	0.000	0
1.0 wt% NaOH	40.18	46.80	0.841	0.043	0.018	0
+ 0.1 wt% Petronate EOR 2095	42.53	25.00	0.820	0.051	0.033	0
Injection Water	47.23	49.00	0.018	0.040	0.048	0
	49.53	24.30	0.000	0.000	0.006	0
	52.99	36.80	0.000	0.000	0.005	0
1.0 wt% NaOH	56.00	31.20	0.512	0.045	0.006	980
+ 0.1 wt% Petronate EOR 2095	58.18	23.15	0.844	0.056	0.004	1490
+ 1500 mg/L Flopaam 3630S	60.12	20.30	0.847	0.055	0.007	1519
Injection Water	62.32	23.22	0.284	0.044	0.162	595
	63.90	16.78	0.000	0.037	0.039	24
	65.37	15.60	0.000	0.000	0.017	0
1.0 wt% NaOH	70.06	49.76	0.601	0.049	0.025	797
+ 0.1 wt% Petronate EOR 2095	71.73	17.79	0.869	0.048	0.016	981
+ 1000 mg/L Flopaam 3630S	72.90	12.40	0.800	0.045	0.014	1019
Injection Water	75.72	29.99	0.194	0.041	0.048	330
	77.13	15.00	0.000	0.000	0.033	0
1.0 wt% NaOH	78.30	12.40	0.000	0.000	0.025	0
+ 0.1 wt% Petronate EOR 2095	83.64	56.79	0.657	0.049	0.045	428
+ 500 mg/L Flopaam 3630S	84.88	13.20	0.651	0.049	0.045	411
Injection Water	85.94	11.20	0.855	0.048	0.032	489
	89.49	37.80	0.128	0.041	0.010	139
	91.29	19.10	0.000	0.000	0.029	4
	93.08	19.00	0.000	0.000	0.023	0
1000 mg/L Flopaam 3630S	97.67	48.79	0.000	0.000	0.017	703
	100.15	26.40	0.000	0.000	0.011	937
	101.73	16.80	0.000	0.000	0.008	933
Injection Water	105.42	39.20	0.000	0.000	0.010	222
	107.45	21.60	0.000	0.000	0.004	0
	109.18	18.40	0.000	0.000	0.004	0

Amount of Chemical Retained by Core

	lb/acre ft		%*
NaOH	24,447	466.52	11.8
Na ₂ CO ₃	(157,047)	(2,996.8)	---
Petronate EOR 2095	7,321	139.69	35.2
Flopaam 3630S	76	12.46	3.0
Flopaam 3630S Only	653	1.44	0.5
Core Weight	77.93 g		

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 2L

Fluid Injected	Cumulative Effluent V _p	Aqueous Volume mL	Na ₂ CO ₃ wt%	NaHCO ₃ wt%	ORS-162HF wt%	Flopaam 3530S mg/L
Injection Water	34.98	325.54	0.000	0.000	0.000	0
2.0 wt% Na ₂ CO ₃	40.30	49.70	1.741	0.117	0.000	0
2.0 wt% Na ₂ CO ₃	45.29	46.80	2.188	0.000	0.020	0
+ 0.1 wt% ORS-162HF	47.95	24.90	2.297	0.000	0.068	0
Injection Water	53.26	49.90	0.441	0.000	0.040	0
	55.79	23.80	0.000	0.069	0.012	0
	59.62	36.00	0.018	0.000	0.007	0
2.0 wt% Na ₂ CO ₃	63.12	32.80	1.734	0.000	0.011	951
+ 0.1 wt% ORS-162HF	65.46	21.90	2.302	0.000	0.017	1464
+ 1500 mg/L Flopaam 3530S	67.63	19.80	2.304	0.000	0.017	1511
Injection Water	70.11	23.10	0.926	0.009	0.047	511
	71.88	16.60	0.016	0.046	0.046	0
	73.48	15.00	0.000	0.043	0.026	0
2.0 wt% Na ₂ CO ₃	79.00	51.98	1.874	0.000	0.014	705
+ 0.1 wt% ORS-162HF	80.85	17.39	2.280	0.000	0.031	930
+ 1000 mg/L Flopaam 3530S	82.28	13.49	2.304	0.000	0.032	948
Injection Water	85.47	30.00	0.753	0.000	0.040	282
	87.07	15.00	0.034	0.000	0.040	0
2.0 wt% Na ₂ CO ₃	88.45	13.00	0.027	0.000	0.030	0
+ 0.1 wt% ORS-162HF	94.68	58.60	1.939	0.000	0.019	372
+ 500 mg/L Flopaam 3530S	95.97	12.20	1.857	0.000	0.020	371
Injection Water	97.12	10.80	2.251	0.000	0.022	459
	101.03	36.80	0.579	0.023	0.110	99
	103.07	19.20	0.038	0.000	0.033	0
	105.09	19.00	0.020	0.000	0.022	0
1000 mg/L Flopaam 3530S	110.06	46.79	0.013	0.030	0.023	741
	112.68	24.60	0.042	0.000	0.014	1039
	114.44	16.60	0.016	0.028	0.011	1031
Injection Water	118.60	39.10	0.000	0.036	0.013	204
	120.83	21.00	0.000	0.021	0.009	0
	122.76	18.20	0.027	0.000	0.007	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
Na ₂ CO ₃	4,623	78.21	0.8
ORS-162HF	7,082	119.81	30.9
Flopaam 3530S	935	18.70	4.8
Flopaam 3530S Only	1106	15.81	5.6

Core Weight 80.45 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 3L

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	Na_2CO_3 wt%	NaOH wt%	Petronate EOR 2095 wt%	Alcoflood 1275A mg/L
Injection Water	42.40	397.26	0.000	0.000	0.000	0
0.5 wt% NaOH + 0.25 wt% Na_2CO_3	46.90	42.39	0.608	0.212	0.000	0
	49.44	23.99	0.695	0.345	0.000	0
0.5 wt% NaOH + 0.25 wt% Na_2CO_3 + 0.1 wt% EOR 2095	53.19	34.90	0.688	0.366	0.014	0
Injection Water	57.09	36.50	0.203	0.000	0.027	0
	59.16	19.59	0.014	0.000	0.009	0
	61.26	19.76	0.014	0.000	0.008	0
0.5 wt% NaOH + 0.25 wt% Na_2CO_3	65.37	37.50	0.512	0.238	0.009	1013
+ 0.1 wt% Petronate EOR 2095	66.73	12.60	0.779	0.318	0.007	1504
+ 1500 mg/L Alcoflood 1275A	68.76	19.10	0.762	0.330	0.008	1532
Injection Water	71.35	24.10	0.523	0.093	0.117	603
	73.15	16.90	0.058	0.000	0.021	3
	75.22	19.50	0.043	0.000	0.012	0
0.5 wt% NaOH + 0.25 wt% Na_2CO_3	79.10	36.40	0.448	0.144	0.016	620
+ 0.1 wt% Petronate EOR 2095	81.35	21.19	0.793	0.302	0.011	1034
+ 1000 mg/L Alcoflood 1275A	83.72	22.38	0.797	0.317	0.011	1046
Injection Water	88.18	42.10	0.174	0.000	0.136	221
	89.89	16.20	0.018	0.000	0.018	1
	91.14	11.80	0.051	0.000	0.015	0
0.5 wt% NaOH + 0.25 wt% Na_2CO_3	93.56	22.80	0.461	0.128	0.021	155
+ 0.1 wt% Petronate EOR 2095	95.64	19.60	0.523	0.563	0.013	391
+ 500 mg/L Alcoflood 1275A	97.92	21.50	0.472	0.599	0.009	395
Injection Water	102.80	46.00	0.145	0.000	0.098	58
	105.20	22.70	0.014	0.000	0.012	0
	107.61	22.70	0.014	0.000	0.011	0
	108.88	12.00	0.014	0.000	0.009	0
1000 mg/L Alcoflood 1275A	112.14	30.79	0.054	0.000	0.011	639
	114.36	21.00	0.056	0.000	0.011	946
Injection Water	116.33	18.58	0.031	0.000	0.010	950
	120.53	39.59	0.029	0.000	0.014	231
	124.34	36.00	0.023	0.000	0.007	0
	126.82	23.40	0.014	0.000	0.006	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	8,926	164.56	12.2
Na_2CO_3	5,264	97.04	3.3
Petronate EOR 2095	2,831	52.19	17.0
Alcoflood 1275A	1,594	34.44	9.5
Alcoflood 1275A Only	1,868	29.38	10.7
Core Weight	81.68 g		

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 4L

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Na ₂ CO ₃ wt%	ORS-97HF wt%	Cyanatrol 770 mg/L
Injection Water	39.26	393.97	0.000	0.000	0.000	0
0.75 wt% NaOH	43.34	40.80	0.424	0.392	0.000	0
	45.75	24.20	0.609	0.399	0.000	0
0.75 wt% NaOH + 0.1 wt% ORS-97H	49.22	34.98	0.583	0.448	0.017	0
Injection Water	52.98	37.80	0.009	0.348	0.017	0
	54.91	19.45	0.000	0.000	0.007	0
	56.86	19.70	0.000	0.000	0.004	0
0.75 wt% NaOH	61.68	37.50	0.361	0.439	0.005	937
+ 0.1 wt% ORS-97HF	62.95	12.70	0.563	0.508	0.008	1501
+ 1500 mg/L Cyanatrol 770	64.87	19.20	0.560	0.512	0.007	1575
Injection Water	67.23	22.80	0.172	0.461	0.119	462
	68.96	17.50	0.000	0.000	0.029	10
	70.89	19.50	0.000	0.000	0.013	0
0.75 wt% NaOH	74.42	35.58	0.332	0.466	0.014	572
+ 0.1 wt% ORS-97HF	76.63	22.39	0.561	0.499	0.012	1054
+ 1000 mg/L Cyanatrol 770	78.87	22.58	0.575	0.508	0.011	1039
Injection Water	83.07	42.38	0.061	0.414	0.117	130
	84.57	15.20	0.000	0.000	0.038	13
	85.74	11.80	0.000	0.000	0.015	0
0.75 wt% NaOH	88.10	23.79	0.059	0.566	0.036	200
+ 0.1 wt% ORS-97HF	90.00	19.19	0.264	0.784	0.031	621
+ 500 mg/L Cyanatrol 770	92.16	21.78	0.316	0.746	0.015	643
Injection Water	95.60	34.79	0.000	0.443	0.100	198
	97.85	22.70	0.000	0.000	0.017	0
	100.25	24.20	0.000	0.000	0.012	0
	101.45	12.09	0.000	0.000	0.009	0
1000 mg/L Cyanatrol 770	104.42	29.98	0.000	0.000	0.009	615
	106.53	21.39	0.000	0.000	0.010	974
Injection Water	108.40	18.79	0.000	0.000	0.010	984
	112.34	39.79	0.000	0.000	0.012	12
	115.94	36.40	0.000	0.000	0.009	0
	118.24	23.20	0.000	0.000	0.007	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	36,104	684.00	27.6
Na ₂ CO ₃	(143,751)	(2,723.4)	---
ORS-97HF	3,849	72.93	22.6
Cyanatrol 770	810	30.17	8.3
Cyanatrol 770 Only	1,592	15.34	5.5
Core Weight	78.77 g		

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 5L

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Alcoflood 1275A mg/L
Injection Water	40.23	393.97	0.000	0.027	0.000	0
0.75 wt% NaOH	44.09	40.58	0.428	0.557	0.014	0
0.75 wt% NaOH + 0.1 wt% ORS-97HF	48.44	45.75	0.623	0.561	0.022	0
Injection Water	51.80	34.90	0.087	0.441	0.053	0
	53.89	21.96	0.000	0.047	0.011	0
	55.03	11.99	0.000	0.098	0.009	0
0.75 wt% NaOH	57.52	25.60	0.289	0.512	0.013	400
+ 0.1 wt% ORS-97HF	60.56	31.70	0.608	0.663	0.019	1604
+ 1500 mg/L Alcoflood 1275A	61.85	13.58	0.595	0.672	0.019	1598
Injection Water	64.04	22.98	0.265	0.512	0.038	723
	65.60	16.40	0.000	0.080	0.073	5
	66.91	13.80	0.000	0.073	0.036	0
0.75 wt% NaOH	69.69	29.18	0.418	0.548	0.025	364
+ 0.1 wt% ORS-97HF	71.78	22.00	0.864	0.735	0.022	990
+ 1000 mg/L Alcoflood 1275A	74.33	26.80	0.914	0.646	0.022	1014
Injection Water	77.29	31.19	0.234	0.512	0.032	354
	78.39	11.60	0.000	0.107	0.070	5
	79.61	12.80	0.000	0.091	0.057	0
0.75 wt% NaOH	81.66	21.60	0.131	0.565	0.023	188
+ 0.1 wt% ORS-97HF	83.58	20.20	0.571	0.668	0.015	507
+ 500 mg/L Alcoflood 1275A	85.88	24.20	0.632	0.614	0.014	530
Injection Water	88.26	25.00	0.171	0.641	0.019	217
	89.50	13.00	0.000	0.060	0.019	5
	90.59	11.50	0.000	0.089	0.011	0
1000 mg/L Alcoflood 1275A	92.87	24.00	0.000	0.109	0.056	739
	94.26	14.60	0.000	0.100	0.051	959
	97.34	32.40	0.000	0.078	0.040	979
Injection Water	101.75	46.40	0.000	0.082	0.044	312
	103.23	15.60	0.000	0.078	0.008	1
	104.55	13.90	0.000	0.082	0.007	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	21,118	400.80	14.1
ORS-97HF	4,612	87.53	25.6
Alcoflood 1275A	851	16.15	5.8
Alcoflood 1275A Only	379	7.20	1.9
Core Weight	76.63 g		

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Linear Corelood 6L

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Injection Water	38.19	393.97	0.000	0.000	0.000	0
1.0 wt% NaOH	42.12	39.85	0.593	0.530	0.000	0
1.0 wt% NaOH + 0.1 wt% ORS-97HF	46.66	46.10	0.895	0.623	0.006	0
Injection Water	50.22	36.16	0.159	0.463	0.065	0
	52.42	22.40	0.000	0.042	0.013	0
	53.65	12.50	0.000	0.040	0.007	0
1.0 wt% NaOH	56.01	23.40	0.385	0.557	0.011	417
+ 0.1 wt% ORS-97HF	59.18	32.00	0.927	0.610	0.015	1520
+ 1500 mg/L Flopaam 3630S	60.52	13.58	1.117	0.922	0.017	1601
Injection Water	62.78	22.99	0.349	0.712	0.039	664
	64.41	16.60	0.000	0.127	0.019	30
	65.81	14.19	0.000	0.098	0.038	0
1.0 wt% NaOH	68.56	27.99	0.349	0.632	0.017	682
+ 0.1 wt% ORS-97HF	70.76	22.39	0.890	0.677	0.014	1071
+ 1000 mg/L Flopaam 3630S	73.40	26.79	0.894	0.699	0.015	1084
Injection Water	76.54	31.99	0.277	0.521	0.036	373
	77.74	12.20	0.000	0.056	0.016	0
	79.08	13.60	0.000	0.053	0.043	0
1.0 wt% NaOH	81.09	20.40	0.165	0.565	0.012	230
+ 0.1 wt% ORS-97HF	83.15	21.00	0.906	0.637	0.018	496
+ 500 mg/L Flopaam 3630S	85.57	24.60	0.929	0.632	0.022	515
Injection Water	88.10	25.70	0.368	0.588	0.191	213
	89.36	12.80	0.000	0.073	0.114	3
	90.41	10.70	0.000	0.071	0.052	0
1000 mg/L Flopaam 3630S	92.57	21.99	0.000	0.087	0.071	502
	94.11	15.58	0.000	0.073	0.054	928
	97.31	32.59	0.000	0.065	0.032	952
Injection Water	101.95	47.20	0.000	0.042	0.014	219
	103.47	15.40	0.000	0.049	0.012	0
	104.74	13.00	0.000	0.053	0.035	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	1,074	20.2	0.6
Na_2CO_3	(183,723)	(3,456.0)	---
ORS-97HF	3,177	59.8	17.7
Flopaam 3630S	105	2.0	0.7
Flopaam 3630S Only	354	6.7	1.8
Core Weight	77.68 g		

* - percent of injected chemical retained by rock

Injected Fluids Summary: Warner Radial Corefloods

Coreflood Number	1R	2R	3R	4R	5R	6R	7R	8R	9R	10R	11R	12R	13R	14R
Warner Crude Oil														
Well	00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4													
Viscosity at 35° C	cp	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0	52.0
Produced Water														
Viscosity at 35° C	cp	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Unsoftened Injection Water														
Viscosity at 35° C	cp	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69	0.69
Alkaline-Surfactant-Polymer Solution														
Water														
Alkaline Type	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection	Softened Injection
Alkali Concentration	NaOH	NaOH	NaOH	Na ₂ CO ₃	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH
	0.75	0.5	0.5	2.0	0.75	0.625	0.75	0.5	0.625	0.625	0.75	1.0	0.75	0.75
Alkaline Type		Na ₂ CO ₃				Na ₂ CO ₃		Na ₂ CO ₃						
Alkali Concentration		0.25	0.25			0.5		0.25						
Surfactant Type	ORS-164HF	Petronate EOR 2095	Petrostep B-100	ORS-162HF	ORS-97HF	ORS-162HF	ORS-97HF	Petrostep B-100	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF
Surfactant Concentration	wt%	0.1	0.1	0.1	0.1	0.1	0.1	0.05	0.1	0.1	0.15	0.1	0.15	0.15
Surfactant Type			Stepantian AS-1216					Stepantian AS-1216						
Surfactant Concentration	wt%		0.05					0.05						
Polymer Type	Flopaam 3630S	Flopaam 3630S	Alcoflood 1275A	Alcoflood 1275A	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Alcoflood 1275A	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S
Polymer Concentration	mg/L	1200	1200	1500	1500	1200	1200	1200	1200	1200	1200	1200	1200	1200
Viscosity at 35° C	cp	25.1	20.6	22.8	17.8	23.2	20.3	19.4	15.9	22.2	22.8	18.2	19.6	20.5
Screen Factor at 35° C		53.6	48.2	28.8	24.3	51.1	47.7	68.7	32.6	69.7	66.0	60.6	56.3	71.4
Alkaline-Surfactant-Polymer Solution														
Water														
Alkaline Type											Softened Injection			Softened Injection
Alkali Concentration	wt%										NaOH	NaOH		NaOH
											0.75	0.75		0.75
Surfactant Type											ORS-97HF			ORS-97HF
Surfactant Concentration	wt%										0.1	0.1		0.1
Polymer Type												Flopaam 3630S		
Polymer Concentration	mg/L											1200		1200
Viscosity at 35° C	cp											21.9		20.6
Screen Factor at 35° C												66.6		68.2
Polymer Solution														
Polymer Type	Flopaam 3630S	Flopaam 3630S	Alcoflood 1275A	Alcoflood 1275A	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Alcoflood 1275A	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S	Flopaam 3630S
Polymer Concentration	mg/L	1200	1200	1500	1500	1200	1200	1200	1200	1200	1200	1200	1200	1200
Viscosity at 35° C	cp	29.3	29.3	30.5	30.5	30.6	30.6	31.8	20.2	30.6	31.1	31.1	32.6	33.1
Screen Factor at 35° C		55.2	55.2	31.0	31.0	55.3	55.3	55.9	28.4	65.3	86.1	86.1	76.0	92.5

Performance Summary: Warner Radial Corefloods

Coreflood Number	1R	2R	3R	4R	5R	6R	7R	8R	9R	10R	11R	12R	13R	14R
Coreflood Temperature	35	35	35	35	35	35	35	35	35	35	35	35	35	35
Core Properties														
Core Restoration Technique	Restored Oil-Wet	Restored Oil-Wet	Restored Oil-Wet	Restored Oil-Wet	Restored Oil-Wet	Restored Oil-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet	Restored Water-Wet
Well	00/04-21-007-16W4 00/04-21-007-16W4 02/09-20-007-16W4 02/09-20-007-16W4 00/16-20-007-16W4 00/16-20-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 00/04-21-007-16W4 02/09-20-007-16W4 00/16-20-007-16W4 00/16-20-007-16W4 00/16-20-007-16W4 00/16-20-007-16W4 00/16-20-007-16W4													
Depth	3196.3 ft	3196.7	3246.4	3246.7	3232.5	3233.6	3199.8	3200.8	3215.6	3234.9	3220.7	3220.9	3246.9	3237.8
Pore Volume	78.90 mL	80.10	76.96	80.74	75.12	74.79	74.19	70.49	76.68	73.19	79.58	76.59	80.08	80.78
Porosity	25.6 %	25.8	24.6	25.9	23.9	23.7	24.3	22.7	24.8	23.3	25.4	24.6	25.3	25.9
Effective Oil Permeability	274 md	431	337	474	145	127	875	530	333	481	1180	837	1041	1294
Effective Permeability to Water	14.8 md	36.1	14.9	24.9	15.1	21.0	16.7	13.9	6.6	17.0	23.1	18.8	38.0	37.2
Relative Permeability to Water	0.054 k _{rw} /k _{ro}	0.084	0.044	0.053	0.104	0.165	0.019	0.026	0.020	0.035	0.020	0.022	0.036	0.029
Absolute Permeability	365 md	675	358	678	688	677	966	432	874	790	417	1124	429	1378
Mobility Ratio	4.1	6.3	3.3	4.0	7.8	12.5	1.4	2.0	1.5	2.7	1.5	1.7	2.7	2.2
Fluids Injected														
Produced Water	V _p	3.122	3.238	3.099	2.976	3.139	3.133	3.694	3.998	4.213	4.485	3.771	3.908	4.235
Alkali-Surfactant-Polymer														
Alkaline Type	NaOH	NaOH	NaOH	Na ₂ CO ₃	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH	NaOH
Alkaline Concentration	0.75 wt%	0.5	0.5	2.0	0.75	0.625	0.75	0.5	0.625	0.625	0.75	1.0	0.75	0.75
Alkaline Type	---	Na ₂ CO ₃	Na ₂ CO ₃	---	---	Na ₂ CO ₃	---	Na ₂ CO ₃	---	---	---	---	---	---
Alkaline Concentration	---	0.25	0.25	---	---	0.5	---	---	---	---	---	---	---	---
Surfactant Type	ORS-164HF	Petronate EOR 209E	Petrostep B-100	ORS-162HF	ORS-97HF	ORS-162HF	ORS-97HF	Petrostep B-100	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF	ORS-97HF
Surfactant Concentration	0.1 wt%	0.1	0.05	0.1	0.1	0.1	0.1	0.05	0.1	0.1	0.15	0.1	0.15	0.15
Surfactant Type	---	---	Stepantian AS-1216	---	---	---	---	Stepantian AS-1216	---	---	---	---	---	---
Surfactant Concentration	---	---	0.05	---	---	---	---	0.05	---	---	---	---	---	---
Polymer T Type	Fiopaam 3630S	Fiopaam 3630S	Alcoflood 1275A	Alcoflood 1275A	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Alcoflood 1275A	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S
Polymer Concentration	1200 mg/L	1200	1500	1500	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Polymer Concentration	0.341 V _p	0.331	0.333	0.321	0.327	0.301	0.324	0.343	0.311	0.355	0.296	0.053	0.340	0.152
Alkali-Surfactant-Polymer														
Alkaline Type	---	---	---	---	---	---	---	---	---	---	---	NaOH	---	NaOH
Alkaline Concentration	---	---	---	---	---	---	---	---	---	---	---	0.75	---	0.75
Surfactant Type	---	---	---	---	---	---	---	---	---	---	---	ORS-97HF	---	ORS-97HF
Surfactant Concentration	---	---	---	---	---	---	---	---	---	---	---	0.1	---	0.1
Polymer Type	---	---	---	---	---	---	---	---	---	---	---	Fiopaam 3630S	---	Fiopaam 3630S
Polymer Concentration	---	---	---	---	---	---	---	---	---	---	---	1200	---	1200
Polymer Concentration	---	---	---	---	---	---	---	---	---	---	---	0.252	---	0.159
Polymer														
Polymer T Type	Fiopaam 3630S	Fiopaam 3630S	Alcoflood 1275A	Alcoflood 1275A	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Alcoflood 1275A	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S	Fiopaam 3630S
Polymer Concentration	1200 mg/L	1200	1500	1500	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Polymer Concentration	0.357 V _p	0.343	0.338	0.317	0.323	0.328	0.317	0.341	0.332	0.338	0.312	0.323	0.312	0.305
Unsoftened Injection Water	2.203 V _p	2.287	2.325	2.218	2.159	2.181	3.195	3.361	2.430	2.506	2.981	3.111	2.624	2.354

Warner Radial Coreflood 1R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 78.90 ml
Initial Oil Saturation: 65.99 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Production Water at 0.51 ft/day									
1	1.99	0.00	1.99	1.99	0.00	1.99	0.03	100.0	3.0
2	4.20	0.00	4.20	6.19	0.00	6.19	0.08	100.0	9.4
3	4.30	0.30	4.00	10.49	0.30	10.19	0.13	93.0	15.4
4	4.10	1.40	2.70	14.59	1.70	12.89	0.18	65.9	19.5
5	4.30	3.30	1.00	18.89	5.00	13.89	0.24	23.3	21.0
6	4.20	3.70	0.50	23.09	8.70	14.39	0.29	11.9	21.8
7	4.30	3.90	0.40	27.39	12.60	14.79	0.35	9.3	22.4
8	4.20	3.90	0.30	31.59	16.50	15.09	0.40	7.1	22.9
9	4.30	4.00	0.30	35.89	20.50	15.39	0.45	7.0	23.3
10	4.10	3.80	0.30	39.99	24.30	15.69	0.51	7.3	23.8
11	4.20	3.90	0.30	44.19	28.20	15.99	0.56	7.1	24.2
12	4.00	3.70	0.30	48.19	31.90	16.29	0.61	7.5	24.7
13	4.10	3.85	0.25	52.29	35.75	16.54	0.66	6.1	25.1
14	4.00	3.70	0.30	56.29	39.45	16.84	0.71	7.5	25.5
15	4.10	3.90	0.20	60.39	43.35	17.04	0.77	4.9	25.8
16	4.20	4.00	0.20	64.59	47.35	17.24	0.82	4.8	26.1
17	4.10	3.90	0.20	68.69	51.25	17.44	0.87	4.9	26.4
18	4.20	4.00	0.20	72.89	55.25	17.64	0.92	4.8	26.7
19	4.30	4.05	0.25	77.19	59.30	17.89	0.98	5.8	27.1
20	4.10	3.95	0.15	81.29	63.25	18.04	1.03	3.7	27.3
21	4.10	3.90	0.20	85.39	67.15	18.24	1.08	4.9	27.6
22	4.20	4.00	0.20	89.59	71.15	18.44	1.14	4.8	27.9
23	4.20	3.95	0.25	93.79	75.10	18.69	1.19	6.0	28.3
24	4.10	3.95	0.15	97.89	79.05	18.84	1.24	3.7	28.5
25	4.20	4.05	0.15	102.09	83.10	18.99	1.29	3.6	28.8
26	4.20	4.10	0.10	106.29	87.20	19.09	1.35	2.4	28.9
27	4.00	3.90	0.10	110.29	91.10	19.19	1.40	2.5	29.1
28	3.90	3.70	0.20	114.19	94.80	19.39	1.45	5.1	29.4
29	3.80	3.60	0.20	117.99	98.40	19.59	1.50	5.3	29.7
30	3.80	3.60	0.20	121.79	102.00	19.79	1.54	5.3	30.0
31	3.90	3.75	0.15	125.69	105.75	19.94	1.59	3.8	30.2
32	3.70	3.55	0.15	129.39	109.30	20.09	1.64	4.1	30.4
33	4.00	3.90	0.10	133.39	113.20	20.19	1.69	2.5	30.6
34	4.40	4.25	0.15	137.79	117.45	20.34	1.75	3.4	30.8
35	4.40	4.25	0.15	142.19	121.70	20.49	1.80	3.4	31.1
36	4.30	4.15	0.15	146.49	125.85	20.64	1.86	3.5	31.3
37	4.20	4.00	0.20	150.69	129.85	20.84	1.91	4.8	31.6
38	4.10	3.90	0.20	154.79	133.75	21.04	1.96	4.9	31.9
39	5.00	4.85	0.15	159.79	138.60	21.19	2.03	3.0	32.1
40	6.90	6.80	0.10	166.69	145.40	21.29	2.11	1.4	32.3

Warner Radial Coreflood 1R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 78.90 ml

Initial Oil Saturation: 65.99 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Production Water at 0.51 ft/day									
41	5.20	5.10	0.10	171.89	150.50	21.39	2.18	1.9	32.4
42	5.30	5.10	0.20	177.19	155.60	21.59	2.25	3.8	32.7
43	5.30	5.20	0.10	182.49	160.80	21.69	2.31	1.9	32.9
44	5.20	5.10	0.10	187.69	165.90	21.79	2.38	1.9	33.0
45	5.60	5.50	0.10	193.29	171.40	21.89	2.45	1.8	33.2
46	5.30	5.20	0.10	198.59	176.60	21.99	2.52	1.9	33.3
47	5.20	5.10	0.10	203.79	181.70	22.09	2.58	1.9	33.5
48	5.30	5.20	0.10	209.09	186.90	22.19	2.65	1.9	33.6
49	5.20	5.10	0.10	214.29	192.00	22.29	2.72	1.9	33.8
50	5.20	5.10	0.10	219.49	197.10	22.39	2.78	1.9	33.9
51	5.10	4.90	0.20	224.59	202.00	22.59	2.85	3.9	34.2
52	4.30	4.28	0.02	228.89	206.28	22.61	2.90	0.5	34.3
53	3.60	3.59	0.01	232.49	209.87	22.62	2.95	0.3	34.3
54	5.50	5.40	0.10	237.99	215.27	22.72	3.02	1.8	34.4
55	4.30	4.25	0.05	242.29	219.52	22.77	3.07	1.2	34.5
56	4.00	3.98	0.02	246.29	223.50	22.79	3.12	0.5	34.5
0.75 wt% NaOH + 0.1 wt% ORS-164HF + 1200 mg/L Flopaam 3630S at 0.51 ft/day									
57	3.20	3.10	0.10	249.49	226.60	22.89	3.16	3.1	34.7
58	3.20	3.10	0.10	252.69	229.70	22.99	3.20	3.1	34.8
59	3.20	3.00	0.20	255.89	232.70	23.19	3.24	6.3	35.1
60	3.20	2.80	0.40	259.09	235.50	23.59	3.28	12.5	35.7
61	3.50	2.45	1.05	262.59	237.95	24.64	3.33	30.0	37.3
62	3.50	2.45	1.05	266.09	240.40	25.69	3.37	30.0	38.9
63	3.50	2.40	1.10	269.59	242.80	26.79	3.42	31.4	40.6
64	3.60	2.50	1.10	273.19	245.30	27.89	3.46	30.6	42.3
1200 mg/L Flopaam 3630S at 0.51 ft/day									
65	3.60	2.80	0.80	276.79	248.10	28.69	3.51	22.2	43.5
66	3.40	2.75	0.65	280.19	250.85	29.34	3.55	19.1	44.5
67	3.60	3.25	0.35	283.79	254.10	29.69	3.60	9.7	45.0
68	3.60	3.30	0.30	287.39	257.40	29.99	3.64	8.3	45.4
69	3.50	3.10	0.40	290.89	260.50	30.39	3.69	11.4	46.1
70	3.40	3.00	0.40	294.29	263.50	30.79	3.73	11.8	46.7
71	3.20	2.80	0.40	297.49	266.30	31.19	3.77	12.5	47.3
72	3.90	3.65	0.25	301.39	269.95	31.44	3.82	6.4	47.6
73	4.10	3.80	0.30	305.49	273.75	31.74	3.87	7.3	48.1
74	4.20	3.85	0.35	309.69	277.60	32.09	3.93	8.3	48.6
Injection Water at 0.51 ft/day									
75	4.10	3.80	0.30	313.79	281.40	32.39	3.98	7.3	49.1
76	4.40	4.05	0.35	318.19	285.45	32.74	4.03	8.0	49.6

Warner Radial Coreflood 1R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 78.90 ml

Initial Oil Saturation: 65.99 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.51 ft/day									
77	4.30	4.00	0.30	322.49	289.45	33.04	4.09	7.0	50.1
78	4.30	4.10	0.20	326.79	293.55	33.24	4.14	4.7	50.4
79	4.00	3.85	0.15	330.79	297.40	33.39	4.19	3.8	50.6
80	4.40	4.25	0.15	335.19	301.65	33.54	4.25	3.4	50.8
81	4.00	3.90	0.10	339.19	305.55	33.64	4.30	2.5	51.0
82	4.30	4.20	0.10	343.49	309.75	33.74	4.35	2.3	51.1
83	4.00	3.85	0.15	347.49	313.60	33.89	4.40	3.8	51.4
84	4.10	4.00	0.10	351.59	317.60	33.99	4.46	2.4	51.5
85	4.00	3.90	0.10	355.59	321.50	34.09	4.51	2.5	51.7
86	4.10	4.00	0.10	359.69	325.50	34.19	4.56	2.4	51.8
87	4.10	4.00	0.10	363.79	329.50	34.29	4.61	2.4	52.0
88	4.00	3.85	0.15	367.79	333.35	34.44	4.66	3.8	52.2
89	4.30	4.15	0.15	372.09	337.50	34.59	4.72	3.5	52.4
90	4.00	3.90	0.10	376.09	341.40	34.69	4.77	2.5	52.6
91	4.10	4.00	0.10	380.19	345.40	34.79	4.82	2.4	52.7
92	4.10	3.95	0.15	384.29	349.35	34.94	4.87	3.7	52.9
93	4.20	4.10	0.10	388.49	353.45	35.04	4.92	2.4	53.1
94	4.20	4.00	0.20	392.69	357.45	35.24	4.98	4.8	53.4
95	4.20	4.05	0.15	396.89	361.50	35.39	5.03	3.6	53.6
96	4.20	4.05	0.15	401.09	365.55	35.54	5.08	3.6	53.9
97	4.10	3.95	0.15	405.19	369.50	35.69	5.14	3.7	54.1
98	8.70	8.50	0.20	413.89	378.00	35.89	5.25	2.3	54.4
99	4.30	4.20	0.10	418.19	382.20	35.99	5.30	2.3	54.5
100	3.90	3.80	0.10	422.09	386.00	36.09	5.35	2.6	54.7
101	4.20	4.10	0.10	426.29	390.10	36.19	5.40	2.4	54.8
102	3.90	3.80	0.10	430.19	393.90	36.29	5.45	2.6	55.0
103	4.00	3.90	0.10	434.19	397.80	36.39	5.50	2.5	55.1
104	4.10	4.00	0.10	438.29	401.80	36.49	5.56	2.4	55.3
105	4.10	4.00	0.10	442.39	405.80	36.59	5.61	2.4	55.4
106	4.00	3.90	0.10	446.39	409.70	36.69	5.66	2.5	55.6
107	4.20	4.10	0.10	450.59	413.80	36.79	5.71	2.4	55.8
108	4.10	4.00	0.10	454.69	417.80	36.89	5.76	2.4	55.9
109	4.40	4.30	0.10	459.09	422.10	36.99	5.82	2.3	56.1
110	4.10	4.05	0.05	463.19	426.15	37.04	5.87	1.2	56.1
111	4.20	4.15	0.05	467.39	430.30	37.09	5.92	1.2	56.2
112	4.00	3.96	0.04	471.39	434.26	37.13	5.97	1.0	56.3
113	4.10	4.08	0.02	475.49	438.34	37.15	6.03	0.5	56.3
114	4.00	3.98	0.02	479.49	442.32	37.17	6.08	0.5	56.3
115	4.00	3.98	0.02	483.49	446.30	37.19	6.13	0.5	56.4

Warner Radial Coreflood 2R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.10 ml
Initial Oil Saturation: 66.84 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Production Water at 0.50 ft/day									
1	0.70	0.00	0.70	0.70	0.00	0.70	0.01	100.0	1.0
2	3.40	1.70	1.70	4.10	1.70	2.40	0.05	50.0	3.6
3	4.40	3.10	1.30	8.50	4.80	3.70	0.11	29.5	5.5
4	4.50	3.50	1.00	13.00	8.30	4.70	0.16	22.2	7.0
5	4.40	3.70	0.70	17.40	12.00	5.40	0.22	15.9	8.1
6	4.30	3.90	0.40	21.70	15.90	5.80	0.27	9.3	8.7
7	4.20	3.90	0.30	25.90	19.80	6.10	0.32	7.1	9.1
8	4.30	4.10	0.20	30.20	23.90	6.30	0.38	4.7	9.4
9	4.10	3.95	0.15	34.30	27.85	6.45	0.43	3.7	9.6
10	4.00	3.90	0.10	38.30	31.75	6.55	0.48	2.5	9.8
11	4.10	4.00	0.10	42.40	35.75	6.65	0.53	2.4	9.9
12	4.10	4.00	0.10	46.50	39.75	6.75	0.58	2.4	10.1
13	4.20	4.10	0.10	50.70	43.85	6.85	0.63	2.4	10.2
14	4.00	3.90	0.10	54.70	47.75	6.95	0.68	2.5	10.4
15	4.10	4.00	0.10	58.80	51.75	7.05	0.73	2.4	10.5
16	4.30	4.20	0.10	63.10	55.95	7.15	0.79	2.3	10.7
17	4.20	4.10	0.10	67.30	60.05	7.25	0.84	2.4	10.8
18	4.10	4.00	0.10	71.40	64.05	7.35	0.89	2.4	11.0
19	4.20	4.10	0.10	75.60	68.15	7.45	0.94	2.4	11.1
20	4.10	4.00	0.10	79.70	72.15	7.55	1.00	2.4	11.3
21	4.20	4.05	0.15	83.90	76.20	7.70	1.05	3.6	11.5
22	4.30	4.10	0.20	88.20	80.30	7.90	1.10	4.7	11.8
23	4.00	3.90	0.10	92.20	84.20	8.00	1.15	2.5	12.0
24	4.10	4.00	0.10	96.30	88.20	8.10	1.20	2.4	12.1
25	4.10	4.00	0.10	100.40	92.20	8.20	1.25	2.4	12.3
26	4.20	4.15	0.05	104.60	96.35	8.25	1.31	1.2	12.3
27	2.80	2.70	0.10	107.40	99.05	8.35	1.34	3.6	12.5
28	4.50	4.45	0.05	111.90	103.50	8.40	1.40	1.1	12.6
29	1.90	1.85	0.05	113.80	105.35	8.45	1.42	2.6	12.6
30	3.80	3.70	0.10	117.60	109.05	8.55	1.47	2.6	12.8
31	4.00	3.90	0.10	121.60	112.95	8.65	1.52	2.5	12.9
32	0.20	0.20	0.00	121.80	113.15	8.65	1.52	0.0	12.9
33	10.40	10.00	0.40	132.20	123.15	9.05	1.65	3.8	13.5
34	4.10	4.00	0.10	136.30	127.15	9.15	1.70	2.4	13.7
35	4.30	4.20	0.10	140.60	131.35	9.25	1.76	2.3	13.8
36	3.90	3.80	0.10	144.50	135.15	9.35	1.80	2.6	14.0
37	6.00	5.85	0.15	150.50	141.00	9.50	1.88	2.5	14.2
38	6.00	5.90	0.10	156.50	146.90	9.60	1.95	1.7	14.4
39	5.90	5.80	0.10	162.40	152.70	9.70	2.03	1.7	14.5
40	6.10	5.95	0.15	168.50	158.65	9.85	2.10	2.5	14.7

Warner Radial Coreflood 2R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.10 ml

Initial Oil Saturation: 66.84 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Production Water at 0.50 ft/day									
41	5.80	5.70	0.10	174.30	164.35	9.95	2.18	1.7	14.9
42	5.70	5.60	0.10	180.00	169.95	10.05	2.25	1.8	15.0
43	5.80	5.75	0.05	185.80	175.70	10.10	2.32	0.9	15.1
44	6.00	5.90	0.10	191.80	181.60	10.20	2.39	1.7	15.3
45	5.70	5.60	0.10	197.50	187.20	10.30	2.47	1.8	15.4
46	6.20	6.10	0.10	203.70	193.30	10.40	2.54	1.6	15.6
47	6.00	5.90	0.10	209.70	199.20	10.50	2.62	1.7	15.7
48	5.90	5.80	0.10	215.60	205.00	10.60	2.69	1.7	15.9
49	5.80	5.70	0.10	221.40	210.70	10.70	2.76	1.7	16.0
50	5.60	5.57	0.03	227.00	216.27	10.73	2.83	0.5	16.1
51	5.50	5.49	0.01	232.50	221.76	10.74	2.90	0.2	16.1
52	5.40	5.30	0.10	237.90	227.06	10.84	2.97	1.9	16.2
53	4.10	4.09	0.01	242.00	231.15	10.85	3.02	0.2	16.2
54	3.30	3.29	0.01	245.30	234.44	10.86	3.06	0.3	16.2
55	5.40	5.39	0.01	250.70	239.83	10.87	3.13	0.2	16.3
56	4.40	4.38	0.02	255.10	244.21	10.89	3.18	0.5	16.3
57	4.30	4.29	0.01	259.40	248.50	10.90	3.24	0.2	16.3
0.50 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% EOR 2095 + 1200 mg/L Flopaam 3630S at 0.50 ft/day									
58	3.00	2.95	0.05	262.40	251.45	10.95	3.28	1.7	16.4
59	1.50	1.20	0.30	263.90	252.65	11.25	3.29	20.0	16.8
60	3.60	2.40	1.20	267.50	255.05	12.45	3.34	33.3	18.6
61	3.50	1.95	1.55	271.00	257.00	14.00	3.38	44.3	20.9
62	3.50	1.90	1.60	274.50	258.90	15.60	3.43	45.7	23.3
63	3.80	1.95	1.85	278.30	260.85	17.45	3.47	48.7	26.1
64	3.70	2.00	1.70	282.00	262.85	19.15	3.52	45.9	28.7
65	3.90	2.10	1.80	285.90	264.95	20.95	3.57	46.2	31.3
1200 mg/L Flopaam 3630S at 0.50 ft/day									
66	3.20	1.90	1.30	289.10	266.85	22.25	3.61	40.6	33.3
67	3.60	2.20	1.40	292.70	269.05	23.65	3.65	38.9	35.4
68	3.60	2.70	0.90	296.30	271.75	24.55	3.70	25.0	36.7
69	3.30	2.25	1.05	299.60	274.00	25.60	3.74	31.8	38.3
70	3.60	2.50	1.10	303.20	276.50	26.70	3.79	30.6	39.9
71	3.40	2.45	0.95	306.60	278.95	27.65	3.83	27.9	41.4
72	3.40	2.35	1.05	310.00	281.30	28.70	3.87	30.9	42.9
73	3.40	2.65	0.75	313.40	283.95	29.45	3.91	22.1	44.1
Injection Water at 0.50 ft/day									
74	4.80	3.60	1.20	318.20	287.55	30.65	3.97	25.0	45.9
75	4.50	3.80	0.70	322.70	291.35	31.35	4.03	15.6	46.9
76	3.80	3.35	0.45	326.50	294.70	31.80	4.08	11.8	47.6

Warner Radial Coreflood 2R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.10 ml
Initial Oil Saturation: 66.84 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.50 ft/day									
77	4.40	4.00	0.40	330.90	298.70	32.20	4.13	9.1	48.2
78	4.30	3.95	0.35	335.20	302.65	32.55	4.18	8.1	48.7
79	4.10	3.80	0.30	339.30	306.45	32.85	4.24	7.3	49.1
80	4.20	3.95	0.25	343.50	310.40	33.10	4.29	6.0	49.5
81	4.20	3.95	0.25	347.70	314.35	33.35	4.34	6.0	49.9
82	4.20	4.05	0.15	351.90	318.40	33.50	4.39	3.6	50.1
83	4.00	3.85	0.15	355.90	322.25	33.65	4.44	3.8	50.3
84	4.10	4.00	0.10	360.00	326.25	33.75	4.49	2.4	50.5
85	4.30	4.15	0.15	364.30	330.40	33.90	4.55	3.5	50.7
86	4.10	4.00	0.10	368.40	334.40	34.00	4.60	2.4	50.9
87	4.10	3.95	0.15	372.50	338.35	34.15	4.65	3.7	51.1
88	4.10	4.00	0.10	376.60	342.35	34.25	4.70	2.4	51.2
89	4.10	3.95	0.15	380.70	346.30	34.40	4.75	3.7	51.5
90	4.10	4.00	0.10	384.80	350.30	34.50	4.80	2.4	51.6
91	4.10	4.00	0.10	388.90	354.30	34.60	4.86	2.4	51.8
92	4.00	3.90	0.10	392.90	358.20	34.70	4.91	2.5	51.9
93	4.20	4.10	0.10	397.10	362.30	34.80	4.96	2.4	52.1
94	4.10	4.00	0.10	401.20	366.30	34.90	5.01	2.4	52.2
95	4.20	4.05	0.15	405.40	370.35	35.05	5.06	3.6	52.4
96	4.10	4.05	0.05	409.50	374.40	35.10	5.11	1.2	52.5
97	4.00	3.97	0.03	413.50	378.37	35.13	5.16	0.7	52.6
98	8.50	8.35	0.15	422.00	386.72	35.28	5.27	1.8	52.8
99	4.20	4.00	0.20	426.20	390.72	35.48	5.32	4.8	53.1
100	4.20	4.18	0.02	430.40	394.90	35.50	5.37	0.5	53.1
101	4.10	4.05	0.05	434.50	398.95	35.55	5.42	1.2	53.2
102	4.10	4.05	0.05	438.60	403.00	35.60	5.48	1.2	53.3
103	4.10	4.05	0.05	442.70	407.05	35.65	5.53	1.2	53.3
104	4.10	4.05	0.05	446.80	411.10	35.70	5.58	1.2	53.4
105	4.20	4.10	0.10	451.00	415.20	35.80	5.63	2.4	53.6
106	4.10	4.09	0.01	455.10	419.29	35.81	5.68	0.2	53.6
107	4.00	3.90	0.10	459.10	423.19	35.91	5.73	2.5	53.7
108	4.00	3.98	0.02	463.10	427.17	35.93	5.78	0.5	53.8
109	4.10	4.05	0.05	467.20	431.22	35.98	5.83	1.2	53.8
110	4.20	4.10	0.10	471.40	435.32	36.08	5.89	2.4	54.0
111	4.10	4.05	0.05	475.50	439.37	36.13	5.94	1.2	54.1
112	4.50	4.46	0.04	480.00	443.83	36.17	5.99	0.9	54.1
113	4.40	4.38	0.02	484.40	448.21	36.19	6.05	0.5	54.1
114	4.20	4.19	0.01	488.60	452.40	36.20	6.10	0.2	54.2
115	4.00	4.00	0.00	492.60	456.40	36.20	6.15	0.0	54.2
116	4.00	4.00	0.00	496.60	460.40	36.20	6.20	0.0	54.2

Warner Radial Coreflood 3R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.96 ml

Initial Oil Saturation: 60.09 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.54 ft/day									
1	0.32	0.00	0.32	0.32	0.00	0.32	0.00	100.0	0.5
2	4.20	0.20	4.00	4.52	0.20	4.32	0.06	95.2	7.2
3	4.20	0.70	3.50	8.72	0.90	7.82	0.11	83.3	13.0
4	4.20	1.10	3.10	12.92	2.00	10.92	0.17	73.8	18.2
5	4.40	3.10	1.30	17.32	5.10	12.22	0.23	29.5	20.3
6	4.30	3.40	0.90	21.62	8.50	13.12	0.28	20.9	21.8
7	4.30	3.50	0.80	25.92	12.00	13.92	0.34	18.6	23.2
8	4.20	3.50	0.70	30.12	15.50	14.62	0.39	16.7	24.3
9	4.20	3.60	0.60	34.32	19.10	15.22	0.45	14.3	25.3
10	4.30	3.80	0.50	38.62	22.90	15.72	0.50	11.6	26.2
11	4.40	4.00	0.40	43.02	26.90	16.12	0.56	9.1	26.8
12	4.00	3.70	0.30	47.02	30.60	16.42	0.61	7.5	27.3
13	4.30	3.90	0.40	51.32	34.50	16.82	0.67	9.3	28.0
14	4.20	3.90	0.30	55.52	38.40	17.12	0.72	7.1	28.5
15	4.30	4.00	0.30	59.82	42.40	17.42	0.78	7.0	29.0
16	4.20	3.95	0.25	64.02	46.35	17.67	0.83	6.0	29.4
17	4.10	3.85	0.25	68.12	50.20	17.92	0.89	6.1	29.8
18	4.30	4.00	0.30	72.42	54.20	18.22	0.94	7.0	30.3
19	4.20	3.95	0.25	76.62	58.15	18.47	1.00	6.0	30.7
20	4.10	3.80	0.30	80.72	61.95	18.77	1.05	7.3	31.2
21	4.30	4.00	0.30	85.02	65.95	19.07	1.10	7.0	31.7
22	4.40	4.20	0.20	89.42	70.15	19.27	1.16	4.5	32.1
23	4.20	3.95	0.25	93.62	74.10	19.52	1.22	6.0	32.5
24	4.30	4.05	0.25	97.92	78.15	19.77	1.27	5.8	32.9
25	4.10	3.90	0.20	102.02	82.05	19.97	1.33	4.9	33.2
26	4.40	4.20	0.20	106.42	86.25	20.17	1.38	4.5	33.6
27	4.20	4.00	0.20	110.62	90.25	20.37	1.44	4.8	33.9
28	4.40	4.15	0.25	115.02	94.40	20.62	1.49	5.7	34.3
29	4.20	4.00	0.20	119.22	98.40	20.82	1.55	4.8	34.6
30	4.10	3.95	0.15	123.32	102.35	20.97	1.60	3.7	34.9
31	4.30	4.20	0.10	127.62	106.55	21.07	1.66	2.3	35.1
32	4.30	4.10	0.20	131.92	110.65	21.27	1.71	4.7	35.4
33	4.30	4.15	0.15	136.22	114.80	21.42	1.77	3.5	35.6
34	4.20	4.10	0.10	140.42	118.90	21.52	1.82	2.4	35.8
35	4.30	4.20	0.10	144.72	123.10	21.62	1.88	2.3	36.0
36	4.20	4.10	0.10	148.92	127.20	21.72	1.94	2.4	36.1
37	4.20	4.10	0.10	153.12	131.30	21.82	1.99	2.4	36.3
38	4.10	4.00	0.10	157.22	135.30	21.92	2.04	2.4	36.5
39	4.40	4.30	0.10	161.62	139.60	22.02	2.10	2.3	36.6
40	4.40	4.32	0.08	166.02	143.92	22.10	2.16	1.8	36.8

Warner Radial Coreflood 3R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.96 ml
Initial Oil Saturation: 60.09 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.54 ft/day									
41	4.10	4.06	0.04	170.12	147.98	22.14	2.21	1.0	36.8
42	4.30	4.20	0.10	174.42	152.18	22.24	2.27	2.3	37.0
43	4.30	4.20	0.10	178.72	156.38	22.34	2.32	2.3	37.2
44	4.40	4.30	0.10	183.12	160.68	22.44	2.38	2.3	37.3
45	4.20	4.10	0.10	187.32	164.78	22.54	2.43	2.4	37.5
46	4.20	4.10	0.10	191.52	168.88	22.64	2.49	2.4	37.7
47	4.30	4.27	0.03	195.82	173.15	22.67	2.54	0.7	37.7
48	4.30	4.20	0.10	200.12	177.35	22.77	2.60	2.3	37.9
49	4.40	4.30	0.10	204.52	181.65	22.87	2.66	2.3	38.1
50	4.20	4.10	0.10	208.72	185.75	22.97	2.71	2.4	38.2
51	4.30	4.23	0.07	213.02	189.98	23.04	2.77	1.6	38.3
52	4.20	4.12	0.08	217.22	194.10	23.12	2.82	1.9	38.5
53	4.20	4.10	0.10	221.42	198.20	23.22	2.88	2.4	38.6
54	4.20	4.10	0.10	225.62	202.30	23.32	2.93	2.4	38.8
55	4.20	4.15	0.05	229.82	206.45	23.37	2.99	1.2	38.9
56	4.40	4.37	0.03	234.22	210.82	23.40	3.04	0.7	38.9
57	4.30	4.28	0.02	238.52	215.10	23.42	3.10	0.5	39.0
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.05 wt% Petrostep B-100 + 0.05 wt% Stepanan AS-1216 + 1500 mg/L Alcoflood 1275A at 0.54 ft/day									
58	4.70	4.62	0.08	243.22	219.72	23.50	3.16	1.7	39.1
59	4.60	4.50	0.10	247.82	224.22	23.60	3.22	2.2	39.3
60	4.20	4.10	0.10	252.02	228.32	23.70	3.27	2.4	39.4
61	4.10	3.70	0.40	256.12	232.02	24.10	3.33	9.8	40.1
62	4.00	3.40	0.60	260.12	235.42	24.70	3.38	15.0	41.1
63	4.00	2.80	1.20	264.12	238.22	25.90	3.43	30.0	43.1
1500 mg/L Alcoflood 1275A at 0.54 ft/day									
64	4.20	3.15	1.05	268.32	241.37	26.95	3.49	25.0	44.8
65	4.30	2.90	1.40	272.62	244.27	28.35	3.54	32.6	47.2
66	4.40	3.50	0.90	277.02	247.77	29.25	3.60	20.5	48.7
67	4.50	3.70	0.80	281.52	251.47	30.05	3.66	17.8	50.0
68	4.40	3.65	0.75	285.92	255.12	30.80	3.72	17.0	51.3
69	4.20	3.60	0.60	290.12	258.72	31.40	3.77	14.3	52.3
Injection Water at 0.54 ft/day									
70	4.40	3.90	0.50	294.52	262.62	31.90	3.83	11.4	53.1
71	4.40	3.95	0.45	298.92	266.57	32.35	3.88	10.2	53.8
72	4.20	3.85	0.35	303.12	270.42	32.70	3.94	8.3	54.4
73	4.20	3.85	0.35	307.32	274.27	33.05	3.99	8.3	55.0
74	4.30	4.00	0.30	311.62	278.27	33.35	4.05	7.0	55.5
75	4.10	3.80	0.30	315.72	282.07	33.65	4.10	7.3	56.0

Warner Radial Coreflood 3R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.96 ml

Initial Oil Saturation: 60.09 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.54 ft/day									
76	4.20	4.00	0.20	319.92	286.07	33.85	4.16	4.8	56.3
77	4.30	4.05	0.25	324.22	290.12	34.10	4.21	5.8	56.7
78	4.20	4.00	0.20	328.42	294.12	34.30	4.27	4.8	57.1
79	4.20	4.05	0.15	332.62	298.17	34.45	4.32	3.6	57.3
80	4.30	4.10	0.20	336.92	302.27	34.65	4.38	4.7	57.7
81	4.30	4.15	0.15	341.22	306.42	34.80	4.43	3.5	57.9
82	4.20	4.05	0.15	345.42	310.47	34.95	4.49	3.6	58.2
83	4.20	4.10	0.10	349.62	314.57	35.05	4.54	2.4	58.3
84	4.10	4.00	0.10	353.72	318.57	35.15	4.60	2.4	58.5
85	4.20	4.10	0.10	357.92	322.67	35.25	4.65	2.4	58.7
86	4.20	4.17	0.03	362.12	326.84	35.28	4.71	0.7	58.7
87	4.30	4.10	0.20	366.42	330.94	35.48	4.76	4.7	59.0
88	4.40	4.39	0.01	370.82	335.33	35.49	4.82	0.2	59.1
89	4.20	4.20	0.00	375.02	339.53	35.49	4.87	0.0	59.1
90	4.20	4.20	0.00	379.22	343.73	35.49	4.93	0.0	59.1
91	4.30	4.26	0.04	383.52	347.99	35.53	4.98	0.9	59.1
92	4.30	4.26	0.04	387.82	352.25	35.57	5.04	0.9	59.2
93	4.10	4.00	0.10	391.92	356.25	35.67	5.09	2.4	59.4
94	4.30	4.29	0.01	396.22	360.54	35.68	5.15	0.2	59.4
95	4.20	4.18	0.02	400.42	364.72	35.70	5.20	0.5	59.4
96	4.30	4.28	0.02	404.72	369.00	35.72	5.26	0.5	59.4
97	4.20	4.19	0.01	408.92	373.19	35.73	5.31	0.2	59.5
98	4.00	3.98	0.02	412.92	377.17	35.75	5.37	0.5	59.5
99	4.30	4.29	0.01	417.22	381.46	35.76	5.42	0.2	59.5
100	4.30	4.28	0.02	421.52	385.74	35.78	5.48	0.5	59.5
101	4.20	4.19	0.01	425.72	389.93	35.79	5.53	0.2	59.6
102	4.20	4.18	0.02	429.92	394.11	35.81	5.59	0.5	59.6
103	4.30	4.20	0.10	434.22	398.31	35.91	5.64	2.3	59.8
104	4.30	4.29	0.01	438.52	402.60	35.92	5.70	0.2	59.8
105	4.30	4.30	0.00	442.82	406.90	35.92	5.75	0.0	59.8
106	4.10	4.10	0.00	446.92	411.00	35.92	5.81	0.0	59.8
107	4.80	4.80	0.00	451.72	415.80	35.92	5.87	0.0	59.8
108	4.30	4.28	0.02	456.02	420.08	35.94	5.93	0.5	59.8
109	4.20	4.20	0.00	460.22	424.28	35.94	5.98	0.0	59.8
110	4.30	4.30	0.00	464.52	428.58	35.94	6.04	0.0	59.8
111	4.50	4.50	0.00	469.02	433.08	35.94	6.09	0.0	59.8

Warner Radial Coreflood 4R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.74 ml

Initial Oil Saturation: 57.22 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.51 ft/day									
1	0.75	0.00	0.75	0.75	0.00	0.75	0.01	100.0	1.3
2	4.30	0.10	4.20	5.05	0.10	4.95	0.06	97.7	8.7
3	4.30	2.50	1.80	9.35	2.60	6.75	0.12	41.9	11.8
4	4.40	3.60	0.80	13.75	6.20	7.55	0.17	18.2	13.2
5	4.20	3.60	0.60	17.95	9.80	8.15	0.22	14.3	14.2
6	4.20	3.60	0.60	22.15	13.40	8.75	0.27	14.3	15.3
7	4.20	3.90	0.30	26.35	17.30	9.05	0.33	7.1	15.8
8	4.30	4.00	0.30	30.65	21.30	9.35	0.38	7.0	16.3
9	4.10	3.80	0.30	34.75	25.10	9.65	0.43	7.3	16.9
10	4.30	4.00	0.30	39.05	29.10	9.95	0.48	7.0	17.4
11	4.10	3.90	0.20	43.15	33.00	10.15	0.53	4.9	17.7
12	4.30	4.00	0.30	47.45	37.00	10.45	0.59	7.0	18.3
13	4.20	4.00	0.20	51.65	41.00	10.65	0.64	4.8	18.6
14	4.20	3.95	0.25	55.85	44.95	10.90	0.69	6.0	19.0
15	4.40	4.20	0.20	60.25	49.15	11.10	0.75	4.5	19.4
16	4.30	4.20	0.10	64.55	53.35	11.20	0.80	2.3	19.6
17	4.20	4.10	0.10	68.75	57.45	11.30	0.85	2.4	19.7
18	4.30	4.15	0.15	73.05	61.60	11.45	0.90	3.5	20.0
19	4.10	4.00	0.10	77.15	65.60	11.55	0.96	2.4	20.2
20	4.30	4.15	0.15	81.45	69.75	11.70	1.01	3.5	20.4
21	4.40	4.35	0.05	85.85	74.10	11.75	1.06	1.1	20.5
22	4.20	4.05	0.15	90.05	78.15	11.90	1.12	3.6	20.8
23	4.10	3.95	0.15	94.15	82.10	12.05	1.17	3.7	21.1
24	4.30	4.20	0.10	98.45	86.30	12.15	1.22	2.3	21.2
25	4.10	4.00	0.10	102.55	90.30	12.25	1.27	2.4	21.4
26	4.30	4.25	0.05	106.85	94.55	12.30	1.32	1.2	21.5
27	4.40	4.25	0.15	111.25	98.80	12.45	1.38	3.4	21.8
28	4.40	4.30	0.10	115.65	103.10	12.55	1.43	2.3	21.9
29	4.30	4.20	0.10	119.95	107.30	12.65	1.49	2.3	22.1
30	4.40	4.30	0.10	124.35	111.60	12.75	1.54	2.3	22.3
31	4.40	4.35	0.05	128.75	115.95	12.80	1.59	1.1	22.4
32	4.30	4.25	0.05	133.05	120.20	12.85	1.65	1.2	22.5
33	4.40	4.30	0.10	137.45	124.50	12.95	1.70	2.3	22.6
34	4.40	4.30	0.10	141.85	128.80	13.05	1.76	2.3	22.8
35	4.20	4.10	0.10	146.05	132.90	13.15	1.81	2.4	23.0
36	4.20	4.10	0.10	150.25	137.00	13.25	1.86	2.4	23.2
37	4.30	4.20	0.10	154.55	141.20	13.35	1.91	2.3	23.3
38	4.20	4.15	0.05	158.75	145.35	13.40	1.97	1.2	23.4
39	4.20	4.15	0.05	162.95	149.50	13.45	2.02	1.2	23.5
40	4.20	4.17	0.03	167.15	153.67	13.48	2.07	0.7	23.6

Warner Radial Coreflood 4R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.74 ml

Initial Oil Saturation: 57.22 ml

Tube No.	----Produced----			-----Cumulative-----			V _p	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.51 ft/day									
41	4.30	4.27	0.03	171.45	157.94	13.51	2.12	0.7	23.6
42	4.20	4.19	0.01	175.65	162.13	13.52	2.18	0.2	23.6
43	4.40	4.35	0.05	180.05	166.48	13.57	2.23	1.1	23.7
44	4.50	4.42	0.08	184.55	170.90	13.65	2.29	1.8	23.9
45	4.30	4.29	0.01	188.85	175.19	13.66	2.34	0.2	23.9
46	4.30	4.25	0.05	193.15	179.44	13.71	2.39	1.2	24.0
47	4.20	4.12	0.08	197.35	183.56	13.79	2.44	1.9	24.1
48	4.20	4.16	0.04	201.55	187.72	13.83	2.50	1.0	24.2
49	4.20	4.17	0.03	205.75	191.89	13.86	2.55	0.7	24.2
50	4.40	4.38	0.02	210.15	196.27	13.88	2.60	0.5	24.3
51	4.40	4.30	0.10	214.55	200.57	13.98	2.66	2.3	24.4
52	4.10	4.06	0.04	218.65	204.63	14.02	2.71	1.0	24.5
53	4.40	4.39	0.01	223.05	209.02	14.03	2.76	0.2	24.5
54	4.40	4.39	0.01	227.45	213.41	14.04	2.82	0.2	24.5
55	4.00	3.94	0.06	231.45	217.35	14.10	2.87	1.5	24.6
56	4.60	4.60	0.00	236.05	221.95	14.10	2.92	0.0	24.6
57	4.20	4.20	0.00	240.25	226.15	14.10	2.98	0.0	24.6
2.0 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1500 mg/L Alcoflood 1275A at 0.51 ft/day									
58	4.50	4.50	0.00	244.75	230.65	14.10	3.03	0.0	24.6
59	4.00	3.70	0.30	248.75	234.35	14.40	3.08	7.5	25.2
60	4.30	2.90	1.40	253.05	237.25	15.80	3.13	32.6	27.6
61	4.40	2.90	1.50	257.45	240.15	17.30	3.19	34.1	30.2
62	4.30	3.20	1.10	261.75	243.35	18.40	3.24	25.6	32.2
63	4.40	3.45	0.95	266.15	246.80	19.35	3.30	21.6	33.8
1500 mg/L Alcoflood 1275A at 0.51 ft/day									
64	4.30	3.60	0.70	270.45	250.40	20.05	3.35	16.3	35.0
65	4.20	3.75	0.45	274.65	254.15	20.50	3.40	10.7	35.8
66	4.30	3.75	0.55	278.95	257.90	21.05	3.45	12.8	36.8
67	4.30	3.50	0.80	283.25	261.40	21.85	3.51	18.6	38.2
68	4.30	3.50	0.80	287.55	264.90	22.65	3.56	18.6	39.6
69	4.20	3.30	0.90	291.75	268.20	23.55	3.61	21.4	41.2
Injection Water at 0.51 ft/day									
70	4.50	4.25	0.25	296.25	272.45	23.80	3.67	5.6	41.6
71	4.30	3.30	1.00	300.55	275.75	24.80	3.72	23.3	43.3
72	4.20	3.95	0.25	304.75	279.70	25.05	3.77	6.0	43.8
73	4.30	4.10	0.20	309.05	283.80	25.25	3.83	4.7	44.1
74	4.30	4.20	0.10	313.35	288.00	25.35	3.88	2.3	44.3
75	4.20	4.10	0.10	317.55	292.10	25.45	3.93	2.4	44.5
76	4.40	4.34	0.06	321.95	296.44	25.51	3.99	1.4	44.6

Warner Radial Coreflood 4R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.74 ml

Initial Oil Saturation: 57.22 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.51 ft/day									
77	4.30	4.27	0.03	326.25	300.71	25.54	4.04	0.7	44.6
78	4.30	4.29	0.01	330.55	305.00	25.55	4.09	0.2	44.7
79	4.20	4.18	0.02	334.75	309.18	25.57	4.15	0.5	44.7
80	4.30	4.29	0.01	339.05	313.47	25.58	4.20	0.2	44.7
81	4.30	4.30	0.00	343.35	317.77	25.58	4.25	0.0	44.7
82	4.30	4.29	0.01	347.65	322.06	25.59	4.31	0.2	44.7
83	4.30	4.29	0.01	351.95	326.35	25.60	4.36	0.2	44.7
84	4.30	4.29	0.01	356.25	330.64	25.61	4.41	0.2	44.8
85	4.30	4.30	0.00	360.55	334.94	25.61	4.47	0.0	44.8
86	4.10	4.09	0.01	364.65	339.03	25.62	4.52	0.2	44.8
87	4.30	4.29	0.01	368.95	343.32	25.63	4.57	0.2	44.8
88	4.30	4.30	0.00	373.25	347.62	25.63	4.62	0.0	44.8
89	4.20	4.19	0.01	377.45	351.81	25.64	4.67	0.2	44.8
90	4.30	4.29	0.01	381.75	356.10	25.65	4.73	0.2	44.8
91	4.30	4.30	0.00	386.05	360.40	25.65	4.78	0.0	44.8
92	4.20	4.19	0.01	390.25	364.59	25.66	4.83	0.2	44.8
93	4.20	4.18	0.02	394.45	368.77	25.68	4.89	0.5	44.9
94	4.30	4.29	0.01	398.75	373.06	25.69	4.94	0.2	44.9
95	4.20	4.20	0.00	402.95	377.26	25.69	4.99	0.0	44.9
96	4.10	4.10	0.00	407.05	381.36	25.69	5.04	0.0	44.9
97	4.20	4.20	0.00	411.25	385.56	25.69	5.09	0.0	44.9
98	4.20	4.19	0.01	415.45	389.75	25.70	5.15	0.2	44.9
99	4.30	4.30	0.00	419.75	394.05	25.70	5.20	0.0	44.9
100	4.30	4.30	0.00	424.05	398.35	25.70	5.25	0.0	44.9
101	4.20	4.19	0.01	428.25	402.54	25.71	5.30	0.2	44.9
102	4.30	4.30	0.00	432.55	406.84	25.71	5.36	0.0	44.9
103	4.30	4.30	0.00	436.85	411.14	25.71	5.41	0.0	44.9
104	4.10	4.09	0.01	440.95	415.23	25.72	5.46	0.2	44.9
105	4.10	4.10	0.00	445.05	419.33	25.72	5.51	0.0	44.9
106	4.10	4.10	0.00	449.15	423.43	25.72	5.56	0.0	44.9
107	4.80	4.80	0.00	453.95	428.23	25.72	5.62	0.0	44.9
108	4.20	4.20	0.00	458.15	432.43	25.72	5.67	0.0	44.9
109	4.10	4.10	0.00	462.25	436.53	25.72	5.73	0.0	44.9
110	4.20	4.20	0.00	466.45	440.73	25.72	5.78	0.0	44.9
111	4.40	4.40	0.00	470.85	445.13	25.72	5.83	0.0	44.9

Warner Radial Coreflood 5R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 75.12 ml
Initial Oil Saturation: 60.89 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.53 ft/day									
1	0.99	0.00	0.99	0.99	0.00	0.99	0.01	100.0	1.6
2	2.20	0.00	2.20	3.19	0.00	3.19	0.04	100.0	5.2
3	4.20	0.30	3.90	7.39	0.30	7.09	0.10	92.9	11.6
4	4.20	2.55	1.65	11.59	2.85	8.74	0.15	39.3	14.4
5	4.10	3.10	1.00	15.69	5.95	9.74	0.21	24.4	16.0
6	4.50	3.65	0.85	20.19	9.60	10.59	0.27	18.9	17.4
7	5.30	4.80	0.50	25.49	14.40	11.09	0.34	9.4	18.2
8	6.50	6.10	0.40	31.99	20.50	11.49	0.43	6.2	18.9
9	6.70	6.45	0.25	38.69	26.95	11.74	0.52	3.7	19.3
10	6.50	5.90	0.60	45.19	32.85	12.34	0.60	9.2	20.3
11	5.60	5.25	0.35	50.79	38.10	12.69	0.68	6.2	20.8
12	4.70	4.35	0.35	55.49	42.45	13.04	0.74	7.4	21.4
13	3.50	3.30	0.20	58.99	45.75	13.24	0.79	5.7	21.7
14	3.00	2.85	0.15	61.99	48.60	13.39	0.83	5.0	22.0
15	2.80	2.65	0.15	64.79	51.25	13.54	0.86	5.4	22.2
16	2.90	2.70	0.20	67.69	53.95	13.74	0.90	6.9	22.6
17	3.70	3.55	0.15	71.39	57.50	13.89	0.95	4.1	22.8
18	4.90	4.75	0.15	76.29	62.25	14.04	1.02	3.1	23.1
19	5.70	5.55	0.15	81.99	67.80	14.19	1.09	2.6	23.3
20	6.60	6.35	0.25	88.59	74.15	14.44	1.18	3.8	23.7
21	5.90	5.75	0.15	94.49	79.90	14.59	1.26	2.5	24.0
22	4.80	4.70	0.10	99.29	84.60	14.69	1.32	2.1	24.1
23	3.70	3.60	0.10	102.99	88.20	14.79	1.37	2.7	24.3
24	2.70	2.64	0.06	105.69	90.84	14.85	1.41	2.2	24.4
25	2.70	2.65	0.05	108.39	93.49	14.90	1.44	1.9	24.5
26	2.60	2.57	0.03	110.99	96.06	14.93	1.48	1.2	24.5
27	3.40	3.39	0.01	114.39	99.45	14.94	1.52	0.3	24.5
28	4.40	4.25	0.15	118.79	103.70	15.09	1.58	3.4	24.8
29	5.70	5.50	0.20	124.49	109.20	15.29	1.66	3.5	25.1
30	5.90	5.80	0.10	130.39	115.00	15.39	1.74	1.7	25.3
31	5.50	5.46	0.04	135.89	120.46	15.43	1.81	0.7	25.3
32	4.80	4.70	0.10	140.69	125.16	15.53	1.87	2.1	25.5
33	3.60	3.50	0.10	144.29	128.66	15.63	1.92	2.8	25.7
34	2.90	2.88	0.02	147.19	131.54	15.65	1.96	0.7	25.7
35	2.70	2.68	0.02	149.89	134.22	15.67	2.00	0.7	25.7
36	2.80	2.79	0.01	152.69	137.01	15.68	2.03	0.4	25.8
37	3.00	2.98	0.02	155.69	139.99	15.70	2.07	0.7	25.8
38	3.30	3.29	0.01	158.99	143.28	15.71	2.12	0.3	25.8
39	3.90	3.89	0.01	162.89	147.17	15.72	2.17	0.3	25.8
40	4.20	4.18	0.02	167.09	151.35	15.74	2.22	0.5	25.8

Warner Radial Coreflood 5R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 75.12 ml

Initial Oil Saturation: 60.89 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.53 ft/day									
41	4.70	4.67	0.03	171.79	156.02	15.77	2.29	0.6	25.9
42	4.60	4.54	0.06	176.39	160.56	15.83	2.35	1.3	26.0
43	4.20	4.15	0.05	180.59	164.71	15.88	2.40	1.2	26.1
44	3.60	3.58	0.02	184.19	168.29	15.90	2.45	0.6	26.1
45	3.20	3.12	0.08	187.39	171.41	15.98	2.49	2.5	26.2
46	3.10	3.09	0.01	190.49	174.50	15.99	2.54	0.3	26.3
47	3.60	3.59	0.01	194.09	178.09	16.00	2.58	0.3	26.3
48	4.30	4.28	0.02	198.39	182.37	16.02	2.64	0.5	26.3
49	4.00	3.97	0.03	202.39	186.34	16.05	2.69	0.7	26.4
50	2.00	1.97	0.03	204.39	188.31	16.08	2.72	1.5	26.4
51	5.60	5.50	0.10	209.99	193.81	16.18	2.80	1.8	26.6
52	5.10	5.00	0.10	215.09	198.81	16.28	2.86	2.0	26.7
53	4.20	4.12	0.08	219.29	202.93	16.36	2.92	1.9	26.9
54	3.40	3.35	0.05	222.69	206.28	16.41	2.96	1.5	27.0
55	3.10	3.03	0.07	225.79	209.31	16.48	3.01	2.3	27.1
56	3.10	3.09	0.01	228.89	212.40	16.49	3.05	0.3	27.1
57	3.40	3.39	0.01	232.29	215.79	16.50	3.09	0.3	27.1
58	3.50	3.49	0.01	235.79	219.28	16.51	3.14	0.3	27.1
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.53 ft/day									
59	5.90	5.87	0.03	241.69	225.15	16.54	3.22	0.5	27.2
60	6.50	5.80	0.70	248.19	230.95	17.24	3.30	10.8	28.3
61	6.00	3.00	3.00	254.19	233.95	20.24	3.38	50.0	33.2
62	3.70	1.60	2.10	257.89	235.55	22.34	3.43	56.8	36.7
63	2.50	1.30	1.20	260.39	236.85	23.54	3.47	48.0	38.7
1200 mg/L Flopaam 3630S at 0.53 ft/day									
64	3.20	1.75	1.45	263.59	238.60	24.99	3.51	45.3	41.0
65	3.10	2.35	0.75	266.69	240.95	25.74	3.55	24.2	42.3
66	4.00	2.80	1.20	270.69	243.75	26.94	3.60	30.0	44.2
67	4.80	3.45	1.35	275.49	247.20	28.29	3.67	28.1	46.5
68	5.50	3.90	1.60	280.99	251.10	29.89	3.74	29.1	49.1
69	3.70	2.90	0.80	284.69	254.00	30.69	3.79	21.6	50.4
Injection Water at 0.53 ft/day									
70	4.90	3.90	1.00	289.59	257.90	31.69	3.86	20.4	52.0
71	4.80	4.25	0.55	294.39	262.15	32.24	3.92	11.5	52.9
72	4.60	4.10	0.50	298.99	266.25	32.74	3.98	10.9	53.8
73	3.70	3.10	0.60	302.69	269.35	33.34	4.03	16.2	54.8
74	3.30	3.05	0.25	305.99	272.40	33.59	4.07	7.6	55.2
75	3.30	3.10	0.20	309.29	275.50	33.79	4.12	6.1	55.5
76	4.00	3.90	0.10	313.29	279.40	33.89	4.17	2.5	55.7

Warner Radial Coreflood 5R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 75.12 ml
Initial Oil Saturation: 60.89 ml

Tube No.	---Produced---			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	---Volume, ml---			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.53 ft/day									
77	4.50	4.40	0.10	317.79	283.80	33.99	4.23	2.2	55.8
78	5.00	4.90	0.10	322.79	288.70	34.09	4.30	2.0	56.0
79	5.10	5.00	0.10	327.89	293.70	34.19	4.36	2.0	56.2
80	5.10	5.00	0.10	332.99	298.70	34.29	4.43	2.0	56.3
81	4.60	4.52	0.08	337.59	303.22	34.37	4.49	1.7	56.4
82	3.80	3.73	0.07	341.39	306.95	34.44	4.54	1.8	56.6
83	3.30	3.26	0.04	344.69	310.21	34.48	4.59	1.2	56.6
84	3.30	3.26	0.04	347.99	313.47	34.52	4.63	1.2	56.7
85	3.10	3.06	0.04	351.09	316.53	34.56	4.67	1.3	56.8
86	3.60	3.58	0.02	354.69	320.11	34.58	4.72	0.6	56.8
87	4.20	4.19	0.01	358.89	324.30	34.59	4.78	0.2	56.8
88	4.80	4.79	0.01	363.69	329.09	34.60	4.84	0.2	56.8
89	5.20	5.12	0.08	368.89	334.21	34.68	4.91	1.5	57.0
90	4.90	4.89	0.01	373.79	339.10	34.69	4.98	0.2	57.0
91	4.50	4.40	0.10	378.29	343.50	34.79	5.04	2.2	57.1
92	4.00	3.99	0.01	382.29	347.49	34.80	5.09	0.2	57.2
93	3.80	3.79	0.01	386.09	351.28	34.81	5.14	0.3	57.2
94	3.70	3.68	0.02	389.79	354.96	34.83	5.19	0.5	57.2
95	3.60	3.56	0.04	393.39	358.52	34.87	5.24	1.1	57.3
96	3.60	3.59	0.01	396.99	362.11	34.88	5.28	0.3	57.3
97	4.10	4.09	0.01	401.09	366.20	34.89	5.34	0.2	57.3
98	4.40	4.40	0.00	405.49	370.60	34.89	5.40	0.0	57.3
99	4.70	4.69	0.01	410.19	375.29	34.90	5.46	0.2	57.3
100	4.50	4.49	0.01	414.69	379.78	34.91	5.52	0.2	57.3
101	4.30	4.28	0.02	418.99	384.06	34.93	5.58	0.5	57.4
102	3.80	3.79	0.01	422.79	387.85	34.94	5.63	0.3	57.4
103	3.10	3.06	0.04	425.89	390.91	34.98	5.67	1.3	57.4
104	3.00	2.98	0.02	428.89	393.89	35.00	5.71	0.7	57.5
105	3.40	3.39	0.01	432.29	397.28	35.01	5.75	0.3	57.5
106	4.30	4.29	0.01	436.59	401.57	35.02	5.81	0.2	57.5
107	5.00	5.00	0.00	441.59	406.57	35.02	5.88	0.0	57.5
108	5.30	5.30	0.00	446.89	411.87	35.02	5.95	0.0	57.5

Warner Radial Coreflood 6R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.79 ml

Initial Oil Saturation: 59.48 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.54 ft/day									
1	1.09	0.00	1.09	1.09	0.00	1.09	0.01	100.0	1.8
2	2.10	0.00	2.10	3.19	0.00	3.19	0.04	100.0	5.4
3	3.90	0.80	3.10	7.09	0.80	6.29	0.09	79.5	10.6
4	3.90	2.15	1.75	10.99	2.95	8.04	0.15	44.9	13.5
5	4.20	3.10	1.10	15.19	6.05	9.14	0.20	26.2	15.4
6	4.50	3.85	0.65	19.69	9.90	9.79	0.26	14.4	16.5
7	5.10	4.60	0.50	24.79	14.50	10.29	0.33	9.8	17.3
8	6.20	5.80	0.40	30.99	20.30	10.69	0.41	6.5	18.0
9	6.70	6.30	0.40	37.69	26.60	11.09	0.50	6.0	18.6
10	6.30	5.85	0.45	43.99	32.45	11.54	0.59	7.1	19.4
11	5.50	5.10	0.40	49.49	37.55	11.94	0.66	7.3	20.1
12	4.30	4.05	0.25	53.79	41.60	12.19	0.72	5.8	20.5
13	3.70	3.50	0.20	57.49	45.10	12.39	0.77	5.4	20.8
14	3.20	3.05	0.15	60.69	48.15	12.54	0.81	4.7	21.1
15	3.10	2.98	0.12	63.79	51.13	12.66	0.85	3.9	21.3
16	3.20	3.10	0.10	66.99	54.23	12.76	0.90	3.1	21.5
17	3.70	3.60	0.10	70.69	57.83	12.86	0.95	2.7	21.6
18	4.70	4.60	0.10	75.39	62.43	12.96	1.01	2.1	21.8
19	5.90	5.80	0.10	81.29	68.23	13.06	1.09	1.7	22.0
20	6.10	6.00	0.10	87.39	74.23	13.16	1.17	1.6	22.1
21	5.80	5.60	0.20	93.19	79.83	13.36	1.25	3.4	22.5
22	4.50	4.30	0.20	97.69	84.13	13.56	1.31	4.4	22.8
23	3.70	3.45	0.25	101.39	87.58	13.81	1.36	6.8	23.2
24	3.20	3.08	0.12	104.59	90.66	13.93	1.40	3.8	23.4
25	2.90	2.88	0.02	107.49	93.54	13.95	1.44	0.7	23.5
26	2.90	2.86	0.04	110.39	96.40	13.99	1.48	1.4	23.5
27	3.50	3.49	0.01	113.89	99.89	14.00	1.52	0.3	23.5
28	4.80	4.70	0.10	118.69	104.59	14.10	1.59	2.1	23.7
29	5.30	5.15	0.15	123.99	109.74	14.25	1.66	2.8	24.0
30	5.70	5.55	0.15	129.69	115.29	14.40	1.73	2.6	24.2
31	5.40	5.28	0.12	135.09	120.57	14.52	1.81	2.2	24.4
32	4.30	4.24	0.06	139.39	124.81	14.58	1.86	1.4	24.5
33	3.60	3.45	0.15	142.99	128.26	14.73	1.91	4.2	24.8
34	3.20	3.10	0.10	146.19	131.36	14.83	1.95	3.1	24.9
35	2.90	2.88	0.02	149.09	134.24	14.85	1.99	0.7	25.0
36	3.00	2.99	0.01	152.09	137.23	14.86	2.03	0.3	25.0
37	3.00	2.99	0.01	155.09	140.22	14.87	2.07	0.3	25.0
38	3.40	3.39	0.01	158.49	143.61	14.88	2.12	0.3	25.0
39	4.00	3.99	0.01	162.49	147.60	14.89	2.17	0.2	25.0
40	4.40	4.38	0.02	166.89	151.98	14.91	2.23	0.5	25.1

Warner Radial Coreflood 6R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.79 ml

Initial Oil Saturation: 59.48 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.54 ft/day									
41	4.60	4.58	0.02	171.49	156.56	14.93	2.29	0.4	25.1
42	4.40	4.35	0.05	175.89	160.91	14.98	2.35	1.1	25.2
43	4.10	4.00	0.10	179.99	164.91	15.08	2.41	2.4	25.4
44	3.50	3.47	0.03	183.49	168.38	15.11	2.45	0.9	25.4
45	3.10	3.08	0.02	186.59	171.46	15.13	2.49	0.6	25.4
46	3.20	3.19	0.01	189.79	174.65	15.14	2.54	0.3	25.5
47	3.60	3.59	0.01	193.39	178.24	15.15	2.59	0.3	25.5
48	4.30	4.28	0.02	197.69	182.52	15.17	2.64	0.5	25.5
49	4.00	3.98	0.02	201.69	186.50	15.19	2.70	0.5	25.5
50	2.10	2.09	0.01	203.79	188.59	15.20	2.72	0.5	25.6
51	5.40	5.38	0.02	209.19	193.97	15.22	2.80	0.4	25.6
52	4.80	4.73	0.07	213.99	198.70	15.29	2.86	1.5	25.7
53	4.00	3.96	0.04	217.99	202.66	15.33	2.91	1.0	25.8
54	3.20	3.17	0.03	221.19	205.83	15.36	2.96	0.9	25.8
55	2.90	2.89	0.01	224.09	208.72	15.37	3.00	0.3	25.8
56	3.20	3.19	0.01	227.29	211.91	15.38	3.04	0.3	25.9
57	3.50	3.49	0.01	230.79	215.40	15.39	3.09	0.3	25.9
58	3.50	3.46	0.04	234.29	218.86	15.43	3.13	1.1	25.9
0.625 wt% NaOH + 0.5 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1200 mg/L Flopaam 3630S at 0.54 ft/d									
59	4.30	4.22	0.08	238.59	223.08	15.51	3.19	1.9	26.1
60	6.10	5.75	0.35	244.69	228.83	15.86	3.27	5.7	26.7
61	5.80	3.60	2.20	250.49	232.43	18.06	3.35	37.9	30.4
62	3.80	2.20	1.60	254.29	234.63	19.66	3.40	42.1	33.1
63	2.50	1.30	1.20	256.79	235.93	20.86	3.43	48.0	35.1
1200 mg/L Flopaam 3630S at 0.54 ft/day									
64	3.20	1.80	1.40	259.99	237.73	22.26	3.48	43.8	37.4
65	3.30	2.10	1.20	263.29	239.83	23.46	3.52	36.4	39.4
66	4.00	2.85	1.15	267.29	242.68	24.61	3.57	28.8	41.4
67	4.70	3.30	1.40	271.99	245.98	26.01	3.64	29.8	43.7
68	5.60	4.30	1.30	277.59	250.28	27.31	3.71	23.2	45.9
69	3.70	2.90	0.80	281.29	253.18	28.11	3.76	21.6	47.3
Injection Water at 0.54 ft/day									
70	5.50	4.60	0.90	286.79	257.78	29.01	3.83	16.4	48.8
71	5.20	4.15	1.05	291.99	261.93	30.06	3.90	20.2	50.5
72	3.20	3.05	0.15	295.19	264.98	30.21	3.95	4.7	50.8
73	3.80	3.35	0.45	298.99	268.33	30.66	4.00	11.8	51.5
74	3.30	2.95	0.35	302.29	271.28	31.01	4.04	10.6	52.1
75	3.40	3.15	0.25	305.69	274.43	31.26	4.09	7.4	52.6
76	4.00	3.80	0.20	309.69	278.23	31.46	4.14	5.0	52.9

Warner Radial Coreflood 6R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.79 ml

Initial Oil Saturation: 59.48 ml

Tube No.	----Produced----			-----Cumulative-----			V _p	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.54 ft/day									
77	4.70	4.50	0.20	314.39	282.73	31.66	4.20	4.3	53.2
78	5.00	4.85	0.15	319.39	287.58	31.81	4.27	3.0	53.5
79	5.30	5.15	0.15	324.69	292.73	31.96	4.34	2.8	53.7
80	5.00	4.90	0.10	329.69	297.63	32.06	4.41	2.0	53.9
81	4.70	4.55	0.15	334.39	302.18	32.21	4.47	3.2	54.2
82	4.10	4.00	0.10	338.49	306.18	32.31	4.53	2.4	54.3
83	3.20	3.16	0.04	341.69	309.34	32.35	4.57	1.3	54.4
84	3.20	3.16	0.04	344.89	312.50	32.39	4.61	1.3	54.5
85	3.10	3.00	0.10	347.99	315.50	32.49	4.65	3.2	54.6
86	3.90	3.88	0.02	351.89	319.38	32.51	4.71	0.5	54.7
87	4.50	4.48	0.02	356.39	323.86	32.53	4.77	0.4	54.7
88	4.80	4.79	0.01	361.19	328.65	32.54	4.83	0.2	54.7
89	5.10	5.09	0.01	366.29	333.74	32.55	4.90	0.2	54.7
90	4.80	4.79	0.01	371.09	338.53	32.56	4.96	0.2	54.7
91	4.30	4.29	0.01	375.39	342.82	32.57	5.02	0.2	54.8
92	4.00	3.95	0.05	379.39	346.77	32.62	5.07	1.3	54.8
93	3.70	3.67	0.03	383.09	350.44	32.65	5.12	0.8	54.9
94	3.60	3.58	0.02	386.69	354.02	32.67	5.17	0.6	54.9
95	3.60	3.58	0.02	390.29	357.60	32.69	5.22	0.6	55.0
96	4.00	3.99	0.01	394.29	361.59	32.70	5.27	0.2	55.0
97	4.40	4.39	0.01	398.69	365.98	32.71	5.33	0.2	55.0
98	4.70	4.68	0.02	403.39	370.66	32.73	5.39	0.4	55.0
99	4.20	4.19	0.01	407.59	374.85	32.74	5.45	0.2	55.0
100	4.50	4.48	0.02	412.09	379.33	32.76	5.51	0.4	55.1
101	3.80	3.78	0.02	415.89	383.11	32.78	5.56	0.5	55.1
102	3.40	3.39	0.01	419.29	386.50	32.79	5.61	0.3	55.1
103	3.00	2.99	0.01	422.29	389.49	32.80	5.65	0.3	55.1
104	3.10	3.09	0.01	425.39	392.58	32.81	5.69	0.3	55.2
105	3.60	3.58	0.02	428.99	396.16	32.83	5.74	0.6	55.2
106	4.70	4.69	0.01	433.69	400.85	32.84	5.80	0.2	55.2
107	5.50	5.49	0.01	439.19	406.34	32.85	5.87	0.2	55.2
108	5.20	5.20	0.00	444.39	411.54	32.85	5.94	0.0	55.2

Warner Radial Coreflood 7R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.19 ml
Initial Oil Saturation: 56.50 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.52 ft/day									
1	1.68	0.00	1.68	1.68	0.00	1.68	0.02	100.0	3.0
2	5.50	0.00	5.50	7.18	0.00	7.18	0.10	100.0	12.7
3	4.80	0.00	4.80	11.98	0.00	11.98	0.16	100.0	21.2
4	4.80	2.50	2.30	16.78	2.50	14.28	0.23	47.9	25.3
5	5.40	4.20	1.20	22.18	6.70	15.48	0.30	22.2	27.4
6	5.65	4.60	1.05	27.83	11.30	16.53	0.38	18.6	29.3
7	5.70	4.95	0.75	33.53	16.25	17.28	0.45	13.2	30.6
8	5.40	4.65	0.75	38.93	20.90	18.03	0.52	13.9	31.9
9	5.25	4.80	0.45	44.18	25.70	18.48	0.60	8.6	32.7
10	5.40	4.95	0.45	49.58	30.65	18.93	0.67	8.3	33.5
11	5.25	4.75	0.50	54.83	35.40	19.43	0.74	9.5	34.4
12	5.30	4.95	0.35	60.13	40.35	19.78	0.81	6.6	35.0
13	5.30	5.00	0.30	65.43	45.35	20.08	0.88	5.7	35.5
14	5.60	5.30	0.30	71.03	50.65	20.38	0.96	5.4	36.1
15	5.60	5.35	0.25	76.63	56.00	20.63	1.03	4.5	36.5
16	5.15	4.90	0.25	81.78	60.90	20.88	1.10	4.9	37.0
17	5.05	4.78	0.27	86.83	65.68	21.15	1.17	5.3	37.4
18	5.20	4.98	0.22	92.03	70.66	21.37	1.24	4.2	37.8
19	5.20	4.95	0.25	97.23	75.61	21.62	1.31	4.8	38.3
20	5.35	5.15	0.20	102.58	80.76	21.82	1.38	3.7	38.6
21	5.50	5.35	0.15	108.08	86.11	21.97	1.46	2.7	38.9
22	5.20	5.00	0.20	113.28	91.11	22.17	1.53	3.8	39.2
23	5.00	4.85	0.15	118.28	95.96	22.32	1.59	3.0	39.5
24	5.38	5.30	0.08	123.66	101.26	22.40	1.67	1.5	39.6
25	5.20	5.10	0.10	128.86	106.36	22.50	1.74	1.9	39.8
26	5.10	5.00	0.10	133.96	111.36	22.60	1.81	2.0	40.0
27	5.15	5.00	0.15	139.11	116.36	22.75	1.88	2.9	40.3
28	5.45	5.35	0.10	144.56	121.71	22.85	1.95	1.8	40.4
29	5.30	5.20	0.10	149.86	126.91	22.95	2.02	1.9	40.6
30	5.30	5.20	0.10	155.16	132.11	23.05	2.09	1.9	40.8
31	5.25	5.15	0.10	160.41	137.26	23.15	2.16	1.9	41.0
32	5.20	5.15	0.05	165.61	142.41	23.20	2.23	1.0	41.1
33	5.40	5.30	0.10	171.01	147.71	23.30	2.31	1.9	41.2
34	4.85	4.75	0.10	175.86	152.46	23.40	2.37	2.1	41.4
35	5.15	5.08	0.07	181.01	157.54	23.47	2.44	1.4	41.5
36	5.28	5.20	0.08	186.29	162.74	23.55	2.51	1.5	41.7
37	5.18	5.10	0.08	191.47	167.84	23.63	2.58	1.5	41.8
38	5.25	5.20	0.05	196.72	173.04	23.68	2.65	1.0	41.9
39	5.02	5.00	0.02	201.74	178.04	23.70	2.72	0.4	41.9
40	5.23	5.20	0.03	206.97	183.24	23.73	2.79	0.6	42.0

Warner Radial Coreflood 7R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.19 ml

Initial Oil Saturation: 56.50 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.52 ft/day									
41	5.17	5.15	0.02	212.14	188.39	23.75	2.86	0.4	42.0
42	5.52	5.50	0.02	217.66	193.89	23.77	2.93	0.4	42.1
43	5.13	5.10	0.03	222.79	198.99	23.80	3.00	0.6	42.1
44	4.92	4.90	0.02	227.71	203.89	23.82	3.07	0.4	42.2
45	5.02	5.00	0.02	232.73	208.89	23.84	3.14	0.4	42.2
46	5.23	5.20	0.03	237.96	214.09	23.87	3.21	0.6	42.2
47	5.35	5.30	0.05	243.31	219.39	23.92	3.28	0.9	42.3
48	5.20	5.15	0.05	248.51	224.54	23.97	3.35	1.0	42.4
49	5.05	5.00	0.05	253.56	229.54	24.02	3.42	1.0	42.5
50	5.36	5.30	0.06	258.92	234.84	24.08	3.49	1.1	42.6
51	5.11	5.10	0.01	264.03	239.94	24.09	3.56	0.2	42.6
52	5.41	5.40	0.01	269.44	245.34	24.10	3.63	0.2	42.7
53	4.62	4.52	0.10	274.06	249.86	24.20	3.69	2.2	42.8
0.75 wt% NaOH + 0.1 wt% ORS-97 + 1200 mg/L Flopaam 3630S at 0.52 ft/day									
54	6.05	6.00	0.05	280.11	255.86	24.25	3.78	0.8	42.9
55	4.06	4.05	0.01	284.17	259.91	24.26	3.83	0.2	42.9
56	4.95	4.85	0.10	289.12	264.76	24.36	3.90	2.0	43.1
57	4.25	3.90	0.35	293.37	268.66	24.71	3.95	8.2	43.7
58	4.75	3.85	0.90	298.12	272.51	25.61	4.02	18.9	45.3
1200 mg/L Flopaam 3630S at 0.52 ft/day									
59	4.60	3.65	0.95	302.72	276.16	26.56	4.08	20.7	47.0
60	5.10	3.95	1.15	307.82	280.11	27.71	4.15	22.5	49.0
61	4.55	3.75	0.80	312.37	283.86	28.51	4.21	17.6	50.5
62	4.50	3.75	0.75	316.87	287.61	29.26	4.27	16.7	51.8
63	4.75	4.15	0.60	321.62	291.76	29.86	4.34	12.6	52.8
Injection Water at 0.52 ft/day									
64	5.20	4.50	0.70	326.82	296.26	30.56	4.41	13.5	54.1
65	6.20	5.40	0.80	333.02	301.66	31.36	4.49	12.9	55.5
66	6.40	5.98	0.42	339.42	307.64	31.78	4.58	6.6	56.2
67	5.55	5.10	0.45	344.97	312.74	32.23	4.65	8.1	57.0
68	5.05	4.80	0.25	350.02	317.54	32.48	4.72	5.0	57.5
69	5.25	5.05	0.20	355.27	322.59	32.68	4.79	3.8	57.8
70	5.60	5.32	0.28	360.87	327.91	32.96	4.86	5.0	58.3
71	5.50	5.35	0.15	366.37	333.26	33.11	4.94	2.7	58.6
72	5.60	5.50	0.10	371.97	338.76	33.21	5.01	1.8	58.8
73	5.70	5.65	0.05	377.67	344.41	33.26	5.09	0.9	58.9
74	5.45	5.40	0.05	383.12	349.81	33.31	5.16	0.9	59.0
75	5.70	5.60	0.10	388.82	355.41	33.41	5.24	1.8	59.1
76	5.28	5.20	0.08	394.10	360.61	33.49	5.31	1.5	59.3

Warner Radial Coreflood 7R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 74.19 ml
Initial Oil Saturation: 56.50 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.52 ft/day									
77	5.38	5.35	0.03	399.48	365.96	33.52	5.38	0.6	59.3
78	5.52	5.50	0.02	405.00	371.46	33.54	5.46	0.4	59.4
79	5.35	5.35	0.00	410.35	376.81	33.54	5.53	0.0	59.4
80	5.31	5.30	0.01	415.66	382.11	33.55	5.60	0.2	59.4
81	5.01	5.00	0.01	420.67	387.11	33.56	5.67	0.2	59.4
82	5.05	5.00	0.05	425.72	392.11	33.61	5.74	1.0	59.5
83	4.40	4.40	0.00	430.12	396.51	33.61	5.80	0.0	59.5
84	5.22	5.20	0.02	435.34	401.71	33.63	5.87	0.4	59.5
85	5.60	5.55	0.05	440.94	407.26	33.68	5.94	0.9	59.6
86	5.35	5.30	0.05	446.29	412.56	33.73	6.02	0.9	59.7
87	5.26	5.25	0.01	451.55	417.81	33.74	6.09	0.2	59.7
88	4.86	4.85	0.01	456.41	422.66	33.75	6.15	0.2	59.7
89	4.91	4.90	0.01	461.32	427.56	33.76	6.22	0.2	59.8
90	5.06	5.05	0.01	466.38	432.61	33.77	6.29	0.2	59.8
91	5.15	5.05	0.10	471.53	437.66	33.87	6.36	1.9	59.9
92	5.20	5.20	0.00	476.73	442.86	33.87	6.43	0.0	59.9
93	5.00	5.00	0.00	481.73	447.86	33.87	6.49	0.0	59.9
94	5.16	5.15	0.01	486.89	453.01	33.88	6.56	0.2	60.0
95	5.31	5.30	0.01	492.20	458.31	33.89	6.63	0.2	60.0
96	5.20	5.20	0.00	497.40	463.51	33.89	6.70	0.0	60.0
97	5.31	5.30	0.01	502.71	468.81	33.90	6.78	0.2	60.0
98	5.31	5.30	0.01	508.02	474.11	33.91	6.85	0.2	60.0
99	5.20	5.20	0.00	513.22	479.31	33.91	6.92	0.0	60.0
100	5.10	5.05	0.05	518.32	484.36	33.96	6.99	1.0	60.1
101	5.05	5.00	0.05	523.37	489.36	34.01	7.05	1.0	60.2
102	5.15	5.12	0.03	528.52	494.48	34.04	7.12	0.6	60.2
103	5.20	5.15	0.05	533.72	499.63	34.09	7.19	1.0	60.3
104	5.27	5.20	0.07	538.99	504.83	34.16	7.26	1.3	60.5
105	5.16	5.15	0.01	544.15	509.98	34.17	7.33	0.2	60.5
106	5.36	5.35	0.01	549.51	515.33	34.18	7.41	0.2	60.5
107	5.31	5.30	0.01	554.82	520.63	34.19	7.48	0.2	60.5
108	3.86	3.85	0.01	558.68	524.48	34.20	7.53	0.3	60.5

Warner Radial Coreflood 8R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 70.49 ml
Initial Oil Saturation: 60.90 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.55 ft/day									
1	1.48	0.00	1.48	1.48	0.00	1.48	0.02	100.0	2.4
2	5.50	0.00	5.50	6.98	0.00	6.98	0.10	100.0	11.5
3	5.25	1.45	3.80	12.23	1.45	10.78	0.17	72.4	17.7
4	5.25	4.15	1.10	17.48	5.60	11.88	0.25	21.0	19.5
5	5.30	4.25	1.05	22.78	9.85	12.93	0.32	19.8	21.2
6	5.40	4.60	0.80	28.18	14.45	13.73	0.40	14.8	22.5
7	5.55	5.05	0.50	33.73	19.50	14.23	0.48	9.0	23.4
8	5.50	4.90	0.60	39.23	24.40	14.83	0.56	10.9	24.4
9	5.55	5.15	0.40	44.78	29.55	15.23	0.64	7.2	25.0
10	5.50	5.10	0.40	50.28	34.65	15.63	0.71	7.3	25.7
11	5.30	4.95	0.35	55.58	39.60	15.98	0.79	6.6	26.2
12	5.30	4.95	0.35	60.88	44.55	16.33	0.86	6.6	26.8
13	5.30	5.10	0.20	66.18	49.65	16.53	0.94	3.8	27.1
14	5.50	5.28	0.22	71.68	54.93	16.75	1.02	4.0	27.5
15	5.45	5.25	0.20	77.13	60.18	16.95	1.09	3.7	27.8
16	5.60	5.40	0.20	82.73	65.58	17.15	1.17	3.6	28.2
17	5.40	5.20	0.20	88.13	70.78	17.35	1.25	3.7	28.5
18	5.20	5.00	0.20	93.33	75.78	17.55	1.32	3.8	28.8
19	5.25	5.14	0.11	98.58	80.92	17.66	1.40	2.1	29.0
20	5.15	5.00	0.15	103.73	85.92	17.81	1.47	2.9	29.2
21	5.20	5.10	0.10	108.93	91.02	17.91	1.55	1.9	29.4
22	5.35	5.25	0.10	114.28	96.27	18.01	1.62	1.9	29.6
23	5.10	5.00	0.10	119.38	101.27	18.11	1.69	2.0	29.7
24	5.20	5.10	0.10	124.58	106.37	18.21	1.77	1.9	29.9
25	5.20	5.10	0.10	129.78	111.47	18.31	1.84	1.9	30.1
26	5.25	5.15	0.10	135.03	116.62	18.41	1.92	1.9	30.2
27	5.10	5.00	0.10	140.13	121.62	18.51	1.99	2.0	30.4
28	5.30	5.20	0.10	145.43	126.82	18.61	2.06	1.9	30.6
29	5.20	5.10	0.10	150.63	131.92	18.71	2.14	1.9	30.7
30	5.20	5.10	0.10	155.83	137.02	18.81	2.21	1.9	30.9
31	5.25	5.15	0.10	161.08	142.17	18.91	2.29	1.9	31.1
32	5.25	5.15	0.10	166.33	147.32	19.01	2.36	1.9	31.2
33	5.30	5.20	0.10	171.63	152.52	19.11	2.43	1.9	31.4
34	5.35	5.25	0.10	176.98	157.77	19.21	2.51	1.9	31.5
35	5.35	5.25	0.10	182.33	163.02	19.31	2.59	1.9	31.7
36	5.20	5.15	0.05	187.53	168.17	19.36	2.66	1.0	31.8
37	5.23	5.15	0.08	192.76	173.32	19.44	2.73	1.5	31.9
38	5.30	5.20	0.10	198.06	178.52	19.54	2.81	1.9	32.1
39	5.50	5.40	0.10	203.56	183.92	19.64	2.89	1.8	32.2
40	5.25	5.20	0.05	208.81	189.12	19.69	2.96	1.0	32.3

Warner Radial Coreflood 8R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 70.49 ml

Initial Oil Saturation: 60.90 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.55 ft/day									
41	5.15	5.05	0.10	213.96	194.17	19.79	3.04	1.9	32.5
42	5.30	5.25	0.05	219.26	199.42	19.84	3.11	0.9	32.6
43	5.40	5.35	0.05	224.66	204.77	19.89	3.19	0.9	32.7
44	5.28	5.20	0.08	229.94	209.97	19.97	3.26	1.5	32.8
45	4.92	4.85	0.07	234.86	214.82	20.04	3.33	1.4	32.9
46	4.97	4.90	0.07	239.83	219.72	20.11	3.40	1.4	33.0
47	5.33	5.30	0.03	245.16	225.02	20.14	3.48	0.6	33.1
48	5.26	5.20	0.06	250.42	230.22	20.20	3.55	1.1	33.2
49	5.18	5.10	0.08	255.60	235.32	20.28	3.63	1.5	33.3
50	5.20	5.10	0.10	260.80	240.42	20.38	3.70	1.9	33.5
51	5.38	5.35	0.03	266.18	245.77	20.41	3.78	0.6	33.5
52	5.26	5.20	0.06	271.44	250.97	20.47	3.85	1.1	33.6
53	5.30	5.25	0.05	276.74	256.22	20.52	3.93	0.9	33.7
54	5.08	5.00	0.08	281.82	261.22	20.60	4.00	1.6	33.8
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.05 wt% B-100 + 0.05 wt% AS 1216 + 1200 mg/L Flopaam 3630S at 0.55 ft/day									
55	6.43	6.40	0.03	288.25	267.62	20.63	4.09	0.5	33.9
56	4.03	4.00	0.03	292.28	271.62	20.66	4.15	0.7	33.9
57	4.40	3.85	0.55	296.68	275.47	21.21	4.21	12.5	34.8
58	4.70	2.60	2.10	301.38	278.07	23.31	4.28	44.7	38.3
59	4.60	2.45	2.15	305.98	280.52	25.46	4.34	46.7	41.8
1200 mg/L Flopaam 3630S at 0.55 ft/day									
60	4.35	2.50	1.85	310.33	283.02	27.31	4.40	42.5	44.8
61	5.30	3.35	1.95	315.63	286.37	29.26	4.48	36.8	48.0
62	4.75	3.50	1.25	320.38	289.87	30.51	4.55	26.3	50.1
63	4.90	3.90	1.00	325.28	293.77	31.51	4.61	20.4	51.7
64	4.75	3.85	0.90	330.03	297.62	32.41	4.68	18.9	53.2
Injection Water at 0.55 ft/day									
65	5.50	4.65	0.85	335.53	302.27	33.26	4.76	15.5	54.6
66	5.80	5.35	0.45	341.33	307.62	33.71	4.84	7.8	55.4
67	6.10	5.65	0.45	347.43	313.27	34.16	4.93	7.4	56.1
68	5.50	4.80	0.70	352.93	318.07	34.86	5.01	12.7	57.2
69	5.40	5.20	0.20	358.33	323.27	35.06	5.08	3.7	57.6
70	5.20	5.00	0.20	363.53	328.27	35.26	5.16	3.8	57.9
71	5.83	5.80	0.03	369.36	334.07	35.29	5.24	0.5	57.9
72	5.43	5.35	0.08	374.79	339.42	35.37	5.32	1.5	58.1
73	5.28	5.25	0.03	380.07	344.67	35.40	5.39	0.6	58.1
74	5.13	5.10	0.03	385.20	349.77	35.43	5.46	0.6	58.2
75	5.12	5.10	0.02	390.32	354.87	35.45	5.54	0.4	58.2
76	5.46	5.45	0.01	395.78	360.32	35.46	5.61	0.2	58.2

Warner Radial Coreflood 8R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 70.49 ml
Initial Oil Saturation: 60.90 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.55 ft/day									
77	5.35	5.35	0.00	401.13	365.67	35.46	5.69	0.0	58.2
78	5.02	5.00	0.02	406.15	370.67	35.48	5.76	0.4	58.3
79	5.20	5.20	0.00	411.35	375.87	35.48	5.84	0.0	58.3
80	5.10	5.10	0.00	416.45	380.97	35.48	5.91	0.0	58.3
81	5.21	5.20	0.01	421.66	386.17	35.49	5.98	0.2	58.3
82	5.16	5.15	0.01	426.82	391.32	35.50	6.06	0.2	58.3
83	5.10	5.10	0.00	431.92	396.42	35.50	6.13	0.0	58.3
84	5.06	5.05	0.01	436.98	401.47	35.51	6.20	0.2	58.3
85	5.91	5.90	0.01	442.89	407.37	35.52	6.28	0.2	58.3
86	5.40	5.40	0.00	448.29	412.77	35.52	6.36	0.0	58.3
87	5.40	5.40	0.00	453.69	418.17	35.52	6.44	0.0	58.3
88	5.27	5.25	0.02	458.96	423.42	35.54	6.51	0.4	58.4
89	5.06	5.05	0.01	464.02	428.47	35.55	6.58	0.2	58.4
90	4.80	4.80	0.00	468.82	433.27	35.55	6.65	0.0	58.4
91	4.90	4.90	0.00	473.72	438.17	35.55	6.72	0.0	58.4
92	5.10	5.10	0.00	478.82	443.27	35.55	6.79	0.0	58.4
93	5.00	5.00	0.00	483.82	448.27	35.55	6.86	0.0	58.4
94	5.10	5.10	0.00	488.92	453.37	35.55	6.94	0.0	58.4
95	5.06	5.05	0.01	493.98	458.42	35.56	7.01	0.2	58.4
96	5.15	5.15	0.00	499.13	463.57	35.56	7.08	0.0	58.4
97	5.15	5.15	0.00	504.28	468.72	35.56	7.15	0.0	58.4
98	5.31	5.30	0.01	509.59	474.02	35.57	7.23	0.2	58.4
99	5.25	5.25	0.00	514.84	479.27	35.57	7.30	0.0	58.4
100	5.30	5.30	0.00	520.14	484.57	35.57	7.38	0.0	58.4
101	5.25	5.25	0.00	525.39	489.82	35.57	7.45	0.0	58.4
102	5.30	5.30	0.00	530.69	495.12	35.57	7.53	0.0	58.4
103	5.30	5.30	0.00	535.99	500.42	35.57	7.60	0.0	58.4
104	5.30	5.30	0.00	541.29	505.72	35.57	7.68	0.0	58.4
105	5.15	5.15	0.00	546.44	510.87	35.57	7.75	0.0	58.4
106	5.20	5.20	0.00	551.64	516.07	35.57	7.83	0.0	58.4
107	5.20	5.20	0.00	556.84	521.27	35.57	7.90	0.0	58.4
108	5.20	5.20	0.00	562.04	526.47	35.57	7.97	0.0	58.4
109	4.90	4.90	0.00	566.94	531.37	35.57	8.04	0.0	58.4

Warner Radial Coreflood 9R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.68 ml
Initial Oil Saturation: 62.15 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.57 ft/day									
1	0.18	0.00	0.18	0.18	0.00	0.18	0.00	100.0	0.3
2	5.68	0.00	5.68	5.86	0.00	5.86	0.08	100.0	9.4
3	5.75	0.85	4.90	11.61	0.85	10.76	0.15	85.2	17.3
4	6.50	5.00	1.50	18.11	5.85	12.26	0.24	23.1	19.7
5	5.95	5.05	0.90	24.06	10.90	13.16	0.31	15.1	21.2
6	6.35	5.75	0.60	30.41	16.65	13.76	0.40	9.4	22.1
7	6.00	5.50	0.50	36.41	22.15	14.26	0.47	8.3	22.9
8	6.00	5.50	0.50	42.41	27.65	14.76	0.55	8.3	23.7
9	5.60	5.30	0.30	48.01	32.95	15.06	0.63	5.4	24.2
10	5.68	5.42	0.26	53.69	38.37	15.32	0.70	4.6	24.7
11	5.70	5.55	0.15	59.39	43.92	15.47	0.77	2.6	24.9
12	6.02	5.85	0.17	65.41	49.77	15.64	0.85	2.8	25.2
13	6.10	5.88	0.22	71.51	55.65	15.86	0.93	3.6	25.5
14	6.10	5.98	0.12	77.61	61.63	15.98	1.01	2.0	25.7
15	5.90	5.80	0.10	83.51	67.43	16.08	1.09	1.7	25.9
16	5.85	5.70	0.15	89.36	73.13	16.23	1.17	2.6	26.1
17	5.70	5.60	0.10	95.06	78.73	16.33	1.24	1.8	26.3
18	5.90	5.80	0.10	100.96	84.53	16.43	1.32	1.7	26.4
19	6.30	6.20	0.10	107.26	90.73	16.53	1.40	1.6	26.6
20	6.05	5.95	0.10	113.31	96.68	16.63	1.48	1.7	26.8
21	5.75	5.65	0.10	119.06	102.33	16.73	1.55	1.7	26.9
22	5.80	5.70	0.10	124.86	108.03	16.83	1.63	1.7	27.1
23	5.65	5.60	0.05	130.51	113.63	16.88	1.70	0.9	27.2
24	5.70	5.65	0.05	136.21	119.28	16.93	1.78	0.9	27.2
25	5.75	5.70	0.05	141.96	124.98	16.98	1.85	0.9	27.3
26	5.72	5.70	0.02	147.68	130.68	17.00	1.93	0.3	27.4
27	5.90	5.85	0.05	153.58	136.53	17.05	2.00	0.8	27.4
28	5.82	5.80	0.02	159.40	142.33	17.07	2.08	0.3	27.5
29	5.75	5.70	0.05	165.15	148.03	17.12	2.15	0.9	27.5
30	5.62	5.60	0.02	170.77	153.63	17.14	2.23	0.4	27.6
31	5.71	5.70	0.01	176.48	159.33	17.15	2.30	0.2	27.6
32	5.88	5.85	0.03	182.36	165.18	17.18	2.38	0.5	27.6
33	5.92	5.91	0.01	188.28	171.09	17.19	2.46	0.2	27.7
34	5.75	5.70	0.05	194.03	176.79	17.24	2.53	0.9	27.7
35	5.90	5.85	0.05	199.93	182.64	17.29	2.61	0.8	27.8
36	5.80	5.75	0.05	205.73	188.39	17.34	2.68	0.9	27.9
37	5.84	5.80	0.04	211.57	194.19	17.38	2.76	0.7	28.0
38	5.85	5.80	0.05	217.42	199.99	17.43	2.84	0.9	28.0
39	5.95	5.90	0.05	223.37	205.89	17.48	2.91	0.8	28.1
40	5.83	5.80	0.03	229.20	211.69	17.51	2.99	0.5	28.2

Warner Radial Coreflood 9R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.68 ml

Initial Oil Saturation: 62.15 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.57 ft/day									
41	6.27	6.25	0.02	235.47	217.94	17.53	3.07	0.3	28.2
42	5.91	5.90	0.01	241.38	223.84	17.54	3.15	0.2	28.2
43	5.87	5.85	0.02	247.25	229.69	17.56	3.22	0.3	28.3
44	5.71	5.70	0.01	252.96	235.39	17.57	3.30	0.2	28.3
45	5.78	5.75	0.03	258.74	241.14	17.60	3.37	0.5	28.3
46	5.61	5.60	0.01	264.35	246.74	17.61	3.45	0.2	28.3
47	5.86	5.85	0.01	270.21	252.59	17.62	3.52	0.2	28.4
48	6.06	6.05	0.01	276.27	258.64	17.63	3.60	0.2	28.4
49	5.82	5.80	0.02	282.09	264.44	17.65	3.68	0.3	28.4
50	5.51	5.50	0.01	287.60	269.94	17.66	3.75	0.2	28.4
51	5.53	5.50	0.03	293.13	275.44	17.69	3.82	0.5	28.5
52	5.61	5.60	0.01	298.74	281.04	17.70	3.90	0.2	28.5
53	5.87	5.85	0.02	304.61	286.89	17.72	3.97	0.3	28.5
54	5.80	5.80	0.00	310.41	292.69	17.72	4.05	0.0	28.5
55	5.82	5.80	0.02	316.23	298.49	17.74	4.12	0.3	28.5
56	6.80	6.80	0.00	323.03	305.29	17.74	4.21	0.0	28.5
0.625 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Alcoflood 1275A at 0.57 ft/day									
57	4.68	4.60	0.08	327.71	309.89	17.82	4.27	1.7	28.7
58	4.60	4.32	0.28	332.31	314.21	18.10	4.33	6.1	29.1
59	4.40	3.50	0.90	336.71	317.71	19.00	4.39	20.5	30.6
60	4.90	2.80	2.10	341.61	320.51	21.10	4.46	42.9	34.0
61	5.30	2.70	2.60	346.91	323.21	23.70	4.52	49.1	38.1
1200 mg/L Alcoflood 1275A at 0.57 ft/day									
62	5.10	3.00	2.10	352.01	326.21	25.80	4.59	41.2	41.5
63	4.60	3.00	1.60	356.61	329.21	27.40	4.65	34.8	44.1
64	5.00	4.32	0.68	361.61	333.53	28.08	4.72	13.6	45.2
65	4.20	3.51	0.69	365.81	337.04	28.77	4.77	16.4	46.3
66	6.55	6.15	0.40	372.36	343.19	29.17	4.86	6.1	46.9
Injection Water at 0.57 ft/day									
67	6.10	4.90	1.20	378.46	348.09	30.37	4.94	19.7	48.9
68	6.35	6.05	0.30	384.81	354.14	30.67	5.02	4.7	49.3
69	5.95	5.80	0.15	390.76	359.94	30.82	5.10	2.5	49.6
70	5.86	5.85	0.01	396.62	365.79	30.83	5.17	0.2	49.6
71	6.20	6.05	0.15	402.82	371.84	30.98	5.25	2.4	49.8
72	6.08	6.00	0.08	408.90	377.84	31.06	5.33	1.3	50.0
73	5.75	5.70	0.05	414.65	383.54	31.11	5.41	0.9	50.1
74	5.71	5.70	0.01	420.36	389.24	31.12	5.48	0.2	50.1
75	5.85	5.85	0.00	426.21	395.09	31.12	5.56	0.0	50.1

Warner Radial Coreflood 9R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.68 ml
Initial Oil Saturation: 62.15 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.57 ft/day									
76	5.93	5.90	0.03	432.14	400.99	31.15	5.64	0.5	50.1
77	5.45	5.44	0.01	437.59	406.43	31.16	5.71	0.2	50.1
78	5.53	5.45	0.08	443.12	411.88	31.24	5.78	1.4	50.3
79	5.40	5.40	0.00	448.52	417.28	31.24	5.85	0.0	50.3
80	5.70	5.70	0.00	454.22	422.98	31.24	5.92	0.0	50.3
81	5.75	5.75	0.00	459.97	428.73	31.24	6.00	0.0	50.3
82	5.80	5.80	0.00	465.77	434.53	31.24	6.07	0.0	50.3
83	5.75	5.75	0.00	471.52	440.28	31.24	6.15	0.0	50.3
84	5.70	5.70	0.00	477.22	445.98	31.24	6.22	0.0	50.3
85	5.75	5.75	0.00	482.97	451.73	31.24	6.30	0.0	50.3
86	6.30	6.30	0.00	489.27	458.03	31.24	6.38	0.0	50.3
87	6.35	6.35	0.00	495.62	464.38	31.24	6.46	0.0	50.3
88	5.85	5.85	0.00	501.47	470.23	31.24	6.54	0.0	50.3
89	5.51	5.50	0.01	506.98	475.73	31.25	6.61	0.2	50.3
90	5.80	5.80	0.00	512.78	481.53	31.25	6.69	0.0	50.3
91	5.90	5.90	0.00	518.68	487.43	31.25	6.76	0.0	50.3
92	6.20	6.20	0.00	524.88	493.63	31.25	6.85	0.0	50.3
93	6.30	6.24	0.06	531.18	499.87	31.31	6.93	1.0	50.4
94	5.80	5.80	0.00	536.98	505.67	31.31	7.00	0.0	50.4
95	5.80	5.80	0.00	542.78	511.47	31.31	7.08	0.0	50.4
96	5.50	5.50	0.00	548.28	516.97	31.31	7.15	0.0	50.4
97	6.90	6.90	0.00	555.18	523.87	31.31	7.24	0.0	50.4
98	3.50	3.50	0.00	558.68	527.37	31.31	7.29	0.0	50.4

Warner Radial Coreflood 10R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 73.19 ml

Initial Oil Saturation: 59.41 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.60 ft/day									
1	1.20	0.20	1.00	1.20	0.20	1.00	0.02	83.3	1.7
2	5.72	2.75	2.97	6.92	2.95	3.97	0.09	51.9	6.7
3	5.10	2.60	2.50	12.02	5.55	6.47	0.16	49.0	10.9
4	4.94	2.85	2.09	16.96	8.40	8.56	0.23	42.3	14.4
5	5.25	3.15	2.10	22.21	11.55	10.66	0.30	40.0	17.9
6	5.09	3.30	1.79	27.30	14.85	12.45	0.37	35.2	21.0
7	5.78	4.40	1.38	33.08	19.25	13.83	0.45	23.9	23.3
8	6.15	5.20	0.95	39.23	24.45	14.78	0.54	15.4	24.9
9	5.55	4.82	0.73	44.78	29.27	15.51	0.61	13.2	26.1
10	5.75	5.22	0.53	50.53	34.49	16.04	0.69	9.2	27.0
11	5.70	5.32	0.38	56.23	39.81	16.42	0.77	6.7	27.6
12	6.00	5.65	0.35	62.23	45.46	16.77	0.85	5.8	28.2
13	6.30	5.95	0.35	68.53	51.41	17.12	0.94	5.6	28.8
14	6.40	6.05	0.35	74.93	57.46	17.47	1.02	5.5	29.4
15	6.00	5.68	0.32	80.93	63.14	17.79	1.11	5.3	29.9
16	6.00	5.75	0.25	86.93	68.89	18.04	1.19	4.2	30.4
17	5.95	5.70	0.25	92.88	74.59	18.29	1.27	4.2	30.8
18	5.75	5.50	0.25	98.63	80.09	18.54	1.35	4.3	31.2
19	6.00	5.85	0.15	104.63	85.94	18.69	1.43	2.5	31.5
20	6.00	5.85	0.15	110.63	91.79	18.84	1.51	2.5	31.7
21	6.05	5.85	0.20	116.68	97.64	19.04	1.59	3.3	32.0
22	5.90	5.73	0.17	122.58	103.37	19.21	1.67	2.9	32.3
23	5.70	5.55	0.15	128.28	108.92	19.36	1.75	2.6	32.6
24	5.60	5.40	0.20	133.88	114.32	19.56	1.83	3.6	32.9
25	5.70	5.60	0.10	139.58	119.92	19.66	1.91	1.8	33.1
26	5.85	5.70	0.15	145.43	125.62	19.81	1.99	2.6	33.3
27	5.72	5.60	0.12	151.15	131.22	19.93	2.07	2.1	33.5
28	5.85	5.70	0.15	157.00	136.92	20.08	2.15	2.6	33.8
29	5.90	5.80	0.10	162.90	142.72	20.18	2.23	1.7	34.0
30	5.75	5.65	0.10	168.65	148.37	20.28	2.30	1.7	34.1
31	5.85	5.75	0.10	174.50	154.12	20.38	2.38	1.7	34.3
32	5.95	5.85	0.10	180.45	159.97	20.48	2.47	1.7	34.5
33	5.95	5.85	0.10	186.40	165.82	20.58	2.55	1.7	34.6
34	5.85	5.70	0.15	192.25	171.52	20.73	2.63	2.6	34.9
35	6.15	6.05	0.10	198.40	177.57	20.83	2.71	1.6	35.1
36	5.80	5.70	0.10	204.20	183.27	20.93	2.79	1.7	35.2
37	5.80	5.70	0.10	210.00	188.97	21.03	2.87	1.7	35.4
38	5.85	5.75	0.10	215.85	194.72	21.13	2.95	1.7	35.6
39	5.78	5.68	0.10	221.63	200.40	21.23	3.03	1.7	35.7
40	6.05	5.95	0.10	227.68	206.35	21.33	3.11	1.7	35.9

Warner Radial Coreflood 10R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 73.19 ml

Initial Oil Saturation: 59.41 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.60 ft/day									
41	5.90	5.80	0.10	233.58	212.15	21.43	3.19	1.7	36.1
42	5.95	5.85	0.10	239.53	218.00	21.53	3.27	1.7	36.2
43	5.95	5.85	0.10	245.48	223.85	21.63	3.35	1.7	36.4
44	5.93	5.85	0.08	251.41	229.70	21.71	3.44	1.3	36.5
45	6.13	6.05	0.08	257.54	235.75	21.79	3.52	1.3	36.7
46	5.75	5.65	0.10	263.29	241.40	21.89	3.60	1.7	36.8
47	5.88	5.80	0.08	269.17	247.20	21.97	3.68	1.4	37.0
48	5.90	5.80	0.10	275.07	253.00	22.07	3.76	1.7	37.1
49	5.95	5.85	0.10	281.02	258.85	22.17	3.84	1.7	37.3
50	5.85	5.75	0.10	286.87	264.60	22.27	3.92	1.7	37.5
51	5.78	5.70	0.08	292.65	270.30	22.35	4.00	1.4	37.6
52	5.75	5.70	0.05	298.40	276.00	22.40	4.08	0.9	37.7
53	5.73	5.70	0.03	304.13	281.70	22.43	4.16	0.5	37.8
54	5.87	5.80	0.07	310.00	287.50	22.50	4.24	1.2	37.9
55	5.80	5.75	0.05	315.80	293.25	22.55	4.31	0.9	38.0
56	5.65	5.58	0.07	321.45	298.83	22.62	4.39	1.2	38.1
57	6.81	6.80	0.01	328.26	305.63	22.63	4.49	0.1	38.1
0.625 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.60 ft/day									
58	4.70	4.58	0.12	332.96	310.21	22.75	4.55	2.6	38.3
59	4.90	4.78	0.12	337.86	314.99	22.87	4.62	2.4	38.5
60	4.80	3.85	0.95	342.66	318.84	23.82	4.68	19.8	40.1
61	5.60	3.40	2.20	348.26	322.24	26.02	4.76	39.3	43.8
62	6.00	3.60	2.40	354.26	325.84	28.42	4.84	40.0	47.8
1200 mg/L Flopaam 3630S at 0.60 ft/day									
63	5.35	3.85	1.50	359.61	329.69	29.92	4.91	28.0	50.4
64	5.80	4.58	1.22	365.41	334.27	31.14	4.99	21.0	52.4
65	4.70	3.95	0.75	370.11	338.22	31.89	5.06	16.0	53.7
66	5.20	4.40	0.80	375.31	342.62	32.69	5.13	15.4	55.0
67	3.70	3.10	0.60	379.01	345.72	33.29	5.18	16.2	56.0
Injection Water at 0.60 ft/day									
68	5.90	5.30	0.60	384.91	351.02	33.89	5.26	10.2	57.0
69	6.35	5.90	0.45	391.26	356.92	34.34	5.35	7.1	57.8
70	6.05	5.72	0.33	397.31	362.64	34.67	5.43	5.5	58.4
71	5.70	5.30	0.40	403.01	367.94	35.07	5.51	7.0	59.0
72	5.85	5.70	0.15	408.86	373.64	35.22	5.59	2.6	59.3
73	6.30	6.20	0.10	415.16	379.84	35.32	5.67	1.6	59.5
74	5.83	5.75	0.08	420.99	385.59	35.40	5.75	1.4	59.6
75	5.65	5.35	0.30	426.64	390.94	35.70	5.83	5.3	60.1

Warner Radial Coreflood 10R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 73.19 ml
Initial Oil Saturation: 59.41 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.60 ft/day									
76	5.80	5.70	0.10	432.44	396.64	35.80	5.91	1.7	60.3
77	5.70	5.65	0.05	438.14	402.29	35.85	5.99	0.9	60.3
78	5.72	5.65	0.07	443.86	407.94	35.92	6.06	1.2	60.5
79	5.73	5.65	0.08	449.59	413.59	36.00	6.14	1.4	60.6
80	5.60	5.55	0.05	455.19	419.14	36.05	6.22	0.9	60.7
81	5.65	5.60	0.05	460.84	424.74	36.10	6.30	0.9	60.8
82	5.70	5.70	0.00	466.54	430.44	36.10	6.37	0.0	60.8
83	5.65	5.65	0.00	472.19	436.09	36.10	6.45	0.0	60.8
84	5.75	5.70	0.05	477.94	441.79	36.15	6.53	0.9	60.8
85	5.75	5.75	0.00	483.69	447.54	36.15	6.61	0.0	60.8
86	5.62	5.60	0.02	489.31	453.14	36.17	6.69	0.4	60.9
87	6.00	6.00	0.00	495.31	459.14	36.17	6.77	0.0	60.9
88	6.35	6.35	0.00	501.66	465.49	36.17	6.85	0.0	60.9
89	5.80	5.80	0.00	507.46	471.29	36.17	6.93	0.0	60.9
90	5.52	5.50	0.02	512.98	476.79	36.19	7.01	0.4	60.9
91	5.62	5.60	0.02	518.60	482.39	36.21	7.09	0.4	60.9
92	5.77	5.75	0.02	524.37	488.14	36.23	7.16	0.3	61.0
93	6.11	6.10	0.01	530.48	494.24	36.24	7.25	0.2	61.0
94	6.20	6.20	0.00	536.68	500.44	36.24	7.33	0.0	61.0
95	6.10	6.05	0.05	542.78	506.49	36.29	7.42	0.8	61.1
96	5.71	5.70	0.01	548.49	512.19	36.30	7.49	0.2	61.1
97	5.51	5.50	0.01	554.00	517.69	36.31	7.57	0.2	61.1
98	5.35	5.35	0.00	559.35	523.04	36.31	7.64	0.0	61.1
99	3.10	3.05	0.05	562.45	526.09	36.36	7.68	1.6	61.2

Warner Radial Coreflood 11R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 79.58 ml
Initial Oil Saturation: 65.34 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.48 ft/day									
1	1.01	0.00	1.01	1.01	0.00	1.01	0.01	100.0	1.5
2	5.30	0.00	5.30	6.31	0.00	6.31	0.08	100.0	9.7
3	5.05	0.25	4.80	11.36	0.25	11.11	0.14	95.0	17.0
4	5.10	0.60	4.50	16.46	0.85	15.61	0.21	88.2	23.9
5	4.85	0.75	4.10	21.31	1.60	19.71	0.27	84.5	30.2
6	5.13	3.40	1.73	26.44	5.00	21.44	0.33	33.7	32.8
7	5.30	4.50	0.80	31.74	9.50	22.24	0.40	15.1	34.0
8	5.20	4.42	0.78	36.94	13.92	23.02	0.46	15.0	35.2
9	5.05	4.35	0.70	41.99	18.27	23.72	0.53	13.9	36.3
10	5.00	4.40	0.60	46.99	22.67	24.32	0.59	12.0	37.2
11	5.40	4.90	0.50	52.39	27.57	24.82	0.66	9.3	38.0
12	5.30	4.90	0.40	57.69	32.47	25.22	0.72	7.5	38.6
13	5.50	5.10	0.40	63.19	37.57	25.62	0.79	7.3	39.2
14	5.20	4.90	0.30	68.39	42.47	25.92	0.86	5.8	39.7
15	5.38	5.01	0.37	73.77	47.48	26.29	0.93	6.9	40.2
16	5.53	5.19	0.34	79.30	52.67	26.63	1.00	6.1	40.8
17	5.35	5.00	0.35	84.65	57.67	26.98	1.06	6.5	41.3
18	5.30	5.00	0.30	89.95	62.67	27.28	1.13	5.7	41.8
19	4.90	4.70	0.20	94.85	67.37	27.48	1.19	4.1	42.1
20	5.20	5.00	0.20	100.05	72.37	27.68	1.26	3.8	42.4
21	5.40	5.15	0.25	105.45	77.52	27.93	1.33	4.6	42.7
22	5.20	4.98	0.22	110.65	82.50	28.15	1.39	4.2	43.1
23	5.10	4.90	0.20	115.75	87.40	28.35	1.45	3.9	43.4
24	5.20	5.02	0.18	120.95	92.42	28.53	1.52	3.5	43.7
25	5.60	5.40	0.20	126.55	97.82	28.73	1.59	3.6	44.0
26	5.25	5.00	0.25	131.80	102.82	28.98	1.66	4.8	44.4
27	5.18	5.03	0.15	136.98	107.85	29.13	1.72	2.9	44.6
28	5.28	5.10	0.18	142.26	112.95	29.31	1.79	3.4	44.9
29	5.23	5.08	0.15	147.49	118.03	29.46	1.85	2.9	45.1
30	5.33	5.25	0.08	152.82	123.28	29.54	1.92	1.5	45.2
31	5.00	4.90	0.10	157.82	128.18	29.64	1.98	2.0	45.4
32	5.10	5.00	0.10	162.92	133.18	29.74	2.05	2.0	45.5
33	5.20	5.10	0.10	168.12	138.28	29.84	2.11	1.9	45.7
34	5.33	5.20	0.13	173.45	143.48	29.97	2.18	2.4	45.9
35	5.12	5.00	0.12	178.57	148.48	30.09	2.24	2.3	46.1
36	4.90	4.80	0.10	183.47	153.28	30.19	2.31	2.0	46.2
37	5.35	5.25	0.10	188.82	158.53	30.29	2.37	1.9	46.4
38	5.32	5.22	0.10	194.14	163.75	30.39	2.44	1.9	46.5
39	5.20	5.10	0.10	199.34	168.85	30.49	2.50	1.9	46.7
40	5.05	4.95	0.10	204.39	173.80	30.59	2.57	2.0	46.8

Warner Radial Coreflood 11R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 79.58 ml
Initial Oil Saturation: 65.34 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.48 ft/day									
41	5.10	5.00	0.10	209.49	178.80	30.69	2.63	2.0	47.0
42	5.30	5.20	0.10	214.79	184.00	30.79	2.70	1.9	47.1
43	5.35	5.25	0.10	220.14	189.25	30.89	2.77	1.9	47.3
44	5.10	5.00	0.10	225.24	194.25	30.99	2.83	2.0	47.4
45	5.95	5.85	0.10	231.19	200.10	31.09	2.91	1.7	47.6
46	5.05	5.00	0.05	236.24	205.10	31.14	2.97	1.0	47.7
47	5.08	5.00	0.08	241.32	210.10	31.22	3.03	1.6	47.8
48	5.28	5.20	0.08	246.60	215.30	31.30	3.10	1.5	47.9
49	5.18	5.10	0.08	251.78	220.40	31.38	3.16	1.5	48.0
50	5.17	5.10	0.07	256.95	225.50	31.45	3.23	1.4	48.1
51	5.17	5.10	0.07	262.12	230.60	31.52	3.29	1.4	48.2
52	5.03	5.00	0.03	267.15	235.60	31.55	3.36	0.6	48.3
53	5.10	5.05	0.05	272.25	240.65	31.60	3.42	1.0	48.4
54	5.05	5.00	0.05	277.30	245.65	31.65	3.48	1.0	48.4
55	5.02	5.00	0.02	282.32	250.65	31.67	3.55	0.4	48.5
56	6.04	6.00	0.04	288.36	256.65	31.71	3.62	0.7	48.5
57	6.31	6.30	0.01	294.67	262.95	31.72	3.70	0.2	48.5
58	5.43	5.35	0.08	300.10	268.30	31.80	3.77	1.5	48.7
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.48 ft/day									
59	3.87	3.85	0.02	303.97	272.15	31.82	3.82	0.5	48.7
60	4.06	4.05	0.01	308.03	276.20	31.83	3.87	0.2	48.7
61	4.38	4.20	0.18	312.41	280.40	32.01	3.93	4.1	49.0
62	6.40	5.35	1.05	318.81	285.75	33.06	4.01	16.4	50.6
63	4.85	3.40	1.45	323.66	289.15	34.51	4.07	29.9	52.8
1200 mg/L Flopaam 3630S at 0.48 ft/day									
64	4.50	3.00	1.50	328.16	292.15	36.01	4.12	33.3	55.1
65	4.45	2.88	1.57	332.61	295.03	37.58	4.18	35.3	57.5
66	5.45	3.80	1.65	338.06	298.83	39.23	4.25	30.3	60.0
67	5.82	4.30	1.52	343.88	303.13	40.75	4.32	26.1	62.4
68	4.58	3.50	1.08	348.46	306.63	41.83	4.38	23.6	64.0
Injection Water at 0.48 ft/day									
69	4.20	3.35	0.85	352.66	309.98	42.68	4.43	20.2	65.3
70	5.43	4.69	0.74	358.09	314.67	43.42	4.50	13.6	66.5
71	5.30	4.80	0.50	363.39	319.47	43.92	4.57	9.4	67.2
72	4.35	4.10	0.25	367.74	323.57	44.17	4.62	5.7	67.6
73	4.20	3.80	0.40	371.94	327.37	44.57	4.67	9.5	68.2
74	4.95	4.85	0.10	376.89	332.22	44.67	4.74	2.0	68.4
75	6.05	5.85	0.20	382.94	338.07	44.87	4.81	3.3	68.7

Warner Radial Coreflood 11R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 79.58 ml
Initial Oil Saturation: 65.34 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.48 ft/day									
76	6.20	6.05	0.15	389.14	344.12	45.02	4.89	2.4	68.9
77	5.22	4.98	0.24	394.36	349.10	45.26	4.96	4.6	69.3
78	4.35	4.25	0.10	398.71	353.35	45.36	5.01	2.3	69.4
79	4.80	4.70	0.10	403.51	358.05	45.46	5.07	2.1	69.6
80	5.82	5.80	0.02	409.33	363.85	45.48	5.14	0.3	69.6
81	6.18	6.08	0.10	415.51	369.93	45.58	5.22	1.6	69.8
82	5.65	5.55	0.10	421.16	375.48	45.68	5.29	1.8	69.9
83	5.18	5.10	0.08	426.34	380.58	45.76	5.36	1.5	70.0
84	5.01	5.00	0.01	431.35	385.58	45.77	5.42	0.2	70.0
85	5.36	5.30	0.06	436.71	390.88	45.83	5.49	1.1	70.1
86	5.56	5.50	0.06	442.27	396.38	45.89	5.56	1.1	70.2
87	5.76	5.75	0.01	448.03	402.13	45.90	5.63	0.2	70.2
88	5.64	5.58	0.06	453.67	407.71	45.96	5.70	1.1	70.3
89	5.30	5.25	0.05	458.97	412.96	46.01	5.77	0.9	70.4
90	5.01	5.00	0.01	463.98	417.96	46.02	5.83	0.2	70.4
91	4.72	4.70	0.02	468.70	422.66	46.04	5.89	0.4	70.5
92	4.81	4.80	0.01	473.51	427.46	46.05	5.95	0.2	70.5
93	5.16	5.15	0.01	478.67	432.61	46.06	6.01	0.2	70.5
94	5.11	5.10	0.01	483.78	437.71	46.07	6.08	0.2	70.5
95	5.12	5.10	0.02	488.90	442.81	46.09	6.14	0.4	70.5
96	4.80	4.80	0.00	493.70	447.61	46.09	6.20	0.0	70.5
97	5.15	5.15	0.00	498.85	452.76	46.09	6.27	0.0	70.5
98	5.41	5.40	0.01	504.26	458.16	46.10	6.34	0.2	70.6
99	5.26	5.25	0.01	509.52	463.41	46.11	6.40	0.2	70.6
100	4.96	4.95	0.01	514.48	468.36	46.12	6.46	0.2	70.6
101	5.07	5.05	0.02	519.55	473.41	46.14	6.53	0.4	70.6
102	5.01	5.00	0.01	524.56	478.41	46.15	6.59	0.2	70.6
103	5.20	5.20	0.00	529.76	483.61	46.15	6.66	0.0	70.6
104	5.10	5.05	0.05	534.86	488.66	46.20	6.72	1.0	70.7
105	4.97	4.95	0.02	539.83	493.61	46.22	6.78	0.4	70.7
106	4.96	4.95	0.01	544.79	498.56	46.23	6.85	0.2	70.8
107	5.20	5.20	0.00	549.99	503.76	46.23	6.91	0.0	70.8
108	5.21	5.20	0.01	555.20	508.96	46.24	6.98	0.2	70.8
109	5.16	5.15	0.01	560.36	514.11	46.25	7.04	0.2	70.8
110	5.01	5.00	0.01	565.37	519.11	46.26	7.10	0.2	70.8
111	5.20	5.20	0.00	570.57	524.31	46.26	7.17	0.0	70.8
112	5.11	5.10	0.01	575.68	529.41	46.27	7.23	0.2	70.8
113	4.96	4.95	0.01	580.64	534.36	46.28	7.30	0.2	70.8
114	5.06	5.05	0.01	585.70	539.41	46.29	7.36	0.2	70.8

Warner Radial Coreflood 12R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.59 ml
Initial Oil Saturation: 64.20 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.50 ft/day									
1	1.40	0.00	1.40	1.40	0.00	1.40	0.02	100.0	2.2
2	5.40	0.10	5.30	6.80	0.10	6.70	0.09	98.1	10.4
3	5.00	0.25	4.75	11.80	0.35	11.45	0.15	95.0	17.8
4	4.70	0.30	4.40	16.50	0.65	15.85	0.22	93.6	24.7
5	4.75	1.10	3.65	21.25	1.75	19.50	0.28	76.8	30.4
6	4.90	3.90	1.00	26.15	5.65	20.50	0.34	20.4	31.9
7	5.75	4.21	1.54	31.90	9.86	22.04	0.42	26.8	34.3
8	5.10	4.20	0.90	37.00	14.06	22.94	0.48	17.6	35.7
9	5.20	4.45	0.75	42.20	18.51	23.69	0.55	14.4	36.9
10	5.20	4.70	0.50	47.40	23.21	24.19	0.62	9.6	37.7
11	5.30	4.82	0.48	52.70	28.03	24.67	0.69	9.1	38.4
12	5.45	5.05	0.40	58.15	33.08	25.07	0.76	7.3	39.0
13	5.30	5.00	0.30	63.45	38.08	25.37	0.83	5.7	39.5
14	5.30	5.00	0.30	68.75	43.08	25.67	0.90	5.7	40.0
15	5.25	5.00	0.25	74.00	48.08	25.92	0.97	4.8	40.4
16	5.55	5.30	0.25	79.55	53.38	26.17	1.04	4.5	40.8
17	5.50	5.30	0.20	85.05	58.68	26.37	1.11	3.6	41.1
18	5.00	4.85	0.15	90.05	63.53	26.52	1.18	3.0	41.3
19	5.00	4.80	0.20	95.05	68.33	26.72	1.24	4.0	41.6
20	5.30	5.15	0.15	100.35	73.48	26.87	1.31	2.8	41.9
21	5.30	5.15	0.15	105.65	78.63	27.02	1.38	2.8	42.1
22	5.20	5.05	0.15	110.85	83.68	27.17	1.45	2.9	42.3
23	5.05	4.90	0.15	115.90	88.58	27.32	1.51	3.0	42.6
24	4.60	4.50	0.10	120.50	93.08	27.42	1.57	2.2	42.7
25	5.30	5.15	0.15	125.80	98.23	27.57	1.64	2.8	42.9
26	5.10	4.95	0.15	130.90	103.18	27.72	1.71	2.9	43.2
27	5.10	4.89	0.21	136.00	108.07	27.93	1.78	4.1	43.5
28	5.10	5.00	0.10	141.10	113.07	28.03	1.84	2.0	43.7
29	5.27	5.15	0.12	146.37	118.22	28.15	1.91	2.3	43.8
30	5.25	5.15	0.10	151.62	123.37	28.25	1.98	1.9	44.0
31	5.12	5.00	0.12	156.74	128.37	28.37	2.05	2.3	44.2
32	5.20	5.10	0.10	161.94	133.47	28.47	2.11	1.9	44.3
33	5.35	5.25	0.10	167.29	138.72	28.57	2.18	1.9	44.5
34	5.35	5.25	0.10	172.64	143.97	28.67	2.25	1.9	44.7
35	5.25	5.15	0.10	177.89	149.12	28.77	2.32	1.9	44.8
36	4.95	4.90	0.05	182.84	154.02	28.82	2.39	1.0	44.9
37	5.08	5.00	0.08	187.92	159.02	28.90	2.45	1.6	45.0
38	5.23	5.15	0.08	193.15	164.17	28.98	2.52	1.5	45.1
39	5.25	5.15	0.10	198.40	169.32	29.08	2.59	1.9	45.3
40	5.13	5.05	0.08	203.53	174.37	29.16	2.66	1.6	45.4

Warner Radial Coreflood 12R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.59 ml
Initial Oil Saturation: 64.20 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.50 ft/day									
41	4.89	4.80	0.09	208.42	179.17	29.25	2.72	1.8	45.6
42	5.27	5.20	0.07	213.69	184.37	29.32	2.79	1.3	45.7
43	5.37	5.30	0.07	219.06	189.67	29.39	2.86	1.3	45.8
44	5.15	5.05	0.10	224.21	194.72	29.49	2.93	1.9	45.9
45	4.98	4.90	0.08	229.19	199.62	29.57	2.99	1.6	46.1
46	5.07	5.00	0.07	234.26	204.62	29.64	3.06	1.4	46.2
47	5.25	5.20	0.05	239.51	209.82	29.69	3.13	1.0	46.2
48	5.28	5.20	0.08	244.79	215.02	29.77	3.20	1.5	46.4
49	5.08	5.00	0.08	249.87	220.02	29.85	3.26	1.6	46.5
50	5.17	5.15	0.02	255.04	225.17	29.87	3.33	0.4	46.5
51	5.05	5.00	0.05	260.09	230.17	29.92	3.40	1.0	46.6
52	5.31	5.30	0.01	265.40	235.47	29.93	3.47	0.2	46.6
53	5.16	5.15	0.01	270.56	240.62	29.94	3.53	0.2	46.6
54	5.16	5.15	0.01	275.72	245.77	29.95	3.60	0.2	46.7
55	4.65	4.60	0.05	280.37	250.37	30.00	3.66	1.1	46.7
56	6.05	6.04	0.01	286.42	256.41	30.01	3.74	0.2	46.7
57	7.33	7.20	0.13	293.75	263.61	30.14	3.84	1.8	46.9
58	5.55	5.40	0.15	299.30	269.01	30.29	3.91	2.7	47.2
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day									
59	4.08	4.00	0.08	303.38	273.01	30.37	3.96	2.0	47.3
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day									
60	4.10	4.05	0.05	307.48	277.06	30.42	4.01	1.2	47.4
61	3.95	3.80	0.15	311.43	280.86	30.57	4.07	3.8	47.6
62	6.30	5.55	0.75	317.73	286.41	31.32	4.15	11.9	48.8
63	4.95	3.75	1.20	322.68	290.16	32.52	4.21	24.2	50.7
1200 mg/L Flopaam 3630S at 0.50 ft/day									
64	4.60	3.20	1.40	327.28	293.36	33.92	4.27	30.4	52.8
65	4.48	3.21	1.27	331.76	296.57	35.19	4.33	28.3	54.8
66	4.90	3.55	1.35	336.66	300.12	36.54	4.40	27.6	56.9
67	6.05	4.65	1.40	342.71	304.77	37.94	4.47	23.1	59.1
68	4.70	3.75	0.95	347.41	308.52	38.89	4.54	20.2	60.6
Injection Water at 0.50 ft/day									
69	5.00	4.38	0.62	352.41	312.90	39.51	4.60	12.4	61.5
70	5.05	4.62	0.43	357.46	317.52	39.94	4.67	8.5	62.2
71	6.00	5.88	0.12	363.46	323.40	40.06	4.75	2.0	62.4
72	5.30	4.85	0.45	368.76	328.25	40.51	4.81	8.5	63.1
73	4.45	3.80	0.65	373.21	332.05	41.16	4.87	14.6	64.1
74	4.55	4.45	0.10	377.76	336.50	41.26	4.93	2.2	64.3

Warner Radial Coreflood 12R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 76.59 ml
Initial Oil Saturation: 64.20 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.50 ft/day									
75	5.65	5.60	0.05	383.41	342.10	41.31	5.01	0.9	64.3
76	5.95	5.65	0.30	389.36	347.75	41.61	5.08	5.0	64.8
77	5.60	5.60	0.00	394.96	353.35	41.61	5.16	0.0	64.8
78	4.40	4.10	0.30	399.36	357.45	41.91	5.21	6.8	65.3
79	4.59	4.50	0.09	403.95	361.95	42.00	5.27	2.0	65.4
80	5.60	5.55	0.05	409.55	367.50	42.05	5.35	0.9	65.5
81	6.10	6.00	0.10	415.65	373.50	42.15	5.43	1.6	65.7
82	5.46	5.40	0.06	421.11	378.90	42.21	5.50	1.1	65.7
83	6.00	5.90	0.10	427.11	384.80	42.31	5.58	1.7	65.9
84	4.82	4.80	0.02	431.93	389.60	42.33	5.64	0.4	65.9
85	5.15	5.15	0.00	437.08	394.75	42.33	5.71	0.0	65.9
86	5.35	5.30	0.05	442.43	400.05	42.38	5.78	0.9	66.0
87	5.71	5.70	0.01	448.14	405.75	42.39	5.85	0.2	66.0
88	5.42	5.40	0.02	453.56	411.15	42.41	5.92	0.4	66.1
89	4.72	4.70	0.02	458.28	415.85	42.43	5.98	0.4	66.1
90	5.08	5.05	0.03	463.36	420.90	42.46	6.05	0.6	66.1
91	4.72	4.70	0.02	468.08	425.60	42.48	6.11	0.4	66.2
92	4.76	4.75	0.01	472.84	430.35	42.49	6.17	0.2	66.2
93	5.05	5.05	0.00	477.89	435.40	42.49	6.24	0.0	66.2
94	5.11	5.10	0.01	483.00	440.50	42.50	6.31	0.2	66.2
95	5.07	5.05	0.02	488.07	445.55	42.52	6.37	0.4	66.2
96	4.86	4.85	0.01	492.93	450.40	42.53	6.44	0.2	66.2
97	5.10	5.10	0.00	498.03	455.50	42.53	6.50	0.0	66.2
98	5.30	5.30	0.00	503.33	460.80	42.53	6.57	0.0	66.2
99	5.11	5.10	0.01	508.44	465.90	42.54	6.64	0.2	66.3
100	5.01	5.00	0.01	513.45	470.90	42.55	6.70	0.2	66.3
101	5.26	5.25	0.01	518.71	476.15	42.56	6.77	0.2	66.3
102	5.15	5.15	0.00	523.86	481.30	42.56	6.84	0.0	66.3
103	5.15	5.15	0.00	529.01	486.45	42.56	6.91	0.0	66.3
104	5.07	5.05	0.02	534.08	491.50	42.58	6.97	0.4	66.3
105	5.20	5.20	0.00	539.28	496.70	42.58	7.04	0.0	66.3
106	5.01	5.00	0.01	544.29	501.70	42.59	7.11	0.2	66.3
107	5.30	5.30	0.00	549.59	507.00	42.59	7.18	0.0	66.3
108	5.21	5.20	0.01	554.80	512.20	42.60	7.24	0.2	66.4
109	5.16	5.15	0.01	559.96	517.35	42.61	7.31	0.2	66.4
110	5.06	5.05	0.01	565.02	522.40	42.62	7.38	0.2	66.4
111	5.30	5.30	0.00	570.32	527.70	42.62	7.45	0.0	66.4
112	5.26	5.25	0.01	575.58	532.95	42.63	7.52	0.2	66.4
113	5.01	5.00	0.01	580.59	537.95	42.64	7.58	0.2	66.4
114	5.06	5.05	0.01	585.65	543.00	42.65	7.65	0.2	66.4

Warner Radial Coreflood 13R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.08 ml
Initial Oil Saturation: 70.32 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.50 ft/day									
1	0.32	0.00	0.32	0.32	0.00	0.32	0.00	100.0	0.5
2	5.75	0.00	5.75	6.07	0.00	6.07	0.08	100.0	8.6
3	5.50	0.00	5.50	11.57	0.00	11.57	0.14	100.0	16.5
4	5.20	0.00	5.20	16.77	0.00	16.77	0.21	100.0	23.8
5	5.10	0.55	4.55	21.87	0.55	21.32	0.27	89.2	30.3
6	5.45	2.95	2.50	27.32	3.50	23.82	0.34	45.9	33.9
7	5.60	4.25	1.35	32.92	7.75	25.17	0.41	24.1	35.8
8	5.55	4.55	1.00	38.47	12.30	26.17	0.48	18.0	37.2
9	5.60	4.65	0.95	44.07	16.95	27.12	0.55	17.0	38.6
10	4.95	4.25	0.70	49.02	21.20	27.82	0.61	14.1	39.6
11	4.60	4.05	0.55	53.62	25.25	28.37	0.67	12.0	40.3
12	4.70	4.15	0.55	58.32	29.40	28.92	0.73	11.7	41.1
13	5.35	4.90	0.45	63.67	34.30	29.37	0.80	8.4	41.8
14	5.90	5.50	0.40	69.57	39.80	29.77	0.87	6.8	42.3
15	6.10	5.70	0.40	75.67	45.50	30.17	0.94	6.6	42.9
16	5.60	5.15	0.45	81.27	50.65	30.62	1.01	8.0	43.5
17	5.10	4.85	0.25	86.37	55.50	30.87	1.08	4.9	43.9
18	5.50	5.20	0.30	91.87	60.70	31.17	1.15	5.5	44.3
19	5.75	5.45	0.30	97.62	66.15	31.47	1.22	5.2	44.8
20	5.60	5.30	0.30	103.22	71.45	31.77	1.29	5.4	45.2
21	5.30	5.05	0.25	108.52	76.50	32.02	1.36	4.7	45.5
22	5.25	5.00	0.25	113.77	81.50	32.27	1.42	4.8	45.9
23	5.70	5.45	0.25	119.47	86.95	32.52	1.49	4.4	46.2
24	5.55	5.30	0.25	125.02	92.25	32.77	1.56	4.5	46.6
25	5.60	5.35	0.25	130.62	97.60	33.02	1.63	4.5	47.0
26	5.55	5.40	0.15	136.17	103.00	33.17	1.70	2.7	47.2
27	5.40	5.20	0.20	141.57	108.20	33.37	1.77	3.7	47.5
28	5.45	5.25	0.20	147.02	113.45	33.57	1.84	3.7	47.7
29	5.58	5.50	0.08	152.60	118.95	33.65	1.91	1.4	47.9
30	5.65	5.45	0.20	158.25	124.40	33.85	1.98	3.5	48.1
31	5.60	5.38	0.22	163.85	129.78	34.07	2.05	3.9	48.4
32	5.60	5.40	0.20	169.45	135.18	34.27	2.12	3.6	48.7
33	5.60	5.40	0.20	175.05	140.58	34.47	2.19	3.6	49.0
34	5.50	5.35	0.15	180.55	145.93	34.62	2.25	2.7	49.2
35	5.55	5.40	0.15	186.10	151.33	34.77	2.32	2.7	49.4
36	5.58	5.40	0.18	191.68	156.73	34.95	2.39	3.2	49.7
37	5.40	5.25	0.15	197.08	161.98	35.10	2.46	2.8	49.9
38	5.65	5.50	0.15	202.73	167.48	35.25	2.53	2.7	50.1
39	5.40	5.20	0.20	208.13	172.68	35.45	2.60	3.7	50.4
40	5.45	5.30	0.15	213.58	177.98	35.60	2.67	2.8	50.6

Warner Radial Coreflood 13R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.08 ml

Initial Oil Saturation: 70.32 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Produced Water at 0.50 ft/day									
41	5.55	5.45	0.10	219.13	183.43	35.70	2.74	1.8	50.8
42	5.45	5.35	0.10	224.58	188.78	35.80	2.80	1.8	50.9
43	5.30	5.20	0.10	229.88	193.98	35.90	2.87	1.9	51.1
44	5.35	5.25	0.10	235.23	199.23	36.00	2.94	1.9	51.2
45	5.30	5.20	0.10	240.53	204.43	36.10	3.00	1.9	51.3
46	5.40	5.30	0.10	245.93	209.73	36.20	3.07	1.9	51.5
47	5.55	5.45	0.10	251.48	215.18	36.30	3.14	1.8	51.6
48	5.40	5.30	0.10	256.88	220.48	36.40	3.21	1.9	51.8
49	5.45	5.35	0.10	262.33	225.83	36.50	3.28	1.8	51.9
50	5.60	5.50	0.10	267.93	231.33	36.60	3.35	1.8	52.0
51	5.38	5.30	0.08	273.31	236.63	36.68	3.41	1.5	52.2
52	5.35	5.25	0.10	278.66	241.88	36.78	3.48	1.9	52.3
53	5.53	5.45	0.08	284.19	247.33	36.86	3.55	1.4	52.4
54	5.55	5.45	0.10	289.74	252.78	36.96	3.62	1.8	52.6
55	5.33	5.25	0.08	295.07	258.03	37.04	3.68	1.5	52.7
56	5.20	5.10	0.10	300.27	263.13	37.14	3.75	1.9	52.8
57	5.25	5.20	0.05	305.52	268.33	37.19	3.82	1.0	52.9
58	5.38	5.30	0.08	310.90	273.63	37.27	3.88	1.5	53.0
59	5.43	5.35	0.08	316.33	278.98	37.35	3.95	1.5	53.1
60	4.60	4.50	0.10	320.93	283.48	37.45	4.01	2.2	53.3
61	4.80	4.75	0.05	325.73	288.23	37.50	4.07	1.0	53.3
62	4.83	4.80	0.03	330.56	293.03	37.53	4.13	0.6	53.4
63	4.26	4.20	0.06	334.82	297.23	37.59	4.18	1.4	53.5
64	4.31	4.30	0.01	339.13	301.53	37.60	4.23	0.2	53.5
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day									
65	4.45	4.45	0.00	343.58	305.98	37.60	4.29	0.0	53.5
66	4.60	4.60	0.00	348.18	310.58	37.60	4.35	0.0	53.5
67	3.79	3.70	0.09	351.97	314.28	37.69	4.40	2.4	53.6
68	3.10	2.88	0.22	355.07	317.16	37.91	4.43	7.1	53.9
69	4.65	3.40	1.25	359.72	320.56	39.16	4.49	26.9	55.7
70	6.60	4.32	2.28	366.32	324.88	41.44	4.57	34.5	58.9
1200 mg/L Flopaam 3630S at 0.50 ft/day									
71	5.00	3.70	1.30	371.32	328.58	42.74	4.64	26.0	60.8
72	6.10	4.55	1.55	377.42	333.13	44.29	4.71	25.4	63.0
73	5.65	4.35	1.30	383.07	337.48	45.59	4.78	23.0	64.8
74	3.70	2.90	0.80	386.77	340.38	46.39	4.83	21.6	66.0
75	4.55	3.70	0.85	391.32	344.08	47.24	4.89	18.7	67.2

Warner Radial Coreflood 13R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.08 ml
Initial Oil Saturation: 70.32 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Injection Water at 0.50 ft/day									
76	4.60	3.98	0.62	395.92	348.06	47.86	4.94	13.5	68.1
77	5.00	4.50	0.50	400.92	352.56	48.36	5.01	10.0	68.8
78	5.20	4.85	0.35	406.12	357.41	48.71	5.07	6.7	69.3
79	5.50	5.30	0.20	411.62	362.71	48.91	5.14	3.6	69.6
80	5.40	5.30	0.10	417.02	368.01	49.01	5.21	1.9	69.7
81	5.20	5.00	0.20	422.22	373.01	49.21	5.27	3.8	70.0
82	5.10	4.95	0.15	427.32	377.96	49.36	5.34	2.9	70.2
83	5.40	5.25	0.15	432.72	383.21	49.51	5.40	2.8	70.4
84	5.49	5.40	0.09	438.21	388.61	49.60	5.47	1.6	70.5
85	5.65	5.55	0.10	443.86	394.16	49.70	5.54	1.8	70.7
86	5.40	5.28	0.12	449.26	399.44	49.82	5.61	2.2	70.8
87	5.65	5.55	0.10	454.91	404.99	49.92	5.68	1.8	71.0
88	5.36	5.35	0.01	460.27	410.34	49.93	5.75	0.2	71.0
89	5.80	5.70	0.10	466.07	416.04	50.03	5.82	1.7	71.1
90	5.55	5.50	0.05	471.62	421.54	50.08	5.89	0.9	71.2
91	5.25	5.20	0.05	476.87	426.74	50.13	5.95	1.0	71.3
92	5.20	5.15	0.05	482.07	431.89	50.18	6.02	1.0	71.4
93	5.48	5.40	0.08	487.55	437.29	50.26	6.09	1.5	71.5
94	5.20	5.20	0.00	492.75	442.49	50.26	6.15	0.0	71.5
95	5.80	5.79	0.01	498.55	448.28	50.27	6.23	0.2	71.5
96	5.53	5.50	0.03	504.08	453.78	50.30	6.29	0.5	71.5
97	5.50	5.40	0.10	509.58	459.18	50.40	6.36	1.8	71.7
98	5.15	5.10	0.05	514.73	464.28	50.45	6.43	1.0	71.7
99	5.06	5.05	0.01	519.79	469.33	50.46	6.49	0.2	71.8
100	5.10	5.10	0.00	524.89	474.43	50.46	6.55	0.0	71.8
101	5.37	5.35	0.02	530.26	479.78	50.48	6.62	0.4	71.8
102	5.50	5.50	0.00	535.76	485.28	50.48	6.69	0.0	71.8
103	5.16	5.10	0.06	540.92	490.38	50.54	6.75	1.2	71.9
104	5.20	5.20	0.00	546.12	495.58	50.54	6.82	0.0	71.9
105	5.40	5.40	0.00	551.52	500.98	50.54	6.89	0.0	71.9
106	5.41	5.40	0.01	556.93	506.38	50.55	6.95	0.2	71.9
107	5.25	5.18	0.07	562.18	511.56	50.62	7.02	1.3	72.0
108	5.25	5.25	0.00	567.43	516.81	50.62	7.09	0.0	72.0
109	5.10	5.10	0.00	572.53	521.91	50.62	7.15	0.0	72.0
110	5.40	5.40	0.00	577.93	527.31	50.62	7.22	0.0	72.0
111	5.32	5.25	0.07	583.25	532.56	50.69	7.28	1.3	72.1
112	5.30	5.30	0.00	588.55	537.86	50.69	7.35	0.0	72.1
113	5.05	5.05	0.00	593.60	542.91	50.69	7.41	0.0	72.1
114	5.40	5.40	0.00	599.00	548.31	50.69	7.48	0.0	72.1
115	2.41	2.40	0.01	601.41	550.71	50.70	7.51	0.4	72.1

Warner Radial Coreflood 14R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.78 ml
Initial Oil Saturation: 67.98 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.49 ft/day									
1	0.48	0.00	0.48	0.48	0.00	0.48	0.01	100.0	0.7
2	4.50	0.45	4.05	4.98	0.45	4.53	0.06	90.0	6.7
3	4.10	0.60	3.50	9.08	1.05	8.03	0.11	85.4	11.8
4	5.51	3.65	1.86	14.59	4.70	9.89	0.18	33.8	14.5
5	5.50	4.48	1.02	20.09	9.18	10.91	0.25	18.5	16.0
6	5.50	4.70	0.80	25.59	13.88	11.71	0.32	14.5	17.2
7	5.41	4.85	0.56	31.00	18.73	12.27	0.38	10.4	18.0
8	5.50	4.95	0.55	36.50	23.68	12.82	0.45	10.0	18.9
9	5.50	5.10	0.40	42.00	28.78	13.22	0.52	7.3	19.4
10	5.30	4.90	0.40	47.30	33.68	13.62	0.59	7.5	20.0
11	5.60	5.20	0.40	52.90	38.88	14.02	0.65	7.1	20.6
12	5.55	5.15	0.40	58.45	44.03	14.42	0.72	7.2	21.2
13	5.40	5.15	0.25	63.85	49.18	14.67	0.79	4.6	21.6
14	5.45	5.10	0.35	69.30	54.28	15.02	0.86	6.4	22.1
15	5.70	5.40	0.30	75.00	59.68	15.32	0.93	5.3	22.5
16	5.25	5.10	0.15	80.25	64.78	15.47	0.99	2.9	22.8
17	5.10	4.90	0.20	85.35	69.68	15.67	1.06	3.9	23.1
18	5.20	5.05	0.15	90.55	74.73	15.82	1.12	2.9	23.3
19	5.40	5.25	0.15	95.95	79.98	15.97	1.19	2.8	23.5
20	5.35	5.20	0.15	101.30	85.18	16.12	1.25	2.8	23.7
21	5.45	5.30	0.15	106.75	90.48	16.27	1.32	2.8	23.9
22	5.35	5.20	0.15	112.10	95.68	16.42	1.39	2.8	24.2
23	5.45	5.30	0.15	117.55	100.98	16.57	1.46	2.8	24.4
24	5.40	5.30	0.10	122.95	106.28	16.67	1.52	1.9	24.5
25	5.38	5.28	0.10	128.33	111.56	16.77	1.59	1.9	24.7
26	5.40	5.25	0.15	133.73	116.81	16.92	1.66	2.8	24.9
27	5.35	5.25	0.10	139.08	122.06	17.02	1.72	1.9	25.0
28	5.35	5.20	0.15	144.43	127.26	17.17	1.79	2.8	25.3
29	5.50	5.40	0.10	149.93	132.66	17.27	1.86	1.8	25.4
30	5.30	5.20	0.10	155.23	137.86	17.37	1.92	1.9	25.6
31	5.25	5.20	0.05	160.48	143.06	17.42	1.99	1.0	25.6
32	5.20	5.10	0.10	165.68	148.16	17.52	2.05	1.9	25.8
33	5.30	5.25	0.05	170.98	153.41	17.57	2.12	0.9	25.8
34	5.25	5.15	0.10	176.23	158.56	17.67	2.18	1.9	26.0
35	5.42	5.35	0.07	181.65	163.91	17.74	2.25	1.3	26.1
36	5.23	5.15	0.08	186.88	169.06	17.82	2.31	1.5	26.2
37	5.37	5.30	0.07	192.25	174.36	17.89	2.38	1.3	26.3
38	5.35	5.30	0.05	197.60	179.66	17.94	2.45	0.9	26.4
39	5.43	5.35	0.08	203.03	185.01	18.02	2.51	1.5	26.5
40	5.27	5.20	0.07	208.30	190.21	18.09	2.58	1.3	26.6

Warner Radial Coreflood 14R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.78 ml
Initial Oil Saturation: 67.98 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
	Total	Water	Oil	Total	Water	Oil			
Produced Water at 0.49 ft/day									
41	5.35	5.30	0.05	213.65	195.51	18.14	2.64	0.9	26.7
42	5.52	5.45	0.07	219.17	200.96	18.21	2.71	1.3	26.8
43	5.13	5.10	0.03	224.30	206.06	18.24	2.78	0.6	26.8
44	5.40	5.35	0.05	229.70	211.41	18.29	2.84	0.9	26.9
45	5.25	5.20	0.05	234.95	216.61	18.34	2.91	1.0	27.0
46	5.25	5.20	0.05	240.20	221.81	18.39	2.97	1.0	27.1
47	5.23	5.20	0.03	245.43	227.01	18.42	3.04	0.6	27.1
48	5.38	5.35	0.03	250.81	232.36	18.45	3.10	0.6	27.1
49	5.40	5.35	0.05	256.21	237.71	18.50	3.17	0.9	27.2
50	5.42	5.40	0.02	261.63	243.11	18.52	3.24	0.4	27.2
51	5.48	5.45	0.03	267.11	248.56	18.55	3.31	0.5	27.3
52	5.33	5.30	0.03	272.44	253.86	18.58	3.37	0.6	27.3
53	5.37	5.35	0.02	277.81	259.21	18.60	3.44	0.4	27.4
54	5.40	5.35	0.05	283.21	264.56	18.65	3.51	0.9	27.4
55	5.46	5.45	0.01	288.67	270.01	18.66	3.57	0.2	27.4
56	5.35	5.30	0.05	294.02	275.31	18.71	3.64	0.9	27.5
57	5.24	5.20	0.04	299.26	280.51	18.75	3.70	0.8	27.6
58	5.21	5.20	0.01	304.47	285.71	18.76	3.77	0.2	27.6
59	5.32	5.30	0.02	309.79	291.01	18.78	3.83	0.4	27.6
60	5.58	5.55	0.03	315.37	296.56	18.81	3.90	0.5	27.7
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.49 ft/day									
61	4.51	4.48	0.03	319.88	301.04	18.84	3.96	0.7	27.7
62	4.15	3.35	0.80	324.03	304.39	19.64	4.01	19.3	28.9
63	3.60	1.75	1.85	327.63	306.14	21.49	4.06	51.4	31.6
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.49 ft/day									
64	4.55	2.15	2.40	332.18	308.29	23.89	4.11	52.7	35.1
65	4.05	1.70	2.35	336.23	309.99	26.24	4.16	58.0	38.6
66	4.25	2.05	2.20	340.48	312.04	28.44	4.21	51.8	41.8
1200 mg/L Flopaam 3630S at 0.49 ft/day									
67	4.90	2.50	2.40	345.38	314.54	30.84	4.28	49.0	45.4
68	5.40	2.95	2.45	350.78	317.49	33.29	4.34	45.4	49.0
69	4.95	2.90	2.05	355.73	320.39	35.34	4.40	41.4	52.0
70	5.40	3.65	1.75	361.13	324.04	37.09	4.47	32.4	54.6
71	4.00	2.80	1.20	365.13	326.84	38.29	4.52	30.0	56.3
Injection Water at 0.49 ft/day									
72	4.90	3.85	1.05	370.03	330.69	39.34	4.58	21.4	57.9
73	4.55	2.55	2.00	374.58	333.24	41.34	4.64	44.0	60.8
74	4.85	4.10	0.75	379.43	337.34	42.09	4.70	15.5	61.9

Warner Radial Coreflood 14R
Incremental Oil Cut and Cumulative Oil Recovery

Pore Volume: 80.78 ml
Initial Oil Saturation: 67.98 ml

Tube No.	----Produced----			-----Cumulative-----			V _P	Oil Cut	Oil Recovery
	----Volume, ml----			-----Production-----					
Total	Water	Oil	Total	Water	Oil				
Injection Water at 0.49 ft/day									
75	4.90	4.50	0.40	384.33	341.84	42.49	4.76	8.2	62.5
76	4.95	4.85	0.10	389.28	346.69	42.59	4.82	2.0	62.7
77	5.10	4.95	0.15	394.38	351.64	42.74	4.88	2.9	62.9
78	5.00	4.90	0.10	399.38	356.54	42.84	4.94	2.0	63.0
79	4.96	4.90	0.06	404.34	361.44	42.90	5.01	1.2	63.1
80	5.05	5.00	0.05	409.39	366.44	42.95	5.07	1.0	63.2
81	5.20	5.15	0.05	414.59	371.59	43.00	5.13	1.0	63.3
82	5.23	5.20	0.03	419.82	376.79	43.03	5.20	0.6	63.3
83	5.13	5.10	0.03	424.95	381.89	43.06	5.26	0.6	63.3
84	5.26	5.25	0.01	430.21	387.14	43.07	5.33	0.2	63.4
85	5.55	5.55	0.00	435.76	392.69	43.07	5.39	0.0	63.4
86	5.90	5.90	0.00	441.66	398.59	43.07	5.47	0.0	63.4
87	6.10	6.10	0.00	447.76	404.69	43.07	5.54	0.0	63.4
88	5.61	5.60	0.01	453.37	410.29	43.08	5.61	0.2	63.4
89	5.02	5.00	0.02	458.39	415.29	43.10	5.67	0.4	63.4
90	4.90	4.90	0.00	463.29	420.19	43.10	5.74	0.0	63.4
91	4.86	4.85	0.01	468.15	425.04	43.11	5.80	0.2	63.4
92	5.00	5.00	0.00	473.15	430.04	43.11	5.86	0.0	63.4
93	4.81	4.80	0.01	477.96	434.84	43.12	5.92	0.2	63.4
94	5.01	5.00	0.01	482.97	439.84	43.13	5.98	0.2	63.4
95	5.00	5.00	0.00	487.97	444.84	43.13	6.04	0.0	63.4
96	5.01	5.00	0.01	492.98	449.84	43.14	6.10	0.2	63.5
97	5.05	5.05	0.00	498.03	454.89	43.14	6.17	0.0	63.5
98	5.16	5.15	0.01	503.19	460.04	43.15	6.23	0.2	63.5
99	5.00	5.00	0.00	508.19	465.04	43.15	6.29	0.0	63.5
100	5.31	5.30	0.01	513.50	470.34	43.16	6.36	0.2	63.5
101	5.05	5.05	0.00	518.55	475.39	43.16	6.42	0.0	63.5
102	5.30	5.30	0.00	523.85	480.69	43.16	6.48	0.0	63.5
103	5.21	5.20	0.01	529.06	485.89	43.17	6.55	0.2	63.5
104	5.36	5.35	0.01	534.42	491.24	43.18	6.62	0.2	63.5
105	5.20	5.20	0.00	539.62	496.44	43.18	6.68	0.0	63.5
106	5.30	5.30	0.00	544.92	501.74	43.18	6.75	0.0	63.5
107	5.20	5.20	0.00	550.12	506.94	43.18	6.81	0.0	63.5
108	5.20	5.20	0.00	555.32	512.14	43.18	6.87	0.0	63.5

Warner Radial Coreflood 1R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.51 ft/day							
0	0.00	0.93	0.37	1.30	3.1	18.4	4.1
Production Water at 0.51 ft/day							
1	0.03	0.44	0.06	0.50	1.5	2.8	1.6
2	0.08	0.43	0.04	0.47	1.4	2.2	1.5
3	0.13	0.41	0.07	0.48	1.4	3.4	1.5
4	0.18	0.39	0.09	0.48	1.3	4.6	1.5
5	0.24	0.31	0.15	0.46	1.0	7.6	1.5
6	0.29	0.28	0.16	0.44	0.9	7.8	1.4
7	0.35	0.24	0.19	0.43	0.8	9.4	1.4
8	0.40	0.23	0.19	0.42	0.8	9.6	1.3
9	0.45	0.21	0.21	0.42	0.7	10.4	1.3
10	0.51	0.20	0.22	0.42	0.7	10.8	1.3
11	0.56	0.20	0.22	0.41	0.7	10.8	1.3
12	0.61	0.18	0.22	0.41	0.6	11.2	1.3
13	0.66	0.16	0.25	0.40	0.5	12.4	1.3
14	0.71	0.17	0.23	0.40	0.6	11.7	1.3
15	0.77	0.18	0.21	0.40	0.6	10.6	1.2
16	0.82	0.17	0.22	0.39	0.6	11.0	1.2
17	0.87	0.16	0.23	0.39	0.5	11.4	1.2
18	0.92	0.16	0.22	0.38	0.5	11.2	1.2
19	0.98	0.17	0.20	0.38	0.6	10.2	1.2
20	1.03	0.18	0.19	0.37	0.6	9.6	1.2
21	1.08	0.18	0.18	0.36	0.6	9.0	1.1
22	1.14	0.18	0.18	0.36	0.6	9.0	1.1
23	1.19	0.18	0.18	0.36	0.6	9.0	1.1
24	1.24	0.18	0.18	0.36	0.6	9.0	1.1
25	1.29	0.18	0.17	0.35	0.6	8.6	1.1
26	1.35	0.18	0.16	0.34	0.6	8.2	1.1
27	1.40	0.18	0.16	0.34	0.6	8.2	1.1
28	1.45	0.18	0.16	0.34	0.6	8.2	1.1
29	1.50	0.18	0.16	0.34	0.6	8.2	1.1
30	1.54	0.19	0.16	0.34	0.6	7.8	1.1
31	1.59	0.20	0.15	0.34	0.7	7.4	1.1
32	1.64	0.21	0.13	0.34	0.7	6.6	1.1
33	1.69	0.22	0.12	0.34	0.7	6.2	1.1
34	1.75	0.23	0.12	0.34	0.8	5.8	1.1
35	1.80	0.24	0.10	0.34	0.8	5.2	1.1

Warner Radial Coreflood 1R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Production Water at 0.51 ft/day							
36	1.86	0.25	0.09	0.34	0.8	4.6	1.1
37	1.91	0.26	0.09	0.34	0.9	4.4	1.1
38	1.96	0.26	0.08	0.34	0.9	4.2	1.1
39	2.03	0.26	0.08	0.34	0.9	3.8	1.1
40	2.11	0.26	0.07	0.33	0.9	3.4	1.0
41	2.18	0.26	0.06	0.33	0.9	3.2	1.0
42	2.25	0.27	0.06	0.33	0.9	3.0	1.0
43	2.31	0.27	0.05	0.32	0.9	2.6	1.0
44	2.38	0.28	0.05	0.32	0.9	2.4	1.0
45	2.45	0.28	0.04	0.32	0.9	1.8	1.0
46	2.52	0.30	0.02	0.32	1.0	1.2	1.0
47	2.58	0.30	0.02	0.32	1.0	1.0	1.0
48	2.65	0.30	0.02	0.32	1.0	1.0	1.0
49	2.72	0.30	0.02	0.32	1.0	1.0	1.0
50	2.78	0.30	0.02	0.32	1.0	1.0	1.0
51	2.85	0.30	0.02	0.32	1.0	1.0	1.0
52	2.90	0.30	0.02	0.32	1.0	1.0	1.0
53	2.95	0.30	0.02	0.32	1.0	1.0	1.0
54	3.02	0.30	0.02	0.32	1.0	1.0	1.0
55	3.07	0.30	0.02	0.32	1.0	1.0	1.0
0.75 wt% NaOH + 0.1 wt% ORS-164HF + 1200 mg/L Flopaam 3630S at 0.51 ft/day							
56	3.12	0.30	0.02	0.32	1.0	1.0	1.0
57	3.16	0.21	0.24	0.45	0.7	11.8	1.4
58	3.20	0.46	0.10	0.56	1.5	4.8	1.7
59	3.24	0.67	0.13	0.80	2.2	6.6	2.5
60	3.28	0.82	0.00	0.82	2.7	0.0	2.6
61	3.33	0.79	0.04	0.83	2.6	1.9	2.6
62	3.37	0.73	0.10	0.83	2.4	4.9	2.6
63	3.42	0.79	0.05	0.84	2.6	2.4	2.6
64	3.46	0.79	0.05	0.84	2.6	2.6	2.6
1200 mg/L Flopaam 3630S at 0.51 ft/day							
65	3.51	0.83	0.16	0.99	2.8	8.2	3.1
66	3.55	1.01	0.08	1.08	3.4	3.8	3.4
67	3.60	1.08	0.08	1.16	3.6	3.8	3.6
68	3.64	1.14	0.05	1.18	3.8	2.4	3.7
69	3.69	1.16	0.04	1.20	3.9	1.8	3.8
70	3.73	1.19	0.04	1.22	4.0	1.8	3.8

Warner Radial Coreflood 1R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
1200 mg/L Flopaam 3630S at 0.51 ft/day							
71	3.77	1.22	0.03	1.25	4.1	1.4	3.9
72	3.82	1.25	0.04	1.29	4.2	1.8	4.0
Injection Water at 0.51 ft/day							
73	3.87	1.08	0.04	1.12	3.6	2.2	3.5
74	3.93	0.94	0.10	1.04	3.1	4.8	3.2
75	3.98	0.76	0.16	0.92	2.5	8.2	2.9
76	4.03	0.68	0.08	0.76	2.3	3.8	2.4
77	4.09	0.61	0.02	0.62	2.0	0.8	2.0
78	4.14	0.60	0.01	0.61	2.0	0.4	1.9
79	4.19	0.60	0.01	0.60	2.0	0.4	1.9
80	4.25	0.59	0.01	0.60	2.0	0.4	1.9
81	4.30	0.58	0.02	0.60	1.9	1.0	1.9
82	4.35	0.56	0.04	0.60	1.9	1.8	1.9
83	4.40	0.56	0.04	0.59	1.9	1.8	1.9
84	4.46	0.55	0.04	0.59	1.8	2.0	1.8
85	4.51	0.52	0.06	0.58	1.7	3.0	1.8
86	4.56	0.52	0.06	0.58	1.7	2.8	1.8
87	4.61	0.51	0.05	0.56	1.7	2.4	1.8
88	4.66	0.50	0.06	0.56	1.7	2.8	1.8
89	4.72	0.50	0.06	0.56	1.7	2.8	1.8
90	4.77	0.50	0.06	0.56	1.7	3.0	1.8
91	4.82	0.50	0.07	0.58	1.7	3.6	1.8
92	4.87	0.50	0.08	0.58	1.7	4.0	1.8
93	4.92	0.50	0.08	0.58	1.7	3.8	1.8
94	4.98	0.50	0.06	0.57	1.7	3.2	1.8
95	5.03	0.50	0.06	0.56	1.7	3.2	1.8
96	5.08	0.50	0.06	0.56	1.7	3.0	1.7
97	5.14	0.49	0.05	0.54	1.6	2.6	1.7
98	5.25	0.48	0.06	0.54	1.6	3.0	1.7
99	5.30	0.48	0.06	0.54	1.6	3.2	1.7
100	5.35	0.47	0.07	0.54	1.6	3.6	1.7
101	5.40	0.47	0.08	0.55	1.6	3.8	1.7
102	5.45	0.47	0.08	0.55	1.6	4.0	1.7
103	5.50	0.47	0.08	0.55	1.6	4.0	1.7
104	5.56	0.47	0.08	0.55	1.6	4.0	1.7
105	5.61	0.46	0.08	0.54	1.5	3.8	1.7
106	5.66	0.46	0.08	0.54	1.5	3.8	1.7

Warner Radial Coreflood 1R
Incremental Resistance Factors

Tube No.	Cum	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
	V _P	P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.51 ft/day							
107	5.71	0.46	0.07	0.53	1.5	3.6	1.7
108	5.76	0.45	0.07	0.52	1.5	3.4	1.6
109	5.82	0.44	0.08	0.52	1.5	3.8	1.6
110	5.87	0.44	0.08	0.52	1.5	4.0	1.6
111	5.92	0.44	0.08	0.52	1.5	4.0	1.6
112	5.97	0.44	0.08	0.52	1.5	4.0	1.6
113	6.03	0.44	0.08	0.52	1.5	4.0	1.6
114	6.08	0.44	0.08	0.52	1.5	4.0	1.6
115	6.13	0.44	0.08	0.52	1.5	4.0	1.6

Warner Radial Coreflood 2R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.50 ft/day							
0	0.00	0.51	0.30	0.81	5.6	8.2	6.3
Production Water at 0.50 ft/day							
1	0.01	0.08	0.23	0.31	0.9	6.4	2.4
2	0.05	0.08	0.24	0.32	0.9	6.7	2.5
3	0.11	0.08	0.20	0.28	0.9	5.7	2.2
4	0.16	0.08	0.18	0.26	0.8	4.9	2.0
5	0.22	0.07	0.17	0.24	0.8	4.7	1.9
6	0.27	0.07	0.16	0.23	0.7	4.5	1.8
7	0.32	0.06	0.15	0.21	0.7	4.2	1.6
8	0.38	0.06	0.14	0.20	0.7	3.9	1.6
9	0.43	0.06	0.14	0.20	0.7	3.9	1.6
10	0.48	0.06	0.14	0.20	0.6	4.0	1.6
11	0.53	0.06	0.14	0.20	0.7	3.9	1.6
12	0.58	0.06	0.14	0.20	0.7	3.9	1.6
13	0.63	0.06	0.14	0.20	0.7	3.9	1.6
14	0.68	0.06	0.14	0.20	0.7	3.8	1.5
15	0.73	0.06	0.14	0.20	0.7	3.8	1.5
16	0.79	0.06	0.14	0.20	0.7	3.8	1.5
17	0.84	0.06	0.14	0.20	0.7	3.8	1.5
18	0.89	0.06	0.14	0.20	0.7	3.8	1.5
19	0.94	0.06	0.14	0.20	0.7	3.8	1.5
20	1.00	0.06	0.14	0.20	0.7	3.8	1.5
21	1.05	0.06	0.14	0.20	0.7	3.8	1.5
22	1.10	0.06	0.14	0.20	0.7	3.8	1.5
23	1.15	0.06	0.14	0.20	0.7	3.8	1.5
24	1.20	0.07	0.12	0.19	0.8	3.3	1.5
25	1.25	0.07	0.09	0.16	0.8	2.5	1.3
26	1.31	0.07	0.09	0.16	0.8	2.5	1.3
27	1.34	0.07	0.09	0.16	0.7	2.6	1.3
28	1.40	0.07	0.09	0.16	0.8	2.4	1.3
29	1.42	0.07	0.09	0.16	0.8	2.5	1.3
30	1.47	0.08	0.08	0.16	0.8	2.3	1.3
31	1.52	0.08	0.08	0.16	0.9	2.2	1.3
32	1.52	0.08	0.08	0.16	0.9	2.1	1.3
33	1.65	0.08	0.08	0.16	0.8	2.3	1.3
34	1.70	0.08	0.07	0.16	0.9	2.1	1.2
35	1.76	0.09	0.07	0.15	0.9	1.8	1.2

Warner Radial Coreflood 2R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Production Water at 0.50 ft/day							
36	1.80	0.09	0.06	0.15	1.0	1.6	1.2
37	1.88	0.09	0.05	0.14	1.0	1.5	1.1
38	1.95	0.09	0.05	0.14	1.0	1.4	1.1
39	2.03	0.09	0.05	0.14	1.0	1.4	1.1
40	2.10	0.09	0.05	0.14	1.0	1.4	1.1
41	2.18	0.09	0.05	0.14	1.0	1.5	1.1
42	2.25	0.09	0.06	0.15	1.0	1.6	1.2
43	2.32	0.09	0.06	0.15	1.0	1.7	1.2
44	2.39	0.09	0.06	0.15	1.0	1.7	1.2
45	2.47	0.09	0.06	0.15	1.0	1.6	1.2
46	2.54	0.09	0.05	0.14	1.0	1.5	1.1
47	2.62	0.09	0.03	0.12	1.0	0.7	0.9
48	2.69	0.09	0.03	0.12	1.0	0.7	0.9
49	2.76	0.09	0.03	0.12	1.0	0.7	0.9
50	2.83	0.09	0.03	0.12	1.0	0.8	0.9
51	2.90	0.09	0.03	0.12	1.0	0.8	0.9
52	2.97	0.09	0.03	0.12	1.0	0.8	0.9
53	3.02	0.09	0.03	0.12	1.0	0.8	0.9
54	3.06	0.09	0.03	0.12	1.0	0.8	0.9
55	3.13	0.09	0.03	0.12	1.0	0.8	0.9
56	3.18	0.09	0.04	0.13	1.0	1.0	1.0
57	3.24	0.09	0.04	0.13	1.0	1.0	1.0
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.1 wt% EOR 2095 + 1200 mg/L Flopaam 3630S							
58	3.28	0.28	0.57	0.85	3.0	15.9	6.7
59	3.29	0.30	0.54	0.83	3.2	14.9	6.5
60	3.34	0.32	0.47	0.79	3.4	13.1	6.2
61	3.38	0.32	0.45	0.77	3.5	12.6	6.0
62	3.43	0.33	0.44	0.76	3.6	12.1	6.0
63	3.47	0.30	0.46	0.76	3.3	12.7	5.9
64	3.52	0.30	0.46	0.76	3.3	12.7	5.9
65	3.57	0.30	0.46	0.76	3.3	12.7	5.9
1200 mg/L Flopaam 3630S at 0.50 ft/day							
66	3.61	0.38	0.49	0.87	4.1	13.7	6.8
67	3.65	0.43	0.50	0.93	4.7	14.0	7.3
68	3.70	0.42	0.52	0.94	4.6	14.4	7.3
69	3.74	0.42	0.52	0.94	4.6	14.4	7.3
70	3.79	0.42	0.52	0.94	4.6	14.4	7.3

Warner Radial Coreflood 2R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
1200 mg/L Flopaam 3630S at 0.50 ft/day							
71	3.83	0.42	0.52	0.94	4.6	14.4	7.3
72	3.87	0.42	0.52	0.94	4.6	14.4	7.3
73	3.91	0.42	0.52	0.94	4.6	14.4	7.3
Injection Water at 0.50 ft/day							
74	3.97	0.29	0.48	0.78	3.2	13.4	6.1
75	4.03	0.25	0.39	0.64	2.7	10.9	5.0
76	4.08	0.22	0.31	0.53	2.4	8.6	4.1
77	4.13	0.20	0.26	0.46	2.2	7.2	3.6
78	4.18	0.19	0.24	0.42	2.0	6.6	3.3
79	4.24	0.18	0.21	0.39	2.0	5.9	3.1
80	4.29	0.18	0.19	0.37	2.0	5.3	2.9
81	4.34	0.18	0.16	0.34	2.0	4.6	2.7
82	4.39	0.18	0.16	0.34	1.9	4.6	2.7
83	4.44	0.17	0.17	0.34	1.9	4.7	2.7
84	4.49	0.17	0.16	0.34	1.9	4.6	2.6
85	4.55	0.17	0.16	0.33	1.9	4.4	2.6
86	4.60	0.17	0.16	0.33	1.9	4.4	2.6
87	4.65	0.17	0.16	0.33	1.9	4.3	2.6
88	4.70	0.17	0.16	0.32	1.8	4.3	2.5
89	4.75	0.17	0.16	0.32	1.8	4.3	2.5
90	4.80	0.17	0.16	0.32	1.8	4.3	2.5
91	4.86	0.17	0.16	0.32	1.8	4.3	2.5
92	4.91	0.16	0.16	0.32	1.8	4.3	2.5
93	4.96	0.16	0.15	0.32	1.8	4.2	2.5
94	5.01	0.16	0.15	0.31	1.8	4.1	2.4
95	5.06	0.16	0.14	0.31	1.8	4.0	2.4
96	5.11	0.16	0.14	0.30	1.8	3.9	2.4
97	5.16	0.16	0.14	0.30	1.8	3.8	2.3
98	5.27	0.16	0.14	0.30	1.8	3.8	2.3
99	5.32	0.16	0.14	0.30	1.8	3.8	2.3
100	5.37	0.16	0.13	0.30	1.8	3.7	2.3
101	5.42	0.16	0.13	0.30	1.8	3.7	2.3
102	5.48	0.16	0.13	0.30	1.8	3.7	2.3
103	5.53	0.16	0.14	0.30	1.7	3.8	2.3
104	5.58	0.16	0.14	0.30	1.7	3.8	2.3
105	5.63	0.16	0.13	0.29	1.7	3.7	2.3
106	5.68	0.16	0.13	0.29	1.7	3.7	2.3

Warner Radial Coreflood 2R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.50 ft/day							
107	5.73	0.16	0.13	0.28	1.7	3.6	2.2
108	5.78	0.16	0.13	0.28	1.7	3.6	2.2
109	5.83	0.16	0.12	0.28	1.7	3.4	2.2
110	5.89	0.16	0.12	0.27	1.7	3.2	2.1
111	5.94	0.16	0.11	0.27	1.7	3.1	2.1
112	5.99	0.16	0.11	0.26	1.7	3.0	2.1
113	6.05	0.16	0.10	0.26	1.7	2.9	2.0
114	6.10	0.16	0.10	0.26	1.7	2.9	2.0
115	6.15	0.16	0.10	0.26	1.7	2.9	2.0
116	6.20	0.16	0.10	0.26	1.7	2.9	2.0

Warner Radial Coreflood 3R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
	P ₁	P ₂	P _T				
Warner Crude Oil at 0.54 ft/day							
0	0.00	0.80	0.26	1.06	5.0	1.7	3.3
Produced Water at 0.54 ft/day							
1	0.00	0.37	0.13	0.50	2.3	0.8	1.6
2	0.06	0.37	0.12	0.50	2.3	0.8	1.6
3	0.11	0.38	0.10	0.48	2.4	0.6	1.5
4	0.17	0.35	0.09	0.44	2.2	0.6	1.4
5	0.23	0.32	0.08	0.40	2.0	0.5	1.3
6	0.28	0.28	0.08	0.36	1.8	0.5	1.1
7	0.34	0.26	0.08	0.34	1.6	0.5	1.1
8	0.39	0.24	0.08	0.32	1.5	0.5	1.0
9	0.45	0.22	0.07	0.29	1.4	0.5	0.9
10	0.50	0.20	0.07	0.27	1.3	0.5	0.9
11	0.56	0.17	0.08	0.25	1.1	0.5	0.8
12	0.61	0.16	0.08	0.24	1.0	0.5	0.8
13	0.67	0.16	0.08	0.24	1.0	0.5	0.8
14	0.72	0.16	0.08	0.24	1.0	0.5	0.8
15	0.78	0.16	0.08	0.24	1.0	0.5	0.7
16	0.83	0.16	0.07	0.23	1.0	0.4	0.7
17	0.89	0.16	0.06	0.22	1.0	0.4	0.7
18	0.94	0.16	0.05	0.21	1.0	0.3	0.7
19	1.00	0.16	0.04	0.20	1.0	0.3	0.6
20	1.05	0.16	0.04	0.20	1.0	0.3	0.6
21	1.10	0.16	0.04	0.20	1.0	0.3	0.6
22	1.16	0.16	0.04	0.20	1.0	0.3	0.6
23	1.22	0.16	0.04	0.20	1.0	0.3	0.6
24	1.27	0.16	0.04	0.20	1.0	0.3	0.6
25	1.33	0.16	0.04	0.20	1.0	0.3	0.6
26	1.38	0.16	0.04	0.20	1.0	0.3	0.6
27	1.44	0.16	0.04	0.20	1.0	0.3	0.6
28	1.49	0.16	0.04	0.20	1.0	0.3	0.6
29	1.55	0.16	0.04	0.20	1.0	0.3	0.6
30	1.60	0.16	0.04	0.20	1.0	0.3	0.6
31	1.66	0.16	0.04	0.20	1.0	0.3	0.6
32	1.71	0.16	0.04	0.20	1.0	0.3	0.6
33	1.77	0.16	0.05	0.21	1.0	0.3	0.7
34	1.82	0.16	0.05	0.21	1.0	0.3	0.7

Warner Radial Coreflood 3R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.54 ft/day							
35	1.88	0.16	0.06	0.22	1.0	0.4	0.7
36	1.94	0.16	0.07	0.23	1.0	0.4	0.7
37	1.99	0.16	0.08	0.24	1.0	0.5	0.7
38	2.04	0.16	0.08	0.24	1.0	0.5	0.8
39	2.10	0.16	0.08	0.24	1.0	0.5	0.8
40	2.16	0.16	0.08	0.24	1.0	0.5	0.8
41	2.21	0.16	0.08	0.24	1.0	0.5	0.8
42	2.27	0.16	0.08	0.24	1.0	0.5	0.8
43	2.32	0.16	0.08	0.24	1.0	0.5	0.8
44	2.38	0.16	0.08	0.24	1.0	0.5	0.8
45	2.43	0.16	0.08	0.24	1.0	0.5	0.8
46	2.49	0.16	0.08	0.24	1.0	0.5	0.8
47	2.54	0.16	0.08	0.24	1.0	0.5	0.8
48	2.60	0.16	0.12	0.28	1.0	0.8	0.9
49	2.66	0.16	0.12	0.28	1.0	0.8	0.9
50	2.71	0.16	0.12	0.28	1.0	0.8	0.9
51	2.77	0.16	0.12	0.28	1.0	0.8	0.9
52	2.82	0.16	0.12	0.28	1.0	0.8	0.9
53	2.88	0.16	0.12	0.28	1.0	0.8	0.9
54	2.93	0.16	0.16	0.32	1.0	1.0	1.0
55	2.99	0.16	0.16	0.32	1.0	1.0	1.0
56	3.04	0.16	0.16	0.32	1.0	1.0	1.0
57	3.10	0.16	0.16	0.32	1.0	1.0	1.0
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.05 wt% Petrostep B-100 + 0.05 wt% Stepantan AS-1216 + 1500 mg/L Alcoflood 1275A at 0.54 ft/day							
58	3.16	0.15	0.28	0.42	0.9	1.7	1.3
59	3.22	0.16	0.34	0.50	1.0	2.1	1.6
60	3.27	0.29	0.35	0.64	1.8	2.2	2.0
61	3.33	0.42	0.31	0.73	2.6	2.0	2.3
62	3.38	0.59	0.24	0.82	3.7	1.5	2.6
63	3.43	0.76	0.11	0.86	4.7	0.7	2.7
1500 mg/L Alcoflood 1275A at 0.54 ft/day							
64	3.49	0.75	0.10	0.85	4.7	0.6	2.7
65	3.54	0.70	0.02	0.72	4.4	0.1	2.2
66	3.60	0.56	0.00	0.57	3.5	0.0	1.8
67	3.66	0.50	0.01	0.51	3.1	0.1	1.6

Warner Radial Coreflood 3R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.54 ft/day							
68	3.72	0.43	0.01	0.44	2.7	0.1	1.4
69	3.77	0.40	0.04	0.44	2.5	0.3	1.4
70	3.83	0.34	0.09	0.44	2.2	0.6	1.4
71	3.88	0.30	0.10	0.40	1.9	0.6	1.3
72	3.94	0.26	0.10	0.36	1.6	0.7	1.1
73	3.99	0.21	0.11	0.32	1.3	0.7	1.0
74	4.05	0.17	0.11	0.28	1.1	0.7	0.9
75	4.10	0.15	0.09	0.24	1.0	0.6	0.8
76	4.16	0.14	0.12	0.26	0.9	0.7	0.8
77	4.21	0.14	0.06	0.20	0.9	0.4	0.6
78	4.27	0.12	0.07	0.19	0.8	0.4	0.6
79	4.32	0.10	0.07	0.18	0.7	0.5	0.6
80	4.38	0.10	0.07	0.16	0.6	0.4	0.5
81	4.43	0.10	0.05	0.15	0.7	0.3	0.5
82	4.49	0.09	0.04	0.14	0.6	0.3	0.4
83	4.54	0.08	0.04	0.12	0.5	0.2	0.4
84	4.60	0.08	0.04	0.12	0.5	0.3	0.4
85	4.65	0.08	0.04	0.12	0.5	0.3	0.4
86	4.71	0.08	0.04	0.12	0.5	0.3	0.4
87	4.76	0.08	0.04	0.12	0.5	0.3	0.4
88	4.82	0.12	0.01	0.13	0.8	0.1	0.4
89	4.87	0.12	0.02	0.14	0.8	0.2	0.5
90	4.93	0.12	0.03	0.15	0.8	0.2	0.5
91	4.98	0.12	0.04	0.16	0.8	0.3	0.5
92	5.04	0.12	0.04	0.16	0.8	0.3	0.5
93	5.09	0.14	0.02	0.16	0.9	0.1	0.5
94	5.15	0.14	0.02	0.16	0.9	0.1	0.5
95	5.20	0.14	0.02	0.16	0.9	0.1	0.5
96	5.26	0.14	0.02	0.16	0.9	0.1	0.5
97	5.31	0.14	0.02	0.16	0.9	0.1	0.5
98	5.37	0.14	0.02	0.16	0.9	0.1	0.5
99	5.42	0.14	0.02	0.16	0.9	0.1	0.5
100	5.48	0.14	0.02	0.16	0.9	0.1	0.5
101	5.53	0.14	0.02	0.16	0.9	0.1	0.5
102	5.59	0.14	0.02	0.16	0.9	0.1	0.5
103	5.64	0.14	0.02	0.16	0.9	0.1	0.5
104	5.70	0.12	0.03	0.15	0.8	0.2	0.5

Warner Radial Coreflood 3R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.54 ft/day							
105	5.75	0.11	0.03	0.14	0.7	0.2	0.5
106	5.81	0.11	0.04	0.14	0.7	0.2	0.5
107	5.87	0.11	0.04	0.14	0.7	0.2	0.5
108	5.93	0.11	0.04	0.14	0.7	0.2	0.5
109	5.98	0.11	0.04	0.14	0.7	0.2	0.5
110	6.04	0.11	0.04	0.14	0.7	0.2	0.5
111	6.09	0.11	0.04	0.14	0.7	0.2	0.5

Warner Radial Coreflood 5R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.53 ft/day							
0	0.00	2.16	0.27	2.44	8.3	5.3	7.8
Produced Water at 0.53 ft/day							
1	0.01	0.84	0.23	1.06	3.2	4.3	3.4
2	0.04	0.61	0.19	0.80	2.3	3.7	2.6
3	0.10	0.55	0.19	0.74	2.1	3.6	2.4
4	0.15	0.50	0.17	0.67	1.9	3.2	2.1
5	0.21	0.47	0.14	0.60	1.8	2.7	1.9
6	0.27	0.43	0.13	0.56	1.7	2.6	1.8
7	0.34	0.40	0.12	0.52	1.5	2.3	1.7
8	0.43	0.39	0.09	0.48	1.5	1.8	1.6
9	0.52	0.38	0.08	0.46	1.5	1.5	1.5
10	0.60	0.36	0.08	0.44	1.4	1.5	1.4
11	0.68	0.35	0.05	0.40	1.3	1.0	1.3
12	0.74	0.33	0.05	0.38	1.3	1.0	1.2
13	0.79	0.31	0.05	0.36	1.2	1.0	1.2
14	0.83	0.31	0.04	0.35	1.2	0.8	1.1
15	0.86	0.30	0.04	0.34	1.2	0.7	1.1
16	0.90	0.29	0.03	0.33	1.1	0.7	1.1
17	0.95	0.29	0.03	0.32	1.1	0.7	1.0
18	1.02	0.29	0.03	0.32	1.1	0.7	1.0
19	1.09	0.29	0.03	0.32	1.1	0.7	1.0
20	1.18	0.29	0.03	0.32	1.1	0.7	1.0
21	1.26	0.29	0.03	0.32	1.1	0.7	1.0
22	1.32	0.29	0.03	0.32	1.1	0.7	1.0
23	1.37	0.29	0.03	0.32	1.1	0.7	1.0
24	1.41	0.29	0.03	0.32	1.1	0.7	1.0
25	1.44	0.29	0.03	0.32	1.1	0.7	1.0
26	1.48	0.29	0.03	0.32	1.1	0.7	1.0
27	1.52	0.30	0.02	0.32	1.2	0.3	1.0
28	1.58	0.30	0.02	0.32	1.2	0.3	1.0
29	1.66	0.30	0.02	0.32	1.1	0.5	1.0
30	1.74	0.30	0.02	0.32	1.1	0.3	1.0
31	1.81	0.30	0.03	0.33	1.2	0.5	1.0
32	1.87	0.30	0.02	0.32	1.1	0.4	1.0
33	1.92	0.29	0.03	0.32	1.1	0.5	1.0
34	1.96	0.28	0.04	0.32	1.1	0.7	1.0
35	2.00	0.27	0.04	0.32	1.0	0.8	1.0

Warner Radial Coreflood 5R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.53 ft/day							
36	2.03	0.26	0.05	0.32	1.0	1.0	1.0
37	2.07	0.26	0.06	0.32	1.0	1.2	1.0
38	2.12	0.26	0.06	0.32	1.0	1.2	1.0
39	2.17	0.26	0.06	0.32	1.0	1.2	1.0
40	2.22	0.26	0.06	0.32	1.0	1.2	1.0
41	2.29	0.26	0.06	0.32	1.0	1.2	1.0
42	2.35	0.26	0.06	0.32	1.0	1.2	1.0
43	2.40	0.26	0.06	0.32	1.0	1.2	1.0
44	2.45	0.26	0.06	0.32	1.0	1.2	1.0
45	2.49	0.26	0.06	0.32	1.0	1.2	1.0
46	2.54	0.26	0.06	0.32	1.0	1.2	1.0
47	2.58	0.26	0.06	0.32	1.0	1.2	1.0
48	2.64	0.26	0.05	0.31	1.0	1.0	1.0
49	2.69	0.26	0.05	0.31	1.0	1.0	1.0
50	2.72	0.26	0.05	0.31	1.0	1.0	1.0
51	2.80	0.26	0.05	0.31	1.0	1.0	1.0
52	2.86	0.26	0.05	0.31	1.0	1.0	1.0
53	2.92	0.26	0.05	0.31	1.0	1.0	1.0
54	2.96	0.26	0.05	0.31	1.0	1.0	1.0
55	3.01	0.26	0.05	0.31	1.0	1.0	1.0
56	3.05	0.26	0.05	0.31	1.0	1.0	1.0
57	3.09	0.26	0.05	0.31	1.0	1.0	1.0
58	3.14	0.26	0.05	0.31	1.0	1.0	1.0
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.53 ft/day							
59	3.22	1.80	0.20	2.00	6.9	3.8	6.4
60	3.30	1.70	0.29	1.99	6.6	5.5	6.4
61	3.38	1.51	0.05	1.56	5.8	1.0	5.0
62	3.43	1.26	0.10	1.36	4.8	1.9	4.4
63	3.47	1.14	0.02	1.16	4.4	0.4	3.7
1200 mg/L Flopaam 3630S at 0.53 ft/day							
64	3.51	1.07	0.02	1.09	4.1	0.4	3.5
65	3.55	1.09	0.02	1.11	4.2	0.4	3.6
66	3.60	1.26	0.02	1.29	4.9	0.5	4.1
67	3.67	1.42	0.06	1.48	5.5	1.2	4.8
68	3.74	1.62	0.14	1.76	6.2	2.8	5.7
69	3.79	1.64	0.20	1.84	6.3	3.8	5.9

Warner Radial Coreflood 5R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.53 ft/day							
70	3.86	1.02	0.14	1.16	3.9	2.6	3.7
71	3.92	0.83	0.09	0.92	3.2	1.7	2.9
72	3.98	0.68	0.07	0.75	2.6	1.3	2.4
73	4.03	0.56	0.06	0.62	2.2	1.1	2.0
74	4.07	0.46	0.10	0.56	1.8	1.8	1.8
75	4.12	0.38	0.07	0.45	1.5	1.3	1.4
76	4.17	0.32	0.12	0.43	1.2	2.2	1.4
77	4.23	0.28	0.12	0.41	1.1	2.4	1.3
78	4.30	0.28	0.12	0.39	1.1	2.2	1.3
79	4.36	0.26	0.10	0.37	1.0	2.0	1.2
80	4.43	0.25	0.11	0.36	1.0	2.1	1.1
81	4.49	0.24	0.10	0.34	0.9	2.0	1.1
82	4.54	0.24	0.09	0.33	0.9	1.8	1.1
83	4.59	0.23	0.09	0.32	0.9	1.8	1.0
84	4.63	0.22	0.10	0.32	0.8	1.9	1.0
85	4.67	0.21	0.10	0.32	0.8	2.0	1.0
86	4.72	0.21	0.10	0.31	0.8	2.0	1.0
87	4.78	0.20	0.11	0.31	0.8	2.1	1.0
88	4.84	0.20	0.11	0.31	0.8	2.2	1.0
89	4.91	0.20	0.11	0.31	0.8	2.2	1.0
90	4.98	0.20	0.11	0.31	0.8	2.2	1.0
91	5.04	0.20	0.11	0.31	0.8	2.1	1.0
92	5.09	0.20	0.11	0.31	0.8	2.1	1.0
93	5.14	0.20	0.10	0.30	0.8	2.0	1.0
94	5.19	0.20	0.10	0.30	0.8	1.9	1.0
95	5.24	0.20	0.10	0.30	0.8	1.8	0.9
96	5.28	0.20	0.09	0.29	0.8	1.8	0.9
97	5.34	0.20	0.09	0.29	0.8	1.7	0.9
98	5.40	0.20	0.09	0.29	0.8	1.7	0.9
99	5.46	0.20	0.09	0.29	0.8	1.7	0.9
100	5.52	0.20	0.09	0.29	0.8	1.7	0.9
101	5.58	0.20	0.09	0.29	0.8	1.7	0.9
102	5.63	0.20	0.09	0.29	0.8	1.7	0.9
103	5.67	0.20	0.09	0.29	0.8	1.7	0.9
104	5.71	0.20	0.09	0.29	0.8	1.7	0.9
105	5.75	0.20	0.09	0.29	0.8	1.7	0.9
106	5.81	0.20	0.09	0.29	0.8	1.7	0.9
107	5.88	0.20	0.09	0.29	0.8	1.7	0.9
108	5.95	0.20	0.09	0.29	0.8	1.7	0.9

Warner Radial Coreflood 6R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.54 ft/day							
0	0.00	2.08	0.65	2.73	13.0	10.9	12.4
Produced Water at 0.54 ft/day							
1	0.01	0.76	0.46	1.22	4.7	7.7	5.5
2	0.04	0.54	0.27	0.80	3.4	4.5	3.7
3	0.09	0.48	0.23	0.71	3.0	3.8	3.2
4	0.15	0.44	0.20	0.64	2.8	3.3	2.9
5	0.20	0.40	0.17	0.57	2.5	2.9	2.6
6	0.26	0.37	0.14	0.51	2.3	2.3	2.3
7	0.33	0.35	0.11	0.46	2.2	1.9	2.1
8	0.41	0.32	0.10	0.42	2.0	1.7	1.9
9	0.50	0.29	0.10	0.39	1.8	1.6	1.8
10	0.59	0.28	0.09	0.37	1.8	1.5	1.7
11	0.66	0.26	0.10	0.36	1.7	1.7	1.7
12	0.72	0.24	0.10	0.34	1.5	1.7	1.5
13	0.77	0.23	0.10	0.33	1.5	1.7	1.5
14	0.81	0.20	0.11	0.32	1.3	1.9	1.4
15	0.85	0.20	0.11	0.31	1.3	1.8	1.4
16	0.90	0.20	0.10	0.30	1.3	1.7	1.4
17	0.95	0.20	0.10	0.30	1.3	1.6	1.3
18	1.01	0.20	0.10	0.29	1.2	1.6	1.3
19	1.09	0.19	0.09	0.28	1.2	1.5	1.3
20	1.17	0.18	0.09	0.28	1.2	1.5	1.3
21	1.25	0.18	0.09	0.27	1.1	1.5	1.2
22	1.31	0.18	0.09	0.26	1.1	1.5	1.2
23	1.36	0.17	0.09	0.26	1.1	1.5	1.2
24	1.40	0.17	0.09	0.26	1.1	1.5	1.2
25	1.44	0.16	0.09	0.25	1.0	1.5	1.1
26	1.48	0.16	0.09	0.25	1.0	1.5	1.1
27	1.52	0.16	0.08	0.24	1.0	1.4	1.1
28	1.59	0.16	0.08	0.24	1.0	1.3	1.1
29	1.66	0.16	0.07	0.23	1.0	1.1	1.0
30	1.73	0.16	0.07	0.23	1.0	1.1	1.0
31	1.81	0.16	0.06	0.22	1.0	1.1	1.0
32	1.86	0.16	0.06	0.22	1.0	1.1	1.0
33	1.91	0.16	0.06	0.22	1.0	1.1	1.0
34	1.95	0.16	0.06	0.22	1.0	1.1	1.0
35	1.99	0.16	0.06	0.22	1.0	1.0	1.0
36	2.03	0.16	0.06	0.22	1.0	1.0	1.0

Warner Radial Coreflood 6R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.54 ft/day							
37	2.07	0.16	0.06	0.22	1.0	1.0	1.0
38	2.12	0.16	0.06	0.22	1.0	1.0	1.0
39	2.17	0.16	0.06	0.22	1.0	1.0	1.0
40	2.23	0.16	0.06	0.22	1.0	1.0	1.0
41	2.29	0.16	0.06	0.22	1.0	1.0	1.0
42	2.35	0.16	0.06	0.22	1.0	1.0	1.0
43	2.41	0.16	0.06	0.22	1.0	1.0	1.0
44	2.45	0.16	0.06	0.22	1.0	1.0	1.0
45	2.49	0.16	0.06	0.22	1.0	1.0	1.0
46	2.54	0.16	0.06	0.22	1.0	1.0	1.0
47	2.59	0.16	0.06	0.22	1.0	1.0	1.0
48	2.64	0.16	0.06	0.22	1.0	1.0	1.0
49	2.70	0.16	0.06	0.22	1.0	1.0	1.0
50	2.72	0.16	0.06	0.22	1.0	1.0	1.0
51	2.80	0.16	0.06	0.22	1.0	1.0	1.0
52	2.86	0.16	0.06	0.22	1.0	1.0	1.0
53	2.91	0.16	0.06	0.22	1.0	1.0	1.0
54	2.96	0.16	0.06	0.22	1.0	1.0	1.0
55	3.00	0.16	0.06	0.22	1.0	1.0	1.0
56	3.04	0.16	0.06	0.22	1.0	1.0	1.0
57	3.09	0.16	0.06	0.22	1.0	1.0	1.0
58	3.13	0.16	0.06	0.22	1.0	1.0	1.0
0.625 wt% NaOH + 0.5 wt% Na ₂ CO ₃ + 0.1 wt% ORS-162HF + 1200 mg/L Flopaam 3630S at 0.54 ft/day							
59	3.19	1.76	0.30	2.06	11.0	5.0	9.4
60	3.27	1.30	0.75	2.05	8.2	12.5	9.3
61	3.35	0.88	0.73	1.61	5.5	12.2	7.3
62	3.40	0.66	0.64	1.30	4.2	10.6	5.9
63	3.43	0.56	0.61	1.17	3.5	10.2	5.3
1200 mg/L Flopaam 3630S at 0.54 ft/day							
64	3.48	0.62	0.44	1.06	3.9	7.3	4.8
65	3.52	0.65	0.45	1.10	4.1	7.5	5.0
66	3.57	0.89	0.54	1.43	5.6	9.0	6.5
67	3.64	1.12	0.64	1.76	7.0	10.6	8.0
68	3.71	1.48	0.74	2.22	9.3	12.4	10.1
69	3.76	1.64	0.76	2.40	10.3	12.6	10.9

Warner Radial Coreflood 6R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.54 ft/day							
70	3.83	0.78	0.83	1.61	4.9	13.8	7.3
71	3.90	0.62	0.49	1.10	3.9	8.1	5.0
72	3.95	0.52	0.31	0.83	3.3	5.2	3.8
73	4.00	0.46	0.18	0.65	2.9	3.1	2.9
74	4.04	0.37	0.23	0.60	2.3	3.8	2.7
75	4.09	0.33	0.24	0.57	2.1	3.9	2.6
76	4.14	0.32	0.22	0.54	2.0	3.7	2.4
77	4.20	0.28	0.24	0.52	1.8	4.0	2.4
78	4.27	0.26	0.23	0.49	1.6	3.9	2.2
79	4.34	0.24	0.23	0.47	1.5	3.9	2.1
80	4.41	0.23	0.22	0.45	1.5	3.6	2.0
81	4.47	0.21	0.23	0.44	1.3	3.8	2.0
82	4.53	0.20	0.22	0.42	1.3	3.7	1.9
83	4.57	0.19	0.22	0.41	1.2	3.7	1.9
84	4.61	0.18	0.22	0.40	1.1	3.7	1.8
85	4.65	0.17	0.23	0.40	1.1	3.8	1.8
86	4.71	0.17	0.23	0.40	1.1	3.8	1.8
87	4.77	0.17	0.22	0.39	1.1	3.7	1.8
88	4.83	0.17	0.22	0.39	1.1	3.7	1.8
89	4.90	0.17	0.22	0.38	1.0	3.6	1.7
90	4.96	0.16	0.22	0.38	1.0	3.6	1.7
91	5.02	0.16	0.21	0.38	1.0	3.5	1.7
92	5.07	0.16	0.21	0.37	1.0	3.5	1.7
93	5.12	0.16	0.20	0.37	1.0	3.4	1.7
94	5.17	0.16	0.20	0.36	1.0	3.3	1.7
95	5.22	0.16	0.20	0.36	1.0	3.3	1.6
96	5.27	0.16	0.20	0.36	1.0	3.3	1.6
97	5.33	0.16	0.19	0.35	1.0	3.2	1.6
98	5.39	0.16	0.18	0.34	1.0	3.1	1.6
99	5.45	0.16	0.18	0.34	1.0	2.9	1.5
100	5.51	0.16	0.17	0.33	1.0	2.8	1.5
101	5.56	0.16	0.16	0.32	1.0	2.7	1.5
102	5.61	0.16	0.16	0.32	1.0	2.7	1.5
103	5.65	0.16	0.16	0.32	1.0	2.7	1.5
104	5.69	0.16	0.16	0.32	1.0	2.7	1.5
105	5.74	0.16	0.16	0.32	1.0	2.7	1.5
106	5.80	0.16	0.16	0.32	1.0	2.7	1.5
107	5.87	0.16	0.16	0.32	1.0	2.7	1.5
108	5.94	0.16	0.16	0.32	1.0	2.7	1.5

Warner Radial Coreflood 7R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.52 ft/day							
0	0.00	0.19	0.21	0.40	18.5	0.8	1.4
Produced Water at 0.52 ft/day							
1	0.02	0.05	0.36	0.41	5.0	1.3	1.5
2	0.10	0.05	0.32	0.37	5.0	1.2	1.3
3	0.16	0.05	0.31	0.36	5.0	1.2	1.3
4	0.23	0.05	0.32	0.36	4.5	1.2	1.3
5	0.30	0.04	0.32	0.36	3.5	1.2	1.3
6	0.38	0.03	0.30	0.33	2.5	1.1	1.2
7	0.45	0.02	0.29	0.31	2.0	1.1	1.1
8	0.52	0.02	0.30	0.31	1.5	1.1	1.1
9	0.60	0.02	0.30	0.31	1.5	1.1	1.1
10	0.67	0.02	0.30	0.31	1.5	1.1	1.1
11	0.74	0.01	0.29	0.30	1.0	1.1	1.1
12	0.81	0.01	0.28	0.29	1.0	1.0	1.0
13	0.88	0.01	0.28	0.29	1.0	1.0	1.0
14	0.96	0.01	0.28	0.29	1.0	1.0	1.0
15	1.03	0.01	0.28	0.29	1.0	1.0	1.0
16	1.10	0.01	0.28	0.29	1.0	1.0	1.0
17	1.17	0.01	0.27	0.28	1.0	1.0	1.0
18	1.24	0.01	0.27	0.28	1.0	1.0	1.0
19	1.31	0.01	0.27	0.28	1.0	1.0	1.0
20	1.38	0.01	0.27	0.28	1.0	1.0	1.0
21	1.46	0.01	0.27	0.28	1.0	1.0	1.0
22	1.53	0.01	0.27	0.28	1.0	1.0	1.0
23	1.59	0.01	0.27	0.28	1.0	1.0	1.0
24	1.67	0.01	0.27	0.28	1.0	1.0	1.0
25	1.74	0.01	0.27	0.28	1.0	1.0	1.0
26	1.81	0.01	0.27	0.28	1.0	1.0	1.0
27	1.88	0.01	0.27	0.28	1.0	1.0	1.0
28	1.95	0.01	0.27	0.28	1.0	1.0	1.0
29	2.02	0.01	0.27	0.28	1.0	1.0	1.0
30	2.09	0.01	0.27	0.28	1.0	1.0	1.0
31	2.16	0.01	0.27	0.28	1.0	1.0	1.0
32	2.23	0.01	0.27	0.28	1.0	1.0	1.0
33	2.31	0.01	0.27	0.28	1.0	1.0	1.0
34	2.37	0.01	0.27	0.28	1.0	1.0	1.0
35	2.44	0.01	0.27	0.28	1.0	1.0	1.0
36	2.51	0.01	0.27	0.28	1.0	1.0	1.0

Warner Radial Coreflood 7R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Produced Water at 0.52 ft/day							
37	2.58	0.01	0.27	0.28	1.0	1.0	1.0
38	2.65	0.01	0.27	0.28	1.0	1.0	1.0
39	2.72	0.01	0.27	0.28	1.0	1.0	1.0
40	2.79	0.01	0.27	0.28	1.0	1.0	1.0
41	2.86	0.01	0.27	0.28	1.0	1.0	1.0
42	2.93	0.01	0.27	0.28	1.0	1.0	1.0
43	3.00	0.01	0.27	0.28	1.0	1.0	1.0
44	3.07	0.01	0.27	0.28	1.0	1.0	1.0
45	3.14	0.01	0.27	0.28	1.0	1.0	1.0
46	3.21	0.01	0.27	0.28	1.0	1.0	1.0
47	3.28	0.01	0.27	0.28	1.0	1.0	1.0
48	3.35	0.01	0.27	0.28	1.0	1.0	1.0
49	3.42	0.01	0.27	0.28	1.0	1.0	1.0
50	3.49	0.01	0.27	0.28	1.0	1.0	1.0
51	3.56	0.01	0.27	0.28	1.0	1.0	1.0
52	3.63	0.01	0.27	0.28	1.0	1.0	1.0
53	3.69	0.01	0.27	0.28	1.0	1.0	1.0
0.75 wt% NaOH + 0.1 wt% ORS-97 + 1200 mg/L Flopaam 3630S at 0.52 ft/day							
54	3.78	0.12	0.34	0.46	12.0	1.3	1.7
55	3.83	0.17	0.45	0.62	17.0	1.7	2.2
56	3.90	0.17	0.52	0.69	17.0	1.9	2.5
57	3.95	0.18	0.66	0.84	17.5	2.5	3.0
58	4.02	0.20	0.74	0.94	20.0	2.8	3.4
1200 mg/L Flopaam 3630S at 0.52 ft/day							
59	4.08	0.26	0.67	0.93	26.0	2.5	3.4
60	4.15	0.26	0.65	0.91	26.0	2.4	3.3
61	4.21	0.27	0.62	0.89	27.0	2.3	3.2
62	4.27	0.31	0.60	0.90	30.5	2.2	3.3
63	4.34	0.36	0.57	0.92	35.5	2.1	3.3
Injection Water at 0.52 ft/day							
64	4.41	0.14	0.58	0.72	13.5	2.2	2.6
65	4.49	0.07	0.52	0.59	7.0	2.0	2.1
66	4.58	0.06	0.37	0.43	6.0	1.4	1.5
67	4.65	0.06	0.26	0.31	5.5	1.0	1.1
68	4.72	0.06	0.21	0.26	5.5	0.8	0.9
69	4.79	0.05	0.19	0.24	5.0	0.7	0.9
70	4.86	0.05	0.18	0.23	5.0	0.7	0.8

Warner Radial Coreflood 7R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 0.52 ft/day							
71	4.94	0.05	0.17	0.22	5.0	0.6	0.8
72	5.01	0.05	0.16	0.21	5.0	0.6	0.7
73	5.09	0.05	0.15	0.20	5.0	0.6	0.7
74	5.16	0.06	0.14	0.20	6.0	0.5	0.7
75	5.24	0.06	0.13	0.19	6.0	0.5	0.7
76	5.31	0.07	0.11	0.18	6.5	0.4	0.6
77	5.38	0.07	0.11	0.18	6.5	0.4	0.6
78	5.46	0.07	0.11	0.18	6.5	0.4	0.6
79	5.53	0.07	0.11	0.18	7.0	0.4	0.6
80	5.60	0.07	0.11	0.18	7.0	0.4	0.6
81	5.67	0.07	0.11	0.18	7.0	0.4	0.6
82	5.74	0.07	0.11	0.18	7.0	0.4	0.6
83	5.80	0.07	0.11	0.18	7.0	0.4	0.6
84	5.87	0.07	0.11	0.18	7.0	0.4	0.6
85	5.94	0.07	0.11	0.18	7.0	0.4	0.6
86	6.02	0.07	0.11	0.18	7.0	0.4	0.6
87	6.09	0.07	0.11	0.18	7.0	0.4	0.6
88	6.15	0.07	0.11	0.18	7.0	0.4	0.6
89	6.22	0.07	0.11	0.18	7.0	0.4	0.6
90	6.29	0.07	0.11	0.18	7.0	0.4	0.6
91	6.36	0.07	0.11	0.18	7.0	0.4	0.6
92	6.43	0.07	0.11	0.18	7.0	0.4	0.6
93	6.49	0.07	0.11	0.18	7.0	0.4	0.6
94	6.56	0.07	0.11	0.18	7.0	0.4	0.6
95	6.63	0.07	0.11	0.18	7.0	0.4	0.6
96	6.70	0.07	0.11	0.18	7.0	0.4	0.6
97	6.78	0.07	0.11	0.18	7.0	0.4	0.6
98	6.85	0.07	0.11	0.18	7.0	0.4	0.6
99	6.92	0.07	0.11	0.18	7.0	0.4	0.6
100	6.99	0.07	0.11	0.18	7.0	0.4	0.6
101	7.05	0.07	0.11	0.18	7.0	0.4	0.6
102	7.12	0.07	0.11	0.18	7.0	0.4	0.6
103	7.19	0.07	0.11	0.18	7.0	0.4	0.6
104	7.26	0.07	0.11	0.18	7.0	0.4	0.6
105	7.33	0.07	0.11	0.18	7.0	0.4	0.6
106	7.41	0.07	0.11	0.18	7.0	0.4	0.6
107	7.48	0.07	0.11	0.18	7.0	0.4	0.6
108	7.53	0.07	0.11	0.18	7.0	0.4	0.6

Warner Radial Coreflood 8R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.55 ft/day							
0	0.00	0.33	0.31	0.64	13.2	1.0	2.0
Produced Water at 0.55 ft/day							
1	0.02	0.05	0.47	0.51	1.8	1.6	1.6
2	0.10	0.04	0.47	0.51	1.4	1.6	1.6
3	0.17	0.03	0.47	0.49	1.0	1.6	1.5
4	0.25	0.03	0.44	0.46	1.0	1.5	1.4
5	0.32	0.03	0.43	0.46	1.0	1.4	1.4
6	0.40	0.03	0.43	0.45	1.0	1.4	1.4
7	0.48	0.03	0.39	0.42	1.0	1.3	1.3
8	0.56	0.03	0.38	0.41	1.0	1.3	1.2
9	0.64	0.03	0.38	0.41	1.0	1.3	1.2
10	0.71	0.03	0.38	0.41	1.0	1.3	1.2
11	0.79	0.03	0.38	0.41	1.0	1.3	1.2
12	0.86	0.03	0.38	0.41	1.0	1.3	1.2
13	0.94	0.03	0.38	0.40	1.0	1.3	1.2
14	1.02	0.03	0.35	0.37	1.0	1.2	1.1
15	1.09	0.03	0.35	0.37	1.0	1.2	1.1
16	1.17	0.03	0.34	0.37	1.0	1.1	1.1
17	1.25	0.03	0.34	0.37	1.0	1.1	1.1
18	1.32	0.03	0.34	0.36	1.0	1.1	1.1
19	1.40	0.03	0.33	0.36	1.0	1.1	1.1
20	1.47	0.03	0.33	0.36	1.0	1.1	1.1
21	1.55	0.03	0.33	0.36	1.0	1.1	1.1
22	1.62	0.03	0.33	0.36	1.0	1.1	1.1
23	1.69	0.03	0.33	0.36	1.0	1.1	1.1
24	1.77	0.03	0.33	0.36	1.0	1.1	1.1
25	1.84	0.03	0.33	0.36	1.0	1.1	1.1
26	1.92	0.03	0.33	0.36	1.0	1.1	1.1
27	1.99	0.03	0.33	0.36	1.0	1.1	1.1
28	2.06	0.03	0.33	0.36	1.0	1.1	1.1
29	2.14	0.03	0.33	0.36	1.0	1.1	1.1
30	2.21	0.03	0.33	0.36	1.0	1.1	1.1
31	2.29	0.03	0.33	0.36	1.0	1.1	1.1
32	2.36	0.03	0.33	0.36	1.0	1.1	1.1
33	2.43	0.03	0.33	0.35	1.0	1.1	1.1
34	2.51	0.03	0.33	0.35	1.0	1.1	1.1
35	2.59	0.03	0.33	0.35	1.0	1.1	1.1
36	2.66	0.03	0.32	0.35	1.0	1.1	1.1

Warner Radial Coreflood 8R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Produced Water at 0.55 ft/day							
37	2.73	0.03	0.32	0.35	1.0	1.1	1.1
38	2.81	0.03	0.32	0.35	1.0	1.1	1.1
39	2.89	0.03	0.32	0.35	1.0	1.1	1.1
40	2.96	0.03	0.32	0.35	1.0	1.1	1.1
41	3.04	0.03	0.32	0.35	1.0	1.1	1.1
42	3.11	0.03	0.32	0.35	1.0	1.1	1.1
43	3.19	0.03	0.32	0.35	1.0	1.1	1.1
44	3.26	0.03	0.32	0.34	1.0	1.1	1.0
45	3.33	0.03	0.32	0.34	1.0	1.1	1.0
46	3.40	0.03	0.32	0.34	1.0	1.1	1.0
47	3.48	0.03	0.32	0.34	1.0	1.1	1.0
48	3.55	0.03	0.31	0.33	1.0	1.0	1.0
49	3.63	0.03	0.31	0.33	1.0	1.0	1.0
50	3.70	0.03	0.30	0.33	1.0	1.0	1.0
51	3.78	0.03	0.30	0.33	1.0	1.0	1.0
52	3.85	0.03	0.30	0.33	1.0	1.0	1.0
53	3.93	0.03	0.30	0.33	1.0	1.0	1.0
54	4.00	0.03	0.30	0.33	1.0	1.0	1.0
0.5 wt% NaOH + 0.25 wt% Na ₂ CO ₃ + 0.05 wt% B-100 + 0.05 wt% AS 1216 + 1200 mg/L Flopaam 3630S at 0.55 ft/day							
55	4.09	0.20	0.46	0.66	8.0	1.5	2.0
56	4.15	0.18	0.67	0.84	7.0	2.2	2.6
57	4.21	0.18	0.70	0.87	7.0	2.3	2.7
58	4.28	0.18	0.71	0.88	7.0	2.4	2.7
59	4.34	0.18	0.71	0.88	7.0	2.4	2.7
1200 mg/L Flopaam 3630S at 0.55 ft/day							
60	4.40	0.29	0.71	1.00	11.4	2.4	3.1
61	4.48	0.37	0.65	1.02	14.8	2.2	3.1
62	4.55	0.40	0.61	1.01	15.8	2.0	3.1
63	4.61	0.48	0.58	1.06	19.2	1.9	3.2
64	4.68	0.62	0.54	1.16	24.6	1.8	3.6
Injection Water at 0.55 ft/day							
65	4.76	0.22	0.54	0.75	8.6	1.8	2.3
66	4.84	0.21	0.50	0.71	8.4	1.7	2.2
67	4.93	0.19	0.33	0.52	7.6	1.1	1.6
68	5.01	0.18	0.19	0.37	7.0	0.6	1.1
69	5.08	0.17	0.15	0.32	6.6	0.5	1.0
70	5.16	0.17	0.14	0.31	6.6	0.5	0.9

Warner Radial Coreflood 8R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.55 ft/day							
71	5.24	0.16	0.14	0.30	6.4	0.5	0.9
72	5.32	0.16	0.14	0.30	6.4	0.5	0.9
73	5.39	0.16	0.14	0.30	6.4	0.5	0.9
74	5.46	0.15	0.13	0.28	6.0	0.4	0.9
75	5.54	0.15	0.13	0.28	6.0	0.4	0.8
76	5.61	0.15	0.13	0.27	5.8	0.4	0.8
77	5.69	0.15	0.13	0.27	5.8	0.4	0.8
78	5.76	0.14	0.12	0.25	5.4	0.4	0.8
79	5.84	0.14	0.12	0.25	5.4	0.4	0.8
80	5.91	0.13	0.12	0.25	5.2	0.4	0.8
81	5.98	0.13	0.11	0.24	5.2	0.4	0.7
82	6.06	0.13	0.10	0.23	5.2	0.3	0.7
83	6.13	0.13	0.10	0.23	5.2	0.3	0.7
84	6.20	0.13	0.10	0.23	5.2	0.3	0.7
85	6.28	0.13	0.10	0.23	5.2	0.3	0.7
86	6.36	0.13	0.10	0.23	5.2	0.3	0.7
87	6.44	0.13	0.10	0.23	5.2	0.3	0.7
88	6.51	0.13	0.10	0.23	5.2	0.3	0.7
89	6.58	0.13	0.10	0.23	5.2	0.3	0.7
90	6.65	0.13	0.10	0.23	5.2	0.3	0.7
91	6.72	0.13	0.10	0.23	5.2	0.3	0.7
92	6.79	0.13	0.10	0.23	5.2	0.3	0.7
93	6.86	0.13	0.10	0.23	5.2	0.3	0.7
94	6.94	0.13	0.10	0.23	5.2	0.3	0.7
95	7.01	0.13	0.10	0.23	5.2	0.3	0.7
96	7.08	0.13	0.10	0.23	5.2	0.3	0.7
97	7.15	0.13	0.10	0.23	5.2	0.3	0.7
98	7.23	0.13	0.10	0.23	5.2	0.3	0.7
99	7.30	0.13	0.10	0.23	5.2	0.3	0.7
100	7.38	0.13	0.10	0.23	5.2	0.3	0.7
101	7.45	0.13	0.10	0.23	5.2	0.3	0.7
102	7.53	0.13	0.10	0.23	5.2	0.3	0.7
103	7.60	0.13	0.10	0.23	5.2	0.3	0.7
104	7.68	0.13	0.10	0.23	5.2	0.3	0.7
105	7.75	0.13	0.10	0.23	5.2	0.3	0.7
106	7.83	0.13	0.10	0.23	5.2	0.3	0.7
107	7.90	0.13	0.10	0.23	5.2	0.3	0.7
108	7.97	0.13	0.10	0.23	5.2	0.3	0.7
109	8.04	0.13	0.10	0.23	5.2	0.3	0.7

Warner Radial Coreflood 9R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.57 ft/day							
0	0.00	0.15	1.00	1.15	10.0	1.3	1.5
Produced Water at 0.57 ft/day							
1	0.00	0.18	1.06	1.24	12.0	1.4	1.6
2	0.08	0.17	0.98	1.15	11.3	1.3	1.5
3	0.15	0.17	0.88	1.05	11.3	1.2	1.4
4	0.24	0.16	0.81	0.97	10.3	1.1	1.3
5	0.31	0.13	0.81	0.94	8.7	1.1	1.2
6	0.40	0.13	0.79	0.92	8.3	1.1	1.2
7	0.47	0.12	0.78	0.90	8.0	1.0	1.2
8	0.55	0.11	0.76	0.87	7.3	1.0	1.1
9	0.63	0.11	0.74	0.85	7.3	1.0	1.1
10	0.70	0.10	0.75	0.85	6.3	1.0	1.1
11	0.77	0.09	0.76	0.84	5.7	1.0	1.1
12	0.85	0.08	0.75	0.82	5.0	1.0	1.1
13	0.93	0.04	0.77	0.81	2.7	1.0	1.1
14	1.01	0.03	0.77	0.80	2.0	1.0	1.0
15	1.09	0.03	0.77	0.79	1.7	1.0	1.0
16	1.17	0.03	0.75	0.78	1.7	1.0	1.0
17	1.24	0.02	0.76	0.78	1.3	1.0	1.0
18	1.32	0.02	0.76	0.78	1.3	1.0	1.0
19	1.40	0.02	0.76	0.78	1.3	1.0	1.0
20	1.48	0.02	0.76	0.78	1.0	1.0	1.0
21	1.55	0.02	0.76	0.78	1.0	1.0	1.0
22	1.63	0.02	0.76	0.78	1.0	1.0	1.0
23	1.70	0.02	0.76	0.78	1.0	1.0	1.0
24	1.78	0.02	0.76	0.78	1.0	1.0	1.0
25	1.85	0.02	0.76	0.78	1.0	1.0	1.0
26	1.93	0.02	0.76	0.78	1.0	1.0	1.0
27	2.00	0.02	0.76	0.77	1.0	1.0	1.0
28	2.08	0.02	0.75	0.77	1.0	1.0	1.0
29	2.15	0.02	0.75	0.77	1.0	1.0	1.0
30	2.23	0.02	0.75	0.77	1.0	1.0	1.0
31	2.30	0.02	0.75	0.77	1.0	1.0	1.0
32	2.38	0.02	0.75	0.77	1.0	1.0	1.0
33	2.46	0.02	0.75	0.77	1.0	1.0	1.0
34	2.53	0.02	0.75	0.77	1.0	1.0	1.0
35	2.61	0.02	0.75	0.77	1.0	1.0	1.0
36	2.68	0.02	0.75	0.77	1.0	1.0	1.0

Warner Radial Coreflood 9R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.57 ft/day							
37	2.76	0.02	0.75	0.77	1.0	1.0	1.0
38	2.84	0.02	0.75	0.77	1.0	1.0	1.0
39	2.91	0.02	0.75	0.77	1.0	1.0	1.0
40	2.99	0.02	0.75	0.77	1.0	1.0	1.0
41	3.07	0.02	0.75	0.77	1.0	1.0	1.0
42	3.15	0.02	0.75	0.77	1.0	1.0	1.0
43	3.22	0.02	0.75	0.77	1.0	1.0	1.0
44	3.30	0.02	0.75	0.77	1.0	1.0	1.0
45	3.37	0.02	0.75	0.77	1.0	1.0	1.0
46	3.45	0.02	0.75	0.77	1.0	1.0	1.0
47	3.52	0.02	0.75	0.77	1.0	1.0	1.0
48	3.60	0.02	0.75	0.77	1.0	1.0	1.0
49	3.68	0.02	0.75	0.77	1.0	1.0	1.0
50	3.75	0.02	0.75	0.77	1.0	1.0	1.0
51	3.82	0.02	0.75	0.77	1.0	1.0	1.0
52	3.90	0.02	0.75	0.77	1.0	1.0	1.0
53	3.97	0.02	0.75	0.77	1.0	1.0	1.0
54	4.05	0.02	0.75	0.77	1.0	1.0	1.0
55	4.12	0.02	0.75	0.77	1.0	1.0	1.0
56	4.21	0.02	0.75	0.77	1.0	1.0	1.0
0.625 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Alcoflood 1275A at 0.57 ft/day							
57	4.27	0.04	1.11	1.15	2.7	1.5	1.5
58	4.33	0.08	1.86	1.94	5.3	2.5	2.5
59	4.39	0.17	2.68	2.85	11.3	3.6	3.7
60	4.46	0.20	3.78	3.98	13.3	5.0	5.2
61	4.52	0.23	4.63	4.85	15.0	6.2	6.3
1200 mg/L Alcoflood 1275A at 0.57 ft/day							
62	4.59	0.09	4.76	4.85	6.0	6.3	6.3
63	4.65	0.03	5.60	5.62	1.7	7.5	7.3
64	4.72	0.03	5.85	5.87	1.7	7.8	7.7
65	4.77	0.03	6.07	6.09	1.7	8.1	8.0
66	4.86	0.03	6.23	6.25	1.7	8.3	8.2
Injection Water at 0.57 ft/day							
67	4.94	0.03	0.97	0.99	1.7	1.3	1.3
68	5.02	0.03	0.79	0.81	1.7	1.0	1.1
69	5.10	0.03	0.58	0.60	1.7	0.8	0.8
70	5.17	0.03	0.46	0.49	1.7	0.6	0.6

Warner Radial Coreflood 9R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.57 ft/day							
71	5.25	0.03	0.39	0.41	1.7	0.5	0.5
72	5.33	0.03	0.32	0.35	1.7	0.4	0.5
73	5.41	0.03	0.29	0.32	1.7	0.4	0.4
74	5.48	0.03	0.28	0.30	1.7	0.4	0.4
75	5.56	0.03	0.27	0.30	1.7	0.4	0.4
76	5.64	0.03	0.27	0.29	1.7	0.4	0.4
77	5.71	0.03	0.27	0.30	1.7	0.4	0.4
78	5.78	0.03	0.28	0.31	1.7	0.4	0.4
79	5.85	0.03	0.31	0.33	1.7	0.4	0.4
80	5.92	0.03	0.34	0.37	1.7	0.5	0.5
81	6.00	0.03	0.39	0.41	1.7	0.5	0.5
82	6.07	0.03	0.42	0.45	1.7	0.6	0.6
83	6.15	0.02	0.43	0.45	1.3	0.6	0.6
84	6.22	0.02	0.43	0.45	1.3	0.6	0.6
85	6.30	0.02	0.43	0.45	1.3	0.6	0.6
86	6.38	0.02	0.42	0.44	1.3	0.6	0.6
87	6.46	0.02	0.41	0.43	1.3	0.5	0.6
88	6.54	0.02	0.39	0.41	1.3	0.5	0.5
89	6.61	0.02	0.36	0.38	1.3	0.5	0.5
90	6.69	0.02	0.35	0.37	1.3	0.5	0.5
91	6.76	0.02	0.34	0.36	1.3	0.5	0.5
92	6.85	0.02	0.32	0.34	1.3	0.4	0.4
93	6.93	0.02	0.31	0.33	1.3	0.4	0.4
94	7.00	0.02	0.31	0.33	1.3	0.4	0.4
95	7.08	0.02	0.30	0.32	1.3	0.4	0.4
96	7.15	0.02	0.30	0.32	1.3	0.4	0.4
97	7.24	0.02	0.30	0.32	1.3	0.4	0.4
98	7.29	0.02	0.30	0.32	1.3	0.4	0.4

Warner Radial Coreflood 10R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Warner Crude Oil at 0.60 ft/day							
0	0.00	0.59	0.22	0.80	3.9	1.4	2.7
Produced Water at 0.60 ft/day							
1	0.02	0.26	0.34	0.60	1.7	2.2	2.0
2	0.09	0.25	0.32	0.57	1.7	2.1	1.9
3	0.16	0.23	0.31	0.54	1.5	2.0	1.8
4	0.23	0.22	0.30	0.52	1.4	2.0	1.7
5	0.30	0.21	0.29	0.50	1.4	1.9	1.7
6	0.37	0.20	0.25	0.45	1.3	1.6	1.5
7	0.45	0.20	0.21	0.41	1.3	1.4	1.4
8	0.54	0.19	0.19	0.38	1.3	1.3	1.3
9	0.61	0.19	0.17	0.36	1.2	1.1	1.2
10	0.69	0.19	0.17	0.36	1.2	1.1	1.2
11	0.77	0.19	0.16	0.35	1.2	1.1	1.2
12	0.85	0.18	0.17	0.35	1.2	1.1	1.2
13	0.94	0.18	0.17	0.35	1.2	1.1	1.2
14	1.02	0.17	0.18	0.35	1.1	1.2	1.2
15	1.11	0.17	0.18	0.35	1.1	1.2	1.2
16	1.19	0.16	0.19	0.35	1.1	1.2	1.2
17	1.27	0.16	0.18	0.34	1.1	1.2	1.1
18	1.35	0.16	0.19	0.34	1.0	1.2	1.1
19	1.43	0.16	0.19	0.34	1.0	1.2	1.1
20	1.51	0.16	0.19	0.34	1.0	1.2	1.1
21	1.59	0.15	0.19	0.34	1.0	1.3	1.1
22	1.67	0.15	0.19	0.34	1.0	1.2	1.1
23	1.75	0.15	0.27	0.42	1.0	1.8	1.4
24	1.83	0.15	0.18	0.33	1.0	1.2	1.1
25	1.91	0.15	0.18	0.33	1.0	1.2	1.1
26	1.99	0.15	0.18	0.33	1.0	1.2	1.1
27	2.07	0.15	0.18	0.33	1.0	1.2	1.1
28	2.15	0.15	0.18	0.33	1.0	1.2	1.1
29	2.23	0.15	0.18	0.33	1.0	1.2	1.1
30	2.30	0.15	0.18	0.33	1.0	1.2	1.1
31	2.38	0.15	0.18	0.33	1.0	1.2	1.1
32	2.47	0.15	0.18	0.33	1.0	1.2	1.1
33	2.55	0.15	0.18	0.33	1.0	1.2	1.1
34	2.63	0.15	0.18	0.33	1.0	1.2	1.1
35	2.71	0.15	0.18	0.33	1.0	1.2	1.1
36	2.79	0.15	0.17	0.32	1.0	1.1	1.1

Warner Radial Coreflood 10R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.60 ft/day							
37	2.87	0.15	0.17	0.32	1.0	1.1	1.1
38	2.95	0.15	0.17	0.32	1.0	1.1	1.1
39	3.03	0.15	0.17	0.32	1.0	1.1	1.1
40	3.11	0.15	0.17	0.32	1.0	1.1	1.1
41	3.19	0.15	0.17	0.32	1.0	1.1	1.1
42	3.27	0.15	0.17	0.32	1.0	1.1	1.1
43	3.35	0.15	0.17	0.32	1.0	1.1	1.1
44	3.44	0.15	0.17	0.32	1.0	1.1	1.1
45	3.52	0.15	0.16	0.31	1.0	1.1	1.0
46	3.60	0.15	0.16	0.31	1.0	1.1	1.0
47	3.68	0.15	0.16	0.31	1.0	1.1	1.0
48	3.76	0.15	0.16	0.31	1.0	1.1	1.0
49	3.84	0.15	0.16	0.31	1.0	1.1	1.0
50	3.92	0.15	0.16	0.31	1.0	1.0	1.0
51	4.00	0.15	0.15	0.30	1.0	1.0	1.0
52	4.08	0.15	0.15	0.30	1.0	1.0	1.0
53	4.16	0.15	0.15	0.30	1.0	1.0	1.0
54	4.24	0.15	0.15	0.30	1.0	1.0	1.0
55	4.31	0.15	0.15	0.30	1.0	1.0	1.0
56	4.39	0.15	0.15	0.30	1.0	1.0	1.0
57	4.49	0.15	0.15	0.30	1.0	1.0	1.0
0.625 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.60 ft/day							
58	4.55	0.66	0.30	0.95	4.4	2.0	3.2
59	4.62	0.88	0.53	1.40	5.8	3.5	4.7
60	4.68	0.87	0.72	1.59	5.8	4.8	5.3
61	4.76	0.86	0.82	1.68	5.7	5.5	5.6
62	4.84	0.81	0.85	1.65	5.4	5.6	5.5
1200 mg/L Flopaam 3630S at 0.60 ft/day							
63	4.91	1.13	0.95	2.08	7.5	6.3	6.9
64	4.99	1.10	0.76	1.86	7.3	5.1	6.2
65	5.06	1.15	0.70	1.84	7.6	4.6	6.1
66	5.13	1.35	0.77	2.12	9.0	5.1	7.1
67	5.18	1.60	0.90	2.50	10.7	6.0	8.3
Injection Water at 0.60 ft/day							
68	5.26	0.53	0.69	1.21	3.5	4.6	4.0
69	5.35	0.41	0.47	0.88	2.7	3.1	2.9
70	5.43	0.34	0.33	0.67	2.2	2.2	2.2

Warner Radial Coreflood 10R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.60 ft/day							
71	5.51	0.31	0.29	0.60	2.1	1.9	2.0
72	5.59	0.31	0.26	0.57	2.0	1.7	1.9
73	5.67	0.30	0.22	0.52	2.0	1.5	1.7
74	5.75	0.29	0.18	0.46	1.9	1.2	1.5
75	5.83	0.27	0.19	0.45	1.8	1.2	1.5
76	5.91	0.27	0.18	0.45	1.8	1.2	1.5
77	5.99	0.27	0.18	0.44	1.8	1.2	1.5
78	6.06	0.26	0.16	0.42	1.7	1.1	1.4
79	6.14	0.25	0.14	0.39	1.7	0.9	1.3
80	6.22	0.25	0.14	0.39	1.7	0.9	1.3
81	6.30	0.25	0.14	0.39	1.7	0.9	1.3
82	6.37	0.25	0.14	0.39	1.7	0.9	1.3
83	6.45	0.25	0.14	0.39	1.7	0.9	1.3
84	6.53	0.25	0.14	0.39	1.7	0.9	1.3
85	6.61	0.25	0.14	0.39	1.7	0.9	1.3
86	6.69	0.25	0.14	0.39	1.7	0.9	1.3
87	6.77	0.25	0.14	0.39	1.7	0.9	1.3
88	6.85	0.25	0.14	0.39	1.7	0.9	1.3
89	6.93	0.25	0.14	0.39	1.7	0.9	1.3
90	7.01	0.25	0.14	0.39	1.7	0.9	1.3
91	7.09	0.25	0.14	0.39	1.7	0.9	1.3
92	7.16	0.25	0.14	0.39	1.7	0.9	1.3
93	7.25	0.25	0.14	0.39	1.7	0.9	1.3
94	7.33	0.25	0.14	0.39	1.7	0.9	1.3
95	7.42	0.25	0.14	0.39	1.7	0.9	1.3
96	7.49	0.25	0.14	0.39	1.7	0.9	1.3
97	7.57	0.25	0.14	0.39	1.7	0.9	1.3
98	7.64	0.25	0.14	0.39	1.7	0.9	1.3
99	7.68	0.25	0.14	0.39	1.7	0.9	1.3

Warner Radial Coreflood 11R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Warner Crude Oil at 0.48 ft/day							
0	0.00	0.09	0.19	0.28	4.5	1.1	1.5
Produced Water at 0.48 ft/day							
1	0.01	0.07	0.30	0.37	3.5	1.7	1.9
2	0.08	0.07	0.26	0.33	3.5	1.5	1.7
3	0.14	0.07	0.26	0.33	3.5	1.5	1.7
4	0.21	0.07	0.25	0.32	3.5	1.4	1.7
5	0.27	0.07	0.22	0.28	3.3	1.3	1.5
6	0.33	0.06	0.22	0.28	3.0	1.3	1.4
7	0.40	0.06	0.22	0.28	2.8	1.3	1.4
8	0.46	0.03	0.24	0.27	1.5	1.4	1.4
9	0.53	0.02	0.24	0.26	1.0	1.4	1.4
10	0.59	0.02	0.23	0.25	1.0	1.4	1.3
11	0.66	0.02	0.22	0.24	1.0	1.3	1.3
12	0.72	0.02	0.21	0.23	1.0	1.2	1.2
13	0.79	0.02	0.21	0.23	1.0	1.2	1.2
14	0.86	0.02	0.21	0.23	1.0	1.2	1.2
15	0.93	0.02	0.21	0.23	1.0	1.2	1.2
16	1.00	0.02	0.21	0.23	1.0	1.2	1.2
17	1.06	0.02	0.20	0.22	1.0	1.2	1.2
18	1.13	0.02	0.20	0.22	1.0	1.2	1.2
19	1.19	0.02	0.20	0.22	1.0	1.2	1.2
20	1.26	0.02	0.20	0.22	1.0	1.2	1.2
21	1.33	0.02	0.20	0.22	1.0	1.2	1.2
22	1.39	0.02	0.20	0.22	1.0	1.2	1.2
23	1.45	0.02	0.20	0.22	1.0	1.2	1.2
24	1.52	0.02	0.20	0.22	1.0	1.2	1.2
25	1.59	0.02	0.20	0.22	1.0	1.1	1.1
26	1.66	0.02	0.20	0.22	1.0	1.2	1.2
27	1.72	0.02	0.16	0.18	1.0	0.9	0.9
28	1.79	0.02	0.20	0.22	1.0	1.2	1.2
29	1.85	0.02	0.20	0.22	1.0	1.2	1.2
30	1.92	0.02	0.20	0.22	1.0	1.2	1.2
31	1.98	0.02	0.20	0.22	1.0	1.2	1.2
32	2.05	0.02	0.20	0.22	1.0	1.2	1.2
33	2.11	0.02	0.20	0.22	1.0	1.2	1.2
34	2.18	0.02	0.20	0.22	1.0	1.2	1.2
35	2.24	0.02	0.20	0.22	1.0	1.2	1.2
36	2.31	0.02	0.20	0.22	1.0	1.1	1.1

Warner Radial Coreflood 11R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Produced Water at 0.48 ft/day							
37	2.37	0.02	0.20	0.22	1.0	1.1	1.1
38	2.44	0.02	0.20	0.22	1.0	1.1	1.1
39	2.50	0.02	0.19	0.21	1.0	1.1	1.1
40	2.57	0.02	0.19	0.21	1.0	1.1	1.1
41	2.63	0.02	0.19	0.21	1.0	1.1	1.1
42	2.70	0.02	0.19	0.21	1.0	1.1	1.1
43	2.77	0.02	0.19	0.21	1.0	1.1	1.1
44	2.83	0.02	0.19	0.21	1.0	1.1	1.1
45	2.91	0.02	0.18	0.20	1.0	1.1	1.1
46	2.97	0.02	0.18	0.20	1.0	1.1	1.1
47	3.03	0.02	0.18	0.20	1.0	1.1	1.1
48	3.10	0.02	0.18	0.20	1.0	1.1	1.1
49	3.16	0.02	0.18	0.20	1.0	1.1	1.1
50	3.23	0.02	0.18	0.20	1.0	1.0	1.0
51	3.29	0.02	0.18	0.20	1.0	1.0	1.0
52	3.36	0.02	0.17	0.19	1.0	1.0	1.0
53	3.42	0.02	0.17	0.19	1.0	1.0	1.0
54	3.48	0.02	0.17	0.19	1.0	1.0	1.0
55	3.55	0.02	0.17	0.19	1.0	1.0	1.0
56	3.62	0.02	0.17	0.19	1.0	1.0	1.0
57	3.70	0.02	0.17	0.19	1.0	1.0	1.0
58	3.77	0.02	0.17	0.19	1.0	1.0	1.0
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.48 ft/day							
59	3.82	0.14	0.08	0.22	7.0	0.5	1.2
60	3.87	0.21	0.29	0.50	10.5	1.7	2.6
61	3.93	0.28	0.47	0.75	13.8	2.8	3.9
62	4.01	0.25	0.53	0.78	12.5	3.1	4.1
63	4.07	0.19	0.49	0.68	9.5	2.9	3.6
1200 mg/L Flopaam 3630S at 0.48 ft/day							
64	4.12	0.16	0.45	0.61	8.0	2.6	3.2
65	4.18	0.21	1.02	1.23	10.5	6.0	6.4
66	4.25	0.25	1.21	1.46	12.5	7.1	7.7
67	4.32	0.10	1.36	1.46	4.8	8.0	7.7
68	4.38	0.30	1.05	1.35	14.8	6.2	7.1
Injection Water at 0.48 ft/day							
69	4.43	0.16	0.78	0.94	7.8	4.6	4.9
70	4.50	0.14	0.78	0.92	6.8	4.6	4.8

Warner Radial Coreflood 11R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.48 ft/day							
71	4.57	0.13	0.50	0.63	6.3	2.9	3.3
72	4.62	0.13	0.16	0.28	6.3	0.9	1.5
73	4.67	0.13	0.15	0.28	6.3	0.9	1.4
74	4.74	0.13	0.18	0.30	6.3	1.0	1.6
75	4.81	0.13	0.23	0.35	6.3	1.3	1.8
76	4.89	0.13	0.17	0.29	6.3	1.0	1.5
77	4.96	0.13	0.11	0.23	6.3	0.6	1.2
78	5.01	0.13	0.10	0.23	6.3	0.6	1.2
79	5.07	0.13	0.14	0.26	6.3	0.8	1.4
80	5.14	0.12	0.16	0.28	6.0	0.9	1.4
81	5.22	0.12	0.15	0.27	6.0	0.9	1.4
82	5.29	0.12	0.11	0.23	6.0	0.6	1.2
83	5.36	0.12	0.11	0.23	5.8	0.6	1.2
84	5.42	0.12	0.11	0.23	5.8	0.6	1.2
85	5.49	0.12	0.11	0.23	5.8	0.6	1.2
86	5.56	0.11	0.12	0.23	5.5	0.7	1.2
87	5.63	0.11	0.11	0.22	5.5	0.6	1.2
88	5.70	0.11	0.11	0.22	5.5	0.6	1.1
89	5.77	0.11	0.11	0.22	5.3	0.6	1.1
90	5.83	0.11	0.11	0.22	5.3	0.6	1.1
91	5.89	0.10	0.12	0.22	5.0	0.7	1.1
92	5.95	0.10	0.12	0.22	5.0	0.7	1.1
93	6.01	0.10	0.12	0.22	5.0	0.7	1.1
94	6.08	0.10	0.12	0.22	5.0	0.7	1.1
95	6.14	0.10	0.12	0.22	5.0	0.7	1.1
96	6.20	0.10	0.12	0.22	5.0	0.7	1.1
97	6.27	0.10	0.12	0.22	5.0	0.7	1.1
98	6.34	0.10	0.12	0.22	5.0	0.7	1.1
99	6.40	0.10	0.12	0.22	5.0	0.7	1.1
100	6.46	0.10	0.12	0.22	5.0	0.7	1.1
101	6.53	0.10	0.12	0.22	5.0	0.7	1.1
102	6.59	0.10	0.12	0.22	5.0	0.7	1.1
103	6.66	0.10	0.12	0.22	5.0	0.7	1.1
104	6.72	0.10	0.12	0.22	5.0	0.7	1.1
105	6.78	0.10	0.12	0.22	5.0	0.7	1.1
106	6.85	0.10	0.12	0.22	5.0	0.7	1.1
107	6.91	0.10	0.12	0.22	5.0	0.7	1.1
108	6.98	0.10	0.12	0.22	5.0	0.7	1.1
109	7.04	0.10	0.12	0.22	5.0	0.7	1.1

Warner Radial Coreflood 11R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.48 ft/day							
110	7.10	0.10	0.12	0.22	5.0	0.7	1.1
111	7.17	0.10	0.12	0.22	5.0	0.7	1.1
112	7.23	0.10	0.12	0.22	5.0	0.7	1.1
113	7.30	0.10	0.12	0.22	5.0	0.7	1.1
114	7.36	0.10	0.12	0.22	5.0	0.7	1.1

Warner Radial Coreflood 12R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.50 ft/day							
0	0.00	0.27	0.12	0.39	18.0	0.6	1.7
Produced Water at 0.50 ft/day							
1	0.02	0.08	0.34	0.42	5.3	1.6	1.8
2	0.09	0.08	0.34	0.41	5.0	1.6	1.8
3	0.15	0.05	0.34	0.39	3.3	1.6	1.7
4	0.22	0.05	0.32	0.37	3.3	1.5	1.6
5	0.28	0.05	0.31	0.36	3.3	1.4	1.5
6	0.34	0.05	0.30	0.35	3.3	1.4	1.5
7	0.42	0.05	0.28	0.33	3.3	1.3	1.4
8	0.48	0.05	0.27	0.32	3.3	1.2	1.4
9	0.55	0.05	0.27	0.32	3.0	1.3	1.4
10	0.62	0.04	0.27	0.31	2.7	1.3	1.3
11	0.69	0.04	0.27	0.31	2.7	1.2	1.3
12	0.76	0.04	0.26	0.30	2.7	1.2	1.3
13	0.83	0.04	0.26	0.30	2.3	1.2	1.3
14	0.90	0.04	0.25	0.28	2.3	1.1	1.2
15	0.97	0.04	0.25	0.28	2.3	1.1	1.2
16	1.04	0.03	0.25	0.28	2.0	1.2	1.2
17	1.11	0.03	0.25	0.28	1.7	1.2	1.2
18	1.18	0.03	0.24	0.26	1.7	1.1	1.1
19	1.24	0.03	0.24	0.26	1.7	1.1	1.1
20	1.31	0.03	0.24	0.26	1.7	1.1	1.1
21	1.38	0.03	0.24	0.26	1.7	1.1	1.1
22	1.45	0.03	0.24	0.26	1.7	1.1	1.1
23	1.51	0.03	0.24	0.26	1.7	1.1	1.1
24	1.57	0.03	0.24	0.26	1.7	1.1	1.1
25	1.64	0.03	0.24	0.26	1.7	1.1	1.1
26	1.71	0.02	0.24	0.26	1.3	1.1	1.1
27	1.78	0.02	0.24	0.26	1.3	1.1	1.1
28	1.84	0.02	0.24	0.26	1.3	1.1	1.1
29	1.91	0.02	0.25	0.26	1.0	1.1	1.1
30	1.98	0.02	0.25	0.26	1.0	1.1	1.1
31	2.05	0.02	0.25	0.26	1.0	1.1	1.1
32	2.11	0.01	0.25	0.26	0.7	1.2	1.1
33	2.18	0.01	0.25	0.26	0.7	1.2	1.1
34	2.25	0.01	0.25	0.26	0.7	1.2	1.1
35	2.32	0.01	0.24	0.25	0.7	1.1	1.1
36	2.39	0.01	0.24	0.25	0.7	1.1	1.1

Warner Radial Coreflood 12R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Produced Water at 0.50 ft/day							
37	2.45	0.01	0.24	0.25	0.7	1.1	1.1
38	2.52	0.01	0.24	0.25	0.7	1.1	1.1
39	2.59	0.01	0.24	0.25	0.7	1.1	1.1
40	2.66	0.01	0.23	0.24	0.7	1.1	1.0
41	2.72	0.01	0.23	0.24	0.7	1.1	1.0
42	2.79	0.01	0.23	0.24	0.7	1.1	1.0
43	2.86	0.01	0.23	0.24	0.7	1.1	1.0
44	2.93	0.01	0.23	0.24	0.7	1.0	1.0
45	2.99	0.01	0.22	0.23	0.7	1.0	1.0
46	3.06	0.01	0.22	0.23	0.7	1.0	1.0
47	3.13	0.01	0.22	0.23	0.7	1.0	1.0
48	3.20	0.01	0.22	0.23	0.7	1.0	1.0
49	3.26	0.01	0.22	0.23	0.7	1.0	1.0
50	3.33	0.01	0.22	0.23	0.7	1.0	1.0
51	3.40	0.01	0.22	0.23	0.7	1.0	1.0
52	3.47	0.01	0.22	0.23	0.7	1.0	1.0
53	3.53	0.01	0.22	0.23	0.7	1.0	1.0
54	3.60	0.01	0.22	0.23	0.7	1.0	1.0
55	3.66	0.01	0.22	0.23	0.7	1.0	1.0
56	3.74	0.02	0.22	0.23	1.0	1.0	1.0
57	3.84	0.02	0.22	0.23	1.0	1.0	1.0
58	3.91	0.02	0.22	0.23	1.0	1.0	1.0
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day							
59	3.96	0.03	0.20	0.23	2.0	0.9	1.0
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day							
60	4.01	0.13	0.31	0.44	8.3	1.4	1.9
61	4.07	0.30	0.54	0.84	20.0	2.5	3.6
62	4.15	0.40	0.69	1.09	26.7	3.2	4.7
63	4.21	0.29	0.80	1.09	19.3	3.7	4.7
1200 mg/L Flopaam 3630S at 0.50 ft/day							
64	4.27	0.26	0.58	0.84	17.0	2.7	3.6
65	4.33	0.29	1.48	1.76	19.0	6.9	7.7
66	4.40	0.41	1.83	2.23	27.0	8.5	9.7
67	4.47	0.49	1.91	2.40	32.7	8.9	10.4
68	4.54	0.48	1.73	2.21	32.0	8.0	9.6

Warner Radial Coreflood 12R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Injection Water at 0.50 ft/day							
69	4.60	0.18	1.17	1.34	11.7	5.4	5.8
70	4.67	0.15	1.15	1.30	10.0	5.3	5.7
71	4.75	0.13	0.83	0.95	8.3	3.8	4.1
72	4.81	0.11	0.30	0.40	7.0	1.4	1.7
73	4.87	0.11	0.22	0.32	7.0	1.0	1.4
74	4.93	0.11	0.21	0.31	7.0	1.0	1.3
75	5.01	0.11	0.21	0.32	7.0	1.0	1.4
76	5.08	0.11	0.21	0.31	7.0	1.0	1.3
77	5.16	0.08	0.23	0.31	5.3	1.0	1.3
78	5.21	0.07	0.24	0.31	4.3	1.1	1.3
79	5.27	0.08	0.23	0.31	5.0	1.1	1.3
80	5.35	0.08	0.23	0.30	5.0	1.0	1.3
81	5.43	0.07	0.21	0.28	4.7	1.0	1.2
82	5.50	0.07	0.21	0.28	4.7	1.0	1.2
83	5.58	0.07	0.20	0.26	4.3	0.9	1.1
84	5.64	0.07	0.20	0.26	4.3	0.9	1.1
85	5.71	0.07	0.20	0.26	4.3	0.9	1.1
86	5.78	0.07	0.20	0.26	4.3	0.9	1.1
87	5.85	0.07	0.20	0.26	4.3	0.9	1.1
88	5.92	0.07	0.20	0.26	4.3	0.9	1.1
89	5.98	0.07	0.20	0.26	4.3	0.9	1.1
90	6.05	0.07	0.19	0.25	4.3	0.9	1.1
91	6.11	0.07	0.19	0.25	4.3	0.9	1.1
92	6.17	0.07	0.19	0.25	4.3	0.9	1.1
93	6.24	0.07	0.19	0.25	4.3	0.9	1.1
94	6.31	0.07	0.18	0.25	4.3	0.8	1.1
95	6.37	0.07	0.15	0.21	4.3	0.7	0.9
96	6.44	0.07	0.17	0.24	4.3	0.8	1.0
97	6.50	0.07	0.17	0.23	4.3	0.8	1.0
98	6.57	0.07	0.17	0.23	4.3	0.8	1.0
99	6.64	0.07	0.17	0.23	4.3	0.8	1.0
100	6.70	0.07	0.17	0.23	4.3	0.8	1.0
101	6.77	0.07	0.17	0.23	4.3	0.8	1.0
102	6.84	0.07	0.17	0.23	4.3	0.8	1.0
103	6.91	0.07	0.17	0.23	4.3	0.8	1.0
104	6.97	0.07	0.17	0.23	4.3	0.8	1.0
105	7.04	0.07	0.17	0.23	4.3	0.8	1.0
106	7.11	0.07	0.17	0.23	4.3	0.8	1.0
107	7.18	0.07	0.17	0.23	4.3	0.8	1.0

Warner Radial Coreflood 12R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.50 ft/day							
108	7.24	0.07	0.17	0.23	4.3	0.8	1.0
109	7.31	0.07	0.17	0.23	4.3	0.8	1.0
110	7.38	0.07	0.17	0.23	4.3	0.8	1.0
111	7.45	0.07	0.17	0.23	4.3	0.8	1.0
112	7.52	0.07	0.17	0.23	4.3	0.8	1.0
113	7.58	0.07	0.17	0.23	4.3	0.8	1.0
114	7.65	0.07	0.17	0.23	4.3	0.8	1.0

Warner Radial Coreflood 13R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.50 ft/day							
0	0.00	0.23	0.10	0.33	15.3	1.0	2.8
Produced Water at 0.50 ft/day							
1	0.00	0.19	0.13	0.32	12.7	1.2	2.6
2	0.08	0.16	0.12	0.28	10.7	1.1	2.3
3	0.14	0.12	0.13	0.25	8.0	1.2	2.1
4	0.21	0.10	0.14	0.23	6.3	1.3	1.9
5	0.27	0.08	0.14	0.22	5.3	1.3	1.8
6	0.34	0.06	0.17	0.22	3.7	1.6	1.8
7	0.41	0.06	0.17	0.22	3.7	1.6	1.8
8	0.48	0.06	0.14	0.19	3.7	1.3	1.6
9	0.55	0.05	0.13	0.18	3.0	1.2	1.5
10	0.61	0.05	0.12	0.17	3.0	1.1	1.4
11	0.67	0.05	0.11	0.16	3.0	1.0	1.3
12	0.73	0.05	0.11	0.15	3.0	1.0	1.3
13	0.80	0.04	0.12	0.15	2.3	1.1	1.3
14	0.87	0.04	0.12	0.15	2.3	1.1	1.3
15	0.94	0.04	0.12	0.15	2.3	1.1	1.3
16	1.01	0.03	0.11	0.14	2.0	1.0	1.2
17	1.08	0.03	0.11	0.13	1.7	1.0	1.1
18	1.15	0.02	0.12	0.13	1.0	1.1	1.1
19	1.22	0.02	0.12	0.13	1.0	1.1	1.1
20	1.29	0.02	0.11	0.13	1.0	1.0	1.0
21	1.36	0.02	0.11	0.13	1.0	1.0	1.0
22	1.42	0.02	0.11	0.13	1.0	1.0	1.0
23	1.49	0.02	0.11	0.13	1.0	1.0	1.0
24	1.56	0.02	0.11	0.13	1.0	1.0	1.0
25	1.63	0.02	0.11	0.12	1.0	1.0	1.0
26	1.70	0.02	0.11	0.12	1.0	1.0	1.0
27	1.77	0.02	0.11	0.12	1.0	1.0	1.0
28	1.84	0.02	0.11	0.12	1.0	1.0	1.0
29	1.91	0.02	0.11	0.12	1.0	1.0	1.0
30	1.98	0.02	0.11	0.12	1.0	1.0	1.0
31	2.05	0.02	0.11	0.12	1.0	1.0	1.0
32	2.12	0.02	0.11	0.12	1.0	1.0	1.0
33	2.19	0.02	0.11	0.12	1.0	1.0	1.0
34	2.25	0.02	0.11	0.12	1.0	1.0	1.0
35	2.32	0.02	0.11	0.12	1.0	1.0	1.0
36	2.39	0.02	0.11	0.12	1.0	1.0	1.0

Warner Radial Coreflood 13R
Incremental Resistance Factors

Tube No.	Cum V_P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P_1	P_2	P_T	RF_1	RF_2	RF_T
Produced Water at 0.50 ft/day							
37	2.46	0.02	0.11	0.12	1.0	1.0	1.0
38	2.53	0.02	0.11	0.12	1.0	1.0	1.0
39	2.60	0.02	0.11	0.12	1.0	1.0	1.0
40	2.67	0.02	0.11	0.12	1.0	1.0	1.0
41	2.74	0.02	0.11	0.12	1.0	1.0	1.0
42	2.80	0.02	0.11	0.12	1.0	1.0	1.0
43	2.87	0.02	0.11	0.12	1.0	1.0	1.0
44	2.94	0.02	0.11	0.12	1.0	1.0	1.0
45	3.00	0.02	0.11	0.12	1.0	1.0	1.0
46	3.07	0.02	0.11	0.12	1.0	1.0	1.0
47	3.14	0.02	0.11	0.12	1.0	1.0	1.0
48	3.21	0.02	0.11	0.12	1.0	1.0	1.0
49	3.28	0.02	0.11	0.12	1.0	1.0	1.0
50	3.35	0.02	0.11	0.12	1.0	1.0	1.0
51	3.41	0.02	0.11	0.12	1.0	1.0	1.0
52	3.48	0.02	0.11	0.12	1.0	1.0	1.0
53	3.55	0.02	0.11	0.12	1.0	1.0	1.0
54	3.62	0.02	0.11	0.12	1.0	1.0	1.0
55	3.68	0.02	0.11	0.12	1.0	1.0	1.0
56	3.75	0.02	0.11	0.12	1.0	1.0	1.0
57	3.82	0.02	0.11	0.12	1.0	1.0	1.0
58	3.88	0.02	0.11	0.12	1.0	1.0	1.0
59	3.95	0.02	0.11	0.12	1.0	1.0	1.0
60	4.01	0.02	0.11	0.12	1.0	1.0	1.0
61	4.07	0.02	0.11	0.12	1.0	1.0	1.0
62	4.13	0.02	0.11	0.12	1.0	1.0	1.0
63	4.18	0.02	0.11	0.12	1.0	1.0	1.0
64	4.23	0.02	0.11	0.12	1.0	1.0	1.0
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.50 ft/day							
65	4.29	0.05	0.10	0.15	3.0	1.0	1.2
66	4.35	0.06	0.21	0.26	3.7	2.0	2.2
67	4.40	0.06	0.26	0.31	3.7	2.4	2.6
68	4.43	0.09	0.27	0.36	5.7	2.6	3.0
69	4.49	0.12	0.29	0.41	7.7	2.8	3.4
70	4.57	0.13	0.33	0.46	8.7	3.1	3.8
1200 mg/L Flopaam 3630S at 0.50 ft/day							
71	4.64	0.13	0.33	0.46	8.7	3.1	3.8
72	4.71	0.17	0.32	0.48	11.0	3.0	4.0

Warner Radial Coreflood 13R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
1200 mg/L Flopaam 3630S at 0.50 ft/day							
73	4.78	0.17	0.27	0.43	11.0	2.5	3.6
74	4.83	0.17	0.27	0.43	11.0	2.5	3.6
75	4.89	0.17	0.27	0.43	11.0	2.5	3.6
Injection Water at 0.50 ft/day							
76	4.94	0.09	0.18	0.27	6.0	1.7	2.3
77	5.01	0.09	0.14	0.23	6.0	1.3	1.9
78	5.07	0.09	0.09	0.18	5.7	0.9	1.5
79	5.14	0.09	0.06	0.14	5.7	0.5	1.2
80	5.21	0.08	0.05	0.13	5.3	0.4	1.0
81	5.27	0.08	0.04	0.12	5.0	0.4	1.0
82	5.34	0.08	0.04	0.12	5.0	0.4	1.0
83	5.40	0.07	0.04	0.11	4.3	0.4	0.9
84	5.47	0.06	0.04	0.10	4.0	0.3	0.8
85	5.54	0.05	0.04	0.09	3.3	0.3	0.7
86	5.61	0.05	0.04	0.09	3.3	0.3	0.7
87	5.68	0.05	0.04	0.09	3.0	0.4	0.7
88	5.75	0.05	0.04	0.09	3.0	0.4	0.7
89	5.82	0.05	0.03	0.07	3.0	0.2	0.6
90	5.89	0.05	0.03	0.07	3.0	0.2	0.6
91	5.95	0.05	0.03	0.07	3.0	0.2	0.6
92	6.02	0.05	0.03	0.07	3.0	0.2	0.6
93	6.09	0.05	0.03	0.07	3.0	0.2	0.6
94	6.15	0.05	0.03	0.07	3.0	0.2	0.6
95	6.23	0.05	0.03	0.07	3.0	0.2	0.6
96	6.29	0.05	0.03	0.07	3.0	0.2	0.6
97	6.36	0.05	0.03	0.07	3.0	0.2	0.6
98	6.43	0.05	0.03	0.07	3.0	0.2	0.6
99	6.49	0.05	0.03	0.07	3.0	0.2	0.6
100	6.55	0.05	0.03	0.07	3.0	0.2	0.6
101	6.62	0.05	0.03	0.07	3.0	0.2	0.6
102	6.69	0.05	0.03	0.07	3.0	0.2	0.6
103	6.75	0.05	0.03	0.07	3.0	0.2	0.6
104	6.82	0.05	0.03	0.07	3.0	0.2	0.6
105	6.89	0.05	0.03	0.07	3.0	0.2	0.6
106	6.95	0.05	0.03	0.07	3.0	0.2	0.6
107	7.02	0.05	0.03	0.07	3.0	0.2	0.6
108	7.09	0.05	0.03	0.07	3.0	0.2	0.6
109	7.15	0.05	0.03	0.07	3.0	0.2	0.6

Warner Radial Coreflood 13R
Incremental Resistance Factors

Tube No.	Cum	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
	V _P	P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.50 ft/day							
110	7.22	0.05	0.03	0.07	3.0	0.2	0.6
111	7.28	0.05	0.03	0.07	3.0	0.2	0.6
112	7.35	0.05	0.03	0.07	3.0	0.2	0.6
113	7.41	0.05	0.03	0.07	3.0	0.2	0.6
114	7.48	0.05	0.03	0.07	3.0	0.2	0.6
115	7.51	0.05	0.03	0.07	3.0	0.2	0.6

Warner Radial Coreflood 14R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Warner Crude Oil at 0.49 ft/day							
0	0.00	0.12	0.14	0.26	12.0	1.3	2.2
Produced Water at 0.49 ft/day							
1	0.00	0.04	0.18	0.21	3.5	1.6	1.8
2	0.06	0.02	0.19	0.21	1.5	1.7	1.7
3	0.11	0.02	0.18	0.20	1.5	1.6	1.6
4	0.18	0.02	0.18	0.20	1.5	1.6	1.6
5	0.25	0.01	0.19	0.20	1.0	1.7	1.6
6	0.31	0.01	0.17	0.18	1.0	1.5	1.5
7	0.38	0.01	0.16	0.17	1.0	1.4	1.4
8	0.45	0.01	0.16	0.17	1.0	1.4	1.4
9	0.52	0.01	0.14	0.15	1.0	1.2	1.2
10	0.58	0.01	0.14	0.15	1.0	1.2	1.2
11	0.65	0.01	0.14	0.15	1.0	1.2	1.2
12	0.72	0.01	0.14	0.15	1.0	1.2	1.2
13	0.79	0.01	0.14	0.15	1.0	1.2	1.2
14	0.86	0.01	0.14	0.15	1.0	1.2	1.2
15	0.93	0.01	0.14	0.15	1.0	1.2	1.2
16	0.99	0.01	0.14	0.15	1.0	1.2	1.2
17	1.05	0.01	0.14	0.15	1.0	1.2	1.2
18	1.12	0.01	0.14	0.15	1.0	1.2	1.2
19	1.19	0.01	0.14	0.15	1.0	1.2	1.2
20	1.25	0.01	0.14	0.15	1.0	1.2	1.2
21	1.32	0.01	0.14	0.15	1.0	1.2	1.2
22	1.39	0.01	0.14	0.15	1.0	1.2	1.2
23	1.45	0.01	0.14	0.15	1.0	1.2	1.2
24	1.52	0.01	0.14	0.15	1.0	1.2	1.2
25	1.59	0.01	0.14	0.15	1.0	1.2	1.2
26	1.65	0.01	0.14	0.15	1.0	1.2	1.2
27	1.72	0.01	0.14	0.15	1.0	1.2	1.2
28	1.79	0.01	0.14	0.15	1.0	1.2	1.2
29	1.85	0.01	0.14	0.15	1.0	1.2	1.2
30	1.92	0.01	0.14	0.15	1.0	1.2	1.2
31	1.98	0.01	0.14	0.15	1.0	1.2	1.2
32	2.05	0.01	0.14	0.15	1.0	1.2	1.2
33	2.11	0.01	0.14	0.15	1.0	1.2	1.2
34	2.18	0.01	0.13	0.14	1.0	1.2	1.2
35	2.25	0.01	0.13	0.14	1.0	1.2	1.2
36	2.31	0.01	0.13	0.14	1.0	1.2	1.2

Warner Radial Coreflood 14R
Incremental Resistance Factors

Tube No.	Cum	--Incremental--			-Resistance Factor (Ratio)-		
	V _P	-Differential Pressure (psid)-			RF ₁	RF ₂	RF _T
		P ₁	P ₂	P _T			
Produced Water at 0.49 ft/day							
37	2.38	0.01	0.13	0.14	1.0	1.2	1.2
38	2.44	0.01	0.13	0.14	1.0	1.2	1.2
39	2.51	0.01	0.13	0.14	1.0	1.2	1.2
40	2.58	0.01	0.13	0.14	1.0	1.2	1.2
41	2.64	0.01	0.13	0.14	1.0	1.2	1.2
42	2.71	0.01	0.13	0.14	1.0	1.1	1.1
43	2.77	0.01	0.13	0.14	1.0	1.1	1.1
44	2.84	0.01	0.13	0.14	1.0	1.1	1.1
45	2.91	0.01	0.13	0.14	1.0	1.1	1.1
46	2.97	0.01	0.13	0.14	1.0	1.1	1.1
47	3.04	0.01	0.12	0.13	1.0	1.1	1.1
48	3.10	0.01	0.12	0.13	1.0	1.1	1.1
49	3.17	0.01	0.12	0.13	1.0	1.0	1.0
50	3.24	0.01	0.12	0.13	1.0	1.0	1.0
51	3.30	0.01	0.11	0.12	1.0	1.0	1.0
52	3.37	0.01	0.11	0.12	1.0	1.0	1.0
53	3.44	0.01	0.11	0.12	1.0	1.0	1.0
54	3.50	0.01	0.11	0.12	1.0	1.0	1.0
55	3.57	0.01	0.11	0.12	1.0	1.0	1.0
56	3.64	0.01	0.11	0.12	1.0	1.0	1.0
57	3.70	0.01	0.11	0.12	1.0	1.0	1.0
58	3.77	0.01	0.11	0.12	1.0	1.0	1.0
59	3.83	0.01	0.11	0.12	1.0	1.0	1.0
60	3.90	0.01	0.11	0.12	1.0	1.0	1.0
0.75 wt% NaOH + 0.15 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.49 ft/day							
61	3.96	0.08	0.19	0.26	7.5	1.7	2.2
62	4.01	0.08	0.20	0.28	8.0	1.8	2.3
63	4.05	0.09	0.20	0.29	9.0	1.8	2.4
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S at 0.49 ft/day							
64	4.11	0.10	0.18	0.28	9.5	1.6	2.3
65	4.16	0.10	0.18	0.27	9.5	1.6	2.3
66	4.21	0.10	0.17	0.27	9.5	1.5	2.2
1200 mg/L Flopaam 3630S at 0.49 ft/day							
67	4.27	0.11	0.17	0.28	11.0	1.5	2.3
68	4.34	0.14	0.18	0.32	14.0	1.6	2.6
69	4.40	0.15	0.18	0.33	15.0	1.6	2.7
70	4.47	0.17	0.17	0.34	16.5	1.5	2.8
71	4.52	0.17	0.17	0.34	16.5	1.5	2.8

Warner Radial Coreflood 14R
Incremental Resistance Factors

Tube No.	Cum V _P	--Incremental-- -Differential Pressure (psid)-			-Resistance Factor (Ratio)-		
		P ₁	P ₂	P _T	RF ₁	RF ₂	RF _T
Injection Water at 0.49 ft/day							
72	4.58	0.15	0.09	0.24	15.0	0.8	2.0
73	4.64	0.08	0.06	0.14	7.5	0.5	1.1
74	4.70	0.06	0.05	0.11	6.0	0.5	0.9
75	4.76	0.06	0.03	0.09	6.0	0.2	0.7
76	4.82	0.05	0.03	0.08	5.0	0.3	0.7
77	4.88	0.05	0.03	0.08	5.0	0.2	0.6
78	4.94	0.05	0.03	0.08	5.0	0.2	0.6
79	5.00	0.05	0.02	0.07	5.0	0.2	0.6
80	5.07	0.05	0.02	0.07	5.0	0.2	0.6
81	5.13	0.05	0.02	0.07	5.0	0.1	0.5
82	5.20	0.05	0.02	0.06	4.5	0.1	0.5
83	5.26	0.04	0.02	0.06	3.5	0.2	0.5
84	5.32	0.03	0.02	0.05	3.0	0.2	0.4
85	5.39	0.03	0.02	0.05	3.0	0.1	0.4
86	5.47	0.03	0.02	0.04	2.5	0.1	0.3
87	5.54	0.03	0.01	0.04	2.5	0.1	0.3
88	5.61	0.03	0.01	0.04	2.5	0.1	0.3
89	5.67	0.02	0.02	0.04	2.0	0.1	0.3
90	5.73	0.02	0.02	0.04	2.0	0.1	0.3
91	5.79	0.02	0.02	0.04	2.0	0.1	0.3
92	5.86	0.02	0.02	0.04	2.0	0.1	0.3
93	5.91	0.02	0.02	0.04	1.5	0.2	0.3
94	5.98	0.02	0.02	0.04	1.5	0.2	0.3
95	6.04	0.02	0.02	0.04	1.5	0.2	0.3
96	6.10	0.02	0.02	0.04	1.5	0.2	0.3
97	6.16	0.02	0.02	0.04	1.5	0.2	0.3
98	6.23	0.02	0.02	0.04	1.5	0.2	0.3
99	6.29	0.02	0.02	0.04	1.5	0.2	0.3
100	6.35	0.02	0.02	0.04	1.5	0.2	0.3
101	6.42	0.02	0.02	0.04	1.5	0.2	0.3
102	6.48	0.02	0.02	0.04	1.5	0.2	0.3
103	6.55	0.02	0.02	0.04	1.5	0.2	0.3
104	6.61	0.02	0.02	0.04	1.5	0.2	0.3
105	6.68	0.02	0.02	0.04	1.5	0.2	0.3
106	6.74	0.02	0.02	0.04	1.5	0.2	0.3
107	6.81	0.02	0.02	0.04	1.5	0.2	0.3
108	6.87	0.02	0.02	0.04	1.5	0.2	0.3

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 1R

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Effluent Concentration		
				Na ₂ CO ₃ wt%	ORS-164HF wt%	Flopaam 3630S mg/L
Production Water	3.12	223.50	0.000	0.000	0.000	0
0.75 wt% NaOH +	3.16	226.60	0.000	0.000	0.000	0
0.1 wt% ORS-164HF	3.20	229.70	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	3.24	232.70	0.000	0.000	0.000	0
	3.28	235.50	0.000	0.000	0.000	0
	3.33	237.95	0.000	0.000	0.000	0
	3.37	240.40	0.000	0.000	0.001	0
	3.42	242.80	0.000	0.000	0.002	47
1200 mg/L Flopaam 3630S	3.46	245.30	0.000	0.000	0.003	114
	3.51	248.10	0.000	0.000	0.004	233
	3.55	250.85	0.000	0.000	0.005	299
	3.60	254.10	0.000	0.087	0.006	607
	3.64	257.40	0.013	0.401	0.011	868
	3.69	260.50	0.126	0.457	0.012	981
	3.73	263.50	0.168	0.441	0.011	1026
	3.77	266.30	0.234	0.479	0.011	1034
Injection Water	3.82	269.95	0.307	0.479	0.010	1019
	3.87	273.75	0.318	0.490	0.008	1023
	3.93	277.60	0.282	0.505	0.009	1059
	3.98	281.40	0.269	0.477	0.008	1063
	4.03	285.45	0.255	0.479	0.008	1067
	4.09	289.45	0.184	0.468	0.008	994
	4.14	293.55	0.039	0.432	0.009	692
	4.19	297.40	0.000	0.396	0.007	463
	4.25	301.65	0.000	0.321	0.006	390
	4.30	305.55	0.000	0.292	0.005	329
	4.35	309.75	0.000	0.254	0.005	322
	4.40	313.60	0.000	0.240	0.005	321
	4.46	317.60	0.000	0.223	0.005	267
	4.51	321.50	0.000	0.196	0.004	244
	4.56	325.50	0.000	0.174	0.004	218
	4.61	329.50	0.000	0.156	0.004	199
	4.66	333.35	0.000	0.147	0.004	173
	4.72	337.50	0.000	0.158	0.004	160
	4.77	341.40	0.000	0.134	0.004	142
	4.82	345.40	0.000	0.120	0.004	124
	4.87	349.35	0.000	0.120	0.004	177
	4.92	353.45	0.000	0.109	0.004	98
	4.98	357.45	0.000	0.102	0.004	90
	5.03	361.50	0.000	0.105	0.004	81
	5.08	365.55	0.000	0.100	0.004	79
	5.14	369.50	0.000	0.100	0.003	71
	5.25	378.00	0.000	0.089	0.003	73
	5.30	382.20	0.000	0.089	0.003	51
	5.35	386.00	0.000	0.107	0.003	48

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 1R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent	Volume		Na ₂ CO ₃	ORS-164HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	5.40	390.10	0.000	0.093	0.003	44
	5.45	393.90	0.000	0.082	0.003	42
	5.50	397.80	0.000	0.073	0.003	38
	5.56	401.80	0.000	0.093	0.003	37
	5.61	405.80	0.000	0.078	0.002	30
	5.66	409.70	0.000	0.093	0.002	27
	5.71	413.80	0.000	0.076	0.002	19
	5.76	417.80	0.000	0.071	0.002	16
	5.82	422.10	0.000	0.067	0.002	17
	5.87	426.15	0.000	0.067	0.002	13
	5.92	430.30	0.000	0.065	0.002	14
	5.97	434.26	0.000	0.065	0.002	12
	6.03	438.34	0.000	0.062	0.002	5
	6.08	442.32	0.000	0.062	0.002	4
	6.13	446.30	0.000	0.062	0.002	3

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	788	14.90	52.9
Na ₂ CO ₃	(2,209)	(41.78)	---
ORS-164HF	152	2.87	64.0
Flopaam 3630S	52	0.98	8.8

Core Weight 599.1 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 2R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent V_p	Volume mL		Na_2CO_3 wt%	EOR 2095 wt%	Flopaam 3630S mg/L
Production Water	3.24	248.50	0.000	0.000	0.000	0
0.5 wt% NaOH +	3.28	251.45	0.000	0.000	0.000	0
0.25 wt% Na_2CO_3 +	3.29	252.65	0.000	0.000	0.000	0
0.1 wt% Petronate EOR 2095 +	3.34	255.05	0.000	0.031	0.001	95
1200 mg/L Flopaam 3630S	3.38	257.00	0.000	0.465	0.008	354
	3.43	258.90	0.017	0.545	0.010	483
	3.47	260.85	0.060	0.550	0.012	533
	3.52	262.85	0.144	0.554	0.013	693
	3.57	264.95	0.136	0.572	0.014	752
1200 mg/L Flopaam 3630S	3.61	266.85	0.122	0.577	0.015	760
	3.65	269.05	0.139	0.532	0.014	772
	3.70	271.75	0.128	0.545	0.018	777
	3.74	274.00	0.095	0.492	0.027	789
	3.79	276.50	0.047	0.456	0.024	802
	3.83	278.95	0.026	0.403	0.021	808
	3.87	281.30	0.000	0.309	0.019	844
	3.91	283.95	0.000	0.241	0.015	867
Injection Water	3.97	287.55	0.000	0.219	0.013	900
	4.03	291.35	0.000	0.197	0.015	860
	4.08	294.70	0.000	0.141	0.015	684
	4.13	298.70	0.000	0.108	0.012	484
	4.18	302.65	0.000	0.065	0.010	321
	4.24	306.45	0.000	0.041	0.007	247
	4.29	310.40	0.000	0.030	0.007	247
	4.34	314.35	0.000	0.025	0.006	179
	4.39	318.40	0.000	0.019	0.006	146
	4.44	322.25	0.000	0.019	0.006	154
	4.49	326.25	0.000	0.019	0.005	148
	4.55	330.40	0.000	0.019	0.006	150
	4.60	334.40	0.000	0.019	0.005	147
	4.65	338.35	0.000	0.019	0.005	143
	4.70	342.35	0.000	0.016	0.005	134
	4.75	346.30	0.000	0.016	0.004	136
	4.80	350.30	0.000	0.016	0.004	125
	4.86	354.30	0.000	0.019	0.004	121
	4.91	358.20	0.000	0.016	0.004	115
	4.96	362.30	0.000	0.016	0.004	106
	5.01	366.30	0.000	0.016	0.004	110
	5.06	370.35	0.000	0.010	0.003	112
	5.11	374.40	0.000	0.007	0.003	90
	5.16	378.37	0.000	0.014	0.003	94

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 2R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent	Volume		Na ₂ CO ₃	EOR 2095	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	5.27	386.72	0.000	0.005	0.003	101
	5.32	390.72	0.000	0.007	0.003	86
	5.37	394.90	0.000	0.010	0.003	97
	5.42	398.95	0.000	0.027	0.003	78
	5.48	403.00	0.000	0.014	0.003	76
	5.53	407.05	0.000	0.012	0.003	75
	5.58	411.10	0.000	0.007	0.002	70
	5.63	415.20	0.000	0.003	0.003	68
	5.68	419.29	0.000	0.003	0.002	72
	5.73	423.19	0.000	0.003	0.002	61
	5.78	427.17	0.000	0.003	0.003	65
	5.83	431.22	0.000	0.001	0.002	70
	5.89	435.32	0.000	0.001	0.002	59
	5.94	439.37	0.000	0.000	0.002	45
	5.99	443.83	0.000	0.000	0.002	43
	6.05	448.21	0.000	0.000	0.002	38
	6.10	452.40	0.000	0.000	0.002	37
	6.15	456.40	0.000	0.000	0.002	34
	6.20	460.40	0.000	0.000	0.002	28

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	639	12.11	78.5
Na ₂ CO ₃	82	1.56	4.90
EOR 2095	121	2.28	52.0
Flopaam 3630S	155	2.94	26.5

Core Weight 603.1 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 3R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent V_p	Volume mL		Na_2CO_3 wt%	B-100 & AS-1216 wt%	Alcoflood 1275A mg/L
Production Water	3.10	215.10	0.000	0.000	0.000	0
0.5 wt% NaOH +	3.16	219.72	0.000	0.000	0.000	0
0.25 wt% Na_2CO_3 +	3.22	224.22	0.000	0.000	0.000	0
0.05 wt% Petrostep B-100 +	3.27	228.32	0.000	0.000	0.000	0
0.05 wt% Stepantan AS-1216 +	3.33	232.02	0.000	0.000	0.000	0
1500 mg/L Alcoflood 1275A	3.38	235.42	0.000	0.000	0.000	0
	3.43	238.22	0.000	0.011	0.000	0
1500 mg/L Alcoflood 1275A	3.49	241.37	0.000	0.033	0.000	23
	3.54	244.27	0.000	0.045	0.002	184
	3.60	247.77	0.000	0.301	0.011	430
	3.66	251.47	0.055	0.345	0.020	718
	3.72	255.12	0.097	0.445	0.025	919
	3.77	258.72	0.109	0.557	0.031	1088
Injection Water	3.83	262.62	0.126	0.479	0.035	1113
	3.88	266.57	0.147	0.401	0.030	1121
	3.94	270.42	0.088	0.445	0.026	1169
	3.99	274.27	0.046	0.434	0.022	1100
	4.05	278.27	0.013	0.378	0.019	836
	4.10	282.07	0.000	0.278	0.012	607
	4.16	286.07	0.000	0.200	0.010	468
	4.21	290.12	0.000	0.100	0.008	377
	4.27	294.12	0.000	0.045	0.006	303
	4.32	298.17	0.000	0.033	0.005	213
	4.38	302.27	0.000	0.056	0.004	182
	4.43	306.42	0.000	0.011	0.004	156
	4.49	310.47	0.000	0.045	0.003	135
	4.54	314.57	0.000	0.033	0.003	151
	4.60	318.57	0.000	0.045	0.003	109
	4.65	322.67	0.000	0.022	0.003	100
	4.71	326.84	0.000	0.011	0.003	89
	4.76	330.94	0.000	0.022	0.003	85
	4.82	335.33	0.000	0.000	0.002	76
	4.87	339.53	0.000	0.000	0.003	69
	4.93	343.73	0.000	0.000	0.002	53
	4.98	347.99	0.000	0.000	0.002	56
	5.04	352.25	0.000	0.000	0.002	58
	5.09	356.25	0.000	0.000	0.002	50
	5.15	360.54	0.000	0.000	0.002	52
	5.20	364.72	0.000	0.000	0.002	40
	5.26	369.00	0.000	0.000	0.002	42
	5.31	373.19	0.000	0.000	0.002	35

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 3R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent	Volume		Na ₂ CO ₃	B-100 & AS-1216	Alcoflood 1275A
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	5.37	377.17	0.000	0.000	0.002	34
	5.42	381.46	0.000	0.000	0.002	27
	5.48	385.74	0.000	0.000	0.002	26
	5.53	389.93	0.000	0.000	0.002	29
	5.59	394.11	0.000	0.000	0.002	27
	5.64	398.31	0.000	0.000	0.002	21
	5.70	402.60	0.000	0.000	0.002	19
	5.75	406.90	0.000	0.000	0.002	14
	5.81	411.00	0.000	0.000	0.002	13
	5.87	415.80	0.000	0.000	0.002	11
	5.93	420.08	0.000	0.000	0.002	18
	5.98	424.28	0.000	0.000	0.001	10
	6.04	428.58	0.000	0.000	0.001	6
	6.09	433.08	0.000	0.000	0.001	6

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	549	10.14	70.9
Na ₂ CO ₃	(2)	-0.04	-0.13
B-100 & AS-1216	110	2.03	49.4
Alcoflood 1275A	254	4.70	37.8

Core Weight 622.9 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 4R

Fluid Injected	Cumulative Effluent	Aqueous Volume	Effluent Concentration			
	V_p	mL	NaHCO ₃ wt%	Na ₂ CO ₃ wt%	ORS-162HF wt%	Alcoflood 1275A mg/L
Production Water	2.98	226.15	0.000	0.000	0.000	0
2.0 wt% Na ₂ CO ₃ +	3.03	230.65	0.000	0.000	0.000	0
0.1 wt% ORS-162HF +	3.08	234.35	0.000	0.000	0.000	0
1500 mg/L Alcoflood 1275A	3.13	237.25	0.000	0.022	0.001	77
	3.19	240.15	0.000	0.278	0.002	226
	3.24	243.35	0.000	0.501	0.004	348
	3.30	246.80	0.000	0.779	0.008	599
1500 mg/L Alcoflood 1275A	3.35	250.40	0.000	1.291	0.014	839
	3.40	254.15	0.000	1.514	0.021	973
	3.45	257.90	0.000	1.692	0.024	1061
	3.51	261.40	0.000	1.558	0.024	1161
	3.56	264.90	0.000	1.215	0.022	1194
	3.61	268.20	0.000	0.801	0.021	1230
Injection Water	3.67	272.45	0.000	0.579	0.019	1254
	3.72	275.75	0.000	0.345	0.017	1166
	3.77	279.70	0.000	0.145	0.014	636
	3.83	283.80	0.000	0.067	0.010	321
	3.88	288.00	0.000	0.033	0.008	242
	3.93	292.10	0.000	0.011	0.007	193
	3.99	296.44	0.000	0.022	0.006	156
	4.04	300.71	0.000	0.033	0.005	119
	4.09	305.00	0.000	0.022	0.005	105
	4.15	309.18	0.000	0.011	0.004	91
	4.20	313.47	0.000	0.000	0.004	71
	4.25	317.77	0.000	0.011	0.004	56
	4.31	322.06	0.000	0.000	0.004	48
	4.36	326.35	0.000	0.000	0.003	36
	4.41	330.64	0.000	0.011	0.003	33
	4.47	334.94	0.000	0.000	0.003	28
	4.52	339.03	0.000	0.000	0.003	27
	4.57	343.32	0.000	0.000	0.003	24
	4.62	347.62	0.000	0.000	0.002	21
	4.67	351.81	0.000	0.000	0.002	20
	4.73	356.10	0.000	0.000	0.002	18
	4.78	360.40	0.000	0.000	0.002	17
	4.83	364.59	0.000	0.000	0.002	16
	4.89	368.77	0.000	0.000	0.002	15
	4.94	373.06	0.000	0.000	0.002	13
	4.99	377.26	0.000	0.011	0.002	13
	5.04	381.36	0.000	0.000	0.002	11
	5.09	385.56	0.000	0.000	0.002	11

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 4R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaHCO_3 wt%	Na_2CO_3 wt%	ORS-162HF wt%	Alcoflood 1275A mg/L
Injection Water	5.15	389.75	0.000	0.000	0.002	10
	5.20	394.05	0.000	0.000	0.002	9
	5.25	398.35	0.000	0.000	0.002	8
	5.30	402.54	0.000	0.000	0.002	7
	5.36	406.84	0.000	0.000	0.002	6
	5.41	411.14	0.000	0.000	0.002	6
	5.46	415.23	0.000	0.000	0.002	5
	5.51	419.33	0.000	0.000	0.002	3
	5.56	423.43	0.000	0.000	0.002	2
	5.62	428.23	0.000	0.000	0.002	1
	5.67	432.43	0.000	0.000	0.002	2
	5.73	436.53	0.000	0.000	0.002	1
	5.78	440.73	0.000	0.000	0.001	0
	5.83	445.13	0.000	0.000	0.002	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
Na_2CO_3	1,535	28.88	30.95
ORS-162HF	124	2.34	55.0
Alcoflood 1275A	274	5.15	40.5

Core Weight 610.4 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 5R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent V_p	Volume mL		Na_2CO_3	ORS-97HF	Flopaam 3630S
			wt%		wt%	mg/L
Production Water	3.14	219.28	0.000	0.000	0.000	0
0.75 wt% NaOH +	3.22	225.15	0.000	0.000	0.000	0
0.1 wt% ORS-97HF +	3.30	230.95	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	3.38	233.95	0.000	0.000	0.001	77
	3.43	235.55	0.000	0.000	0.001	329
	3.47	236.85	0.000	0.010	0.001	522
1200 mg/L Flopaam 3630S	3.51	238.60	0.000	0.013	0.002	632
	3.55	240.95	0.000	0.052	0.010	770
	3.60	243.75	0.000	0.177	0.015	895
	3.67	247.20	0.016	0.354	0.019	1016
	3.74	251.10	0.077	0.384	0.025	1138
	3.79	254.00	0.123	0.416	0.019	1201
Injection Water	3.86	257.90	0.201	0.386	0.018	1269
	3.92	262.15	0.205	0.426	0.015	1284
	3.98	266.25	0.195	0.414	0.014	1316
	4.03	269.35	0.153	0.384	0.013	1258
	4.07	272.40	0.092	0.384	0.011	1019
	4.12	275.50	0.053	0.372	0.008	783
	4.17	279.40	0.022	0.345	0.004	582
	4.23	283.80	0.000	0.305	0.003	426
	4.30	288.70	0.000	0.230	0.003	337
	4.36	293.70	0.000	0.200	0.003	264
	4.43	298.70	0.000	0.171	0.002	230
	4.49	303.22	0.000	0.159	0.002	206
	4.54	306.95	0.000	0.150	0.002	170
	4.59	310.21	0.000	0.136	0.002	142
	4.63	313.47	0.000	0.125	0.002	129
	4.67	316.53	0.000	0.115	0.002	116
	4.72	320.11	0.000	0.109	0.002	102
	4.78	324.30	0.000	0.104	0.002	91
	4.84	329.09	0.000	0.100	0.002	74
	4.91	334.21	0.000	0.092	0.002	52
	4.98	339.10	0.000	0.084	0.002	40
	5.04	343.50	0.000	0.079	0.002	34
	5.09	347.49	0.000	0.073	0.002	30
	5.14	351.28	0.000	0.069	0.002	26
	5.19	354.96	0.000	0.067	0.002	23
	5.24	358.52	0.000	0.069	0.002	23
	5.28	362.11	0.000	0.069	0.002	20
	5.34	366.20	0.000	0.065	0.002	17
	5.40	370.60	0.000	0.063	0.002	16

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 5R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent	Volume		Na ₂ CO ₃	ORS-97HF	Flopaam 3630S
	V _p	mL	wt%		wt%	mg/L
Injection Water	5.46	375.29	0.000	0.061	0.001	12
	5.52	379.78	0.000	0.059	0.001	9
	5.58	384.06	0.000	0.059	0.001	8
	5.63	387.85	0.000	0.058	0.001	7
	5.67	390.91	0.000	0.058	0.001	5
	5.71	393.89	0.000	0.058	0.001	4
	5.75	397.28	0.000	0.059	0.001	1
	5.81	401.57	0.000	0.058	0.001	0
	5.88	406.57	0.000	0.054	0.001	0
	5.95	411.87	0.000	0.052	0.001	0

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	831	15.18	69.8
Na ₂ CO ₃	(1,394)	(25.48)	---
ORS-97HF	142	2.59	66.6
Flopaam 3630S	13	0.24	2.5

Core Weight 633.6 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 6R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent V_p	Volume mL		Na_2CO_3 wt%	ORS-162HF wt%	Flopaam 3630S mg/L
Production Water	3.13	218.86	0.000	0.000	0.000	0
0.625 wt% NaOH +	3.19	223.08	0.000	0.000	0.000	0
0.5 wt% Na_2CO_3 +	3.27	228.83	0.000	0.000	0.000	0
0.1 wt% ORS-162HF +	3.35	232.43	0.000	0.016	0.001	91
1200 mg/L Flopaam 3630S	3.40	234.63	0.000	0.069	0.001	284
	3.43	235.93	0.000	0.216	0.001	480
1200 mg/L Flopaam 3630S	3.48	237.73	0.000	0.209	0.002	597
	3.52	239.83	0.000	0.312	0.004	688
	3.57	242.68	0.000	0.383	0.016	773
	3.64	245.98	0.000	0.481	0.018	834
	3.71	250.28	0.000	0.603	0.021	887
	3.76	253.18	0.002	0.772	0.027	936
Injection Water	3.83	257.78	0.063	0.683	0.024	949
	3.90	261.93	0.101	0.650	0.023	941
	3.95	264.98	0.069	0.646	0.022	891
	4.00	268.33	0.066	0.572	0.022	847
	4.04	271.28	0.053	0.516	0.017	799
	4.09	274.43	0.025	0.483	0.012	630
	4.14	278.23	0.008	0.439	0.010	550
	4.20	282.73	0.000	0.347	0.008	419
	4.27	287.58	0.000	0.276	0.006	329
	4.34	292.73	0.000	0.252	0.005	262
	4.41	297.63	0.000	0.216	0.004	242
	4.47	302.18	0.000	0.191	0.004	199
	4.53	306.18	0.000	0.167	0.004	190
	4.57	309.34	0.000	0.149	0.004	195
	4.61	312.50	0.000	0.136	0.003	149
	4.65	315.50	0.000	0.127	0.003	145
	4.71	319.38	0.000	0.116	0.003	138
	4.77	323.86	0.000	0.102	0.003	119
	4.83	328.65	0.000	0.091	0.003	114
	4.90	333.74	0.000	0.082	0.003	102
	4.96	338.53	0.000	0.078	0.002	87
	5.02	342.82	0.000	0.073	0.002	82
	5.07	346.77	0.000	0.069	0.002	76
	5.12	350.44	0.000	0.056	0.002	74
	5.17	354.02	0.000	0.047	0.002	63
	5.22	357.60	0.000	0.042	0.002	61
	5.27	361.59	0.000	0.038	0.002	55
	5.33	365.98	0.000	0.036	0.002	49
	5.39	370.66	0.000	0.036	0.002	59

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 6R

Fluid Injected	Cumulative	Aqueous	NaOH	Effluent Concentration		
	Effluent	Volume		Na ₂ CO ₃	ORS-162HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	5.45	374.85	0.000	0.031	0.002	34
	5.51	379.33	0.000	0.029	0.002	31
	5.56	383.11	0.000	0.022	0.002	29
	5.61	386.50	0.000	0.016	0.002	25
	5.65	389.49	0.000	0.013	0.001	23
	5.69	392.58	0.000	0.011	0.001	16
	5.74	396.16	0.000	0.011	0.001	16
	5.80	400.85	0.000	0.009	0.001	13
	5.87	406.34	0.000	0.004	0.001	7
	5.94	411.54	0.000	0.000	0.001	6

Amount of Chemical Retained by Core

	lb/acre ft	mg/100g rock	%*
NaOH	986	18.06	89.0
Na ₂ CO ₃	(1,113)	-20.39	-56.25
ORS-162HF	97	1.78	49.9
Flopaam 3630S	56	1.03	11.4

Core Weight 632.9 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 7R

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Effluent Concentration		
				Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	3.69	249.86	0.000	0.000	0.000	0
0.75 wt% NaOH +	3.78	255.86	0.000	0.000	0.000	0
0.1 wt% ORS-97HF +	3.83	259.91	0.000	0.033	0.000	0
1200 mg/L Flopaam 3630S	3.90	264.76	0.000	0.000	0.000	0
	3.95	268.66	0.000	0.021	0.000	0
	4.02	272.51	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.08	276.16	0.000	0.033	0.000	15
	4.15	280.11	0.000	0.005	0.000	90
	4.21	283.86	0.000	0.035	0.000	198
	4.27	287.61	0.000	0.117	0.000	320
	4.34	291.76	0.000	0.233	0.000	471
Injection Water	4.41	296.26	0.023	0.406	0.000	639
	4.49	301.66	0.062	0.394	0.000	785
	4.58	307.64	0.048	0.396	0.000	790
	4.65	312.74	0.037	0.336	0.000	545
	4.72	317.54	0.000	0.340	0.000	438
	4.79	322.59	0.000	0.257	0.000	369
	4.86	327.91	0.000	0.231	0.000	304
	4.94	333.26	0.000	0.198	0.000	254
	5.01	338.76	0.000	0.196	0.000	228
	5.09	344.41	0.000	0.161	0.000	218
	5.16	349.81	0.000	0.154	0.000	192
	5.24	355.41	0.000	0.149	0.000	181
	5.31	360.61	0.000	0.126	0.000	175
	5.38	365.96	0.000	0.126	0.000	168
	5.46	371.46	0.000	0.119	0.000	160
	5.53	376.81	0.000	0.107	0.000	151
	5.60	382.11	0.000	0.100	0.000	143
	5.67	387.11	0.000	0.105	0.000	143
	5.74	392.11	0.000	0.100	0.000	143
	5.80	396.51	0.000	0.086	0.000	132
	5.87	401.71	0.000	0.107	0.000	124
	5.94	407.26	0.000	0.089	0.000	107
	6.02	412.56	0.000	0.091	0.000	107
	6.09	417.81	0.000	0.091	0.000	100
	6.15	422.66	0.000	0.091	0.000	107
	6.22	427.56	0.000	0.082	0.000	107
	6.29	432.61	0.000	0.089	0.000	100
	6.36	437.66	0.000	0.079	0.000	89
	6.43	442.86	0.000	0.068	0.000	82
	6.49	447.86	0.000	0.079	0.000	82

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 7R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent	Volume	NaOH	Na ₂ CO ₃	ORS-97HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	6.56	453.01	0.000	0.079	0.000	65
	6.63	458.31	0.000	0.056	0.000	55
	6.70	463.51	0.000	0.056	0.000	52
	6.78	468.81	0.000	0.068	0.000	34
	6.85	474.11	0.000	0.051	0.000	21
	6.92	479.31	0.000	0.051	0.000	21
	6.99	484.36	0.000	0.049	0.000	21
	7.05	489.36	0.000	0.049	0.000	21
	7.12	494.48	0.000	0.047	0.000	21
	7.19	499.63	0.000	0.044	0.000	21
	7.26	504.83	0.000	0.044	0.000	21
	7.33	509.98	0.000	0.056	0.000	21
	7.41	515.33	0.000	0.044	0.000	21
	7.48	520.63	0.000	0.035	0.000	21
	7.53	524.48	0.000	0.035	0.000	21

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	1,180	22.32	93.6
Na ₂ CO ₃	-1,808	-34.19	---
ORS-97HF	214	4.05	100.0
Flopaam 3630S	108	2.04	21.6

Core Weight 594.6 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 8R

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Effluent Concentration		
				Na_2CO_3 wt%	B-100 and AS1216 wt%	Flopaam 3630S mg/L
Production Water	4.00	261.22	0.000	0.000	0.000	0
0.5 wt% NaOH +	4.09	267.62	0.000	0.000	0.000	0
0.25 wt% Na_2CO_3 +	4.15	271.62	0.000	0.012	0.000	0
0.05 wt% Petrostep B-100 +	4.21	275.47	0.000	0.000	0.000	0
0.05 wt% Stepantan AS 1216 +	4.28	278.07	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.34	280.52	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.40	283.02	0.000	0.000	0.000	29
	4.48	286.37	0.000	0.000	0.000	174
	4.55	289.87	0.000	0.117	0.001	393
	4.61	293.77	0.000	0.294	0.002	592
	4.68	297.62	0.000	0.431	0.003	779
Injection Water	4.76	302.27	0.048	0.527	0.006	865
	4.84	307.62	0.066	0.543	0.008	994
	4.93	313.27	0.100	0.497	0.007	983
	5.01	318.07	0.026	0.443	0.007	658
	5.08	323.27	0.000	0.347	0.006	443
	5.16	328.27	0.000	0.184	0.004	287
	5.24	334.07	0.000	0.128	0.004	218
	5.32	339.42	0.000	0.091	0.003	141
	5.39	344.67	0.000	0.082	0.002	135
	5.46	349.77	0.000	0.047	0.002	98
	5.54	354.87	0.000	0.042	0.001	80
	5.61	360.32	0.000	0.044	0.001	80
	5.69	365.67	0.000	0.051	0.001	81
	5.76	370.67	0.000	0.061	0.001	81
	5.84	375.87	0.000	0.058	0.001	74
	5.91	380.97	0.000	0.063	0.001	65
	5.98	386.17	0.000	0.063	0.001	61
	6.06	391.32	0.000	0.058	0.001	58
	6.13	396.42	0.000	0.047	0.001	55
	6.20	401.47	0.000	0.068	0.001	46
	6.28	407.37	0.000	0.063	0.001	46
	6.36	412.77	0.000	0.054	0.001	37
	6.44	418.17	0.000	0.051	0.001	37
	6.51	423.42	0.000	0.049	0.001	28
	6.58	428.47	0.000	0.063	0.001	28
	6.65	433.27	0.000	0.063	0.001	28
	6.72	438.17	0.000	0.033	0.001	28
	6.79	443.27	0.000	0.051	0.001	25
	6.86	448.27	0.000	0.051	0.001	22
	6.94	453.37	0.000	0.047	0.001	22

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 8R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	B-100 and AS1216 wt%	Flopaam 3630S mg/L
Injection Water	7.01	458.42	0.000	0.044	0.001	18
	7.08	463.57	0.000	0.044	0.001	15
	7.15	468.72	0.000	0.044	0.001	12
	7.23	474.02	0.000	0.042	0.001	12
	7.30	479.27	0.000	0.037	0.001	12
	7.38	484.57	0.000	0.037	0.001	12
	7.45	489.82	0.000	0.037	0.001	12
	7.53	495.12	0.000	0.037	0.001	12
	7.60	500.42	0.000	0.037	0.001	9
	7.68	505.72	0.000	0.037	0.001	9
	7.75	510.87	0.000	0.037	0.001	9
	7.83	516.07	0.000	0.037	0.001	8
	7.90	521.27	0.000	0.037	0.001	8
	7.97	526.47	0.000	0.037	0.001	6
	8.04	531.37	0.000	0.037	0.001	6

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	729	13.39	86.8
Na_2CO_3	-1,005	-18.45	-75.0
B-100 and AS1216	163	3.00	77.3
Flopaam 3630S	168	3.08	33.4

Core Weight 622.7 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 9R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Alcoflood 1275A mg/L
Production Water	4.21	305.29	0.000	0.000	0.000	0
0.625 wt% NaOH +	4.27	309.89	0.000	0.000	0.000	0
0.1 wt% ORS-97HF +	4.33	314.21	0.000	0.000	0.000	0
1200 mg/L Alcoflood 1275A	4.39	317.71	0.000	0.000	0.000	0
	4.46	320.51	0.000	0.000	0.000	0
	4.52	323.21	0.000	0.000	0.000	7
1200 mg/L Alcoflood 1275A	4.59	326.21	0.000	0.000	0.000	74
	4.65	329.21	0.000	0.056	0.001	284
	4.72	333.53	0.000	0.210	0.001	418
	4.77	337.04	0.000	0.424	0.002	643
	4.86	343.19	0.099	0.469	0.004	700
Injection Water	4.94	348.09	0.108	0.450	0.004	841
	5.02	354.14	0.094	0.422	0.005	948
	5.10	359.94	0.000	0.389	0.004	627
	5.17	365.79	0.000	0.247	0.004	430
	5.25	371.84	0.000	0.201	0.003	321
	5.33	377.84	0.000	0.140	0.003	270
	5.41	383.54	0.000	0.128	0.003	244
	5.48	389.24	0.000	0.128	0.002	234
	5.56	395.09	0.000	0.114	0.002	191
	5.64	400.99	0.000	0.107	0.002	175
	5.71	406.43	0.000	0.093	0.002	173
	5.78	411.88	0.000	0.082	0.002	162
	5.85	417.28	0.000	0.091	0.001	162
	5.92	422.98	0.000	0.089	0.001	125
	6.00	428.73	0.000	0.077	0.001	115
	6.07	434.53	0.000	0.068	0.001	102
	6.15	440.28	0.000	0.058	0.001	92
	6.22	445.98	0.000	0.049	0.001	86
	6.30	451.73	0.000	0.044	0.001	55
	6.38	458.03	0.000	0.044	0.001	49
	6.46	464.38	0.000	0.037	0.001	40
	6.54	470.23	0.000	0.037	0.001	40
	6.61	475.73	0.000	0.033	0.001	40
	6.69	481.53	0.000	0.028	0.001	29
	6.76	487.43	0.000	0.028	0.001	26
	6.85	493.63	0.000	0.023	0.001	14
	6.93	499.87	0.000	0.019	0.001	14
	7.00	505.67	0.000	0.014	0.001	12
	7.08	511.47	0.000	0.014	0.001	12
	7.15	516.97	0.000	0.014	0.001	9

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 9R

Fluid Injected	Cumulative Effluent	Aqueous Volume	NaOH	Effluent Concentration		
	V_p	mL	wt%	Na ₂ CO ₃ wt%	ORS-97HF wt%	Alcoflood 1275A mg/L
Injection Water	7.24	523.87	0.000	0.014	0.001	6
	7.29	527.37	0.000	0.014	0.001	6

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	839	15.72	84.9
Na ₂ CO ₃	-1,202	-22.51	---
ORS-97HF	178	3.32	84.7
Alcoflood 1275A	149	2.80	29.0

Core Weight 608.1 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 10R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	4.49	305.63	0.000	0.000	0.000	0
0.625 wt% NaOH +	4.55	310.21	0.000	0.000	0.000	0
0.1 wt% ORS-97HF +	4.62	314.99	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.68	318.84	0.000	0.026	0.000	20
	4.76	322.24	0.000	0.061	0.000	119
	4.84	325.84	0.000	0.105	0.001	242
1200 mg/L Flopaam 3630S	4.91	329.69	0.000	0.131	0.001	402
	4.99	334.27	0.000	0.168	0.002	596
	5.06	338.22	0.000	0.161	0.002	768
	5.13	342.62	0.000	0.187	0.002	902
	5.18	345.72	0.000	0.259	0.004	1007
Injection Water	5.26	351.02	0.000	0.322	0.004	833
	5.35	356.92	0.000	0.375	0.004	807
	5.43	362.64	0.000	0.387	0.004	705
	5.51	367.94	0.000	0.401	0.004	583
	5.59	373.64	0.014	0.382	0.004	484
	5.67	379.84	0.000	0.317	0.003	421
	5.75	385.59	0.000	0.264	0.002	296
	5.83	390.94	0.000	0.243	0.002	240
	5.91	396.64	0.000	0.191	0.002	233
	5.99	402.29	0.000	0.187	0.002	197
	6.06	407.94	0.000	0.168	0.002	181
	6.14	413.59	0.000	0.163	0.002	147
	6.22	419.14	0.000	0.149	0.001	152
	6.30	424.74	0.000	0.145	0.001	140
	6.37	430.44	0.000	0.145	0.001	120
	6.45	436.09	0.000	0.145	0.001	115
	6.53	441.79	0.000	0.140	0.001	92
	6.61	447.54	0.000	0.119	0.001	80
	6.69	453.14	0.000	0.110	0.001	61
	6.77	459.14	0.000	0.098	0.001	59
	6.85	465.49	0.000	0.098	0.001	51
	6.93	471.29	0.000	0.096	0.001	44
	7.01	476.79	0.000	0.086	0.001	32
	7.09	482.39	0.000	0.075	0.001	29
	7.16	488.14	0.000	0.075	0.001	27
	7.25	494.24	0.000	0.075	0.001	24
	7.33	500.44	0.000	0.075	0.001	24
	7.42	506.49	0.000	0.065	0.001	21
	7.49	512.19	0.000	0.063	0.001	13
	7.57	517.69	0.000	0.054	0.001	12

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 10R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent	Volume	NaOH	Na ₂ CO ₃	ORS-97HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	7.64	523.04	0.000	0.054	0.001	12
	7.68	526.09	0.000	0.054	0.001	12

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	1,096	20.16	99.4
Na ₂ CO ₃	-2,033	-37.39	---
ORS-97HF	194	3.57	86.5
Flopaam 3630S	81	1.49	15.5

Core Weight 629.4 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 11R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	3.77	268.30	0.000	0.000	0.000	0
0.75 wt% NaOH +	3.82	272.15	0.000	0.000	0.000	0
0.15 wt% ORS-97HF +	3.87	276.20	0.000	0.005	0.000	0
1200 mg/L Flopaam 3630S	3.93	280.40	0.000	0.012	0.000	0
	4.01	285.75	0.000	0.005	0.000	0
	4.07	289.15	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.12	292.15	0.000	0.000	0.000	101
	4.18	295.03	0.000	0.042	0.000	248
	4.25	298.83	0.000	0.105	0.000	407
	4.32	303.13	0.000	0.191	0.000	521
	4.38	306.63	0.000	0.352	0.001	577
Injection Water	4.43	309.98	0.026	0.368	0.002	639
	4.50	314.67	0.034	0.354	0.002	645
	4.57	319.47	0.083	0.331	0.002	686
	4.62	323.57	0.096	0.354	0.002	709
	4.67	327.37	0.063	0.352	0.002	630
	4.74	332.22	0.060	0.331	0.002	506
	4.81	338.07	0.033	0.310	0.003	391
	4.89	344.12	0.000	0.261	0.003	314
	4.96	349.10	0.000	0.231	0.003	257
	5.01	353.35	0.000	0.180	0.002	249
	5.07	358.05	0.000	0.180	0.002	218
	5.14	363.85	0.000	0.152	0.002	214
	5.22	369.93	0.000	0.156	0.002	189
	5.29	375.48	0.000	0.154	0.002	177
	5.36	380.58	0.000	0.131	0.002	164
	5.42	385.58	0.000	0.131	0.001	140
	5.49	390.88	0.000	0.117	0.001	137
	5.56	396.38	0.000	0.105	0.001	115
	5.63	402.13	0.000	0.105	0.001	111
	5.70	407.71	0.000	0.093	0.001	106
	5.77	412.96	0.000	0.093	0.001	100
	5.83	417.96	0.000	0.089	0.001	77
	5.89	422.66	0.000	0.089	0.001	77
	5.95	427.46	0.000	0.084	0.001	71
	6.01	432.61	0.000	0.084	0.001	62
	6.08	437.71	0.000	0.084	0.001	56
	6.14	442.81	0.000	0.065	0.000	44
	6.20	447.61	0.000	0.077	0.000	41
	6.27	452.76	0.000	0.063	0.000	41
	6.34	458.16	0.000	0.063	0.000	35

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 11R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent	Volume	NaOH	Na ₂ CO ₃	ORS-97HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	6.40	463.41	0.000	0.058	0.000	35
	6.46	468.36	0.000	0.058	0.000	32
	6.53	473.41	0.000	0.054	0.000	27
	6.59	478.41	0.000	0.049	0.000	18
	6.66	483.61	0.000	0.040	0.000	18
	6.72	488.66	0.000	0.040	0.000	18
	6.78	493.61	0.000	0.040	0.000	15
	6.85	498.56	0.000	0.040	0.000	15
	6.91	503.76	0.000	0.040	0.000	12
	6.98	508.96	0.000	0.037	0.000	12
	7.04	514.11	0.000	0.037	0.000	12
	7.10	519.11	0.000	0.037	0.000	12
	7.17	524.31	0.000	0.037	0.000	12
	7.23	529.41	0.000	0.037	0.000	12
	7.30	534.36	0.000	0.037	0.000	6
	7.36	539.41	0.000	0.037	0.000	6

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	987	18.89	86.6
Na ₂ CO ₃	-1,775	-33.96	---
ORS-97HF	287	5.49	93.6
Flopaam 3630S	131	2.51	26.2

Core Weight 602.5 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 12R

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Effluent Concentration		
				Na ₂ CO ₃ wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	3.91	269.01	0.000	0.000	0.000	0
1.0 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S	3.96	273.01	0.000	0.000	0.000	0
0.75 wt% NaOH + 0.1 wt% ORS-97HF + 1200 mg/L Flopaam 3630S	4.01	277.06	0.000	0.000	0.000	0
	4.07	280.86	0.000	0.000	0.000	0
	4.15	286.41	0.000	0.000	0.000	0
	4.21	290.16	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.27	293.36	0.000	0.000	0.000	77
	4.33	296.57	0.000	0.002	0.000	213
	4.40	300.12	0.000	0.037	0.000	402
	4.47	304.77	0.000	0.145	0.000	465
	4.54	308.52	0.000	0.296	0.001	595
Injection Water	4.60	312.90	0.013	0.420	0.002	692
	4.67	317.52	0.058	0.431	0.004	749
	4.75	323.40	0.088	0.429	0.003	826
	4.81	328.25	0.076	0.408	0.003	739
	4.87	332.05	0.037	0.410	0.003	590
	4.93	336.50	0.020	0.394	0.002	470
	5.01	342.10	0.002	0.361	0.002	372
	5.08	347.75	0.000	0.338	0.002	322
	5.16	353.35	0.000	0.303	0.002	287
	5.21	357.45	0.000	0.257	0.001	254
	5.27	361.95	0.000	0.229	0.001	231
	5.35	367.50	0.000	0.201	0.001	212
	5.43	373.50	0.000	0.189	0.001	193
	5.50	378.90	0.000	0.175	0.001	165
	5.58	384.80	0.000	0.152	0.001	147
	5.64	389.60	0.000	0.152	0.001	121
	5.71	394.75	0.000	0.119	0.001	117
	5.78	400.05	0.000	0.119	0.001	99
	5.85	405.75	0.000	0.105	0.001	78
	5.92	411.15	0.000	0.105	0.001	70
	5.98	415.85	0.000	0.098	0.000	59
	6.05	420.90	0.000	0.093	0.000	54
	6.11	425.60	0.000	0.084	0.000	54
	6.17	430.35	0.000	0.082	0.000	40
	6.24	435.40	0.000	0.079	0.000	35
	6.31	440.50	0.000	0.079	0.000	27
	6.37	445.55	0.000	0.072	0.000	27
	6.44	450.40	0.000	0.061	0.000	24

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 12R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent	Volume	NaOH	Na ₂ CO ₃	ORS-97HF	Flopaam 3630S
	V _p	mL	wt%	wt%	wt%	mg/L
Injection Water	6.50	455.50	0.000	0.061	0.000	21
	6.57	460.80	0.000	0.061	0.000	16
	6.64	465.90	0.000	0.056	0.000	16
	6.70	470.90	0.000	0.056	0.000	16
	6.77	476.15	0.000	0.056	0.000	16
	6.84	481.30	0.000	0.056	0.000	13
	6.91	486.45	0.000	0.056	0.000	11
	6.97	491.50	0.000	0.044	0.000	11
	7.04	496.70	0.000	0.044	0.000	9
	7.11	501.70	0.000	0.044	0.000	7
	7.18	507.00	0.000	0.044	0.000	5
	7.24	512.20	0.000	0.044	0.000	5
	7.31	517.35	0.000	0.044	0.000	3
	7.38	522.40	0.000	0.033	0.000	3
	7.45	527.70	0.000	0.033	0.000	3
	7.52	532.95	0.000	0.033	0.000	3
	7.58	537.95	0.000	0.033	0.000	3
	7.65	543.00	0.000	0.033	0.000	3

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	1,141	21.52	90.0
Na ₂ CO ₃	-2,078	-39.20	---
ORS-97HF	187	3.52	91.5
Flopaam 3630S	126	2.37	25.2

Core Weight 607.6 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 13R

Fluid Injected	Cumulative Effluent V_p	Aqueous Volume mL	NaOH wt%	Effluent Concentration		
				Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	4.23	301.53	0.000	0.000	0.000	0
0.75 wt% NaOH +	4.29	305.98	0.000	0.000	0.000	0
0.15 wt% ORS-97HF +	4.35	310.58	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.40	314.28	0.000	0.000	0.000	0
	4.43	317.16	0.000	0.000	0.000	0
	4.49	320.56	0.000	0.000	0.000	0
	4.57	324.88	0.000	0.000	0.000	0
1200 mg/L Flopaam 3630S	4.64	328.58	0.000	0.023	0.000	46
	4.71	333.13	0.000	0.051	0.000	171
	4.78	337.48	0.000	0.266	0.001	350
	4.83	340.38	0.051	0.389	0.001	559
	4.89	344.08	0.092	0.438	0.004	699
Injection Water	4.94	348.06	0.113	0.494	0.005	744
	5.01	352.56	0.141	0.466	0.005	824
	5.07	357.41	0.011	0.445	0.006	637
	5.14	362.71	0.028	0.385	0.007	490
	5.21	368.01	0.000	0.289	0.005	309
	5.27	373.01	0.000	0.261	0.004	252
	5.34	377.96	0.000	0.198	0.004	195
	5.40	383.21	0.000	0.156	0.003	150
	5.47	388.61	0.000	0.126	0.003	101
	5.54	394.16	0.000	0.098	0.003	86
	5.61	399.44	0.000	0.098	0.003	73
	5.68	404.99	0.000	0.096	0.002	65
	5.75	410.34	0.000	0.091	0.002	59
	5.82	416.04	0.000	0.091	0.002	46
	5.89	421.54	0.000	0.086	0.002	46
	5.95	426.74	0.000	0.075	0.002	42
	6.02	431.89	0.000	0.072	0.002	42
	6.09	437.29	0.000	0.072	0.002	33
	6.15	442.49	0.000	0.072	0.001	29
	6.23	448.28	0.000	0.072	0.001	29
	6.29	453.78	0.000	0.072	0.001	20
	6.36	459.18	0.000	0.072	0.001	16
	6.43	464.28	0.000	0.072	0.001	16
	6.49	469.33	0.000	0.070	0.001	16
	6.55	474.43	0.000	0.068	0.001	13
	6.62	479.78	0.000	0.068	0.001	13
	6.69	485.28	0.000	0.068	0.001	13
	6.75	490.38	0.000	0.068	0.001	13
	6.82	495.58	0.000	0.068	0.001	13

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 13R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Injection Water	6.89	500.98	0.000	0.063	0.001	13
	6.95	506.38	0.000	0.063	0.001	13
	7.02	511.56	0.000	0.063	0.001	10
	7.09	516.81	0.000	0.063	0.001	10
	7.15	521.91	0.000	0.063	0.001	7
	7.22	527.31	0.000	0.058	0.001	7
	7.28	532.56	0.000	0.058	0.001	7
	7.35	537.86	0.000	0.051	0.001	7
	7.41	542.91	0.000	0.047	0.001	7
	7.48	548.31	0.000	0.047	0.001	7
	7.51	550.71	0.000	0.047	0.001	7

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	1,283	24.35	89.4
Na_2CO_3	-1,339	-25.40	---
ORS-97HF	310	5.87	88.2
Flopaam 3630S	286	5.44	54.0

Core Weight 612.9 g

* - percent of injected chemical retained by rock

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 14R

Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Production Water	3.90	296.56	0.000	0.000	0.000	0
0.75 wt% NaOH +	3.96	301.04	0.000	0.000	0.000	0
0.15 wt% ORS-97HF +	4.01	304.39	0.000	0.007	0.000	0
1200 mg/L Flopaam 3630S	4.06	306.14	0.000	0.082	0.000	18
0.75 wt% NaOH +	4.11	308.29	0.000	0.231	0.001	123
0.1 wt% ORS-97HF +	4.16	309.99	0.000	0.338	0.001	248
1200 mg/L Flopaam 3630S	4.21	312.04	0.014	0.347	0.003	293
1200 mg/L Flopaam 3630S	4.28	314.54	0.020	0.366	0.004	366
	4.34	317.49	0.056	0.368	0.004	429
	4.40	320.39	0.048	0.387	0.004	493
	4.47	324.04	0.011	0.382	0.004	567
	4.52	326.84	0.117	0.338	0.004	649
Injection Water	4.58	330.69	0.071	0.410	0.004	697
	4.64	333.24	0.092	0.387	0.004	750
	4.70	337.34	0.077	0.415	0.004	707
	4.76	341.84	0.069	0.387	0.004	589
	4.82	346.69	0.084	0.198	0.003	466
	4.88	351.64	0.063	0.154	0.003	272
	4.94	356.54	0.000	0.257	0.002	219
	5.01	361.44	0.000	0.163	0.002	144
	5.07	366.44	0.000	0.119	0.002	89
	5.13	371.59	0.000	0.084	0.002	58
	5.20	376.79	0.000	0.084	0.002	54
	5.26	381.89	0.000	0.063	0.002	20
	5.33	387.14	0.000	0.063	0.002	7
	5.39	392.69	0.000	0.040	0.002	0
	5.47	398.59	0.000	0.040	0.001	0
	5.54	404.69	0.000	0.040	0.001	0
	5.61	410.29	0.000	0.040	0.001	0
	5.67	415.29	0.000	0.040	0.001	0
	5.74	420.19	0.000	0.040	0.001	0
	5.80	425.04	0.000	0.040	0.000	0
	5.86	430.04	0.000	0.040	0.000	0
	5.92	434.84	0.000	0.040	0.000	0
	5.98	439.84	0.000	0.040	0.000	0
	6.04	444.84	0.000	0.040	0.000	0
	6.10	449.84	0.000	0.040	0.000	0
	6.17	454.89	0.000	0.040	0.000	0
	6.23	460.04	0.000	0.040	0.000	0
	6.29	465.04	0.000	0.040	0.000	0
	6.36	470.34	0.000	0.040	0.000	0

Incremental Effluent Alkali, Surfactant, and Polymer Concentrations
Warner Coreflood 14R

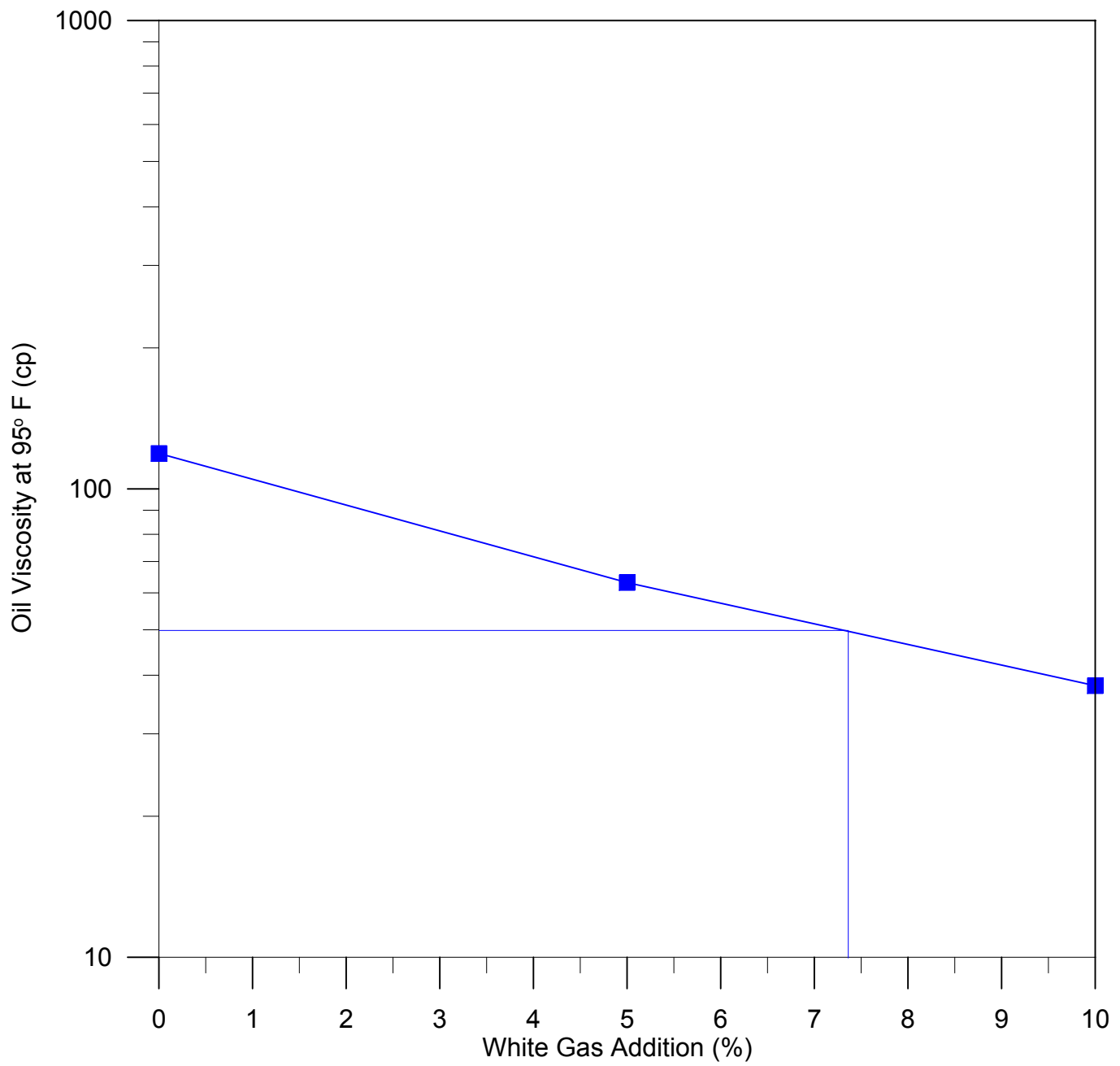
Fluid Injected	Cumulative	Aqueous	Effluent Concentration			
	Effluent V_p	Volume mL	NaOH wt%	Na_2CO_3 wt%	ORS-97HF wt%	Flopaam 3630S mg/L
Injection Water	6.42	475.39	0.000	0.040	0.000	0
	6.48	480.69	0.000	0.040	0.000	0
	6.55	485.89	0.000	0.040	0.000	0
	6.62	491.24	0.000	0.035	0.000	0
	6.68	496.44	0.000	0.030	0.000	0
	6.75	501.74	0.000	0.030	0.000	0
	6.81	506.94	0.000	0.030	0.000	0
	6.87	512.14	0.000	0.030	0.000	0

	Amount of Chemical Retained by Core		
	lb/acre ft	mg/100g rock	%*
NaOH	1,100	21.51	82.9
Na_2CO_3	-1,074	-21.00	---
ORS-97HF	248	4.85	91.3
Flopaam 3630S	290	5.67	56.6

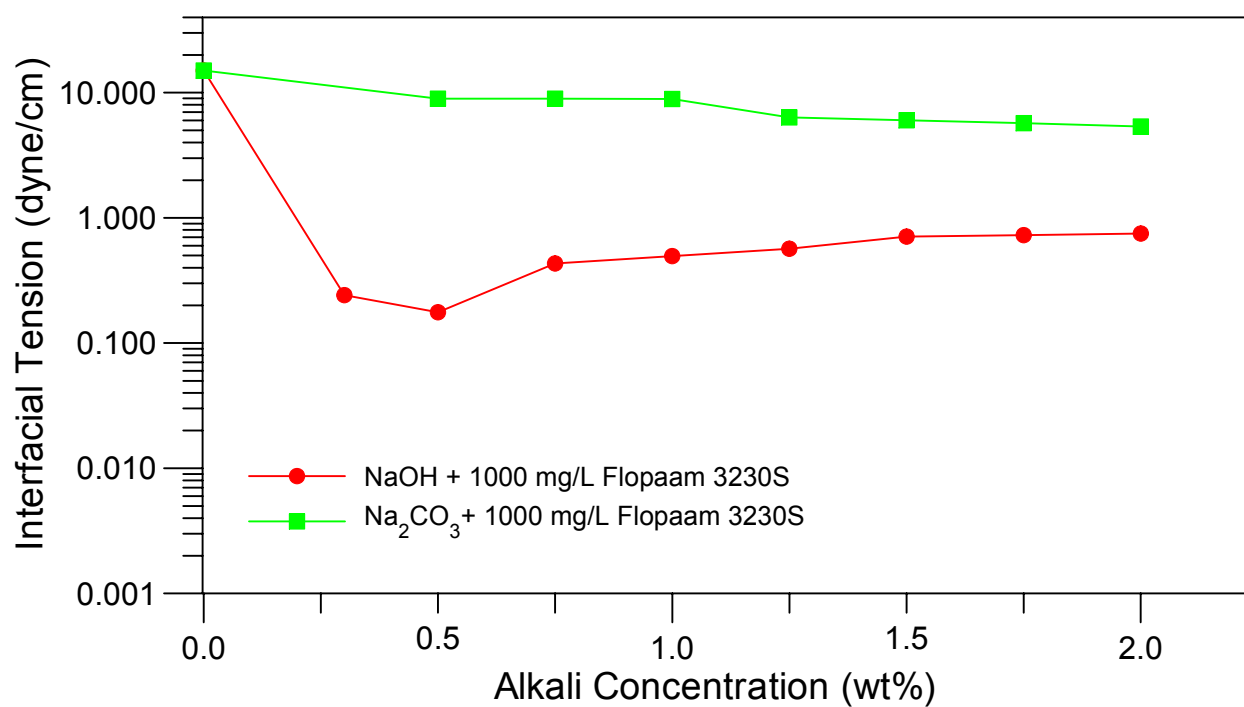
Core Weight 588.2 g

* - percent of injected chemical retained by rock

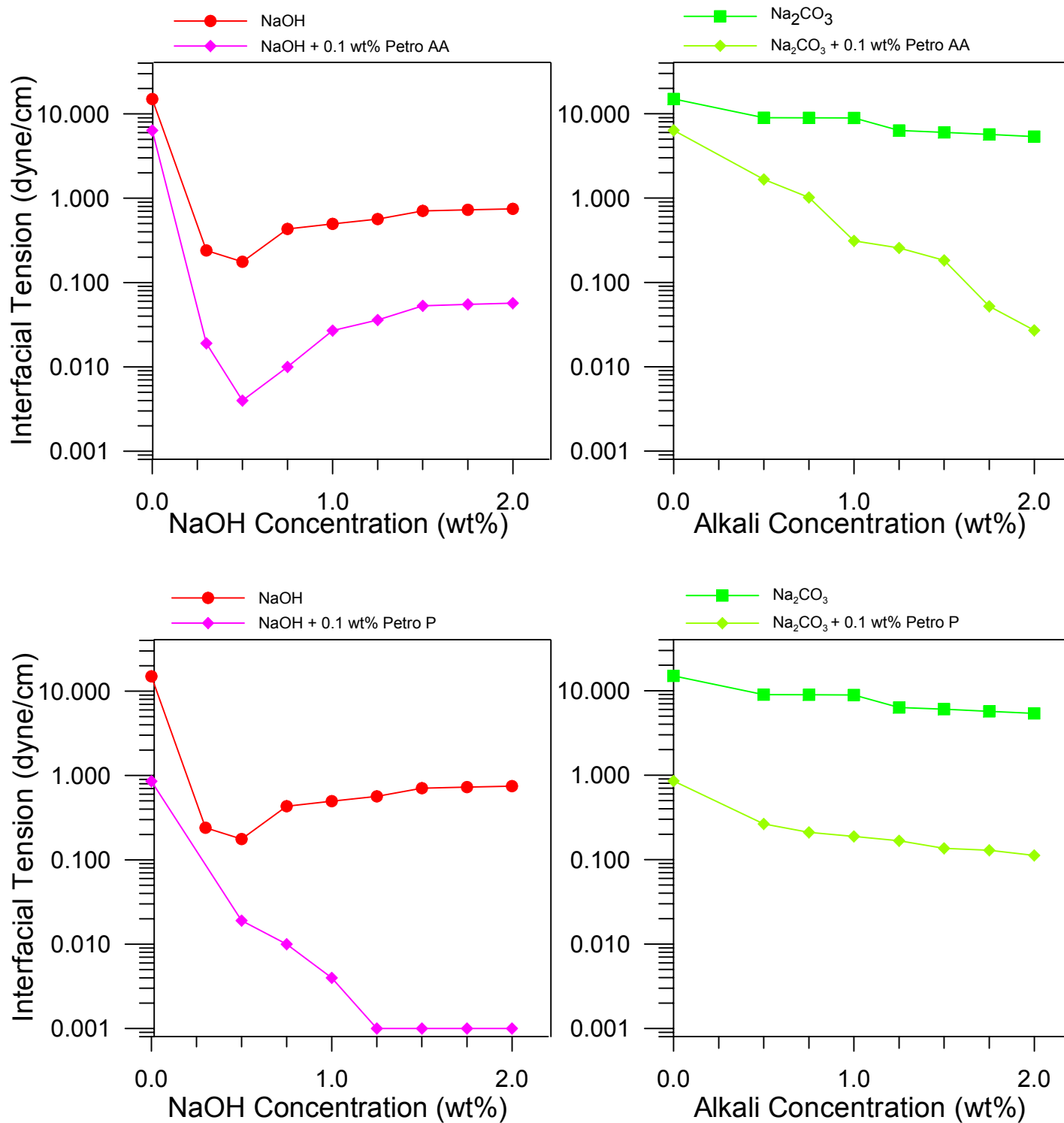
White Gas Addition versus Oil Viscosity at 95° F



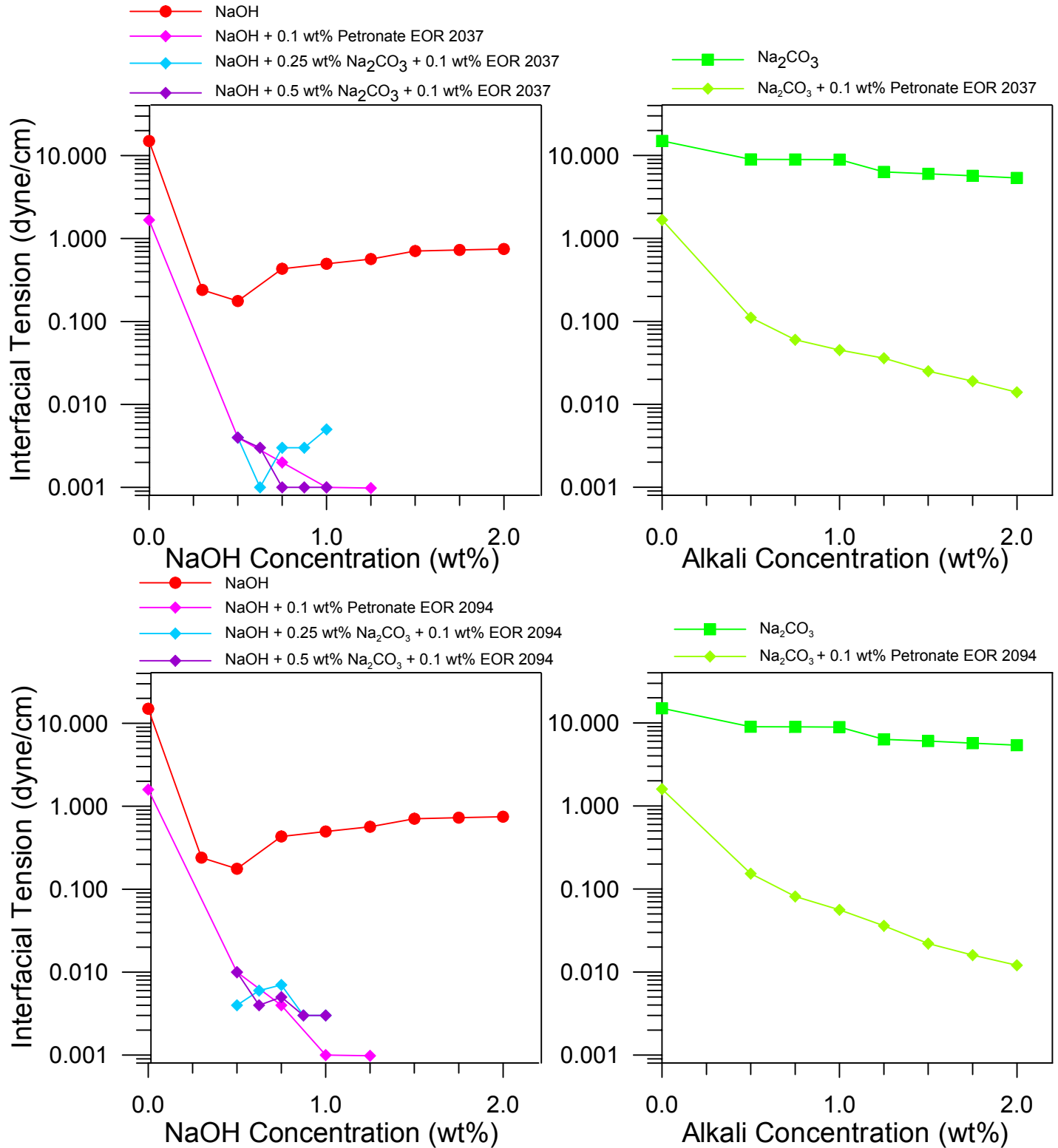
Interfacial Tension Between Aqueous Alkali plus Polymer
Dissolved in Softened Injection Water
and Warner Crude Oil at 35°C



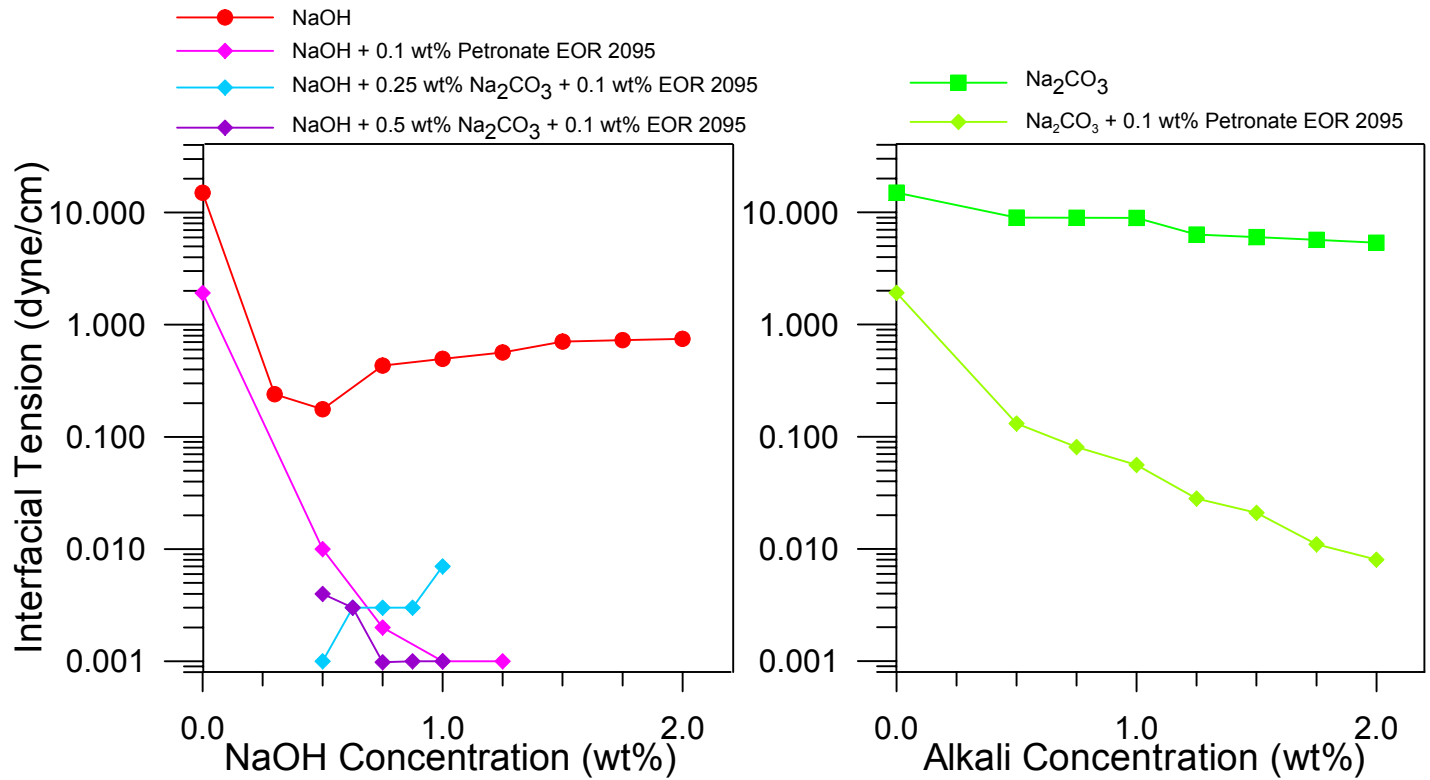
Interfacial Tension between Warner Crude Oil at 35°C
and Aqueous Alkali plus Surfactant plus 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water



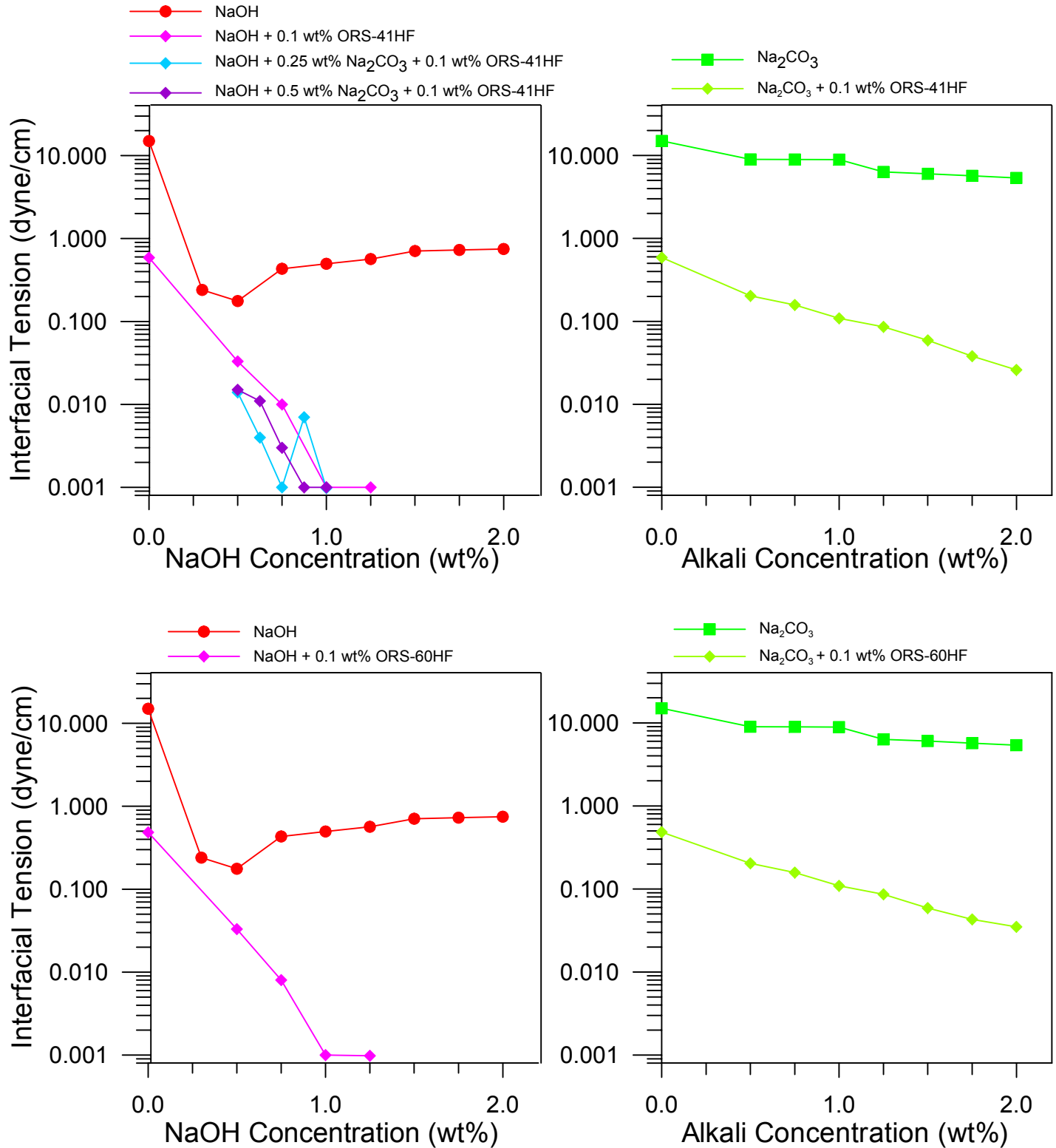
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



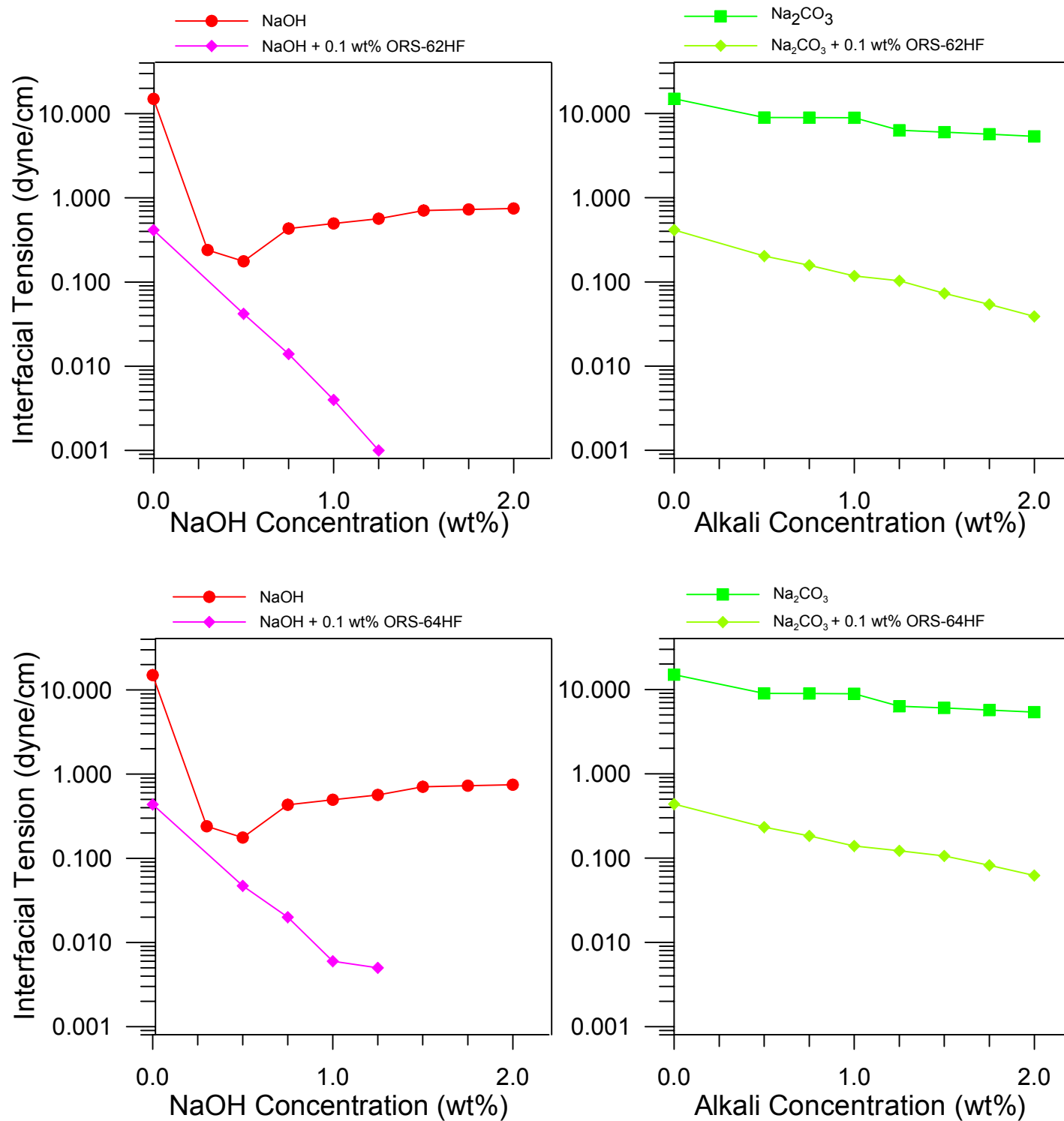
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



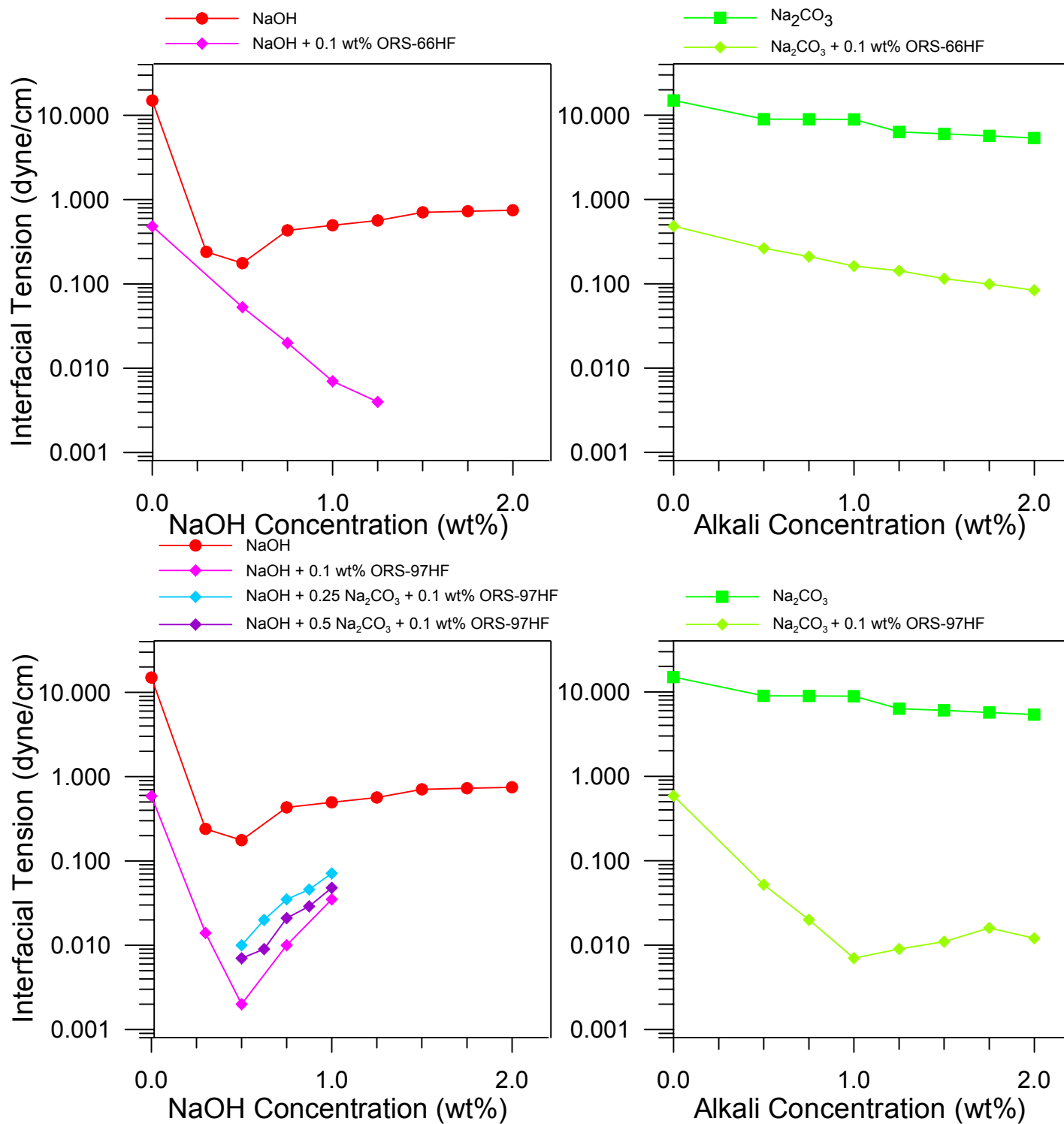
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



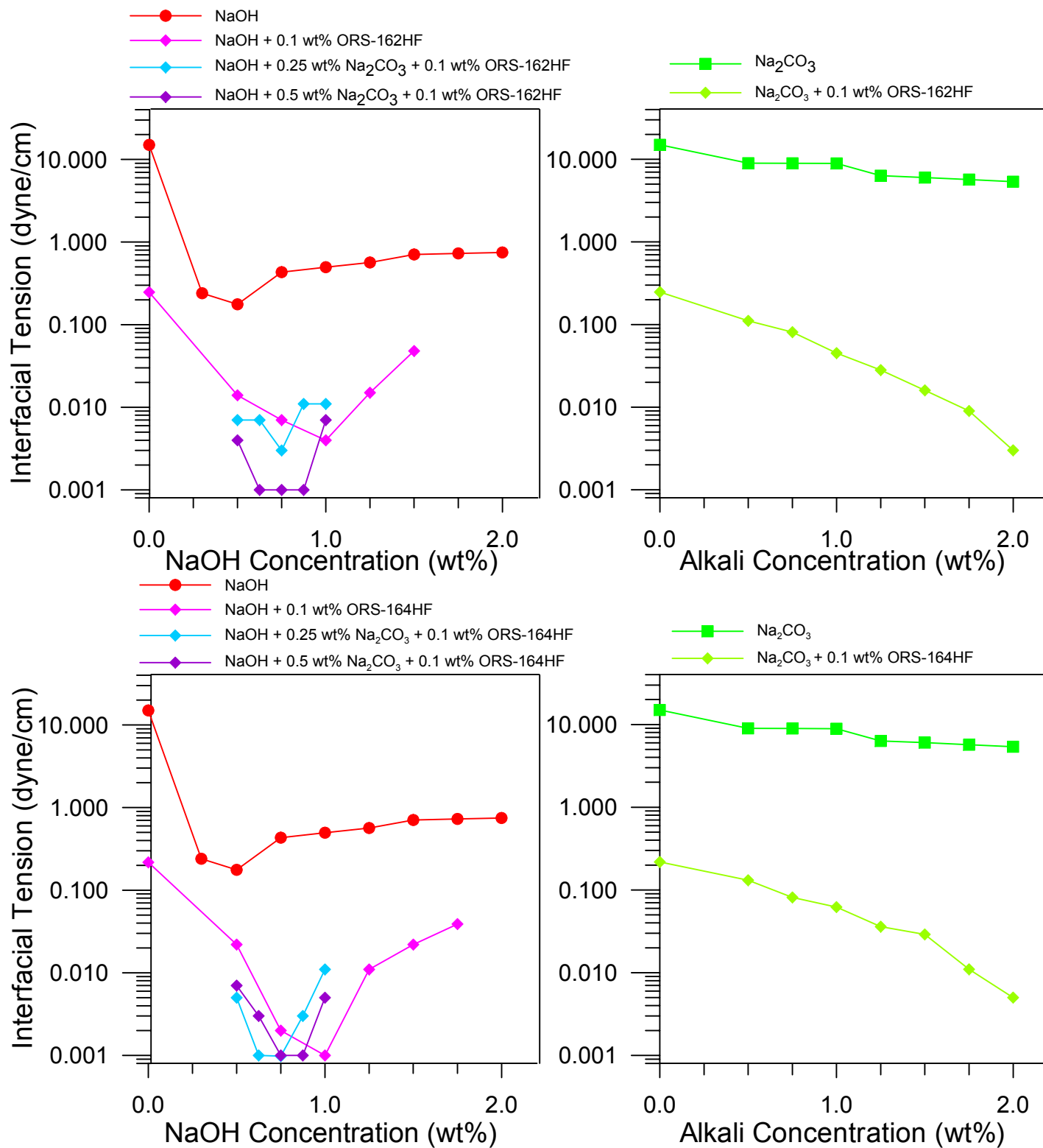
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



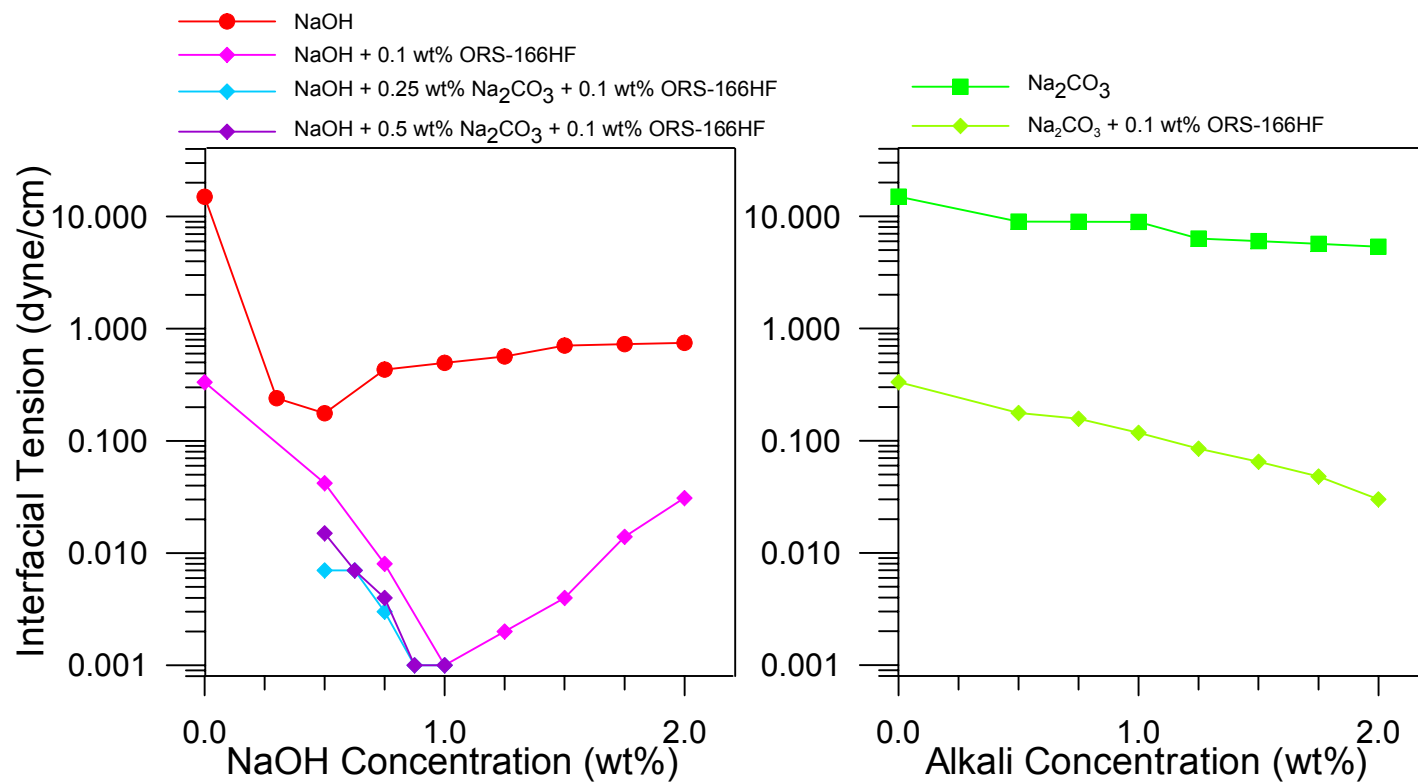
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



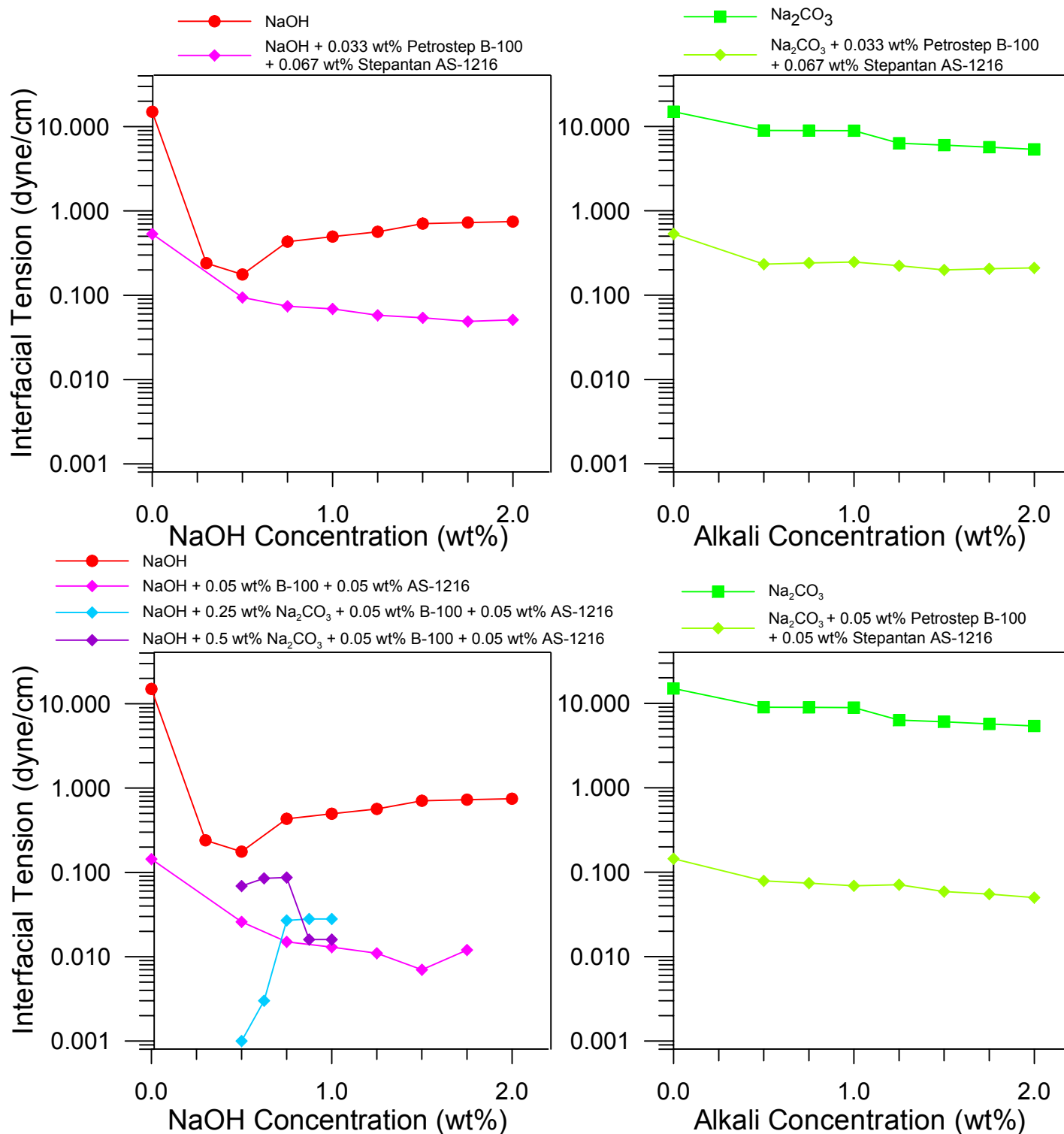
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



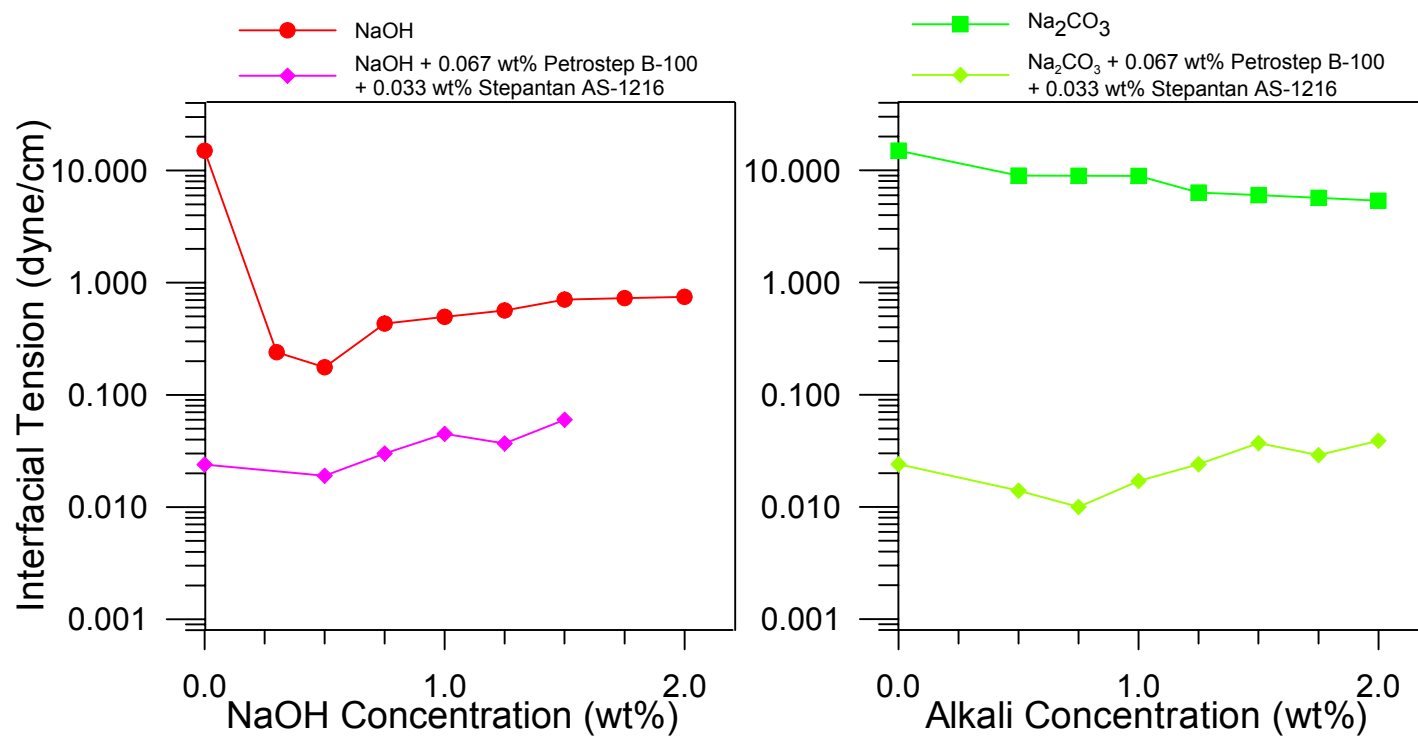
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Dissolved in Softened Injection Water



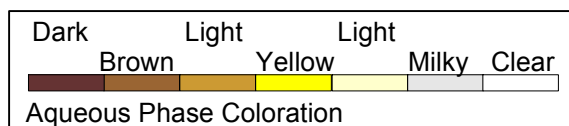
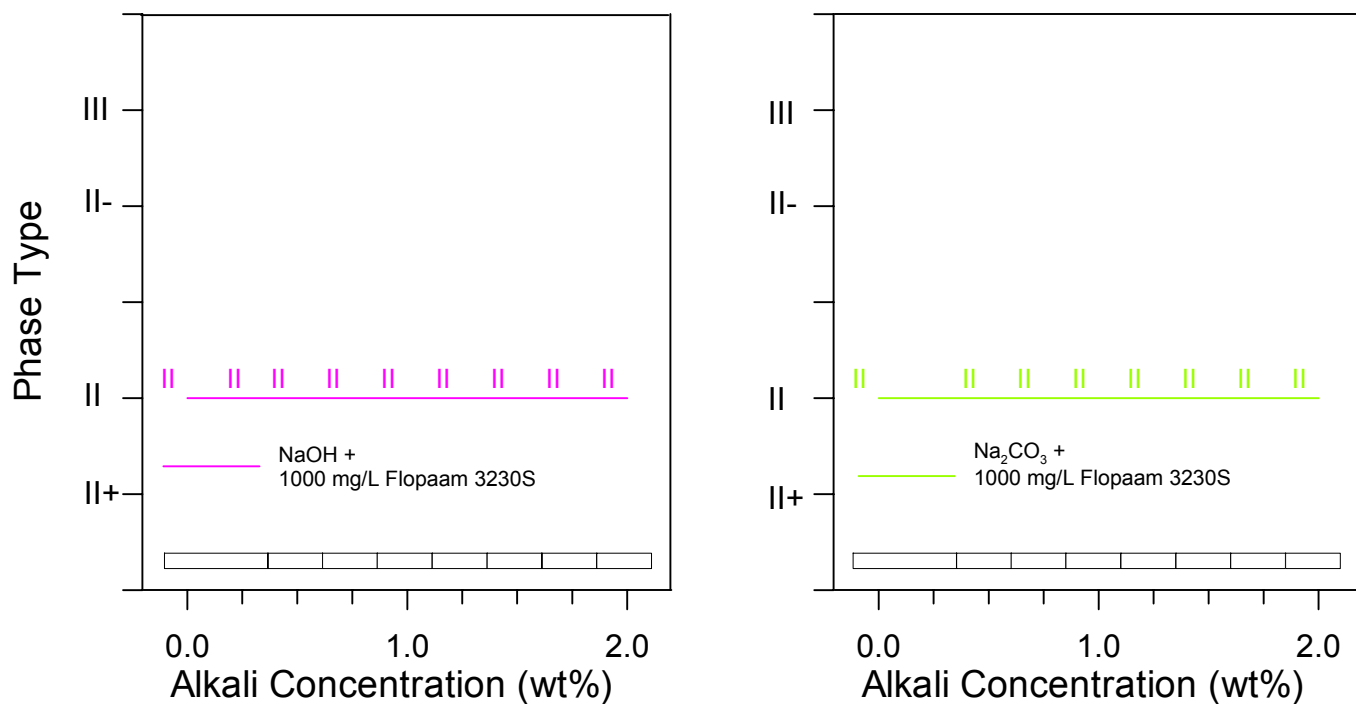
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



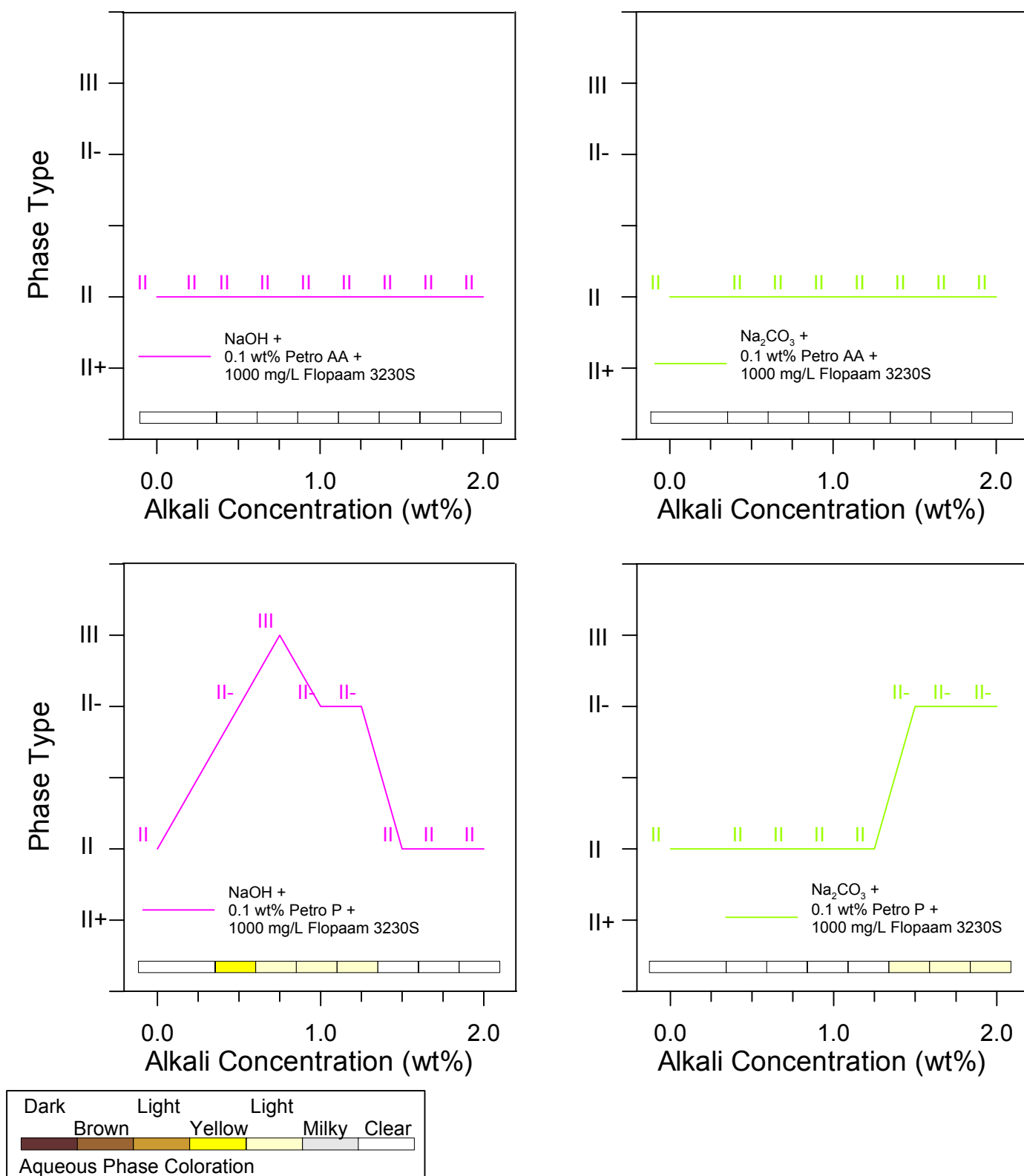
Interfacial Tension between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



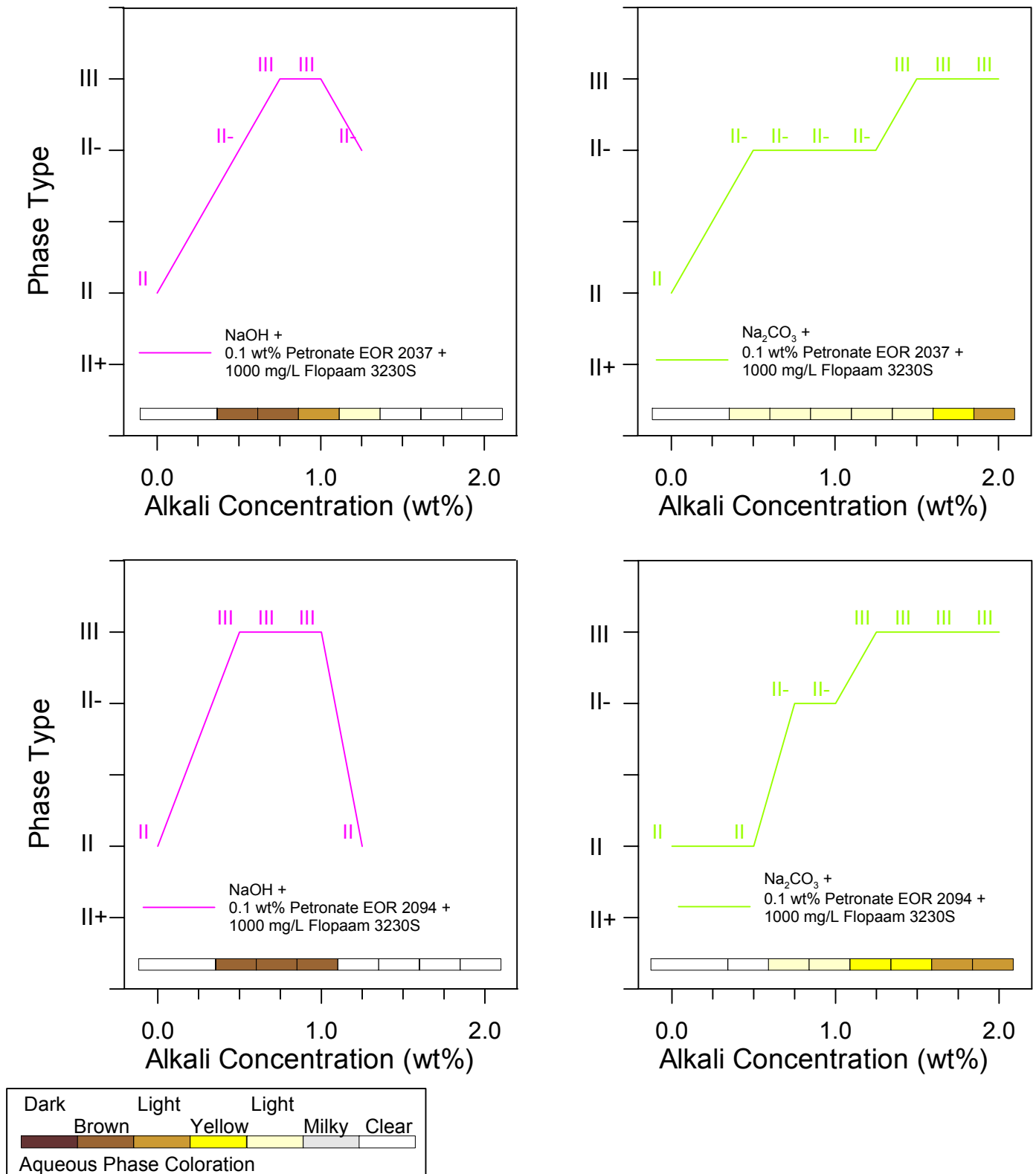
Phase Behavior between Warner Crude Oil at 35°C
and Aqueous Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water



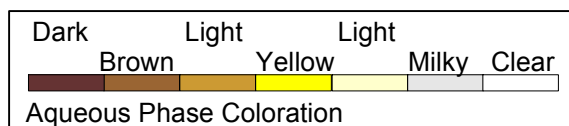
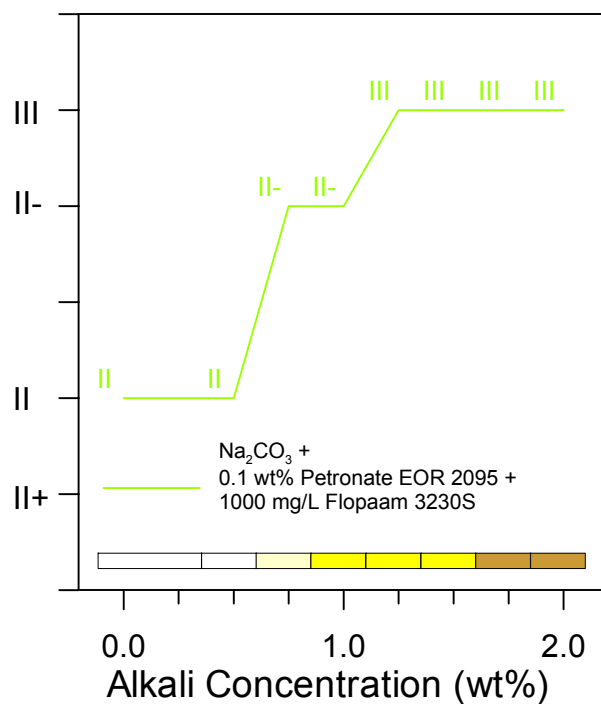
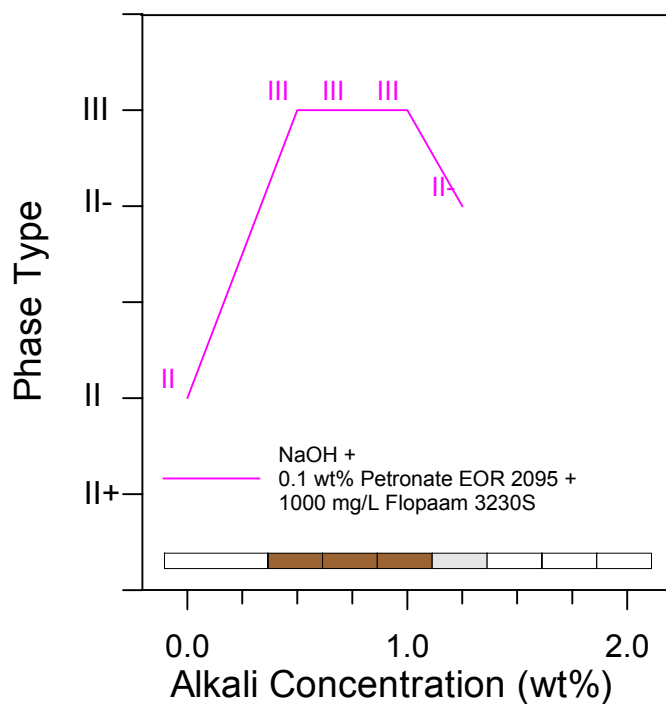
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Dissolved in Softened Injection Water



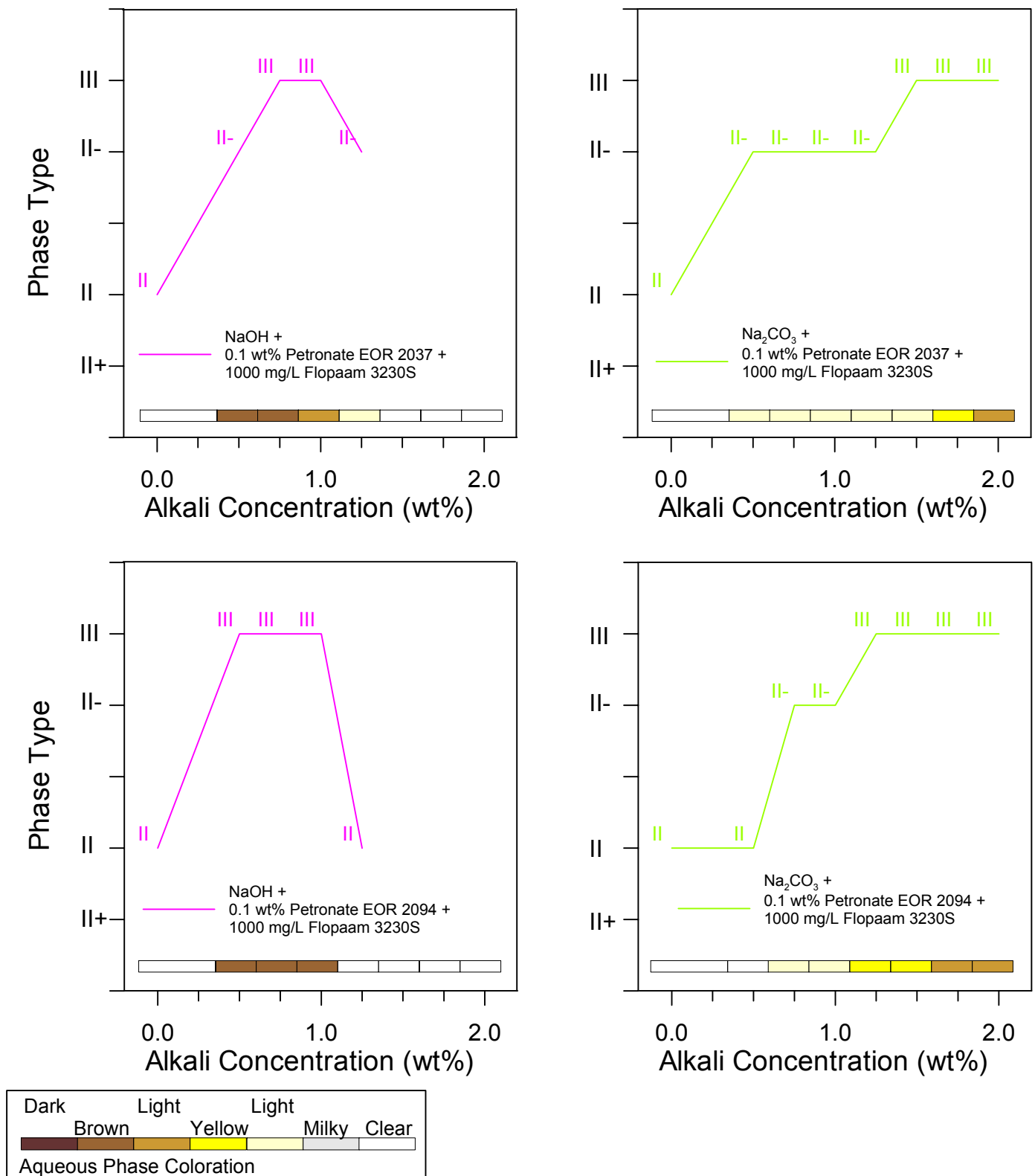
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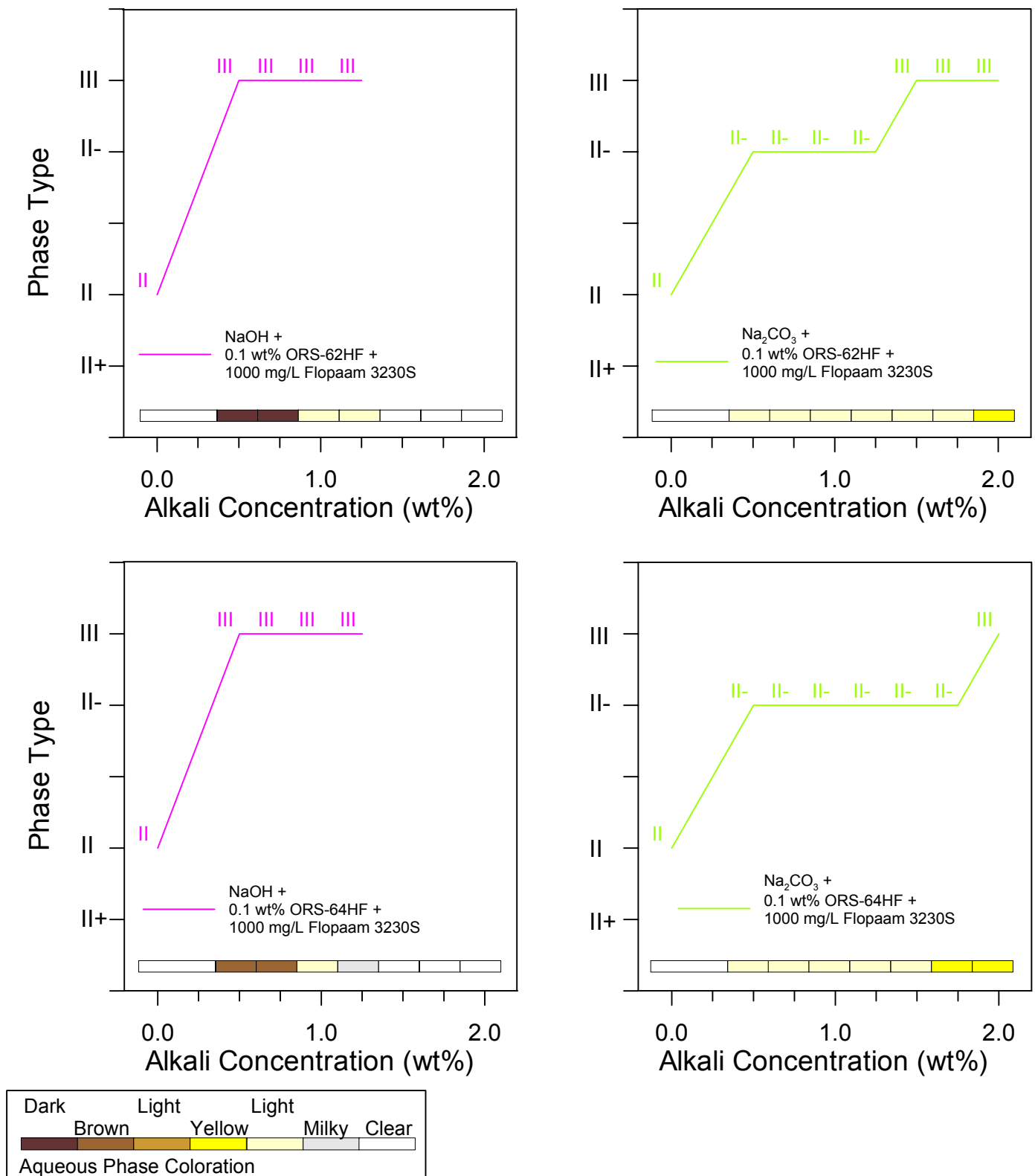
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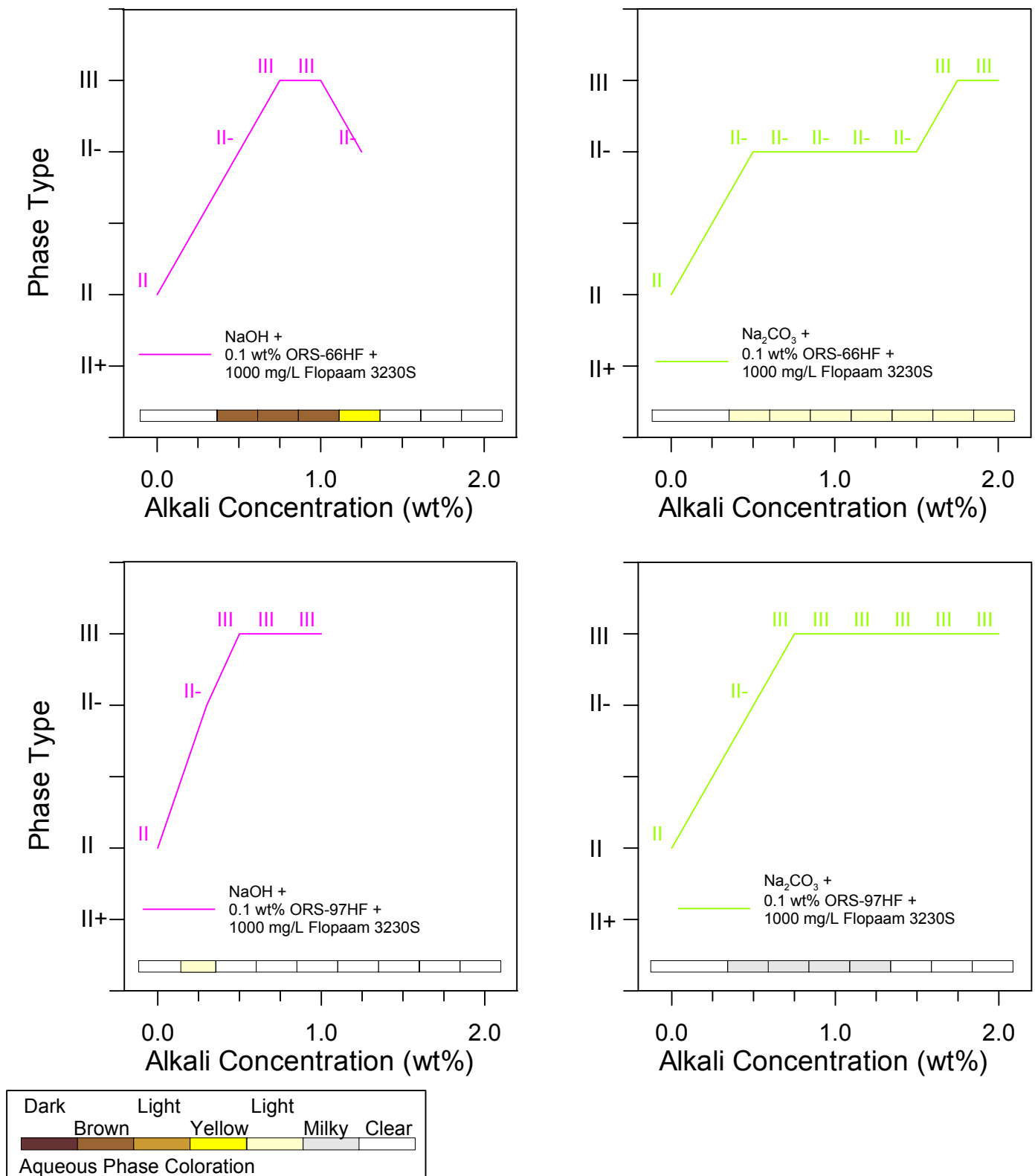
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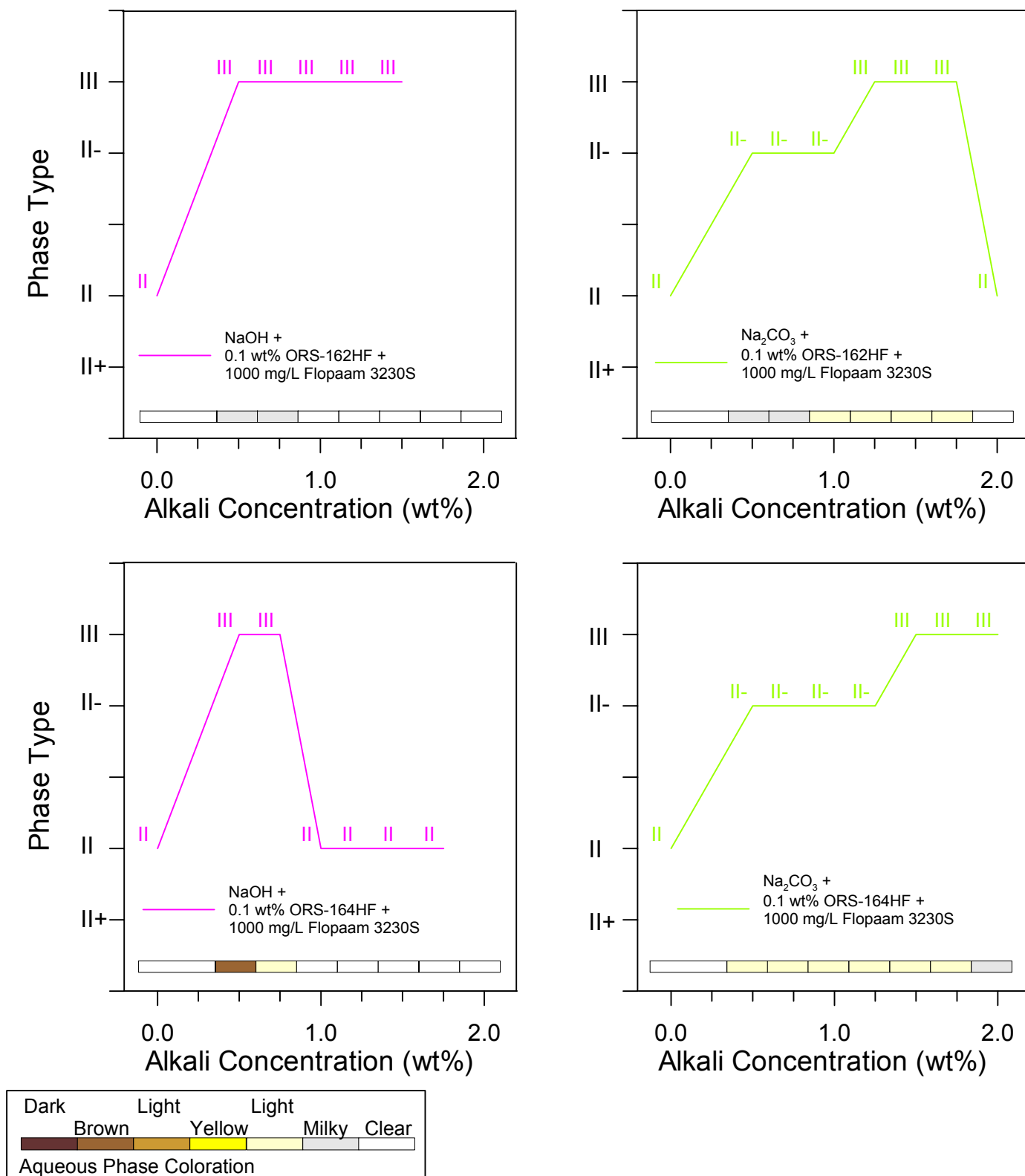
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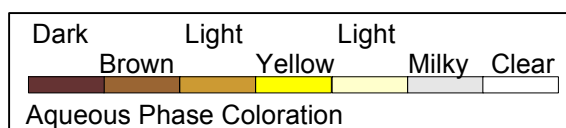
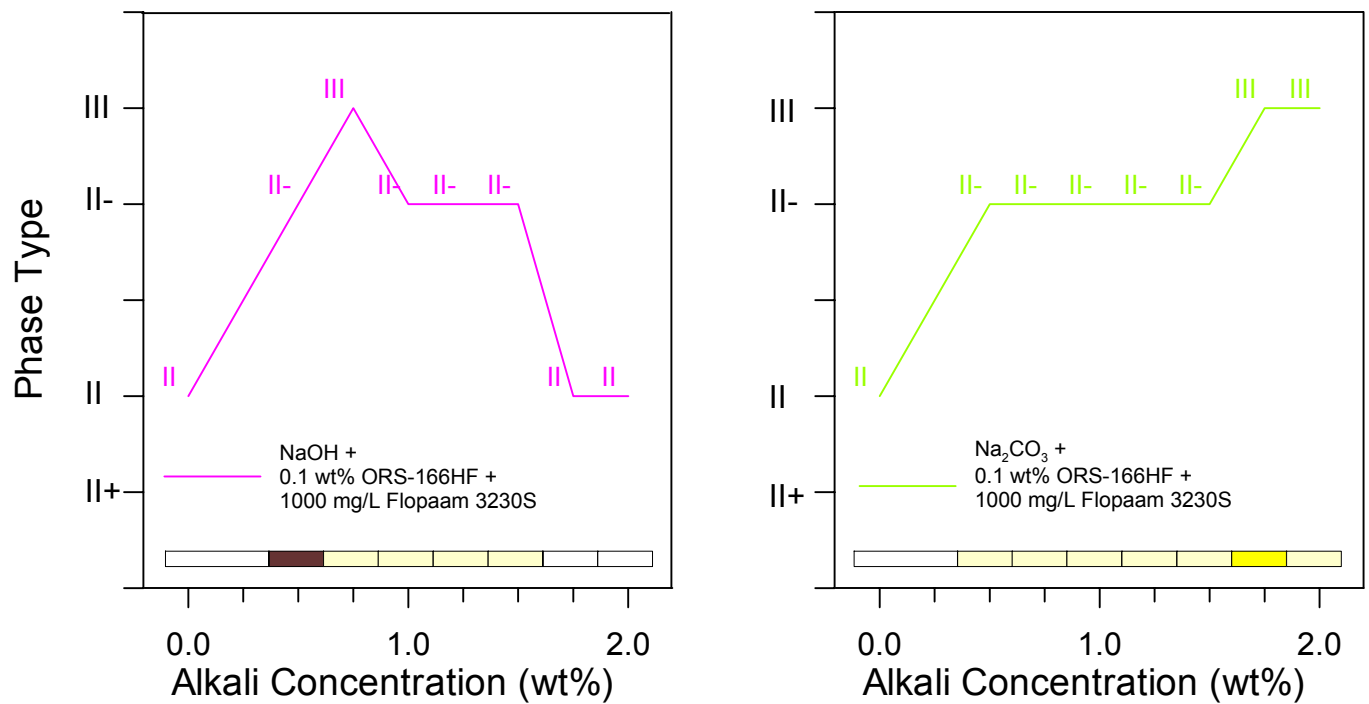
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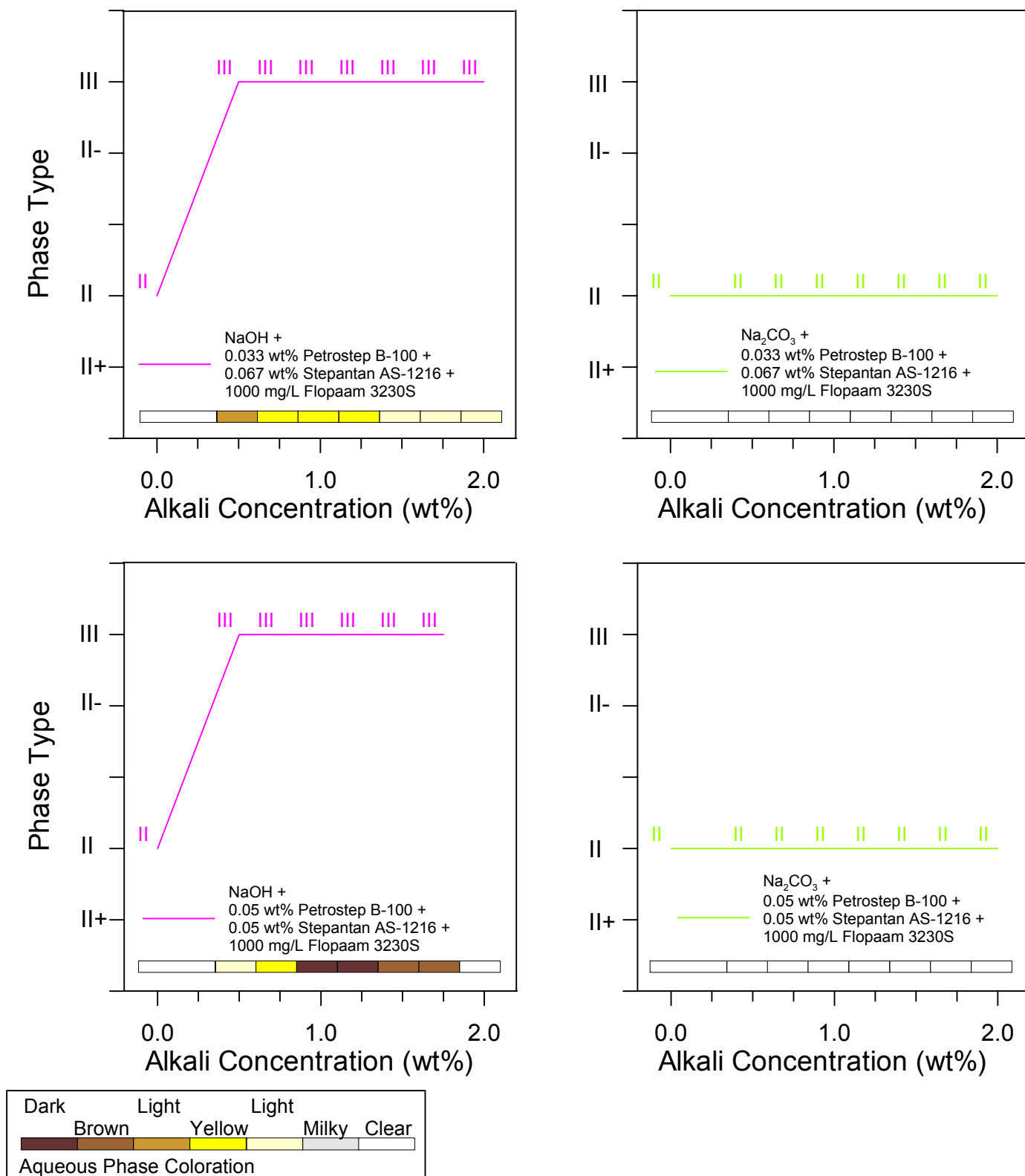
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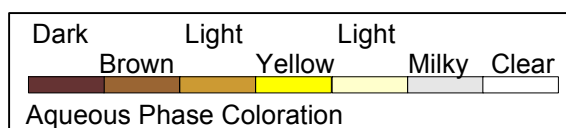
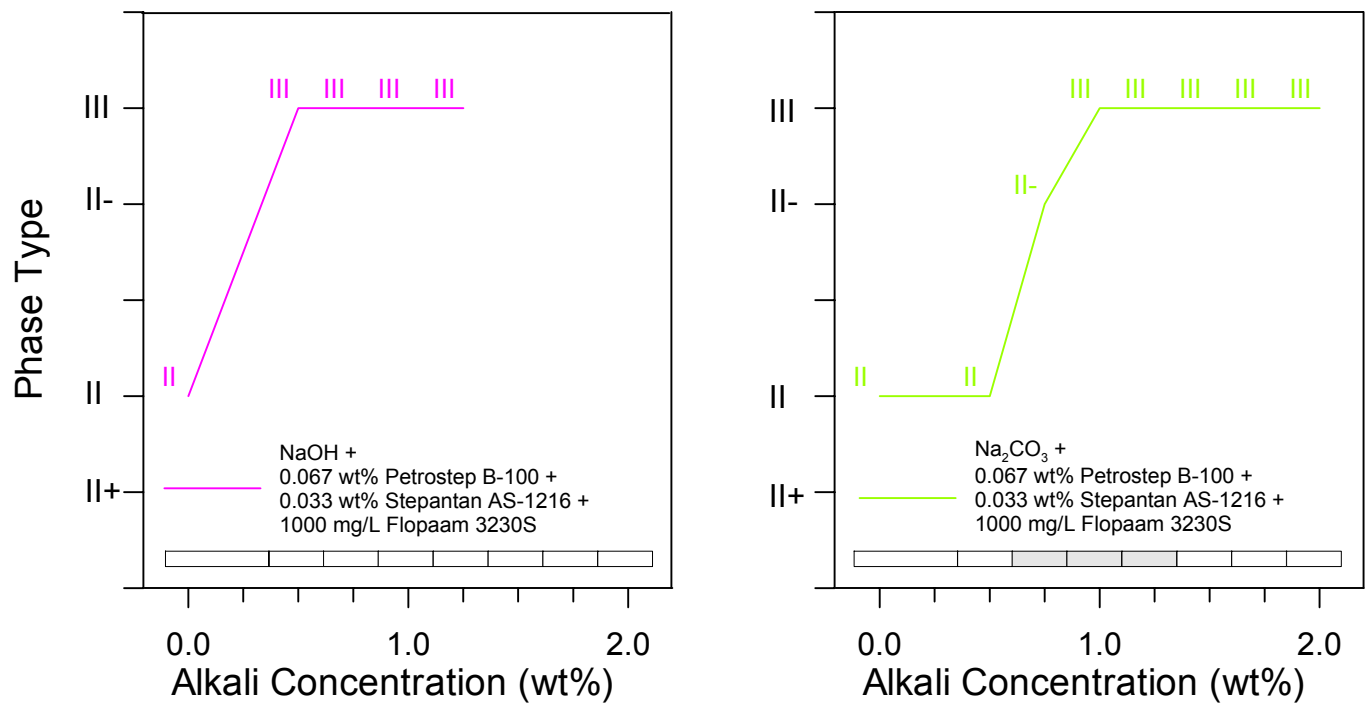
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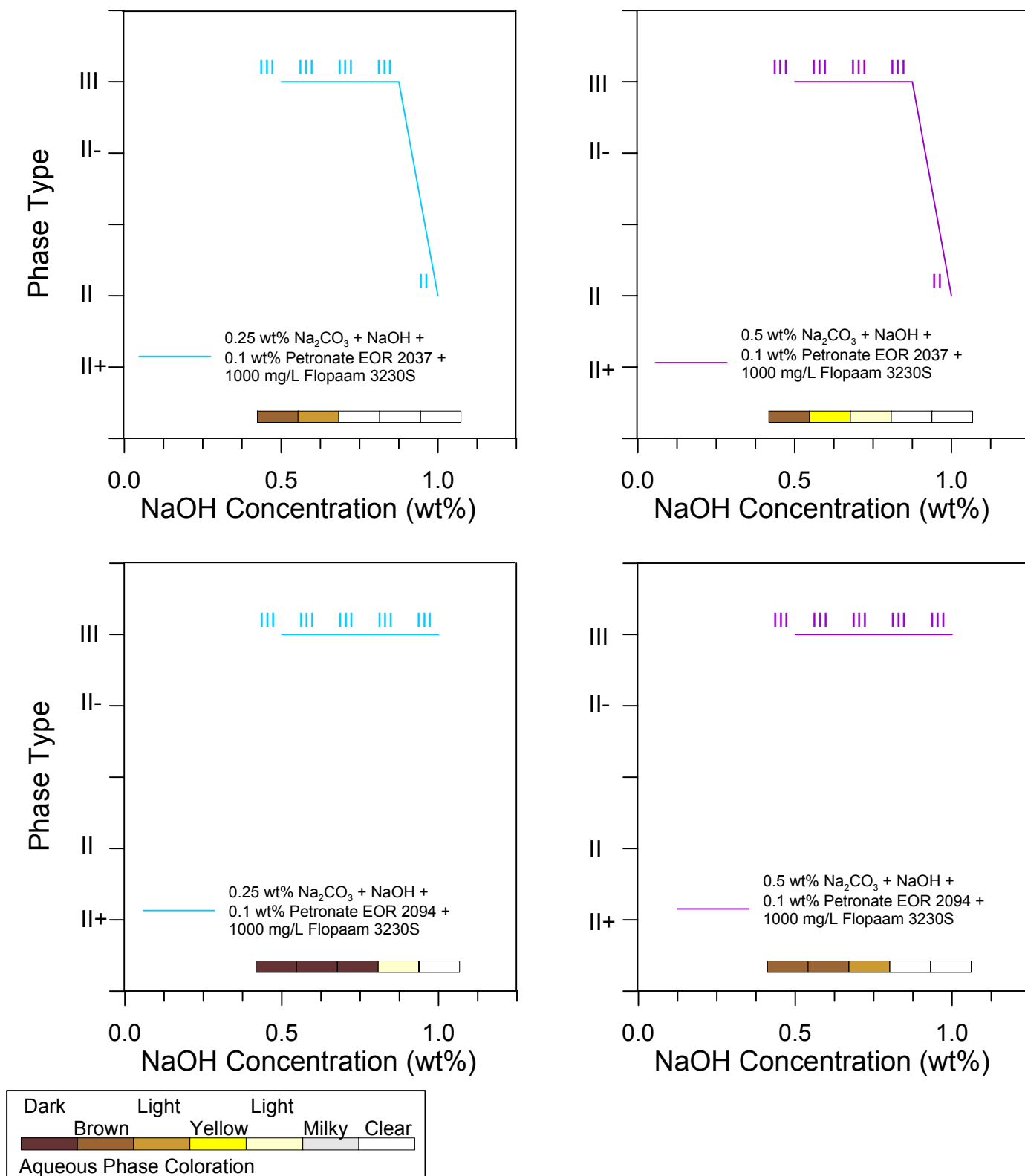
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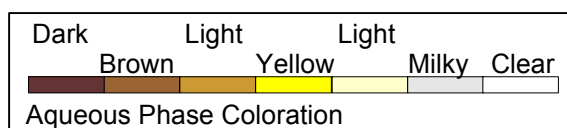
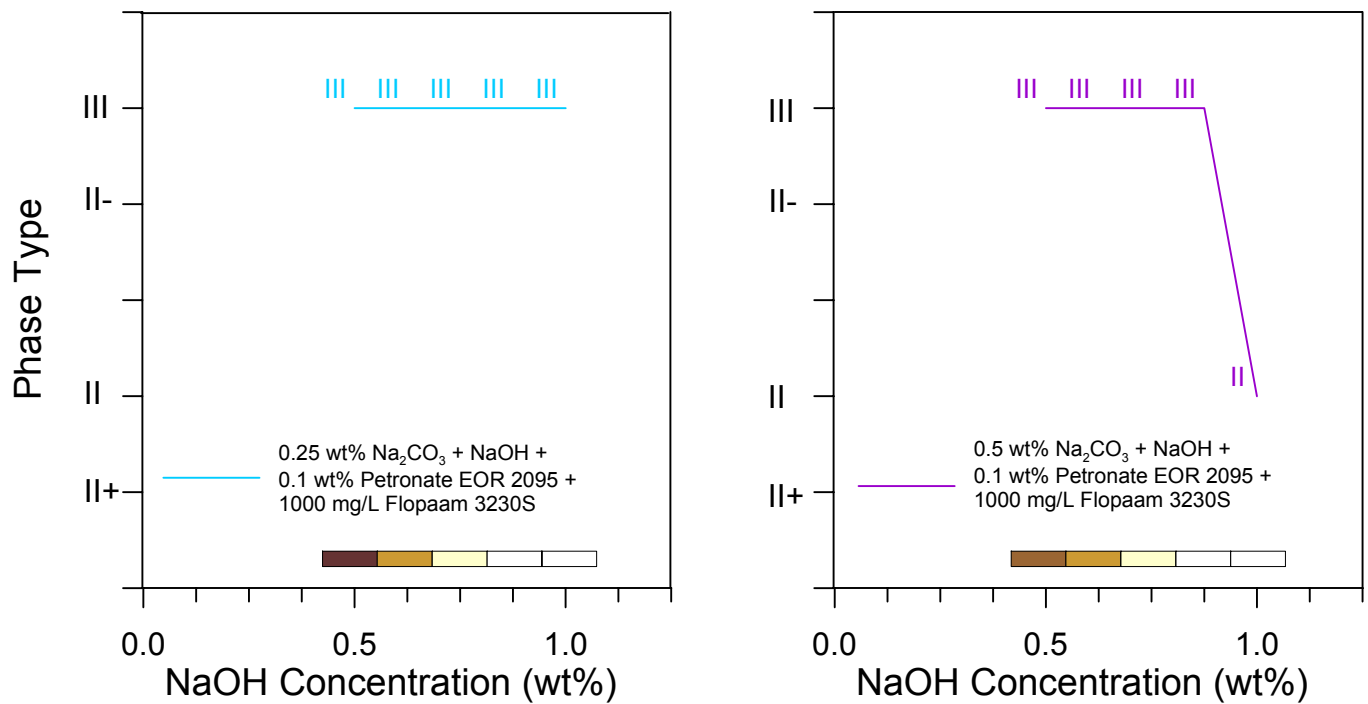
Phase Behavior between Warner Crude Oil at 35°C
and Aqueous Alkali-Surfactant-Polymer
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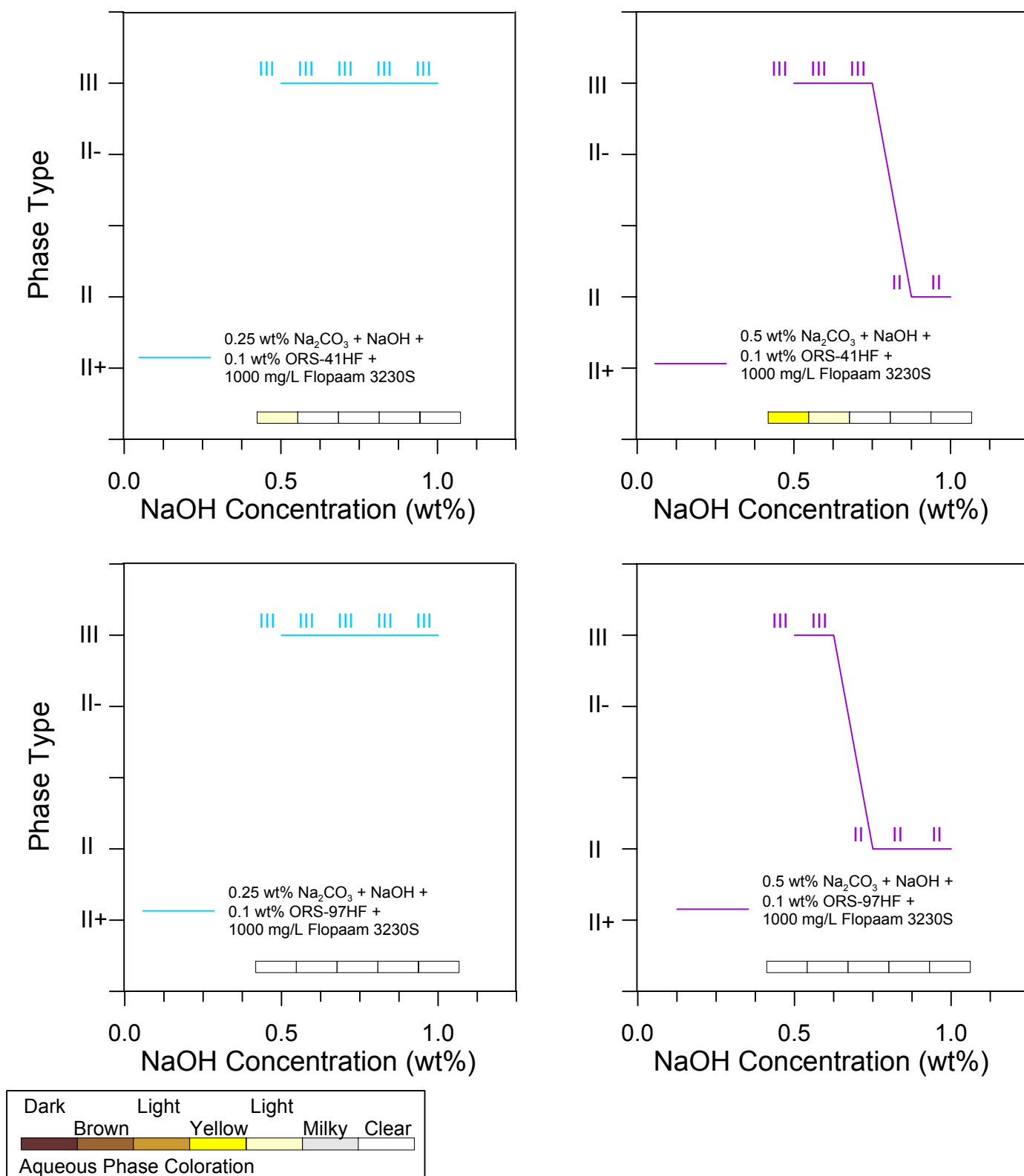
Phase Behavior between Warner Crude Oil at 35°C
and Aqueous Blended Alkali-Surfactant-Polymer
Dissolved in Softened Injection Water



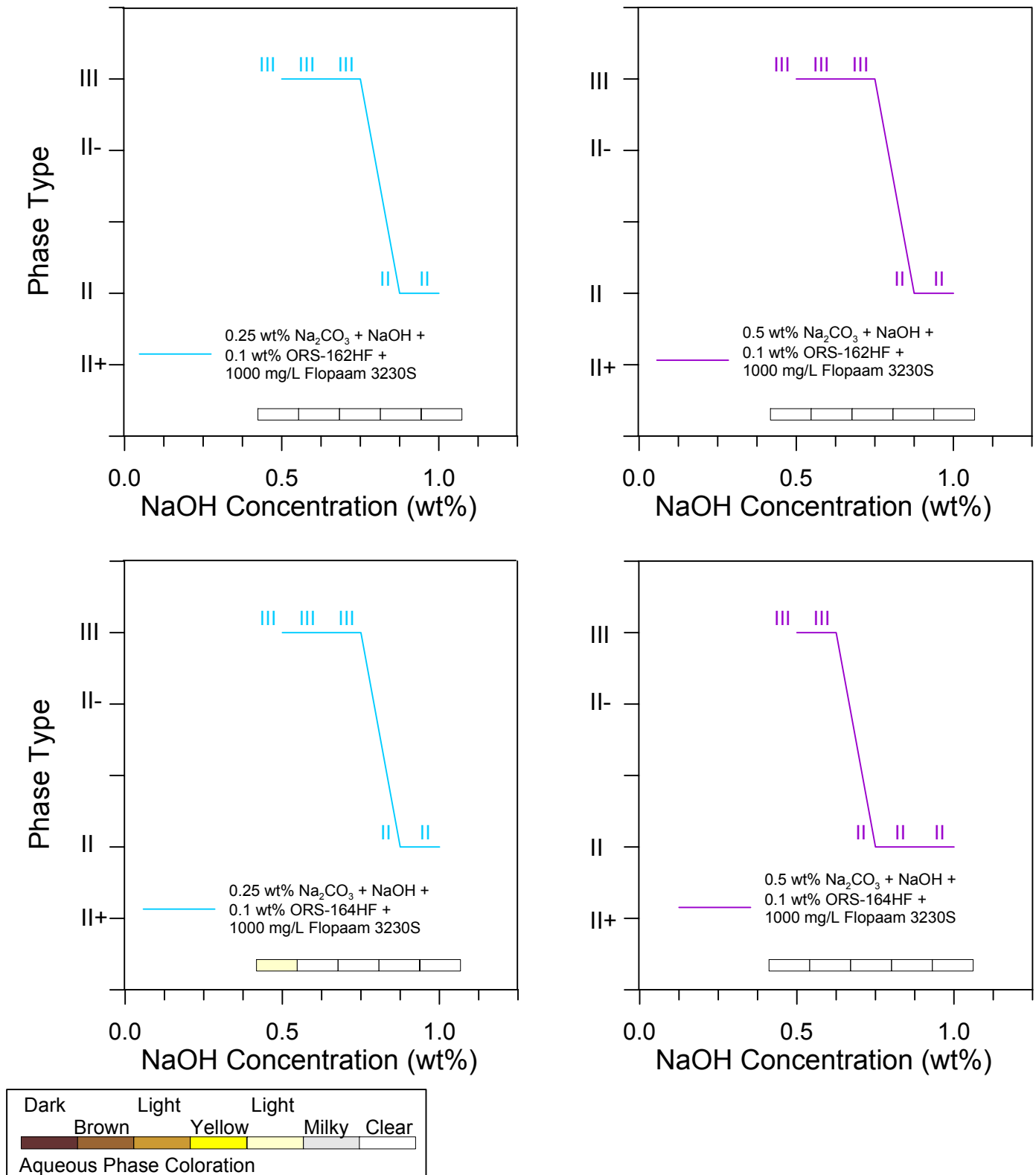
Phase Behavior between Warner Crude Oil at 35°C
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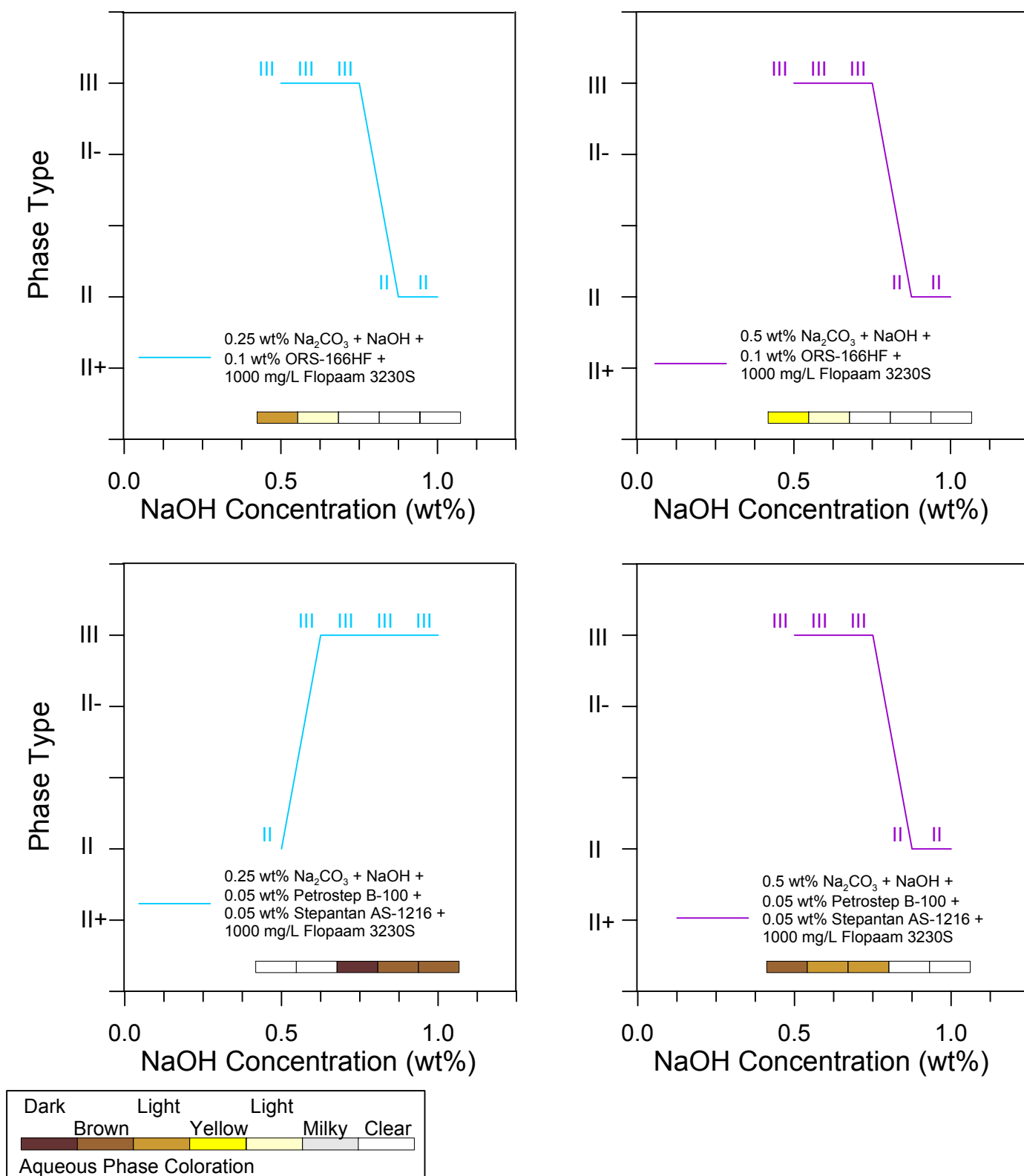
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Dissolved in Softened Injection Water



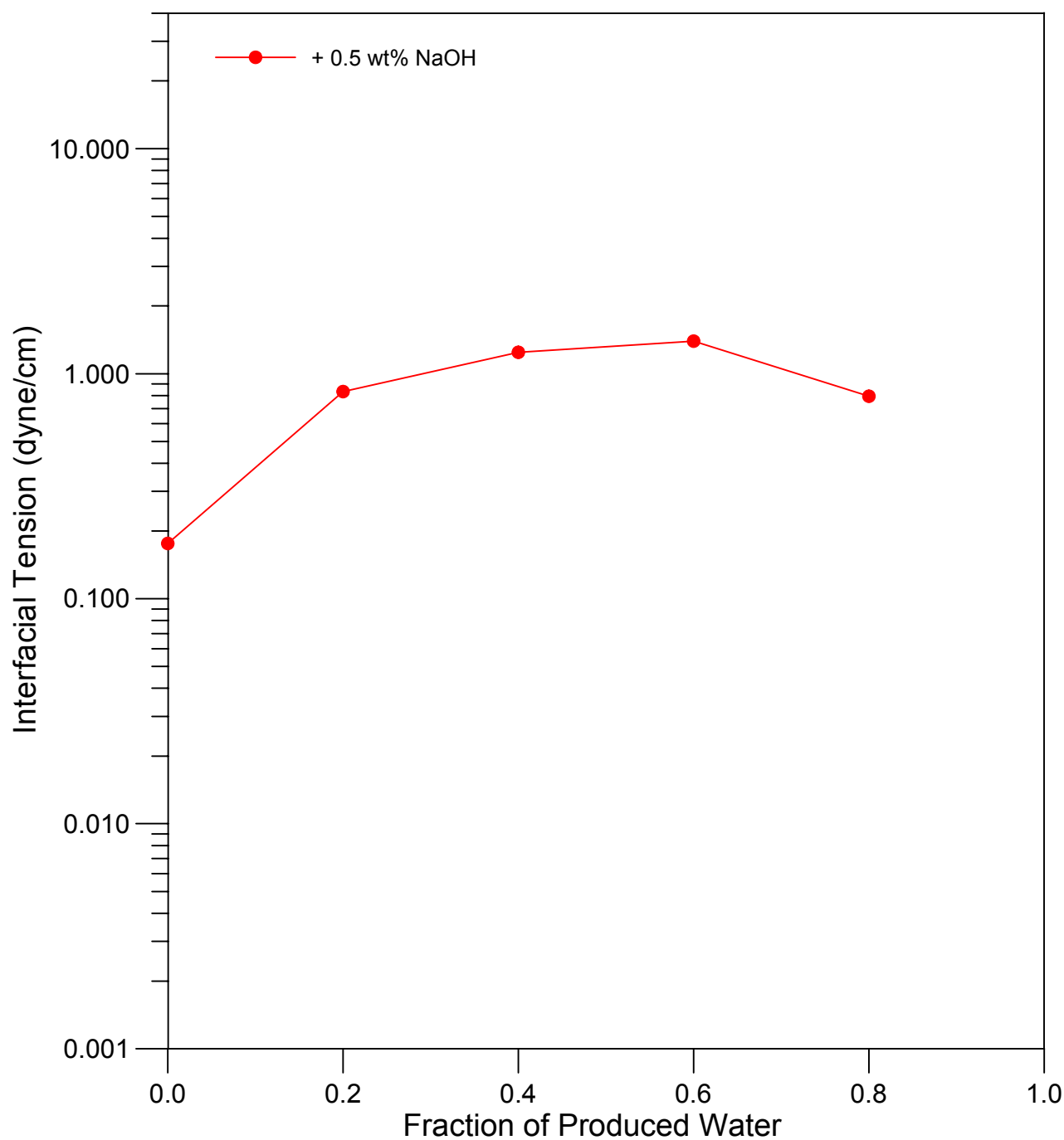
Phase Behavior between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



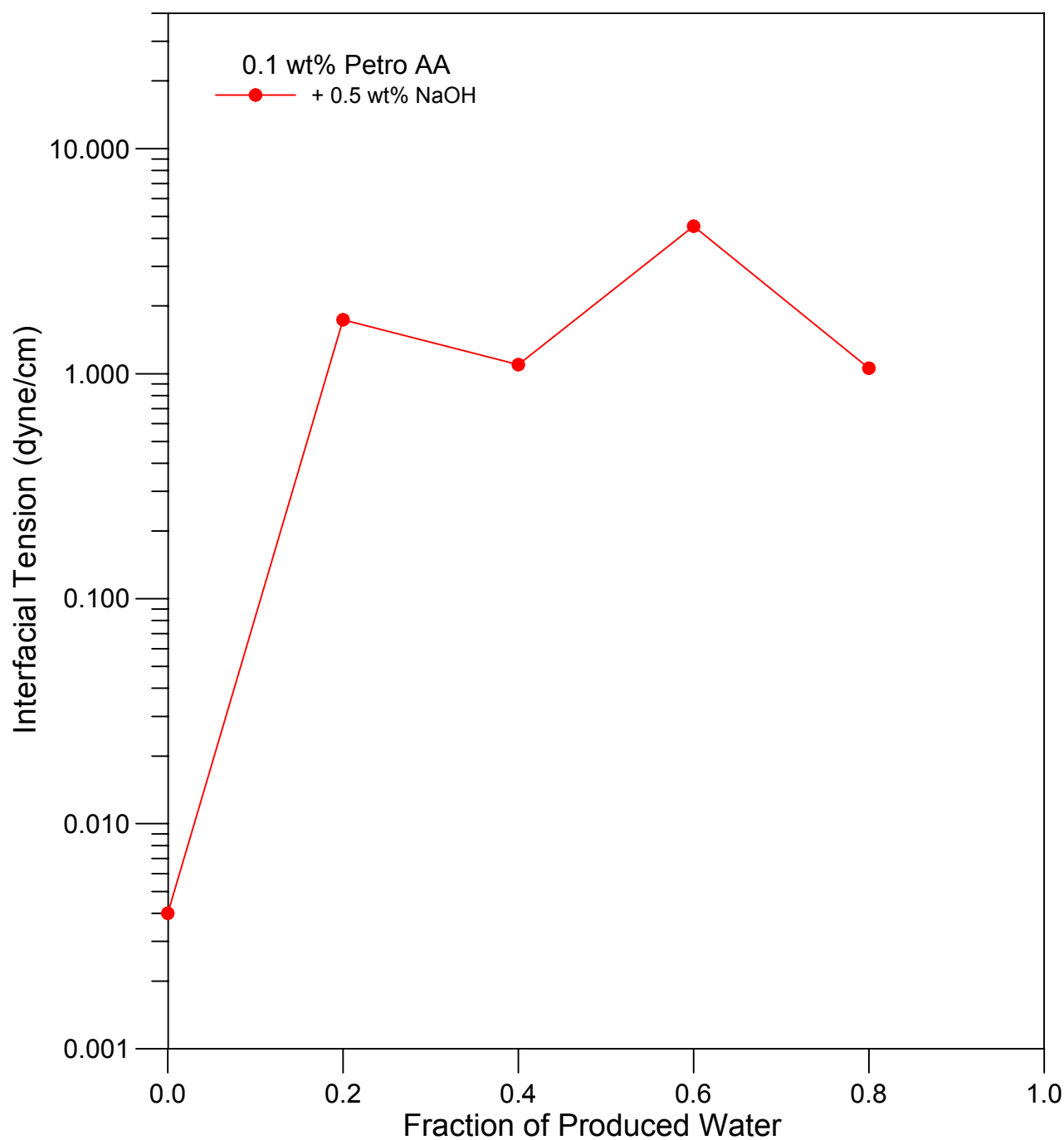
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Dissolved in Softened Injection Water



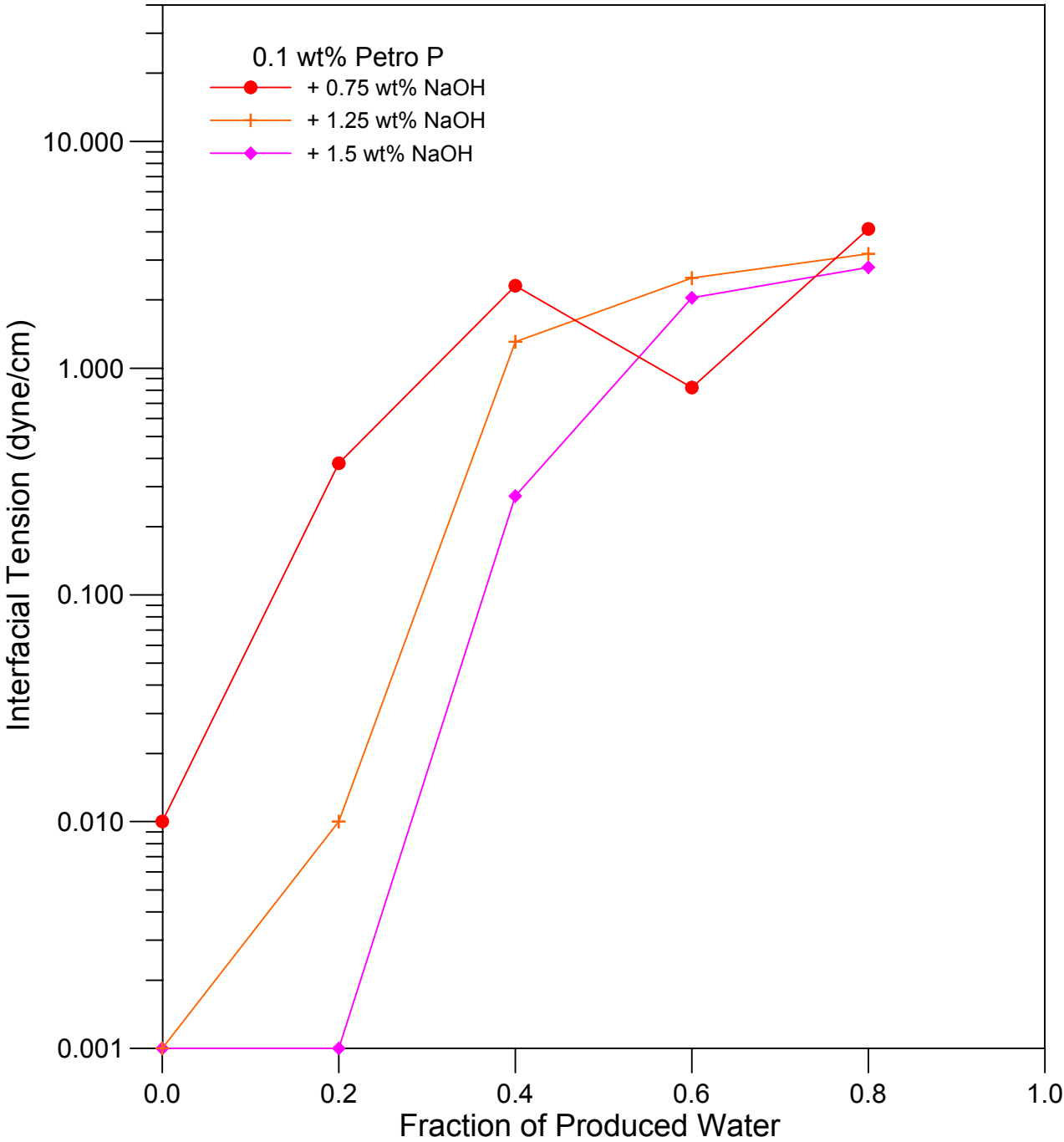
Effect of Produced Water Dilution on the
Interfacial Tension Between Warner Crude Oil at 35°C
and Aqueous Alkali + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water



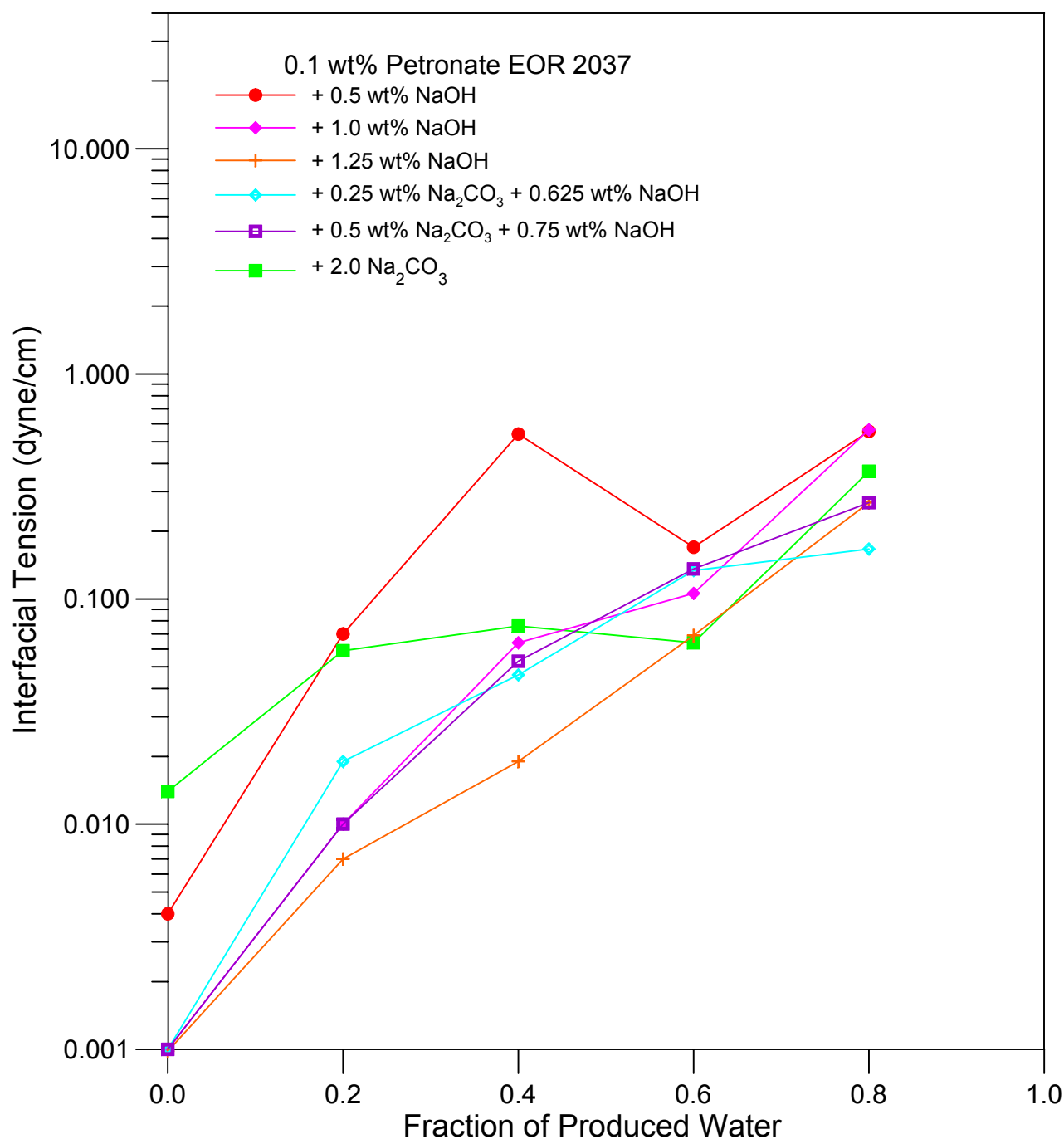
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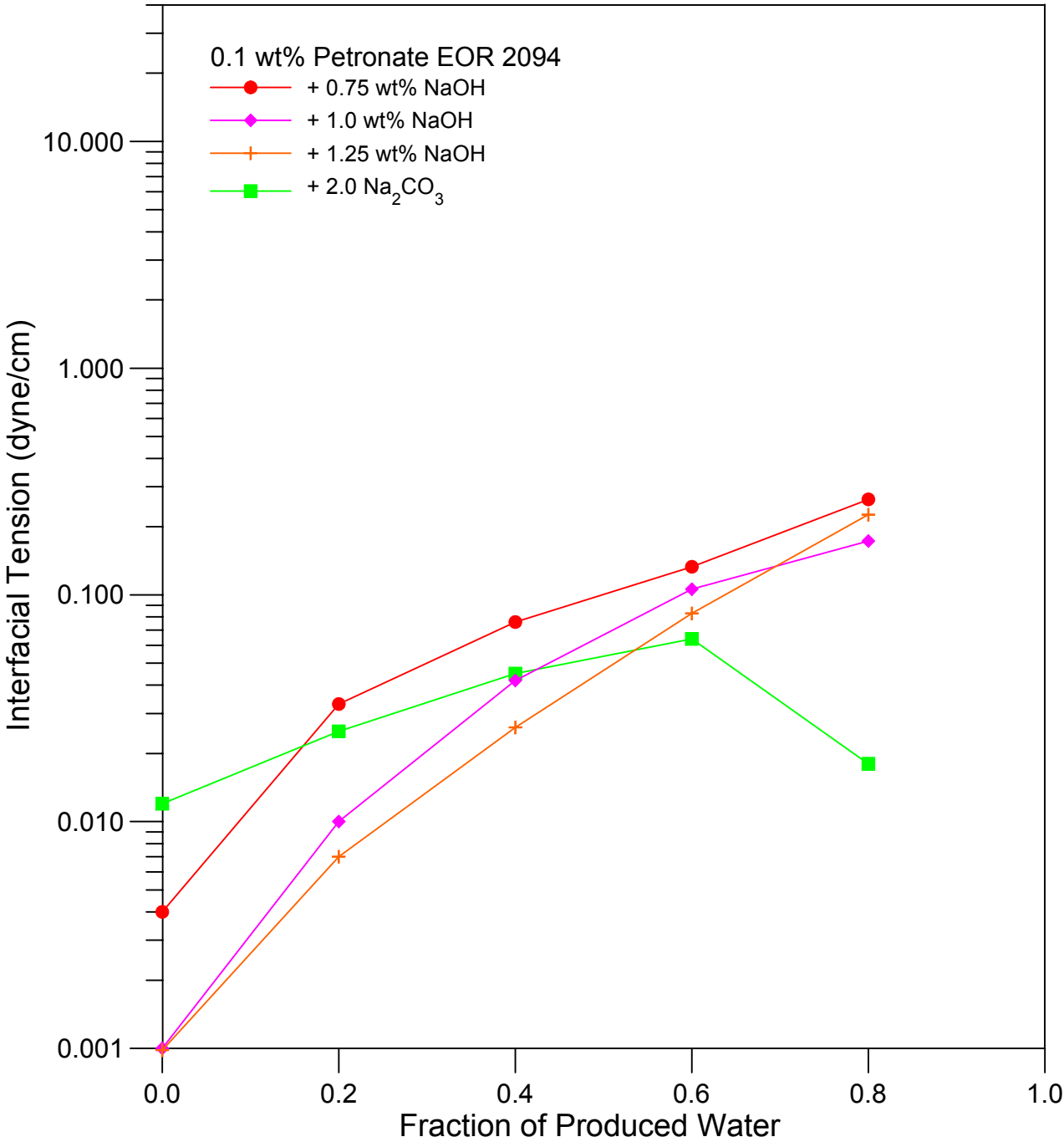
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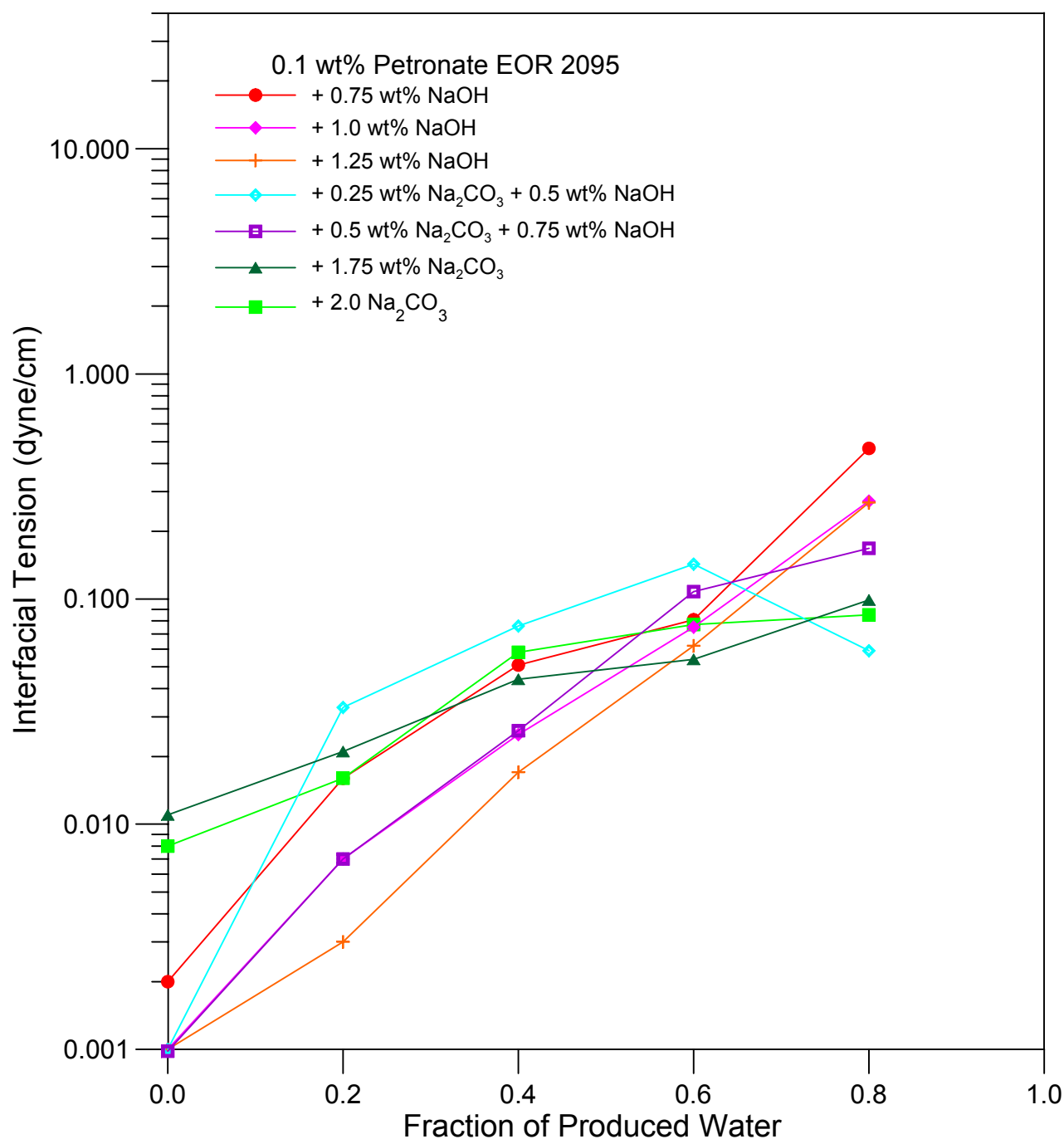
Effect of Produced Water Dilution on the
Interfacial Tension Between Warner Crude Oil at 35°C
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Dissolved in Softened Injection Water



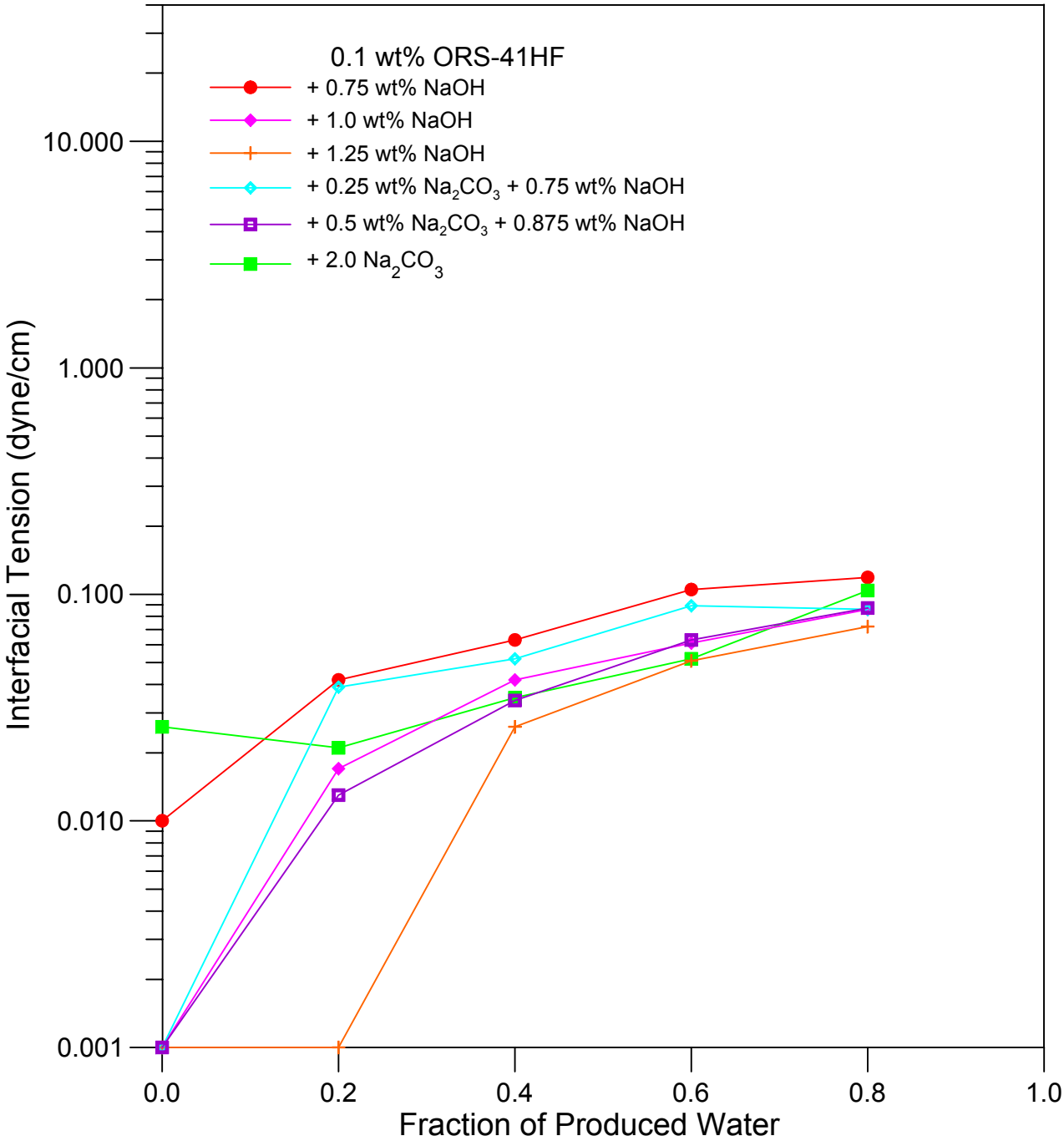
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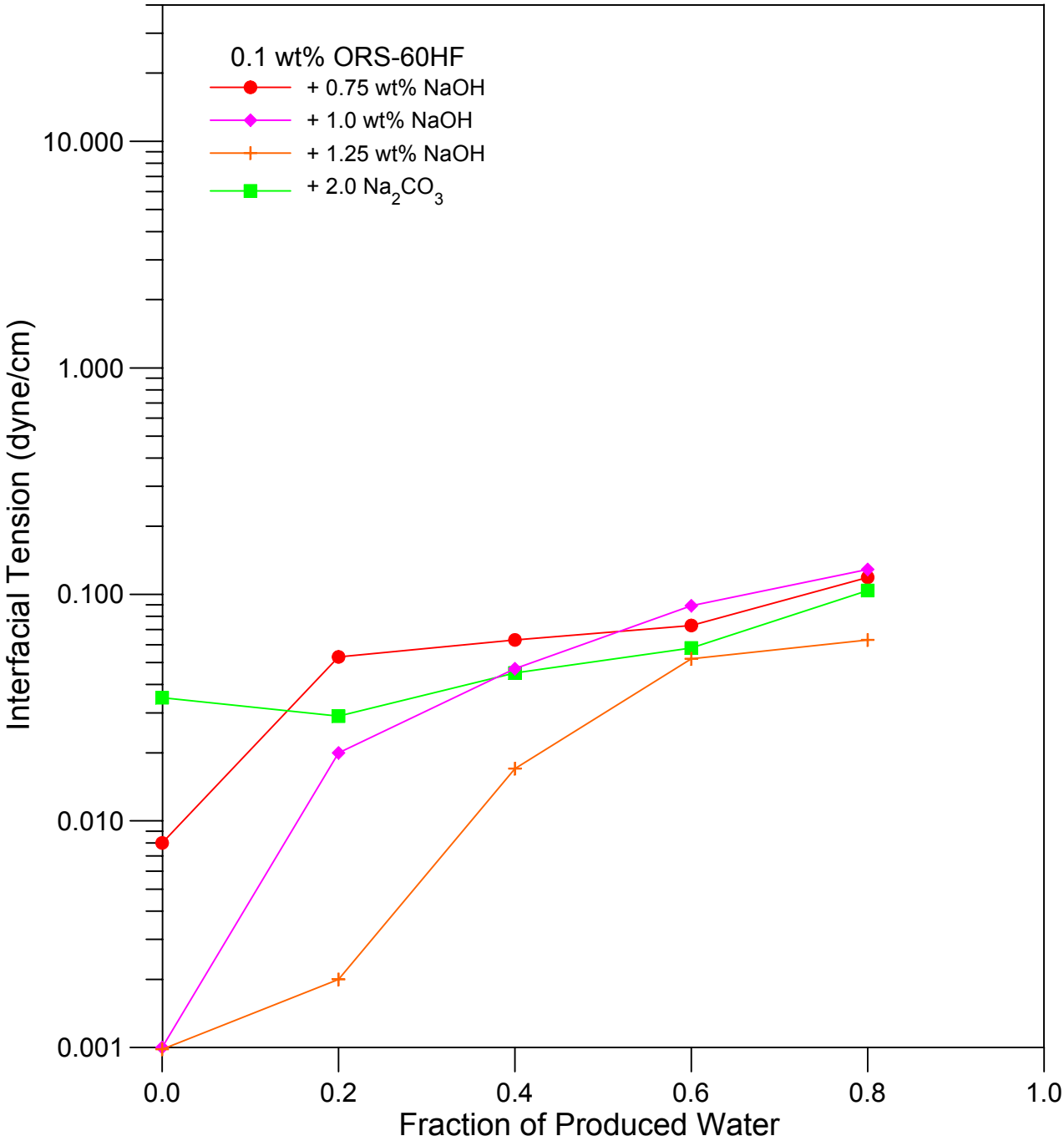
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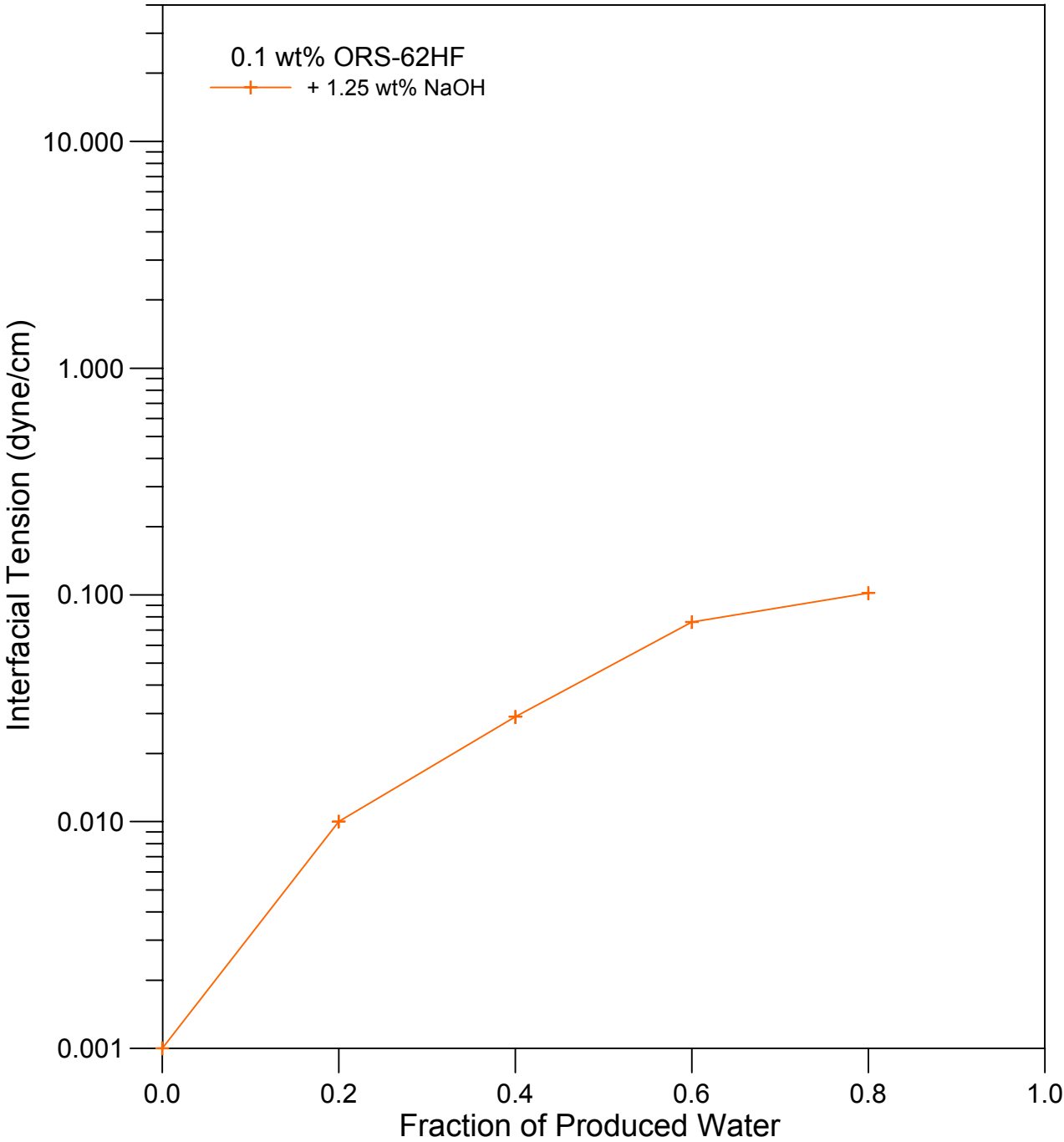
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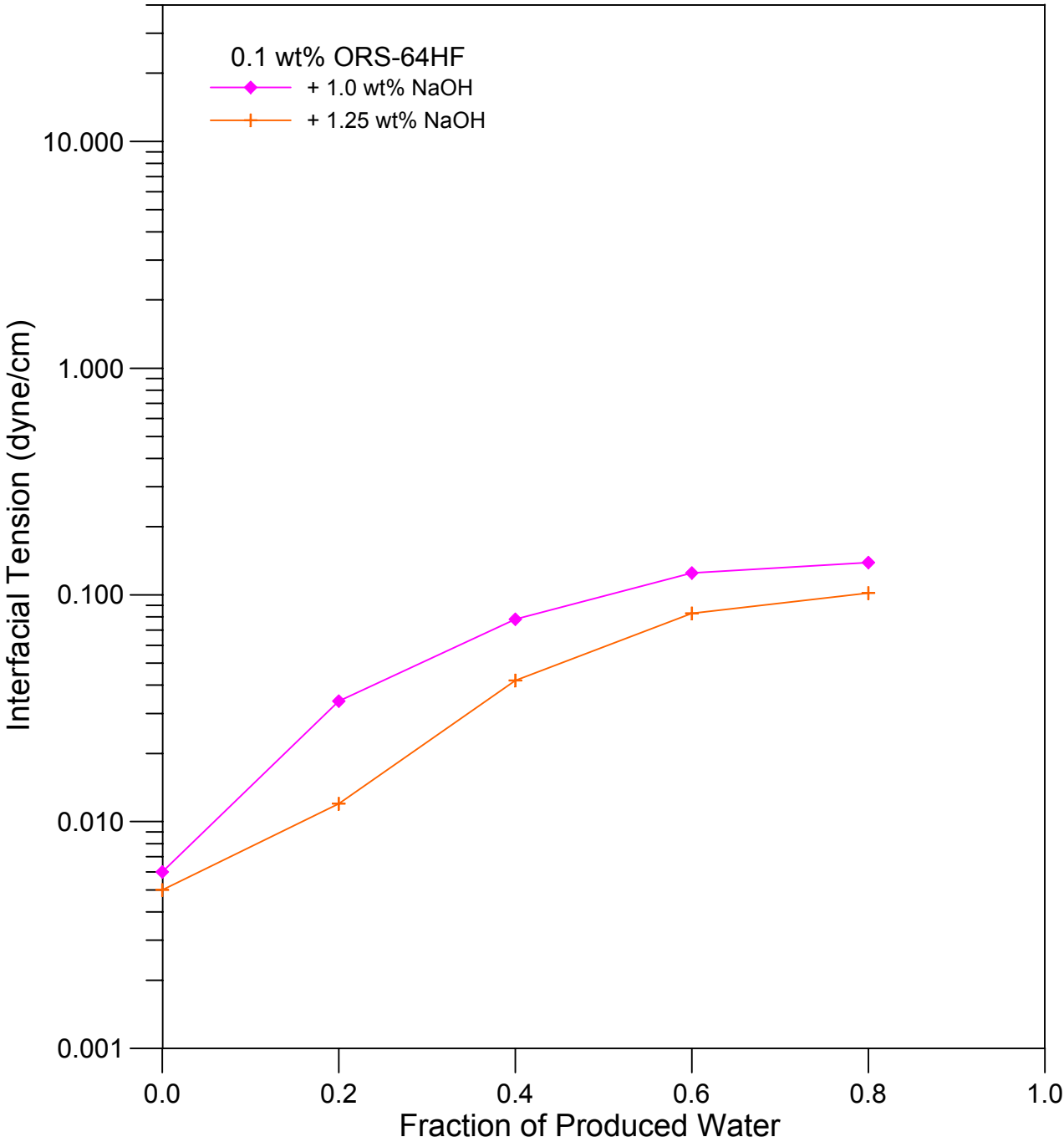
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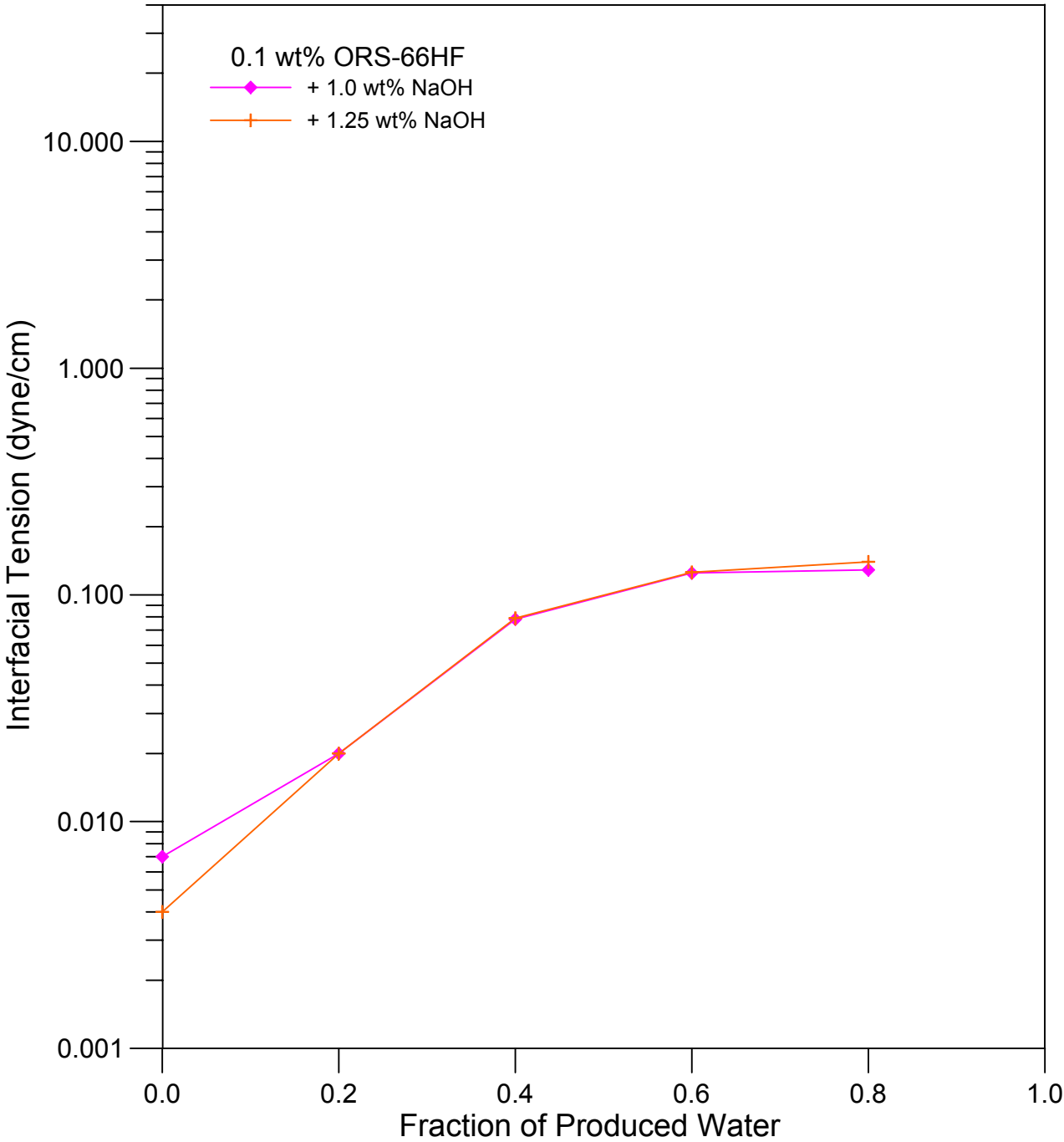
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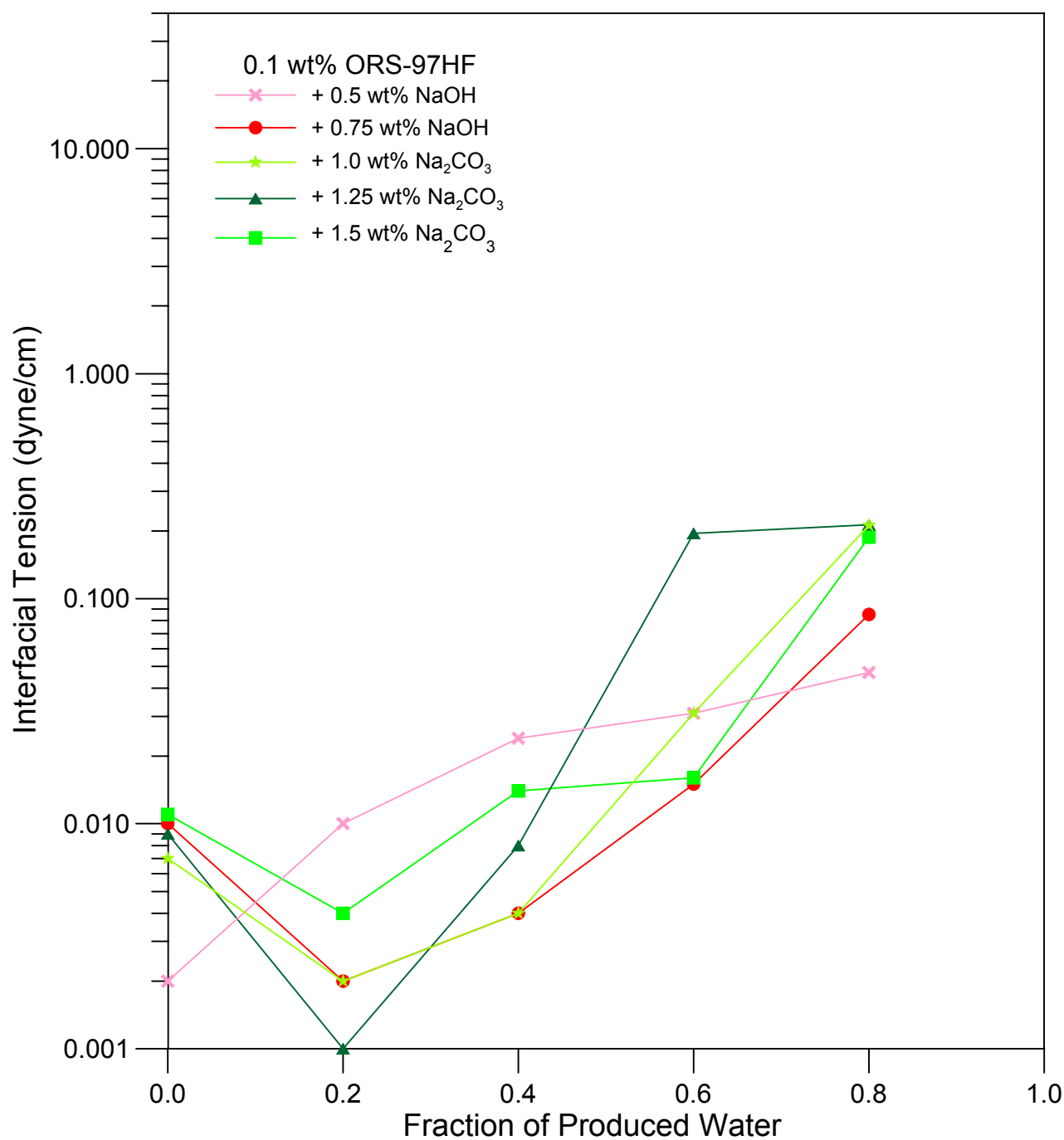
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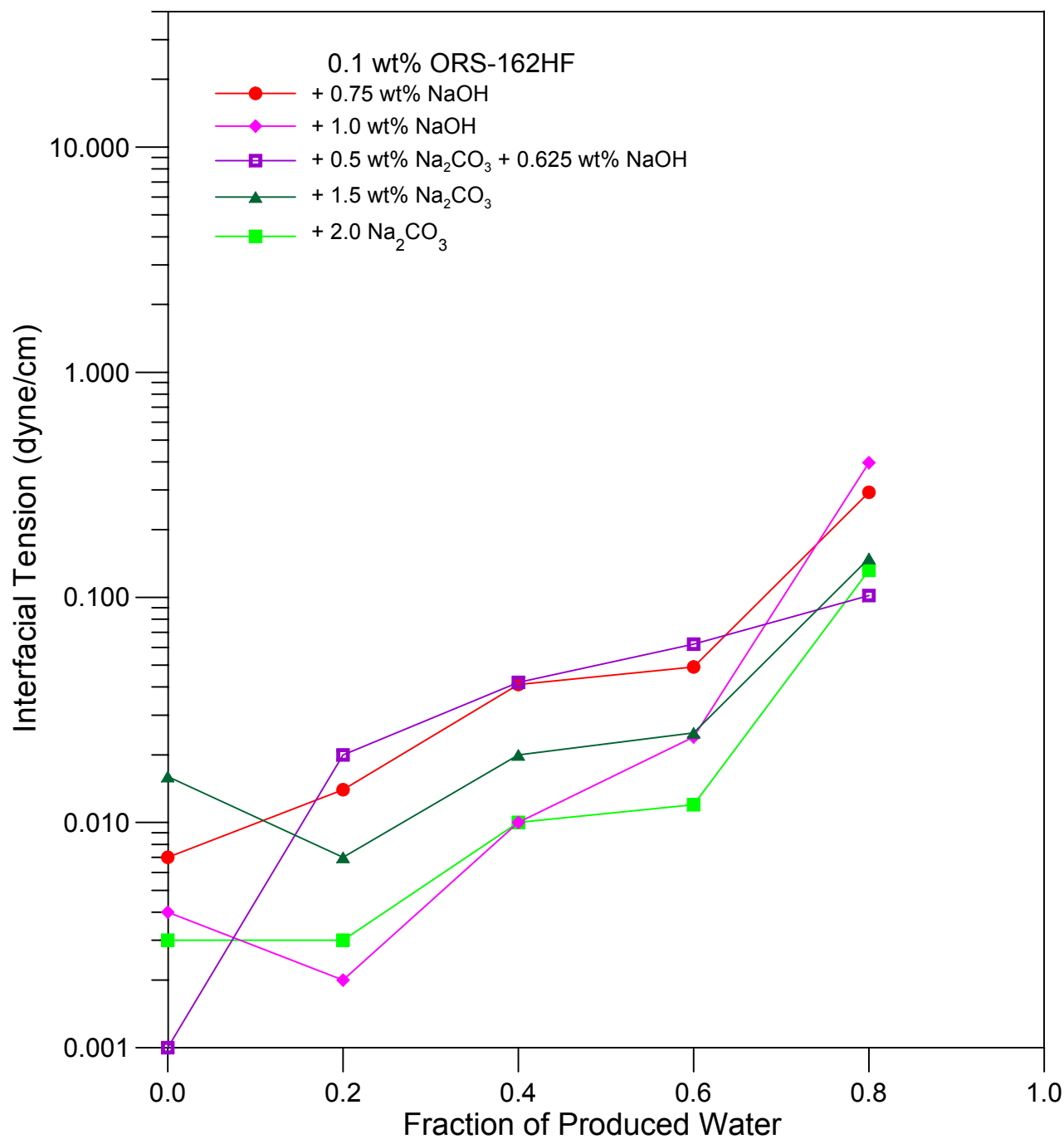
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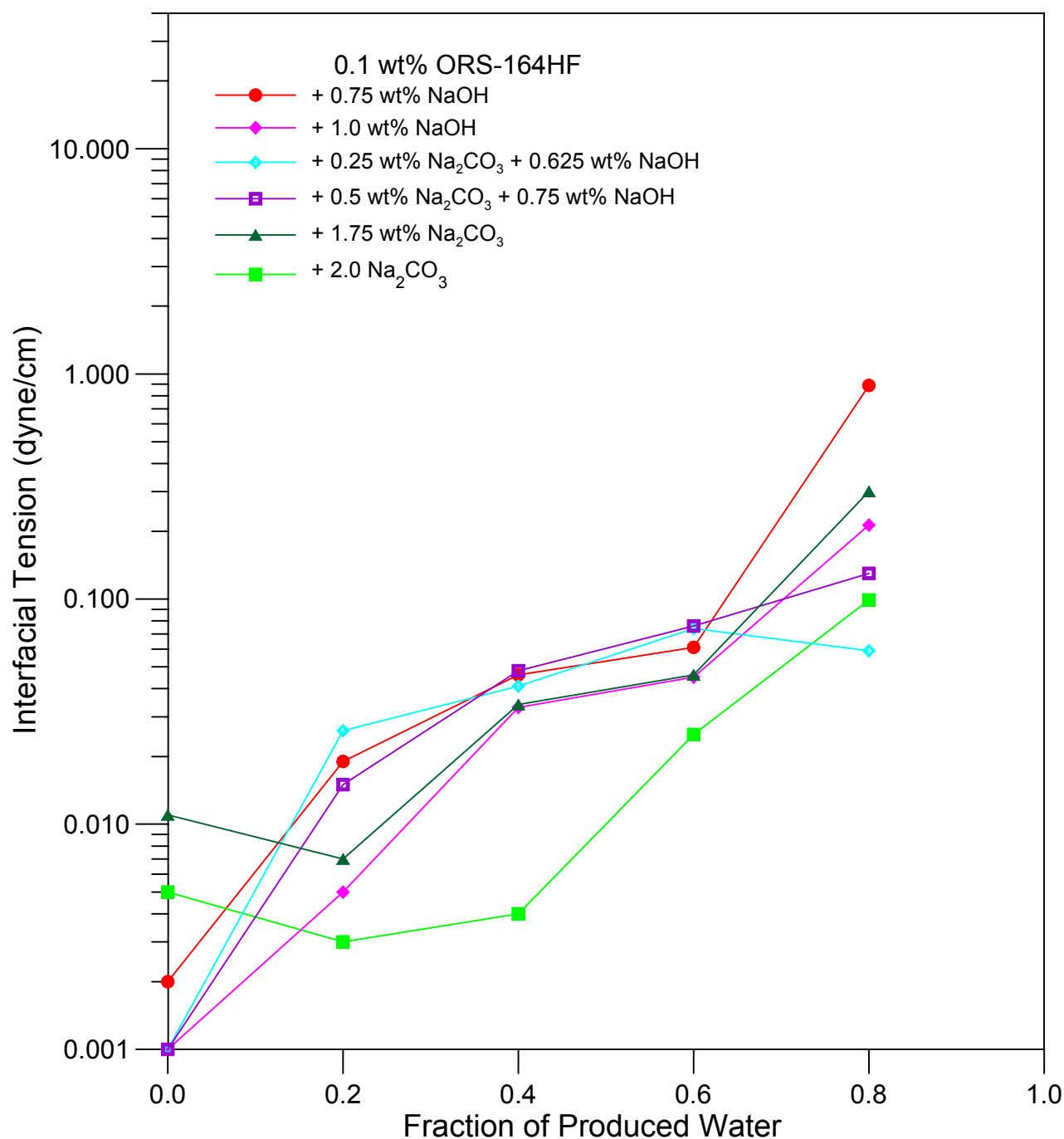
Effect of Produced Water Dilution on the
Interfacial Tension Between Warner Crude Oil at 35°C
and Aqueous Alkali + Surfactant + 1000 mg/L Flopaam 3230S
Dissolved in Softened Injection Water



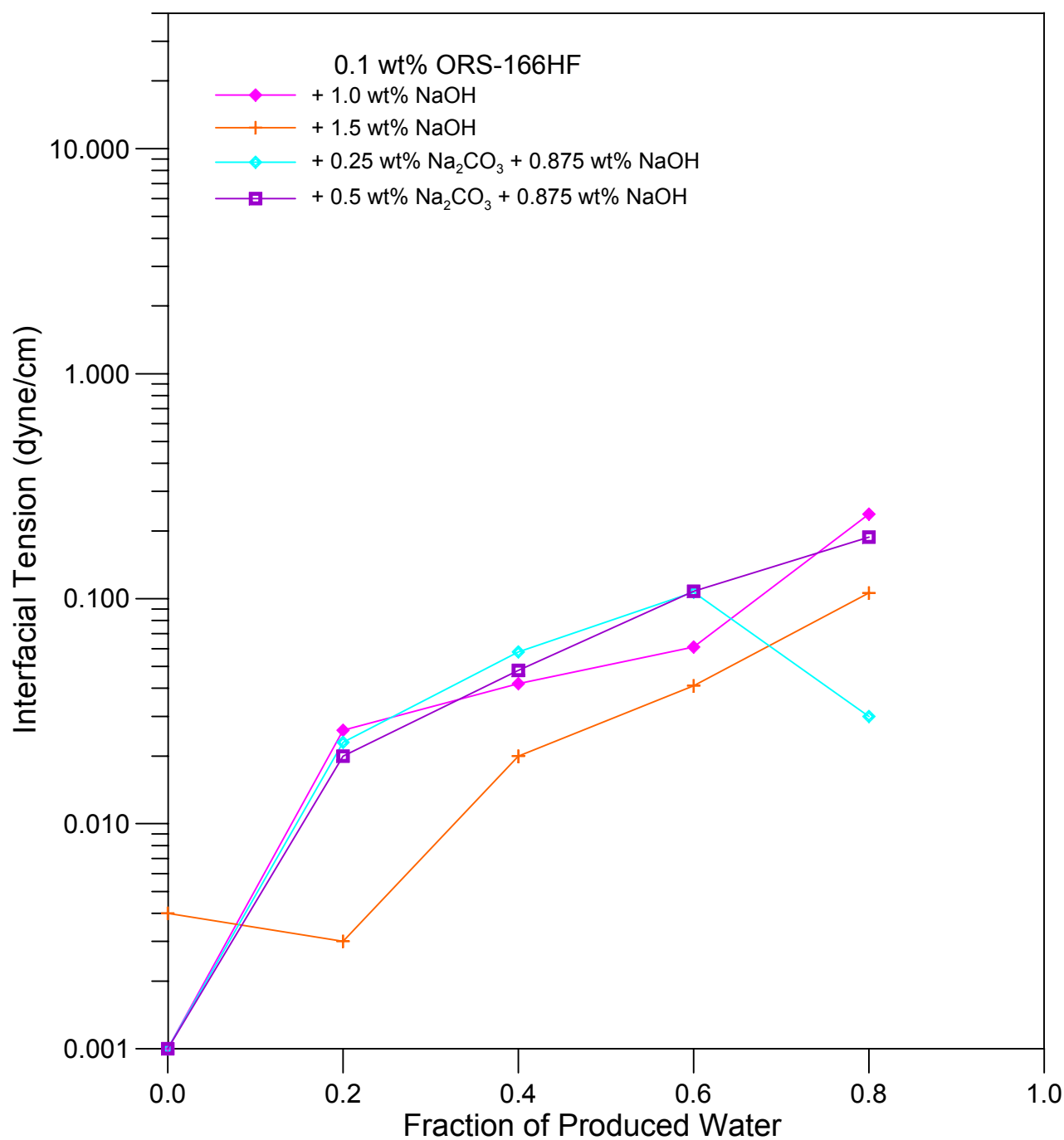
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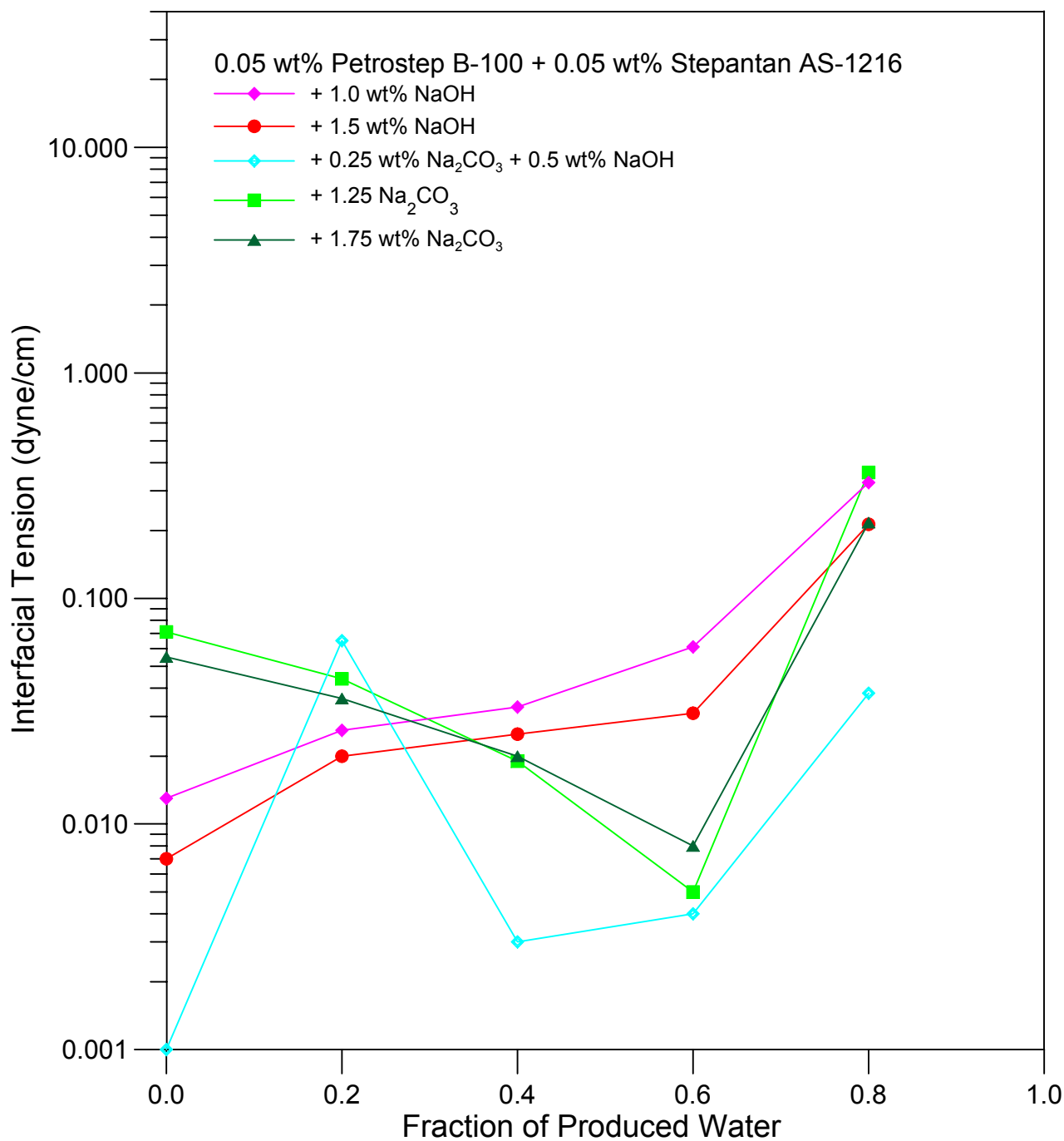
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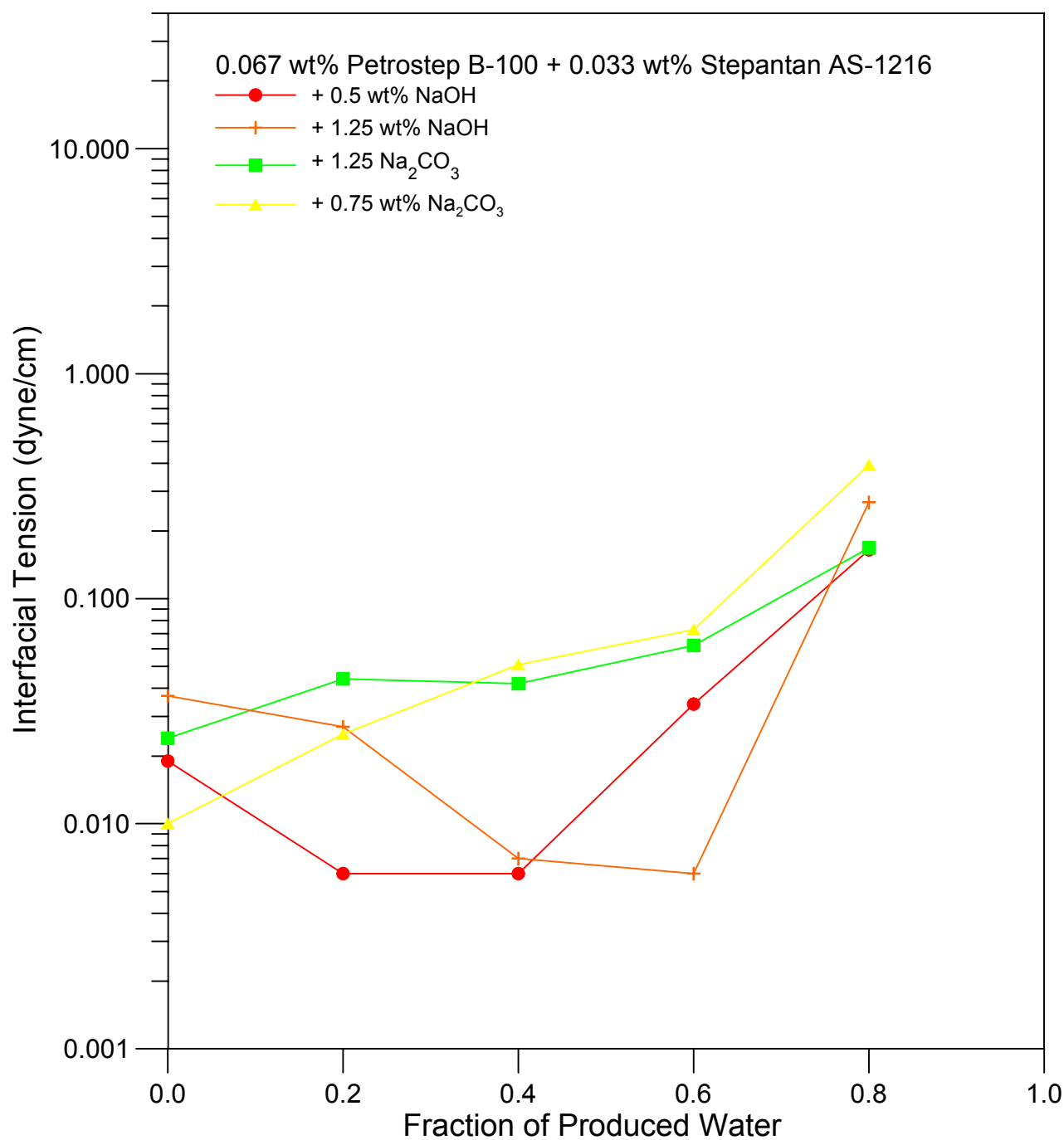
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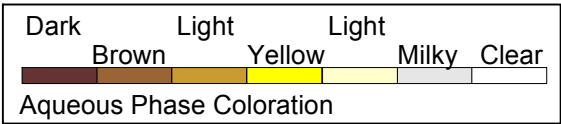
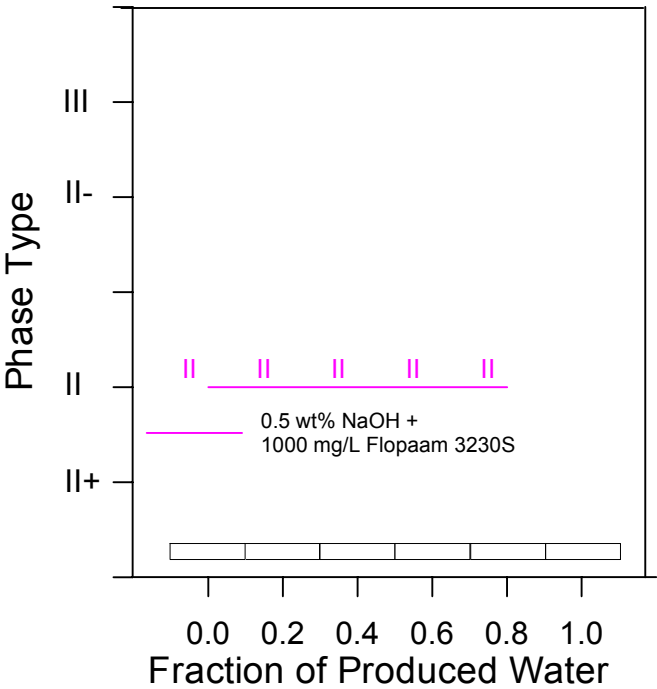
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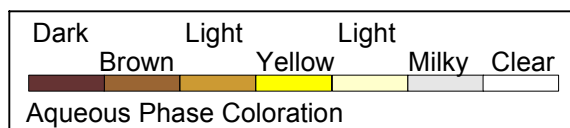
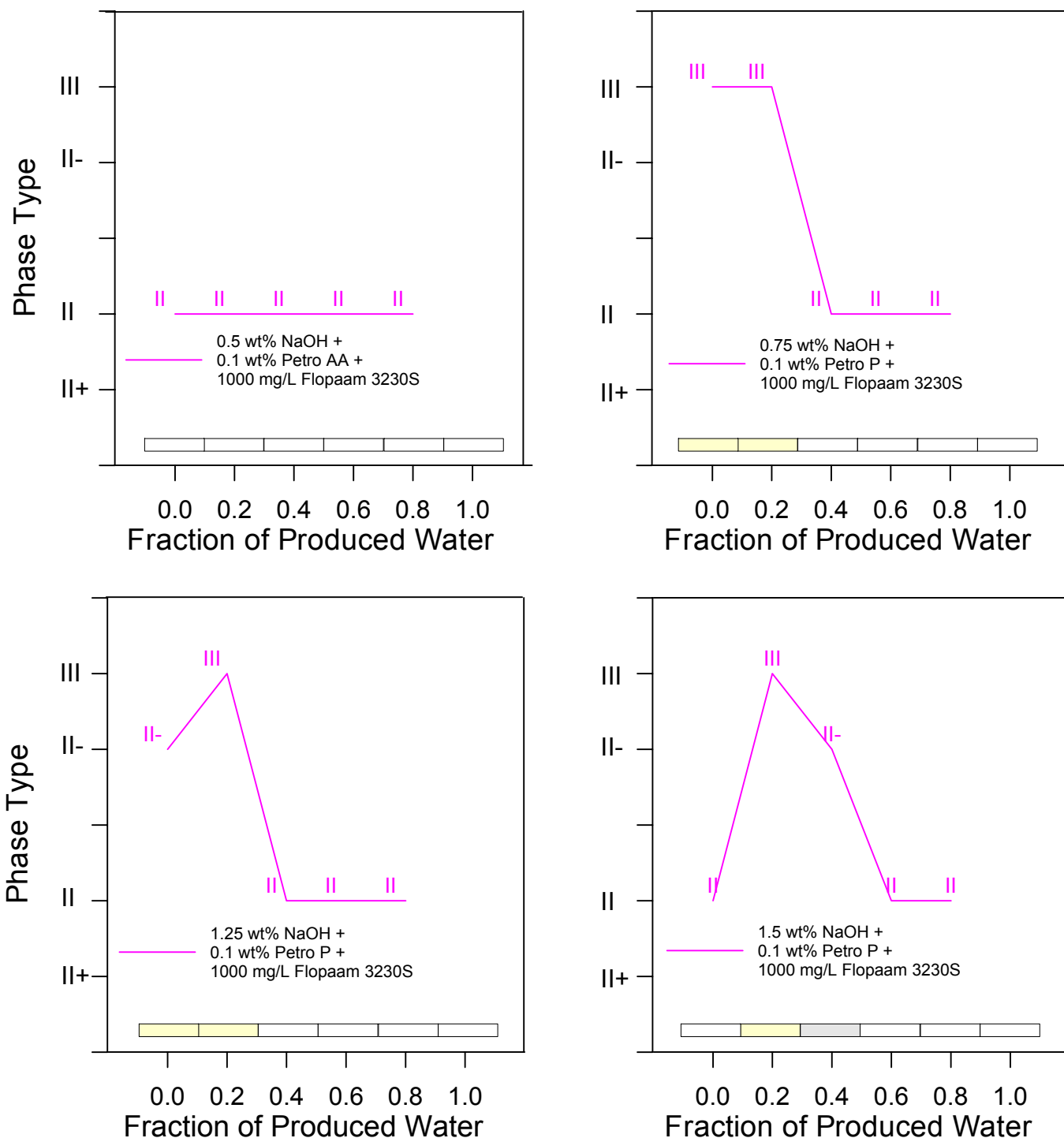
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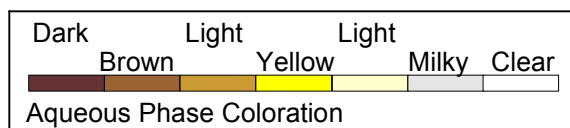
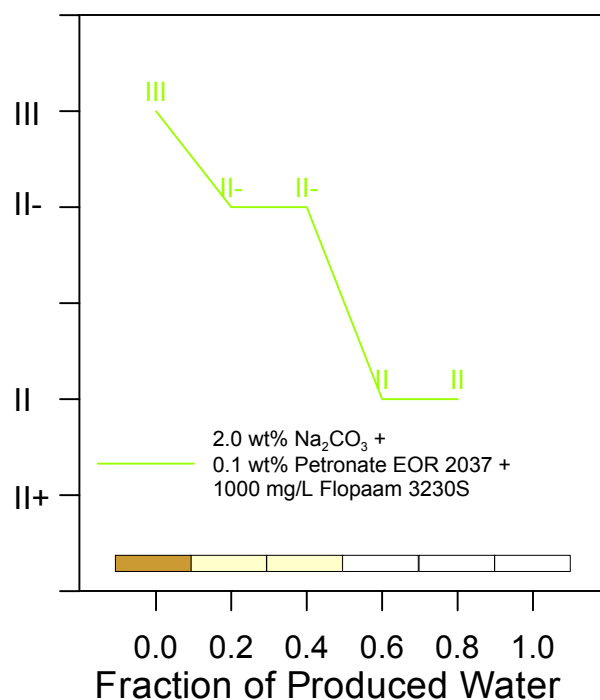
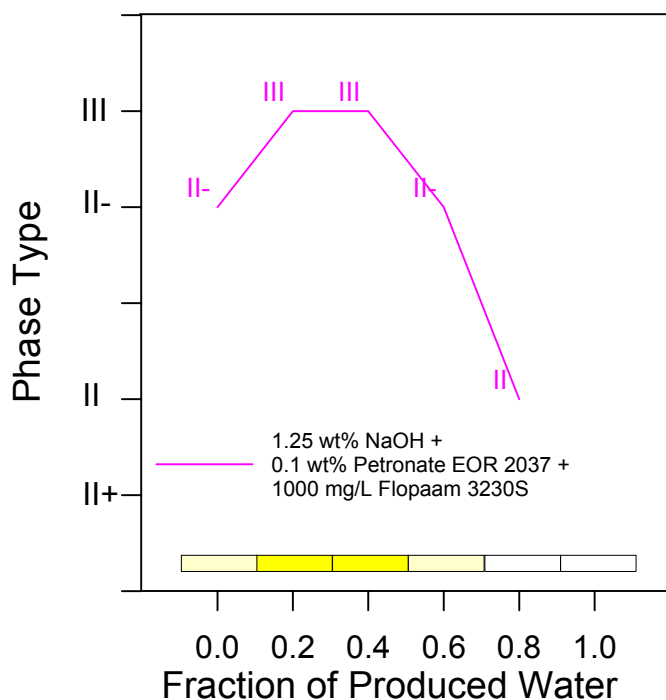
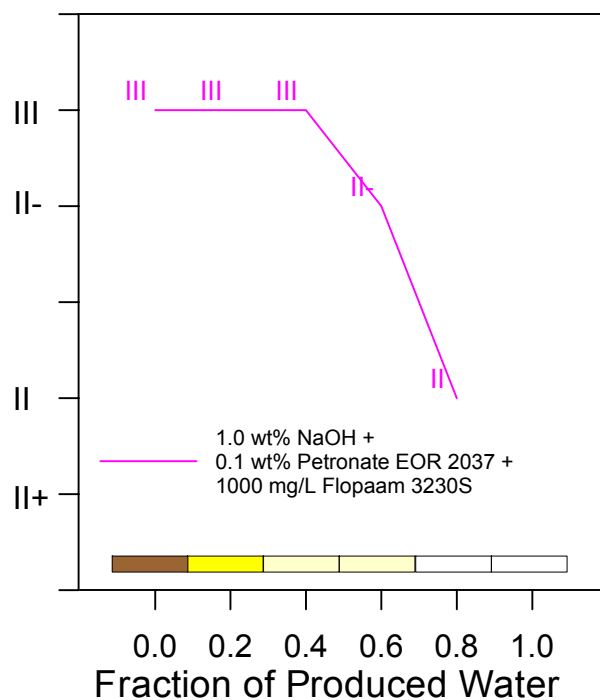
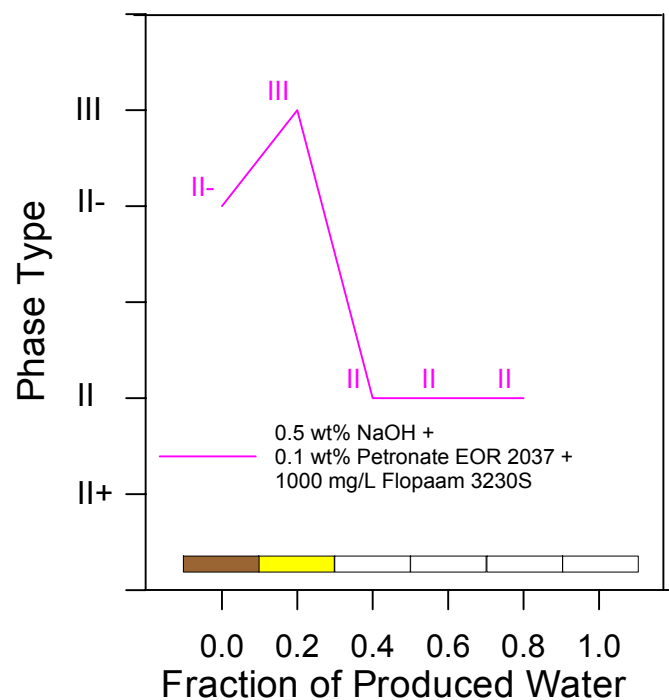
Effect of Produced Water Dilution on the Phase Behavior between Warner Crude Oil at 35°C and Aqueous Alkali-Surfactant-Polymer Dissolved in Softened Injection Water



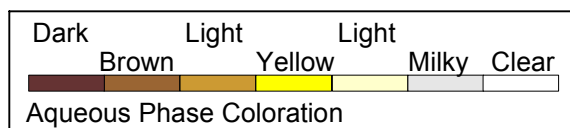
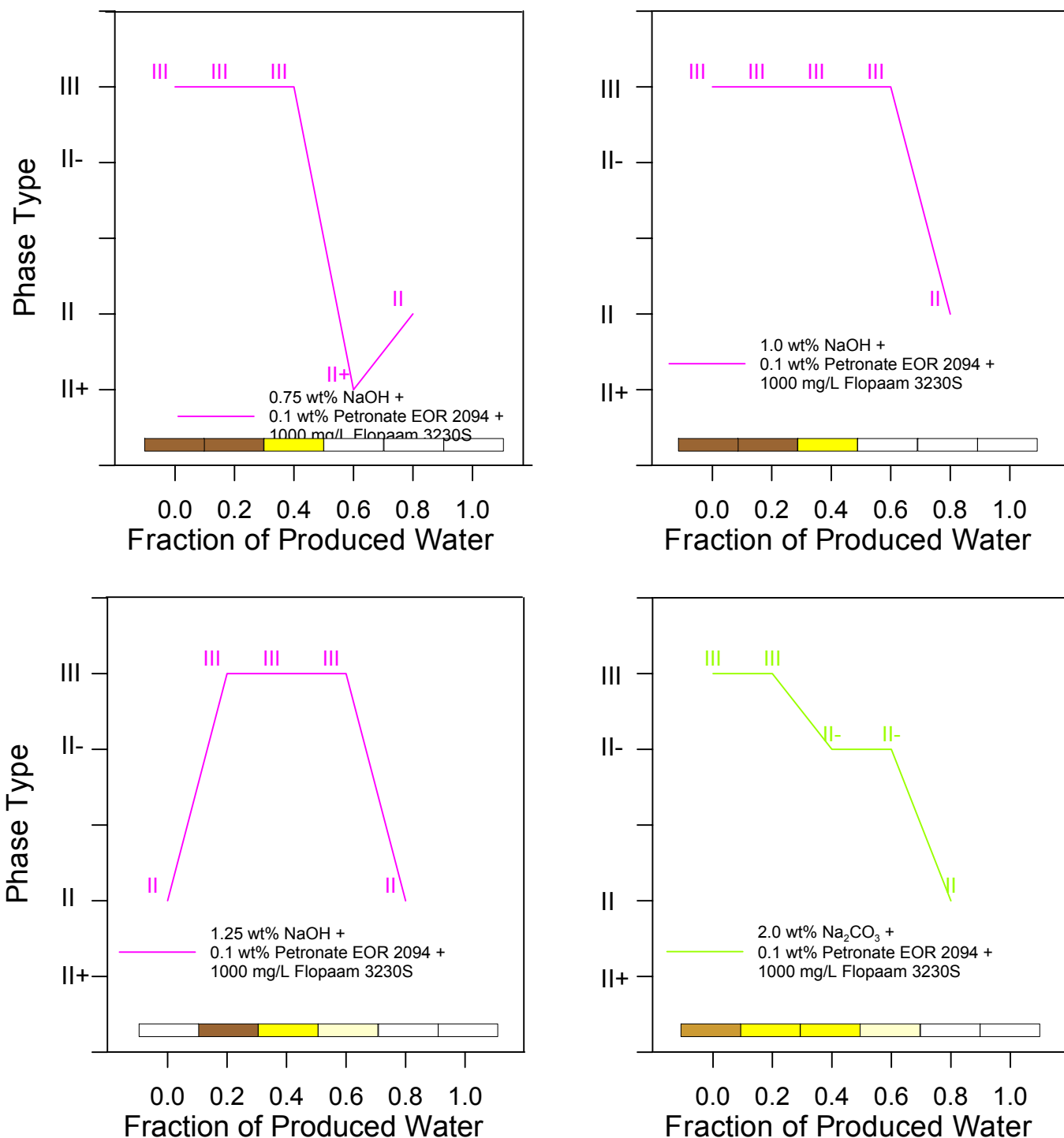
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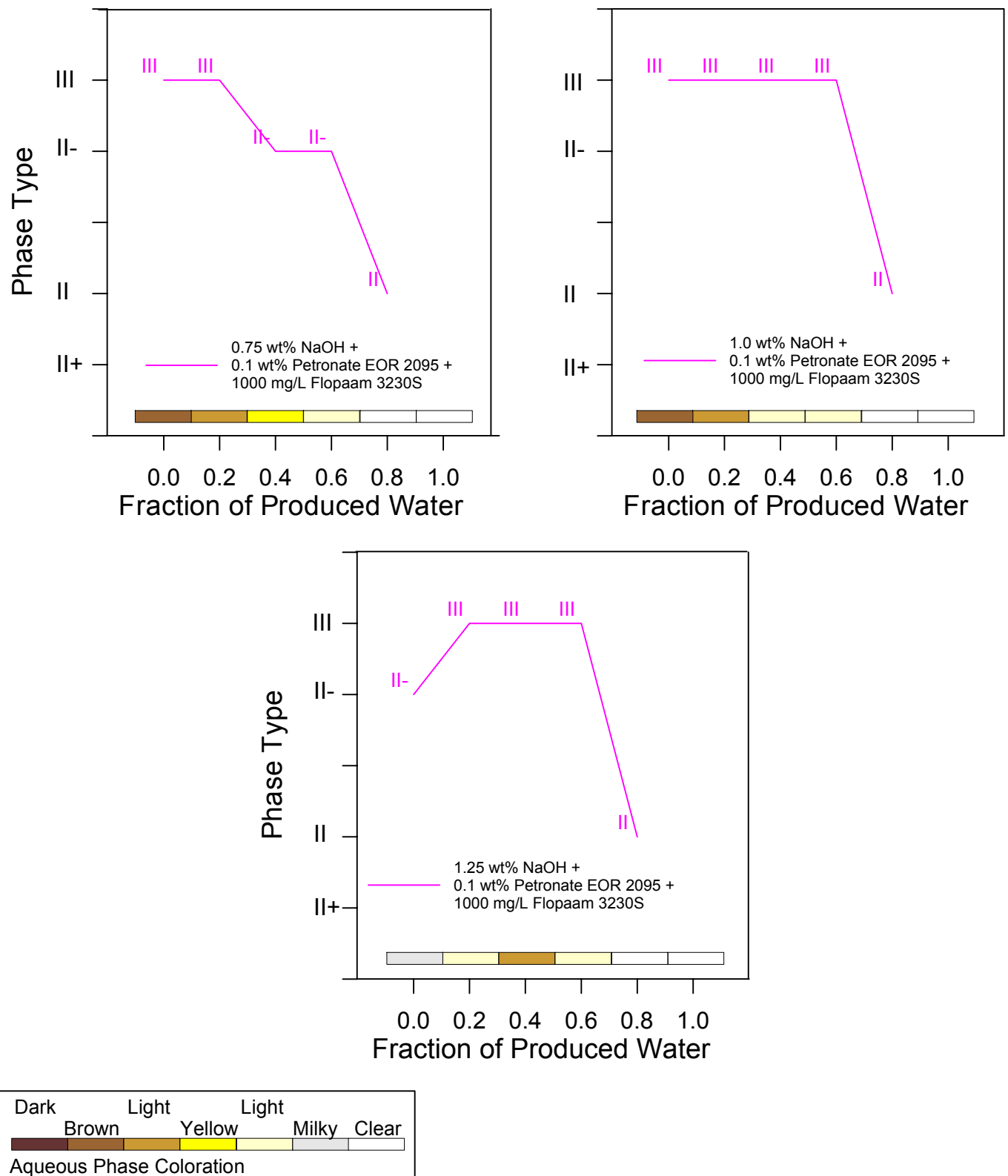
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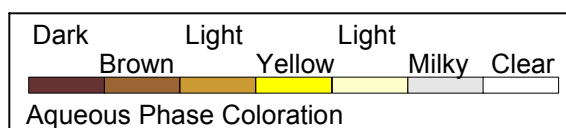
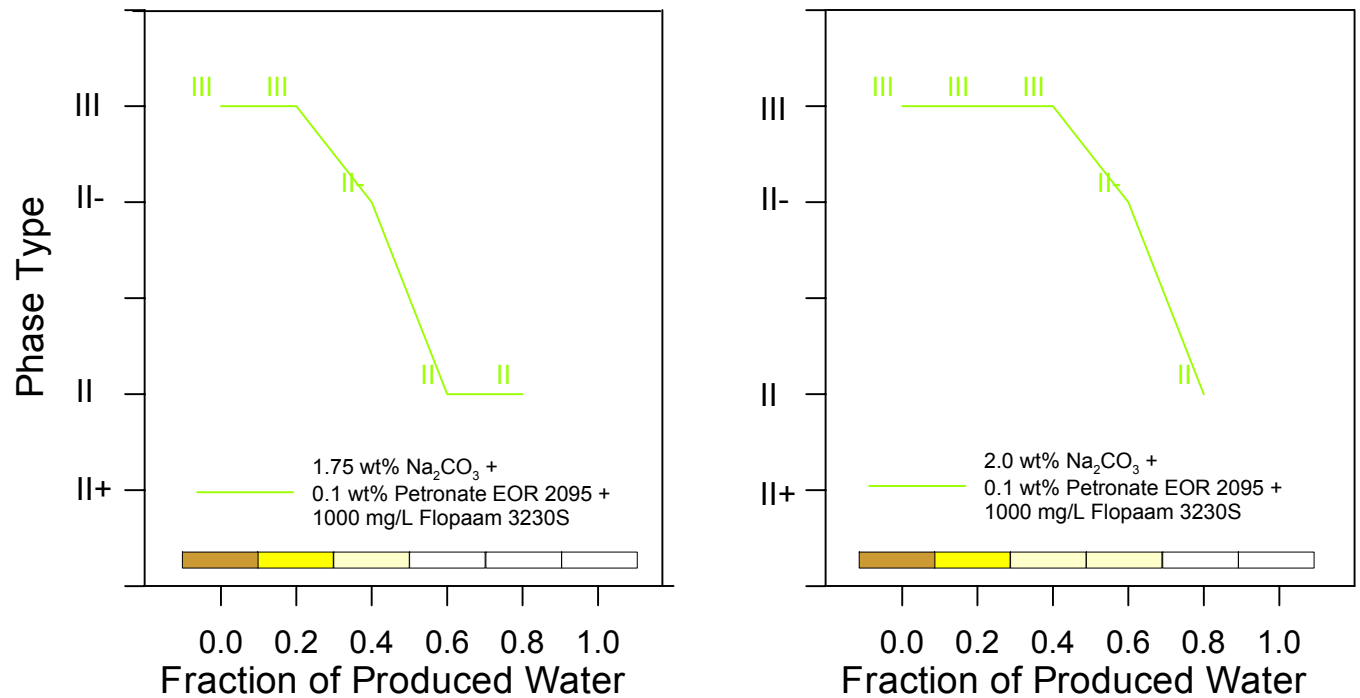
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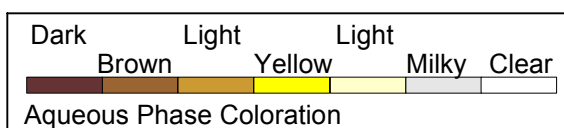
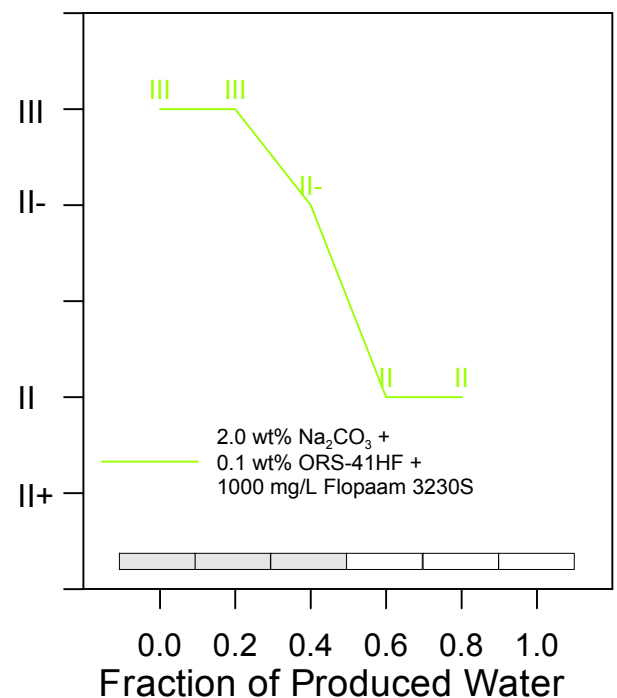
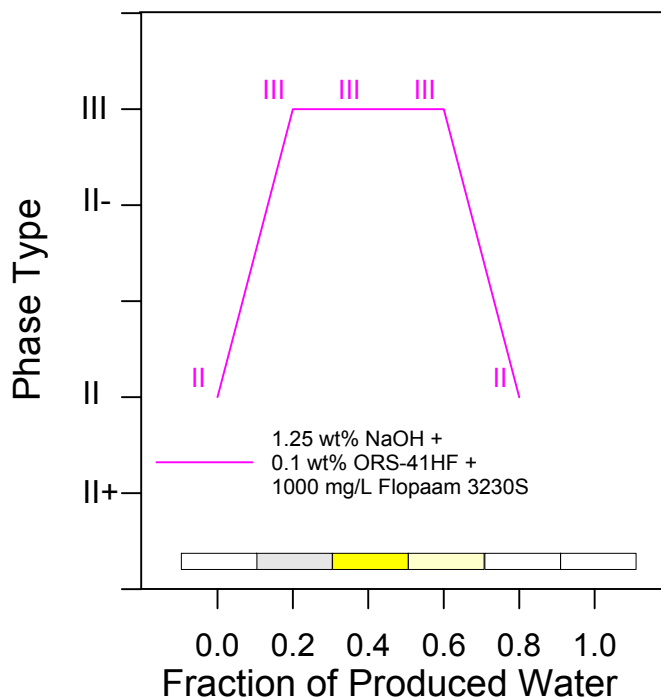
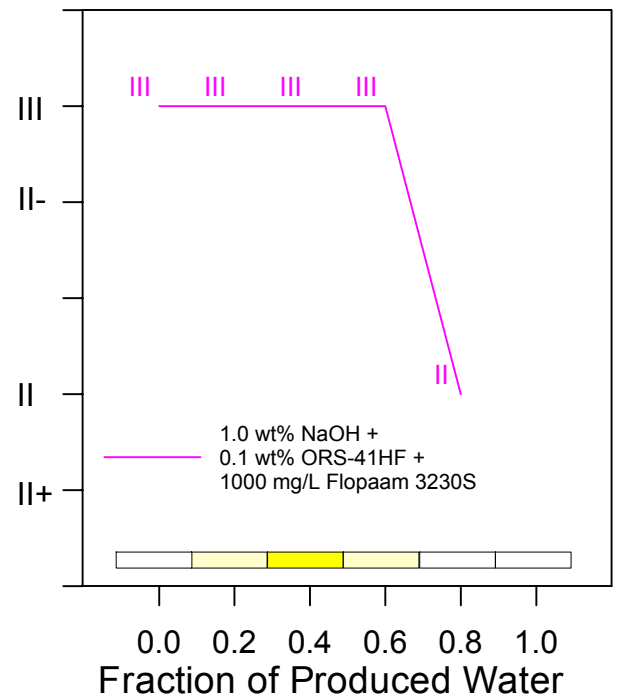
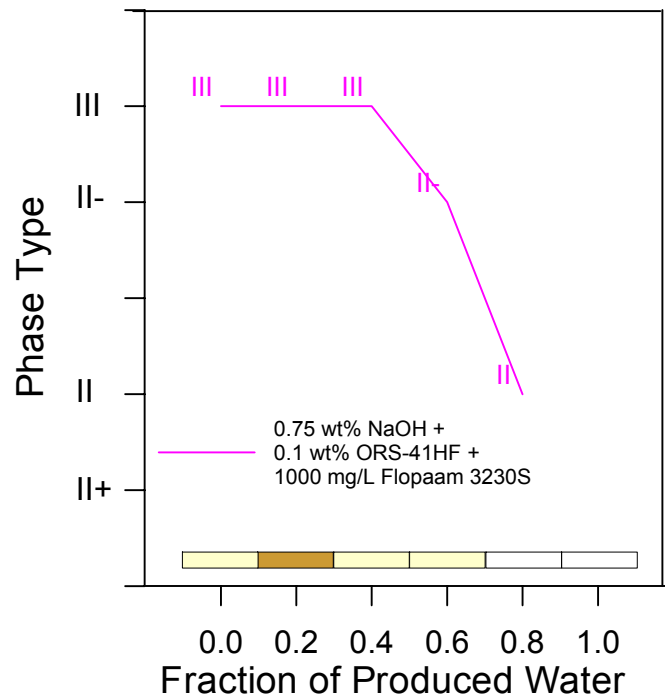
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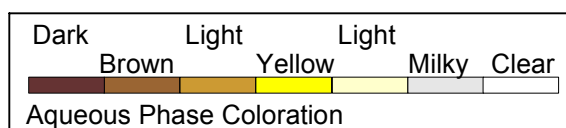
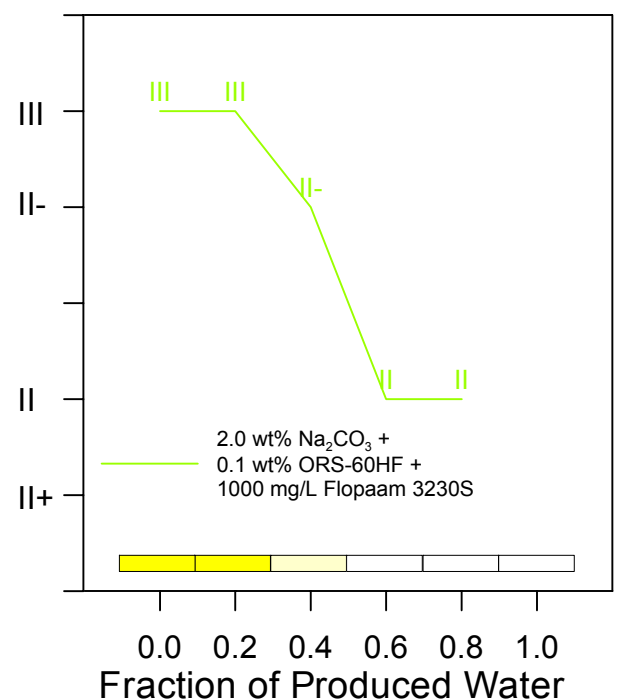
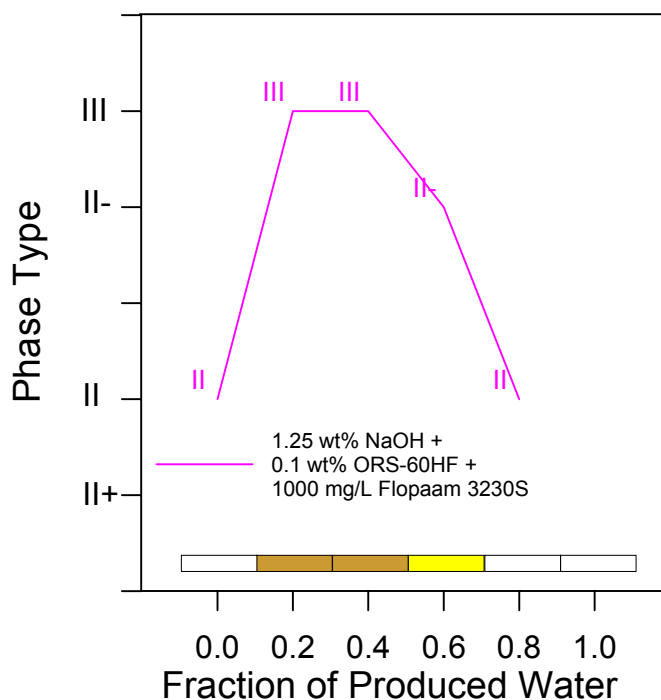
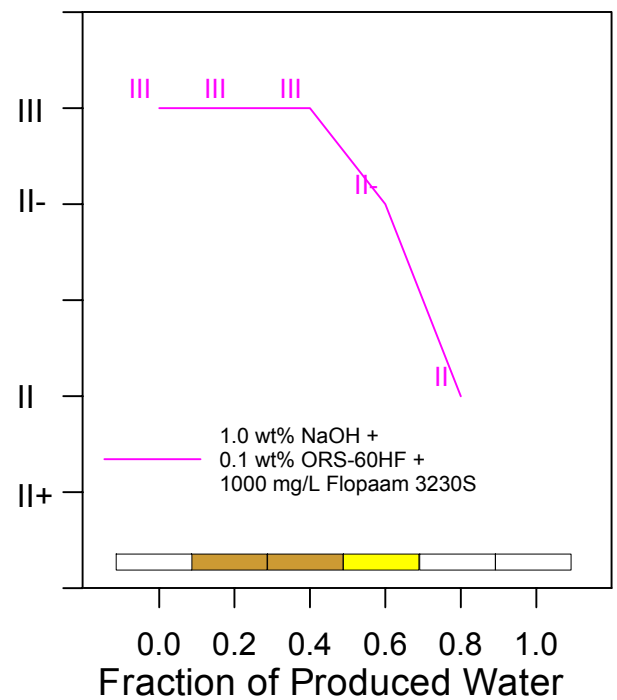
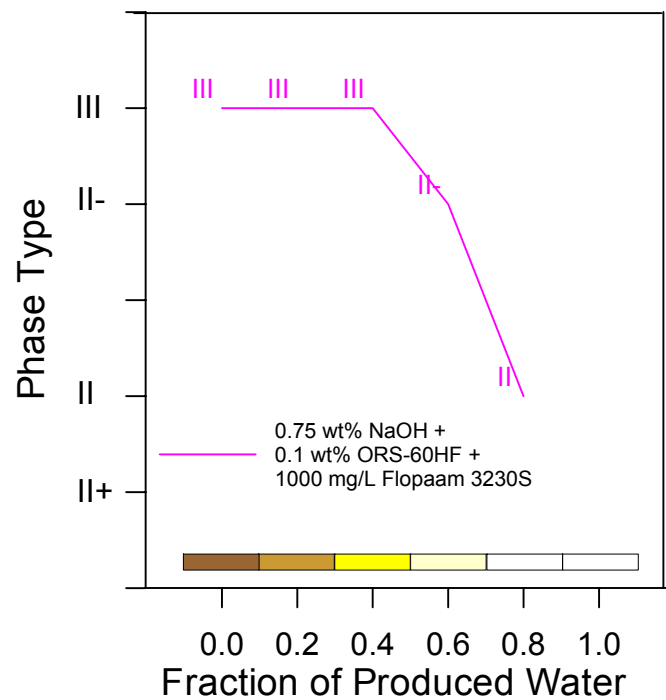
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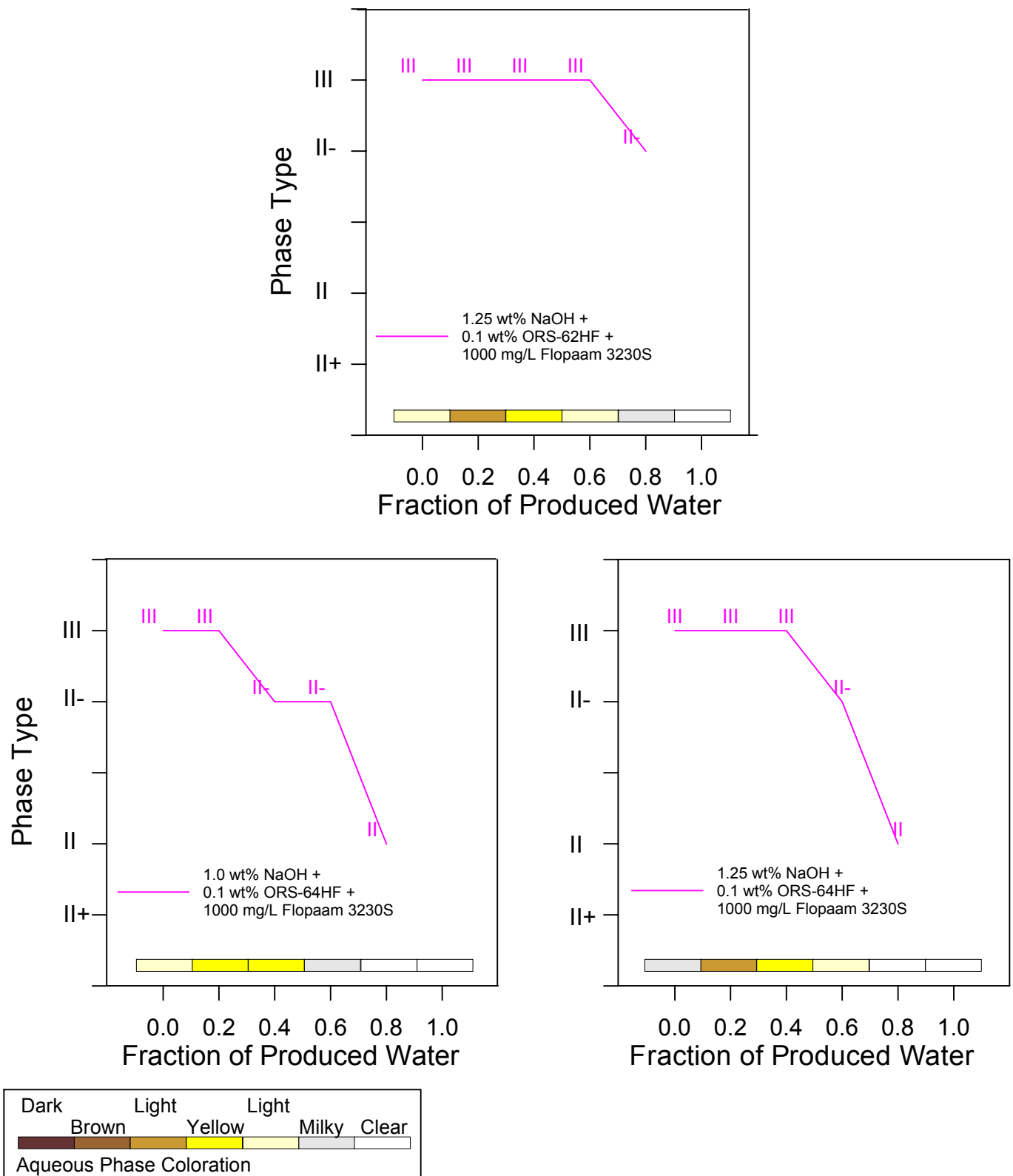
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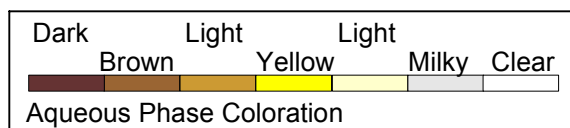
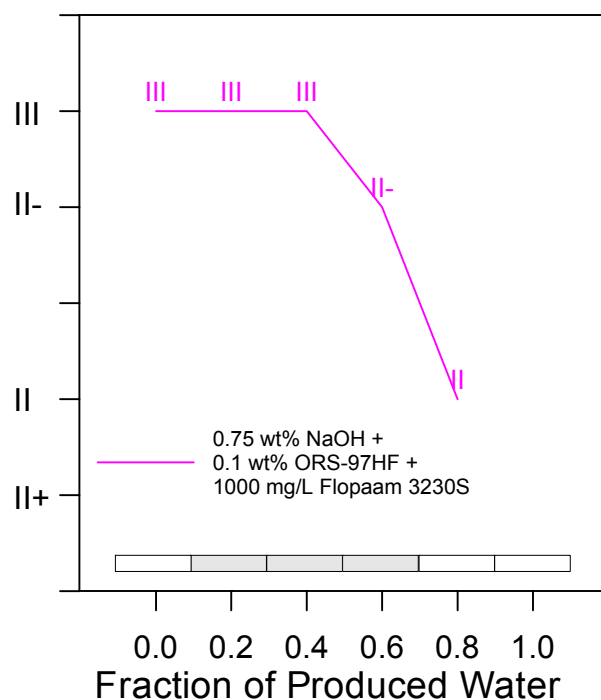
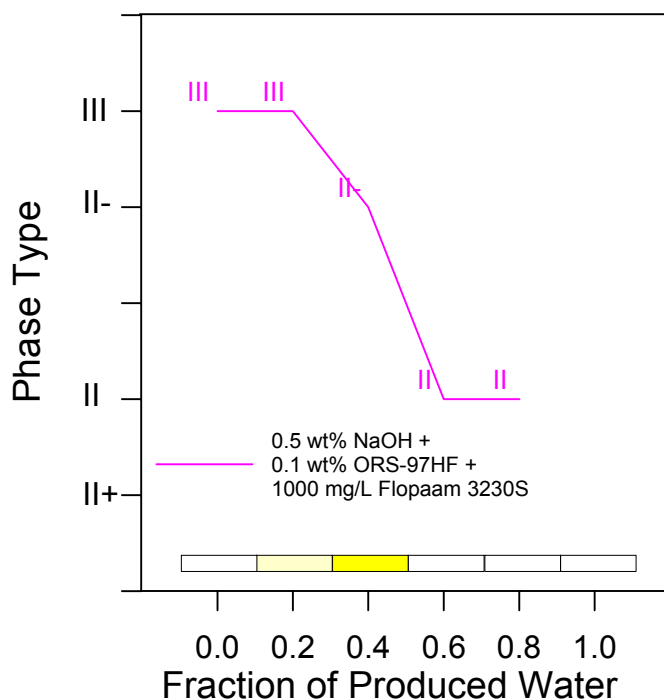
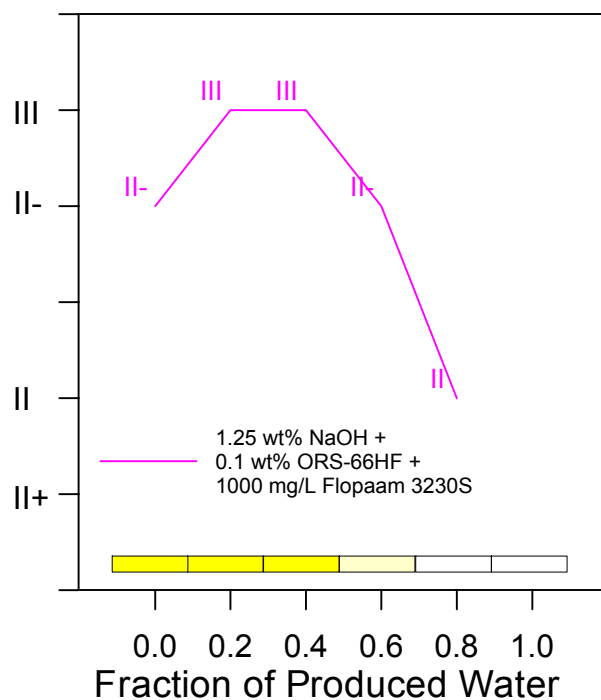
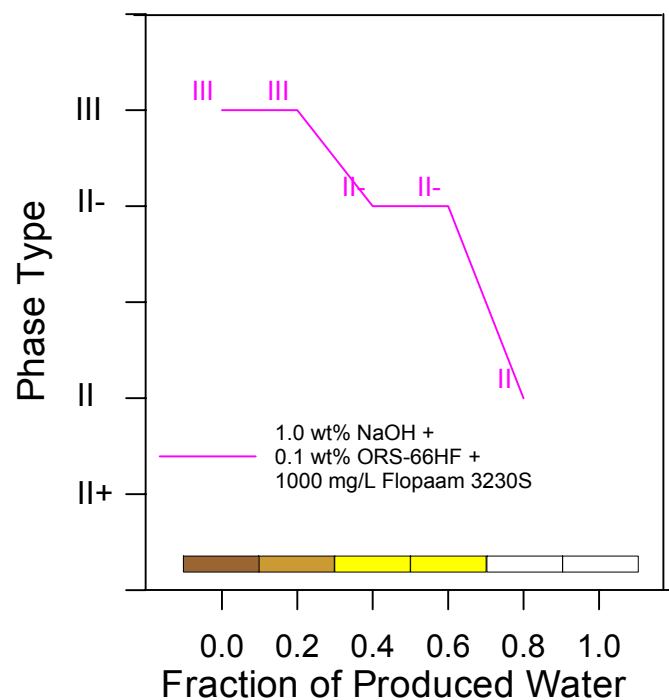
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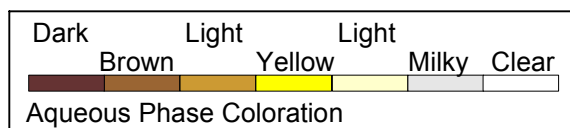
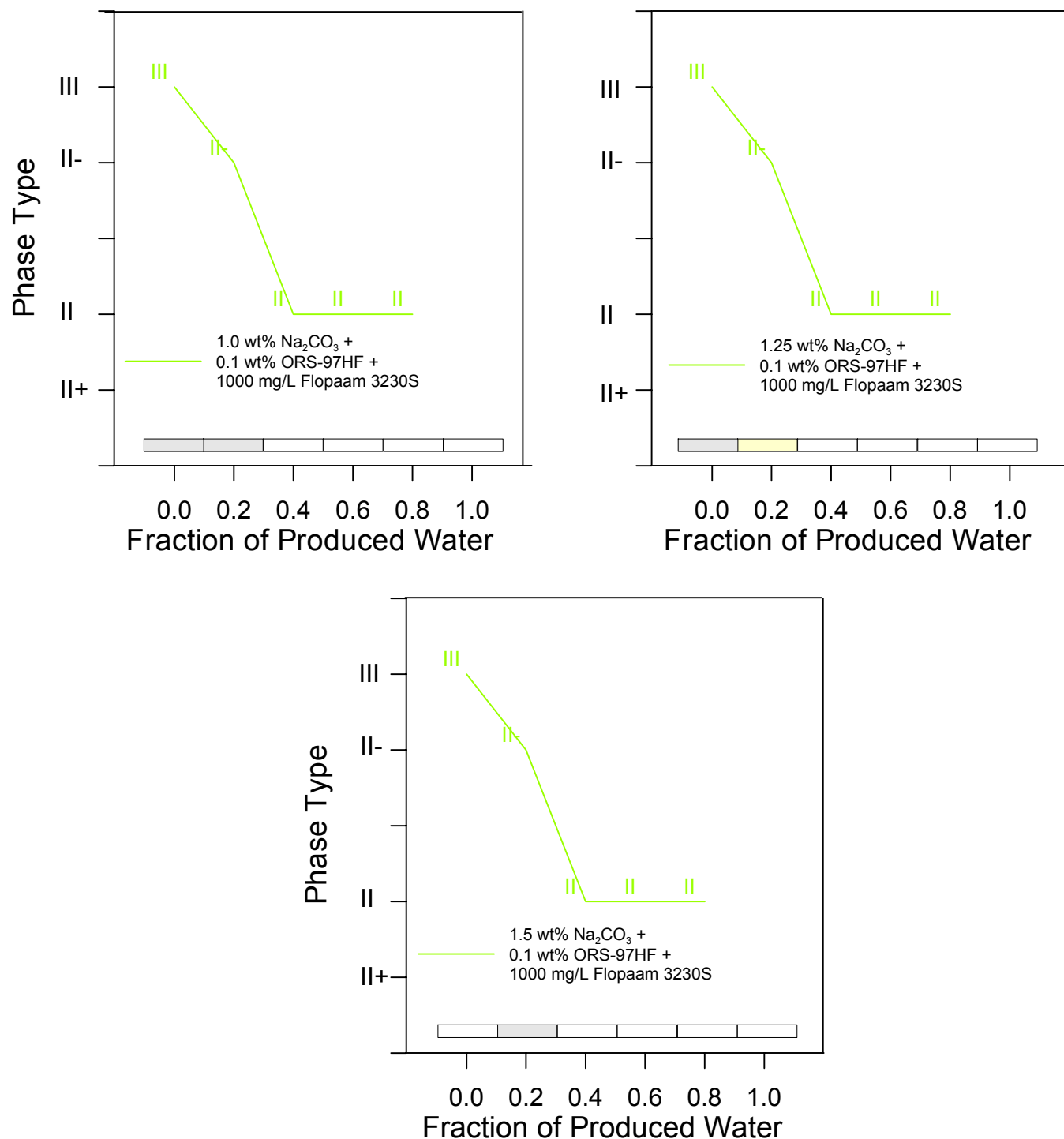
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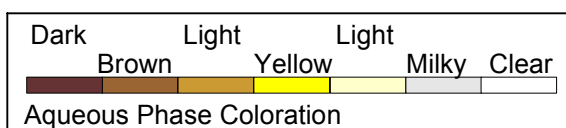
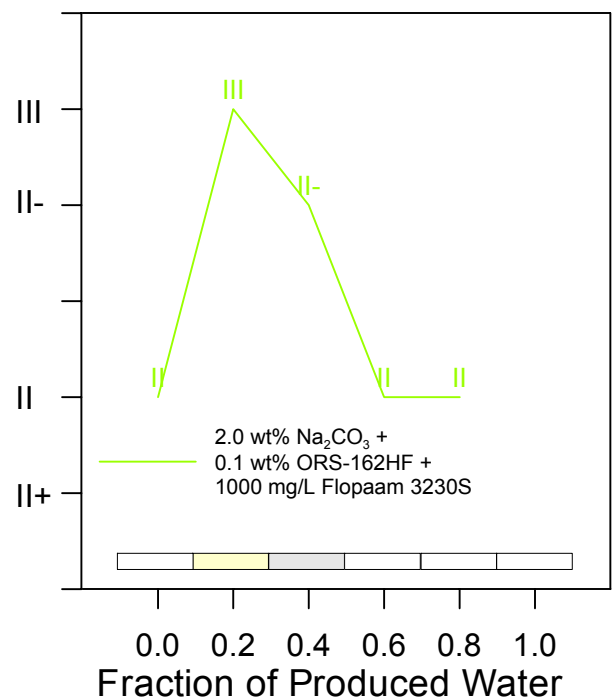
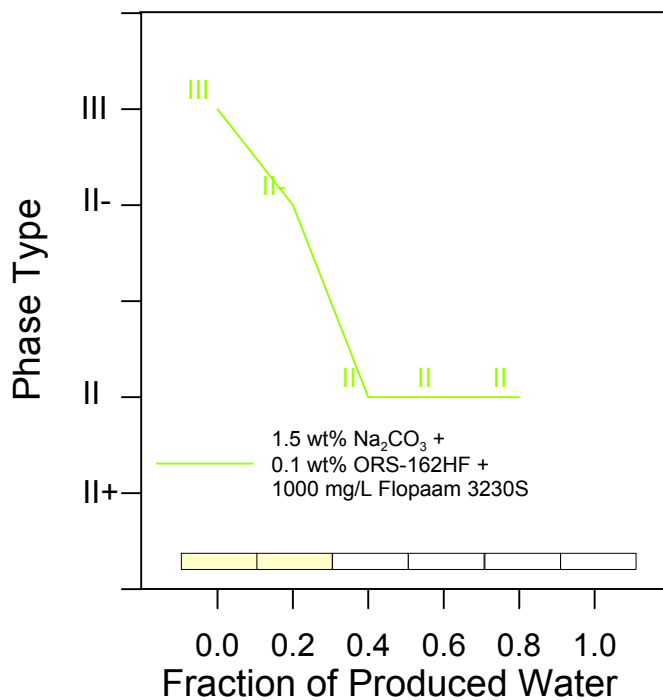
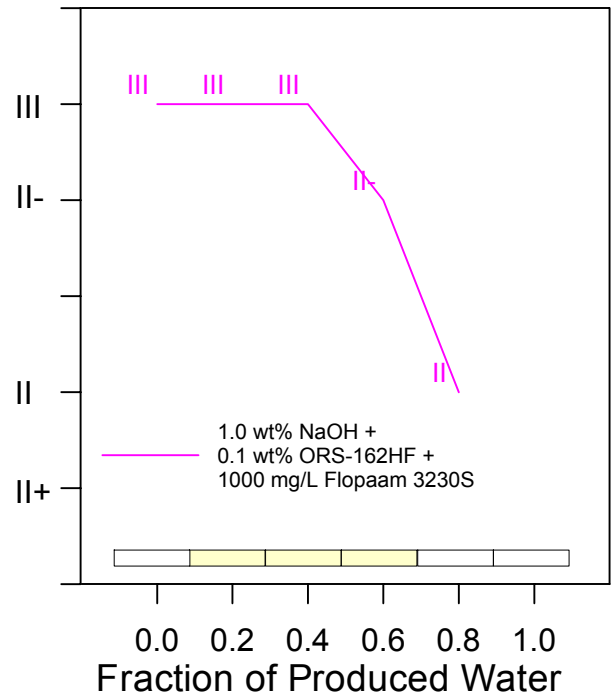
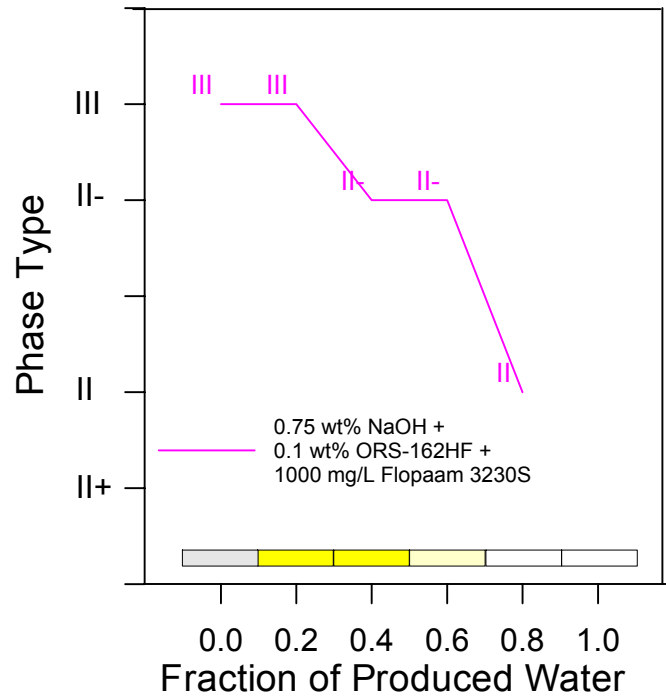
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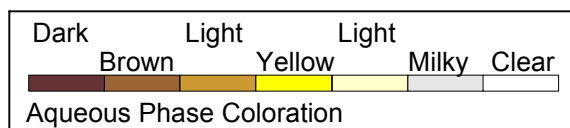
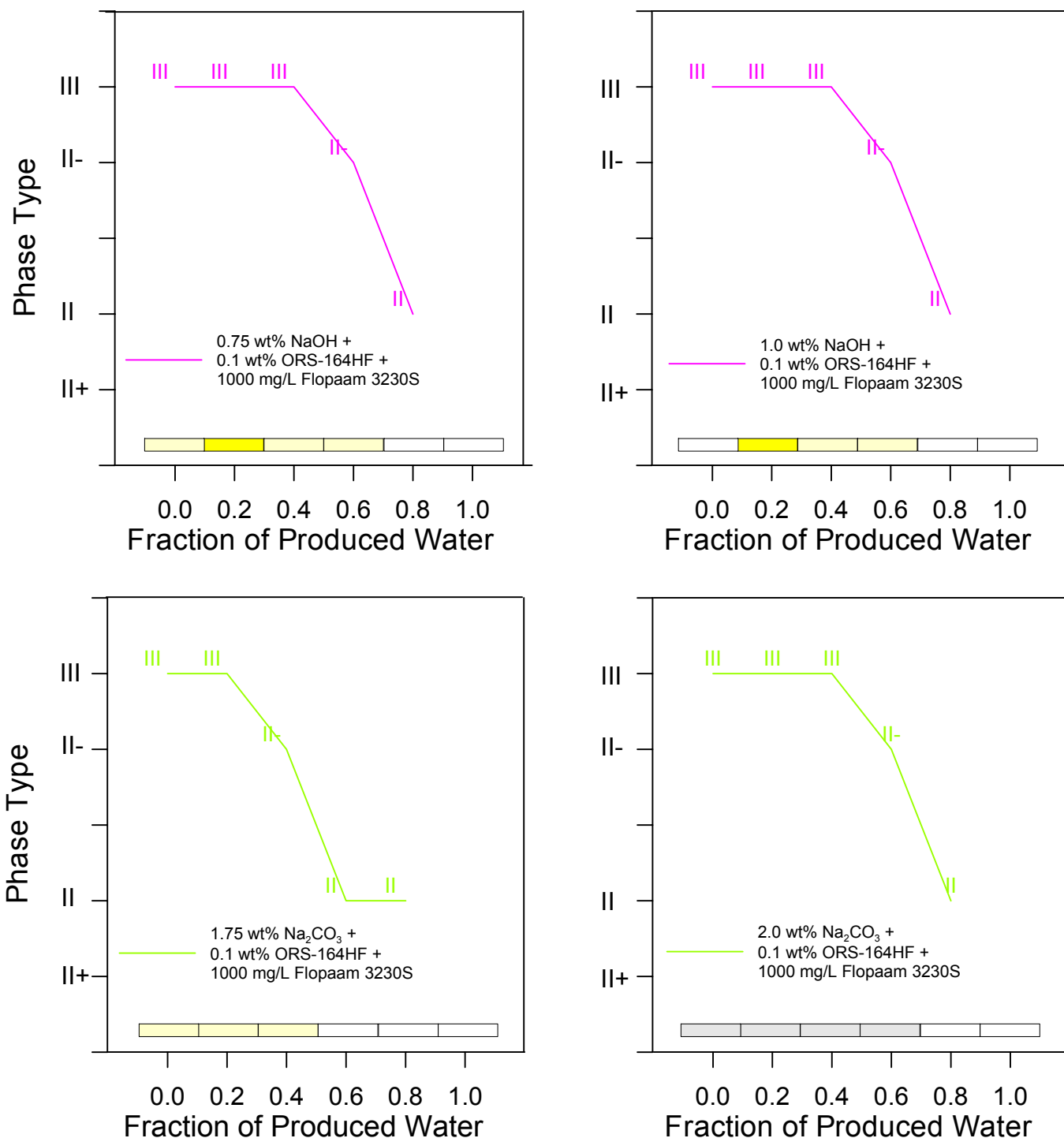
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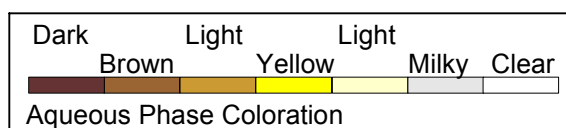
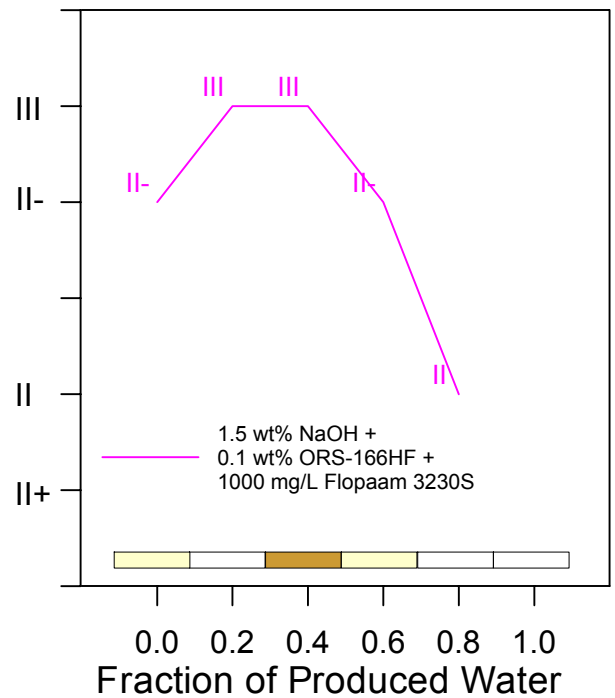
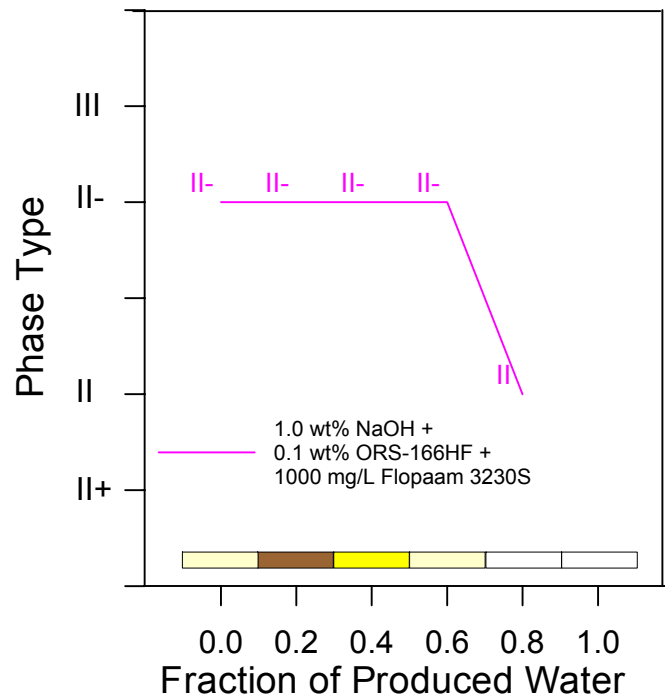
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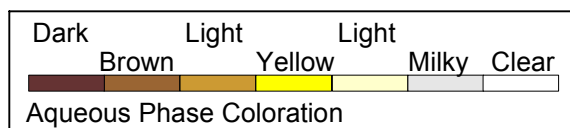
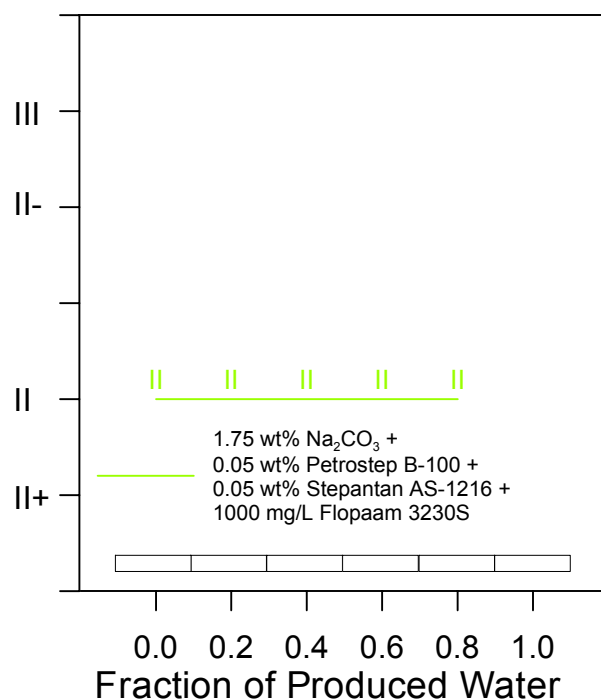
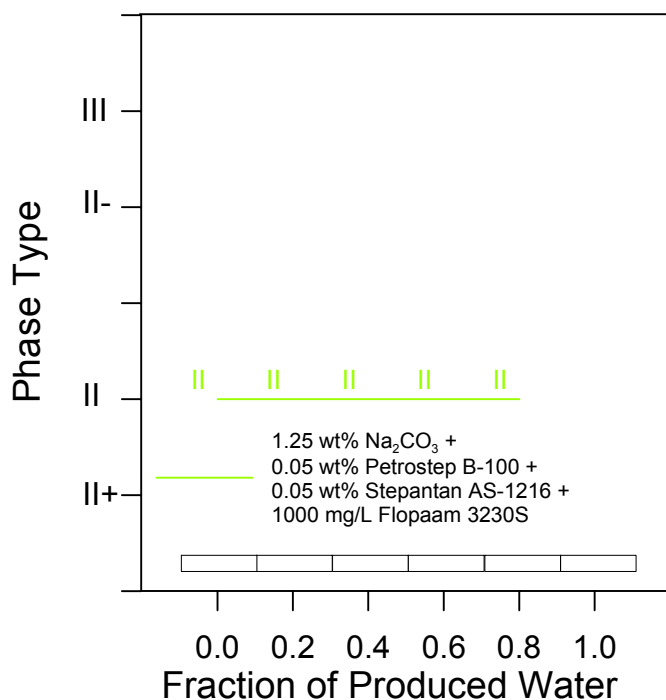
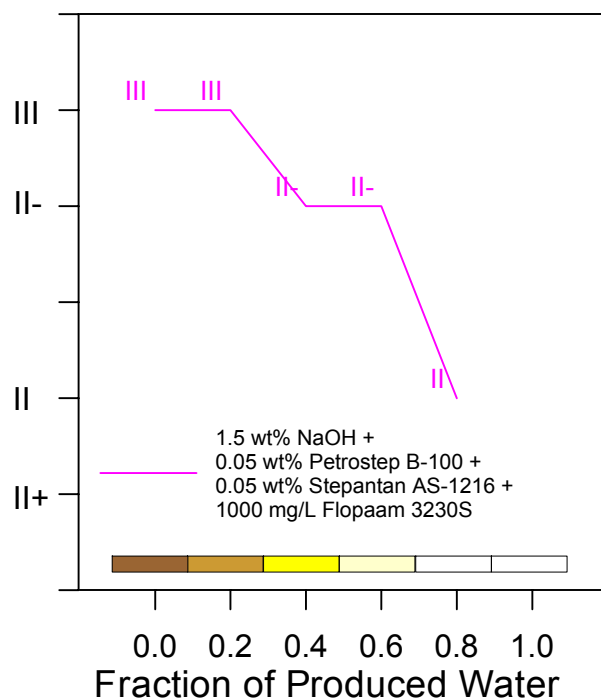
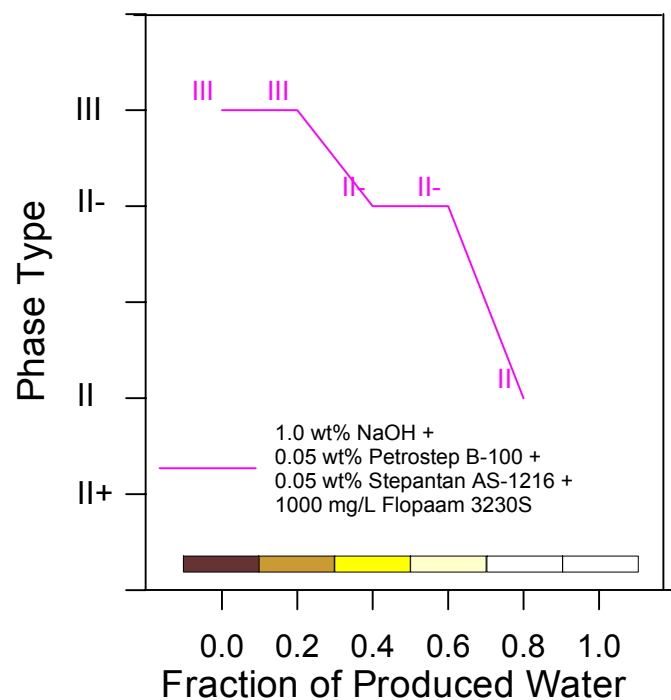
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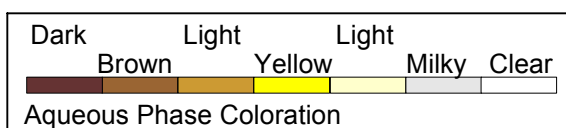
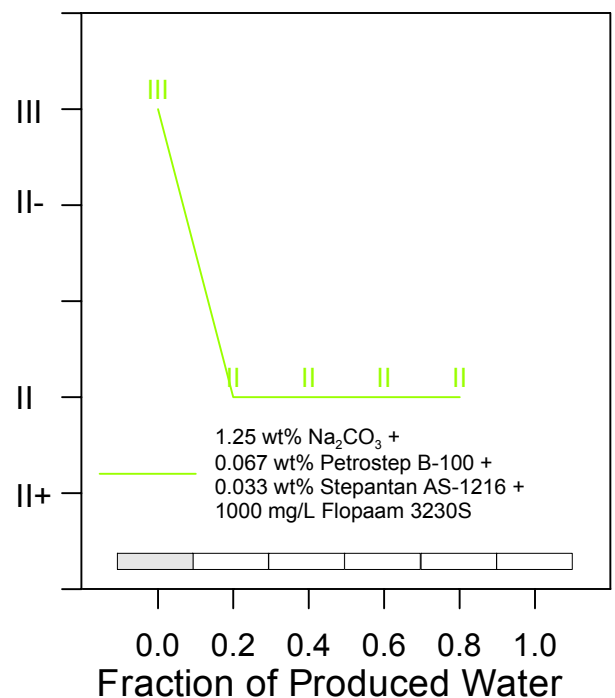
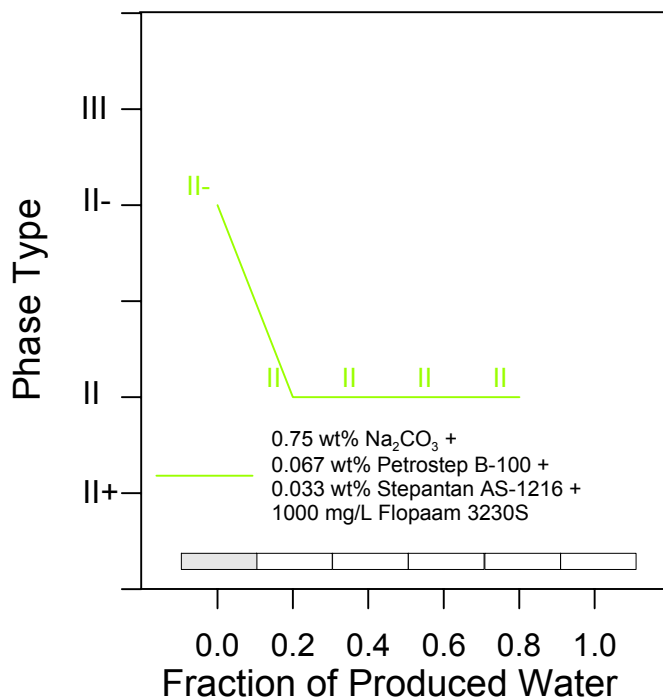
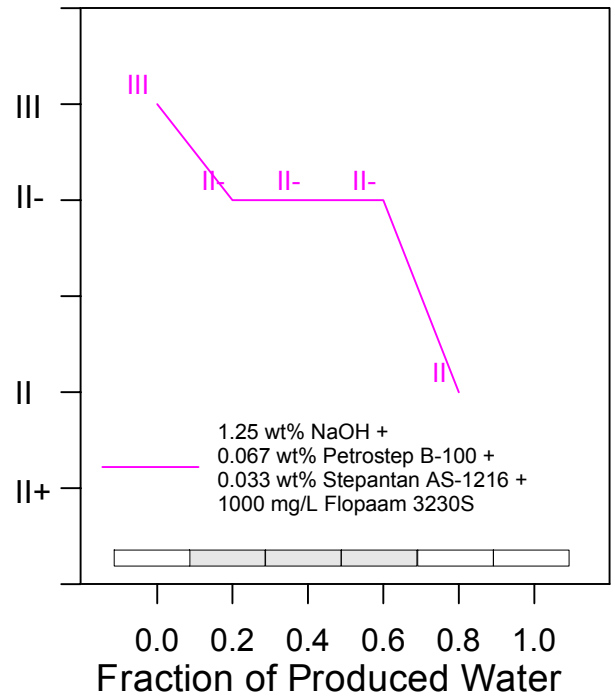
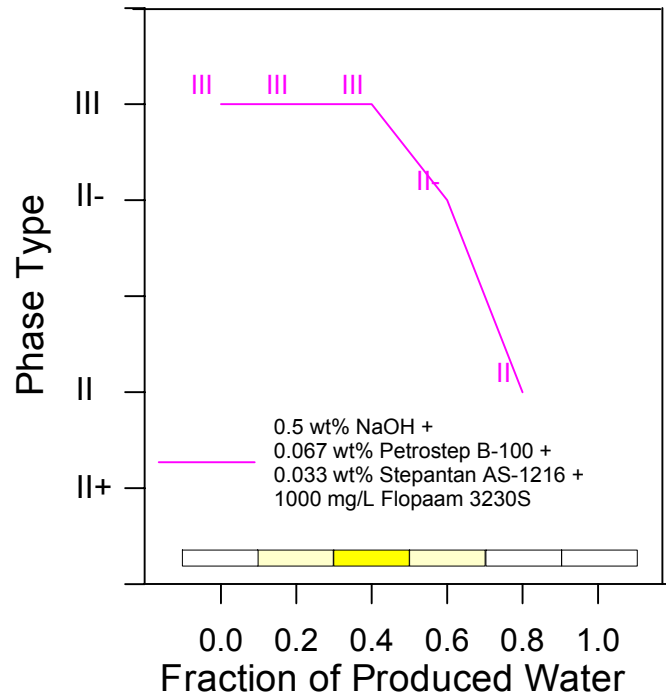
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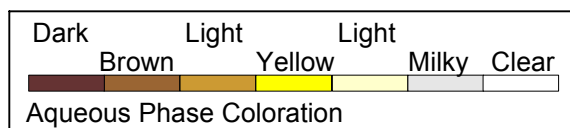
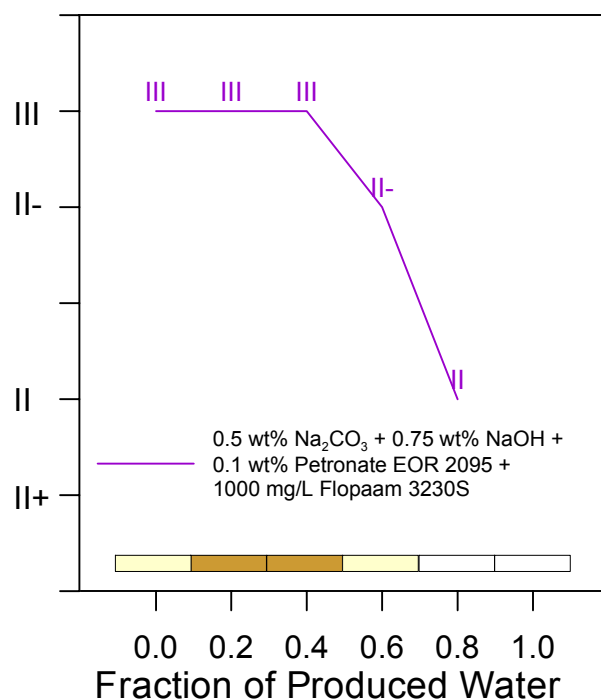
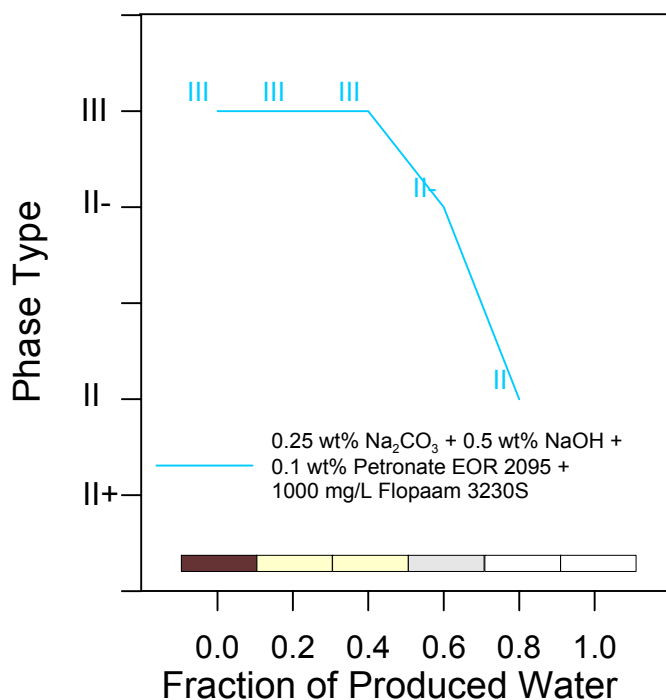
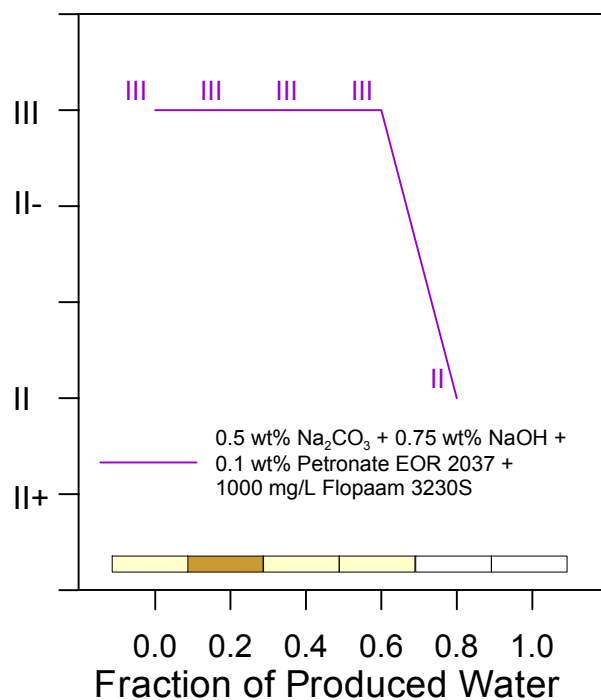
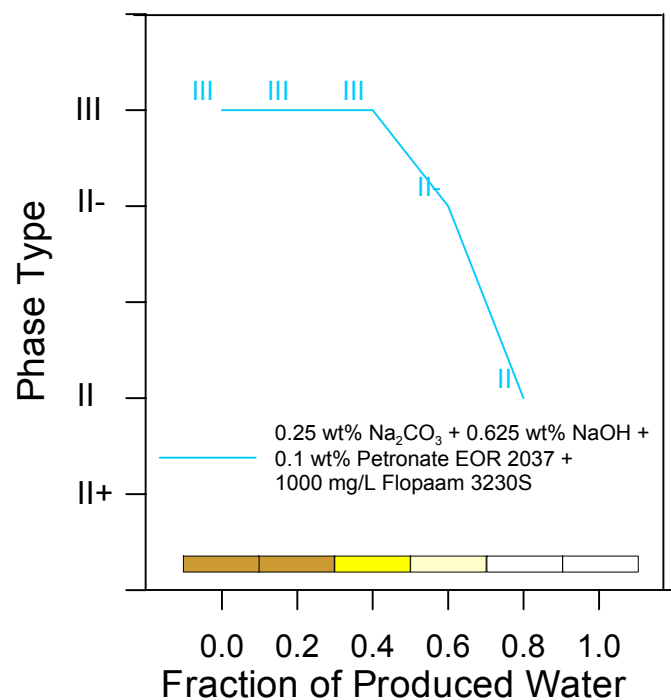
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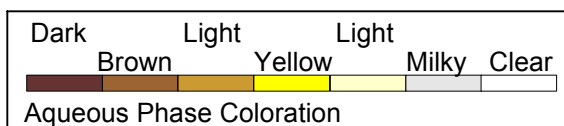
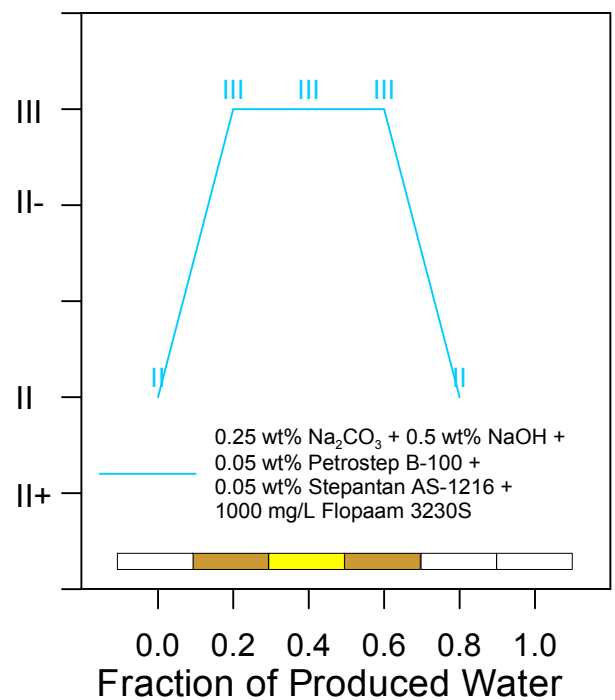
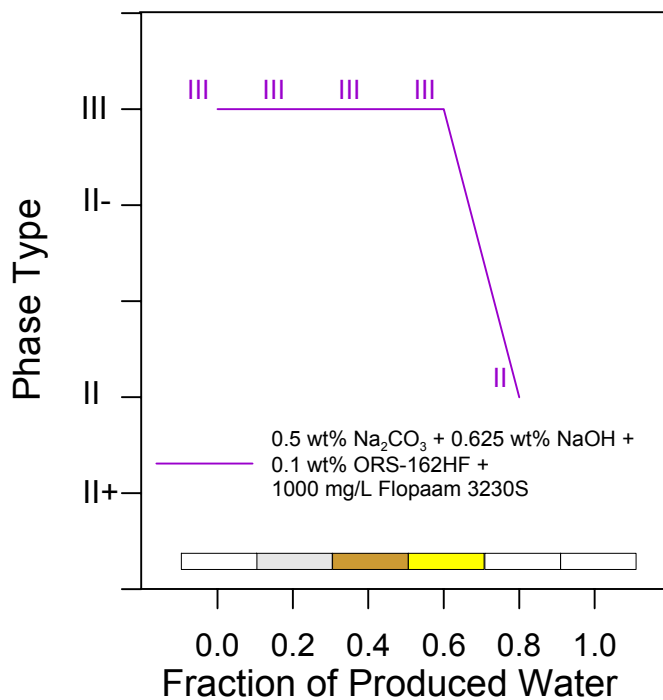
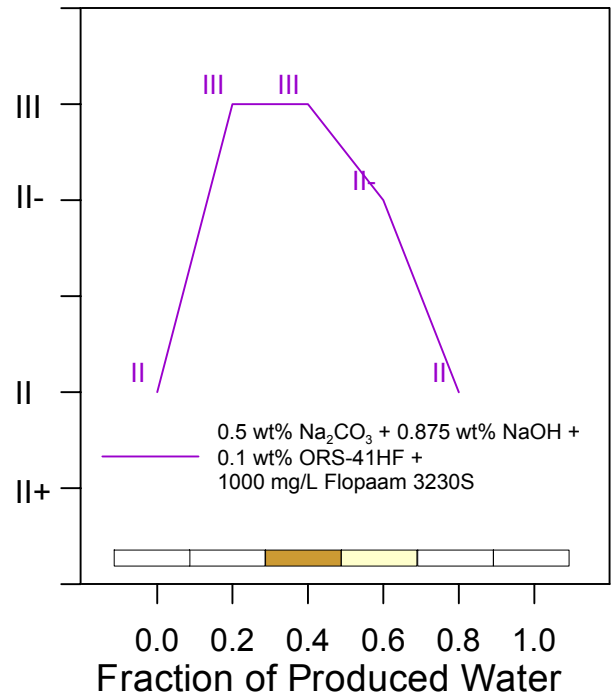
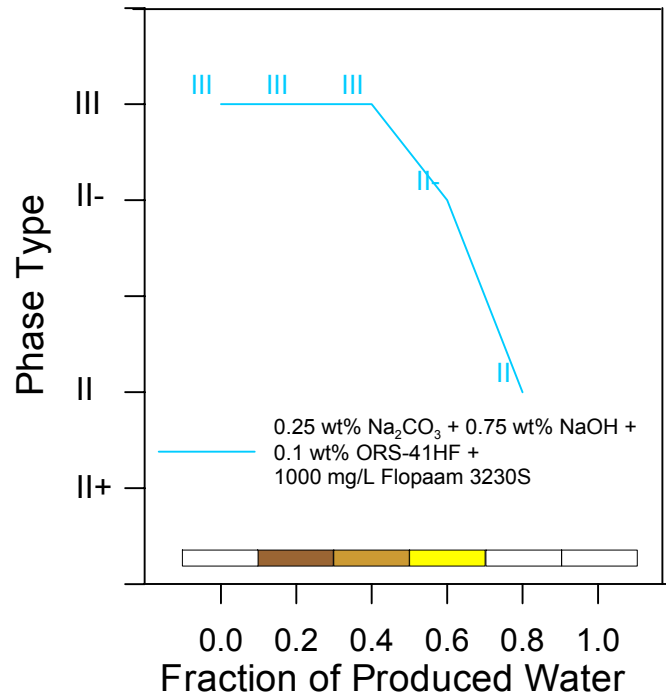
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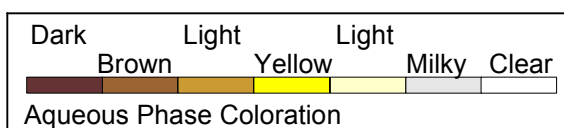
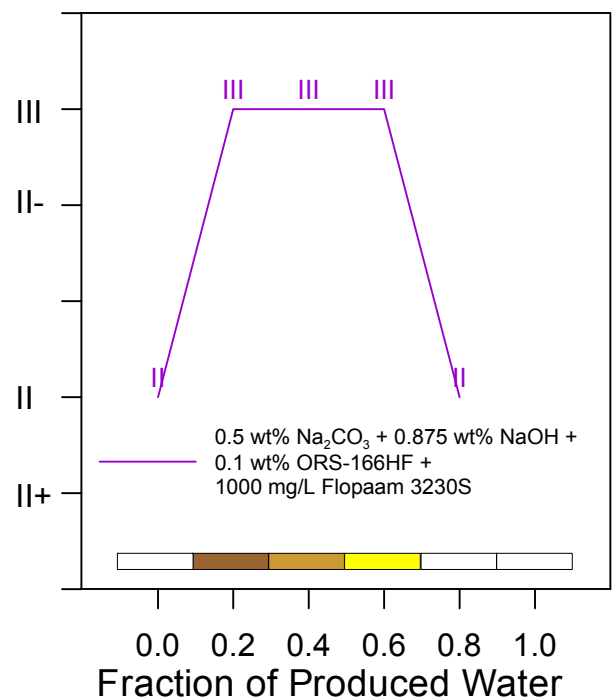
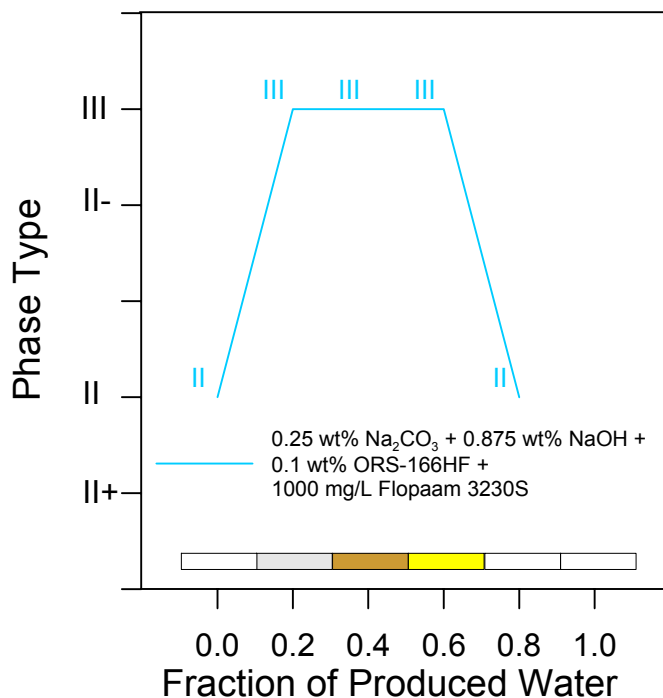
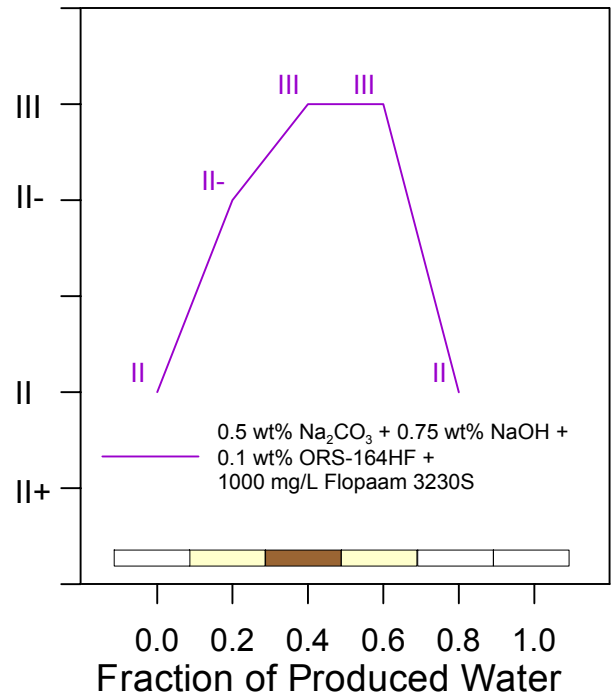
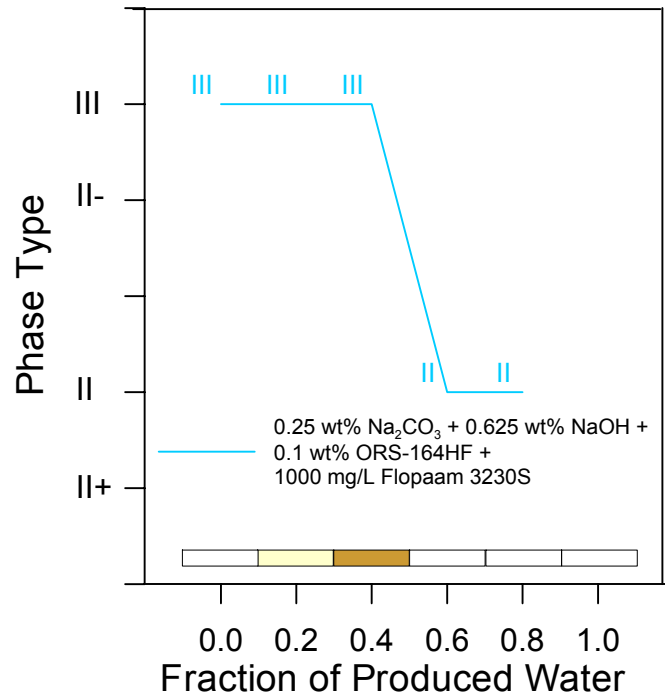
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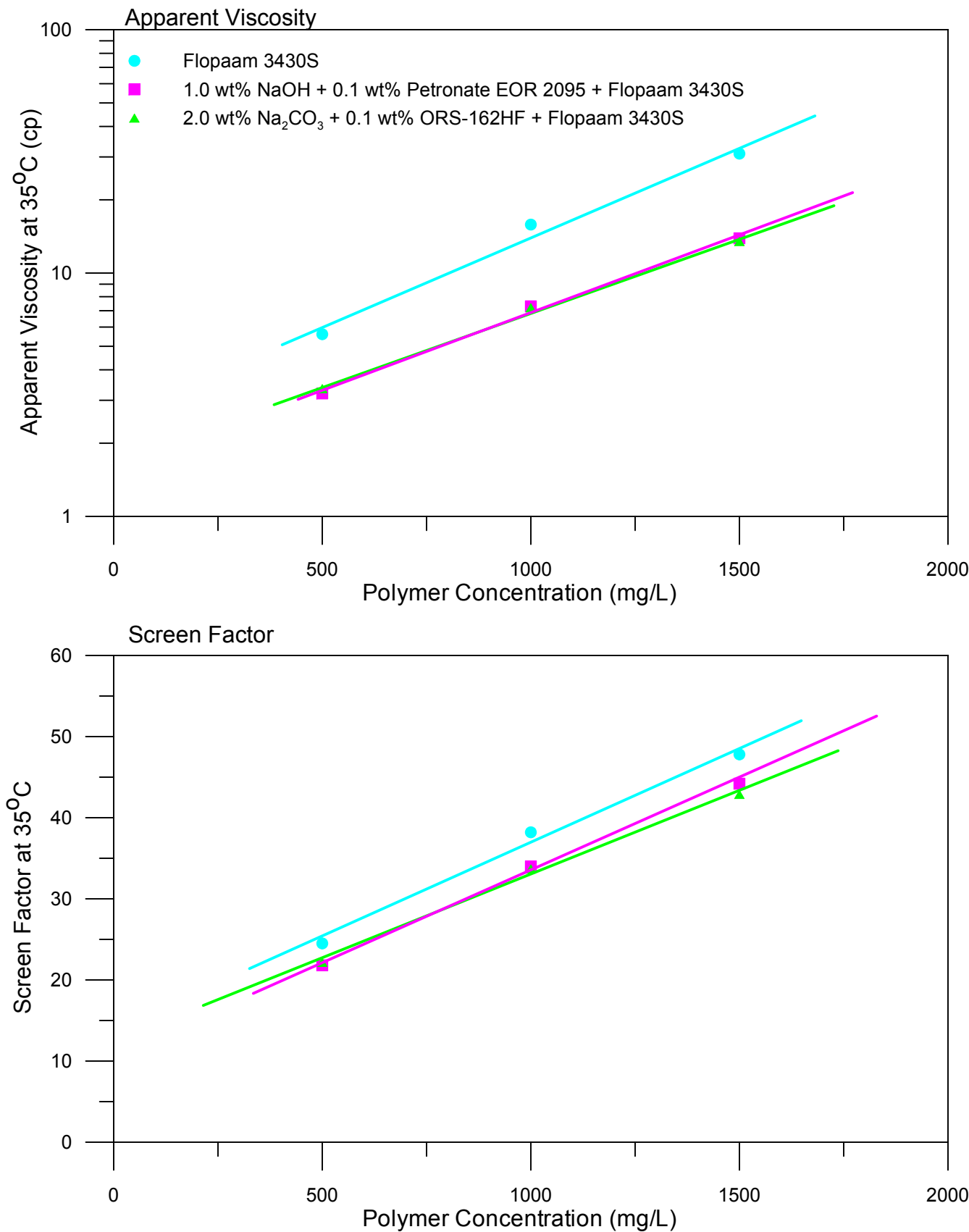
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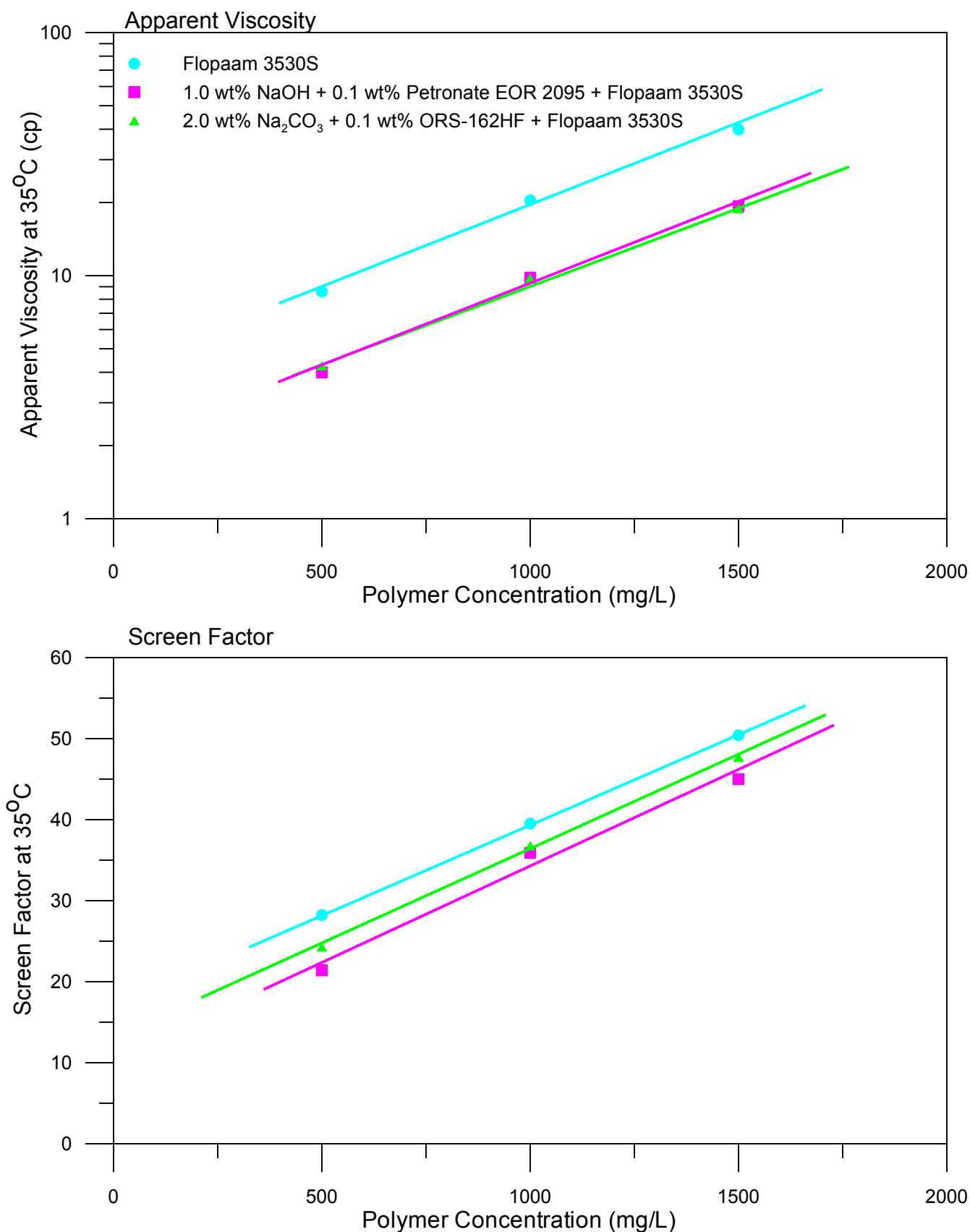
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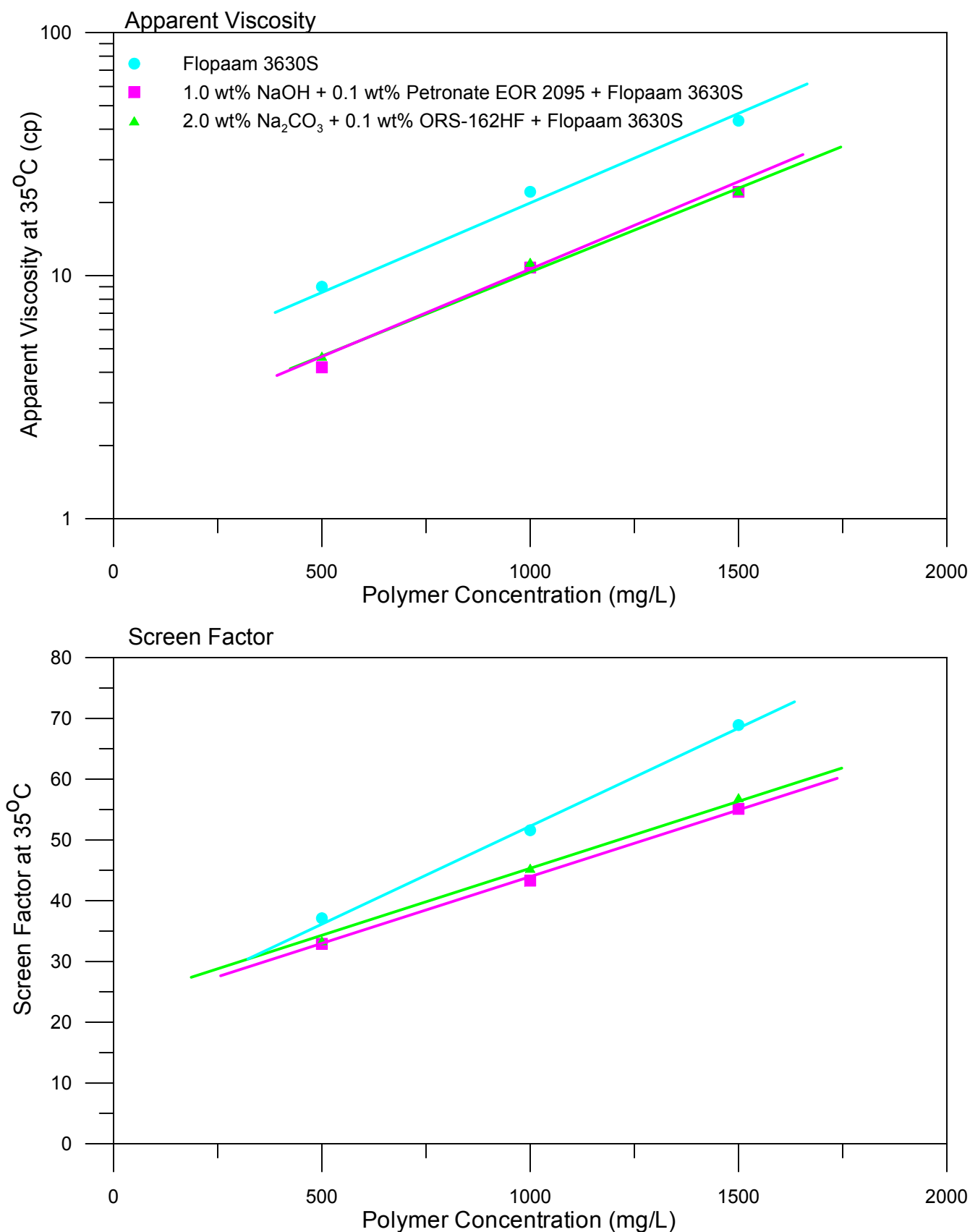
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 35°C
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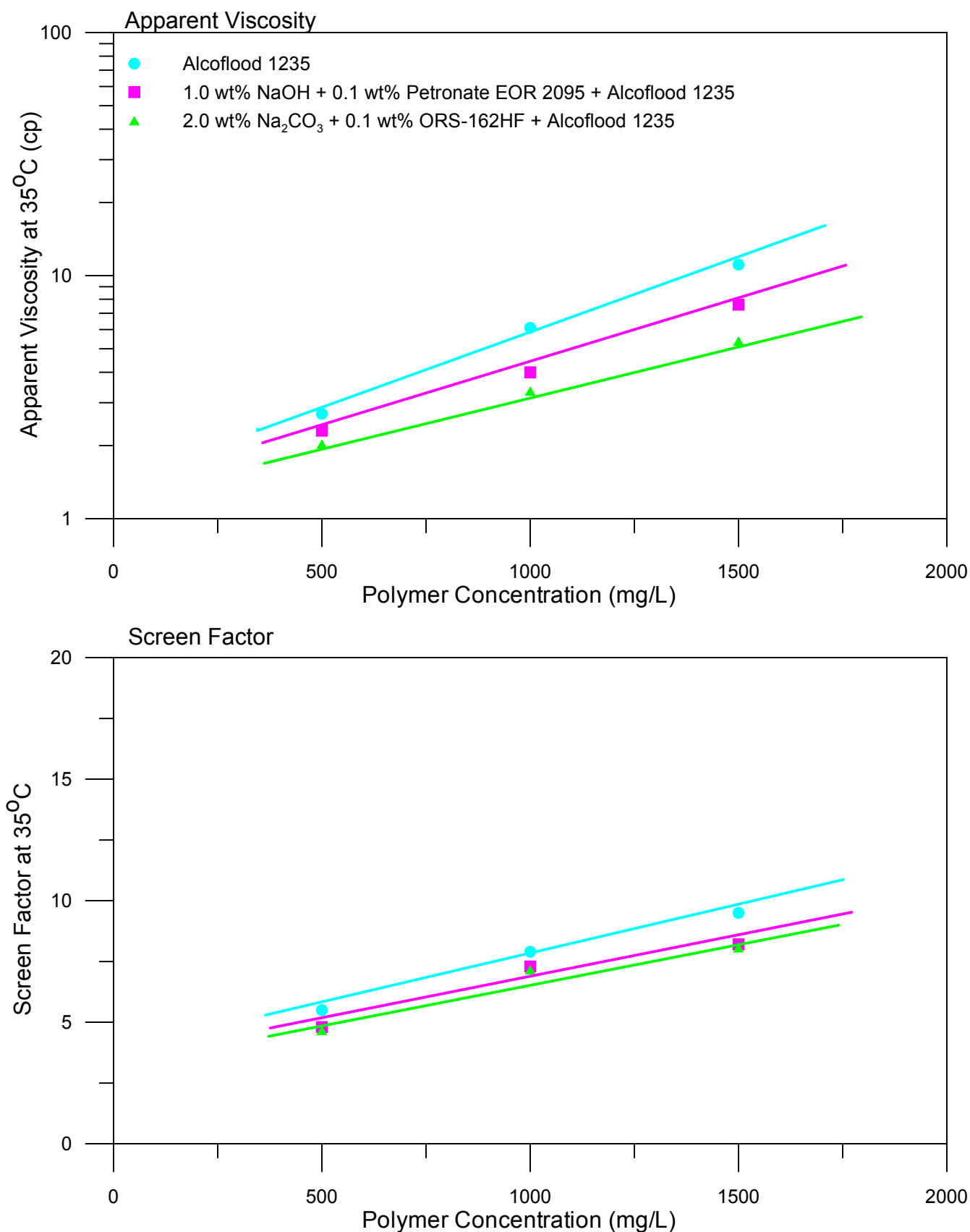
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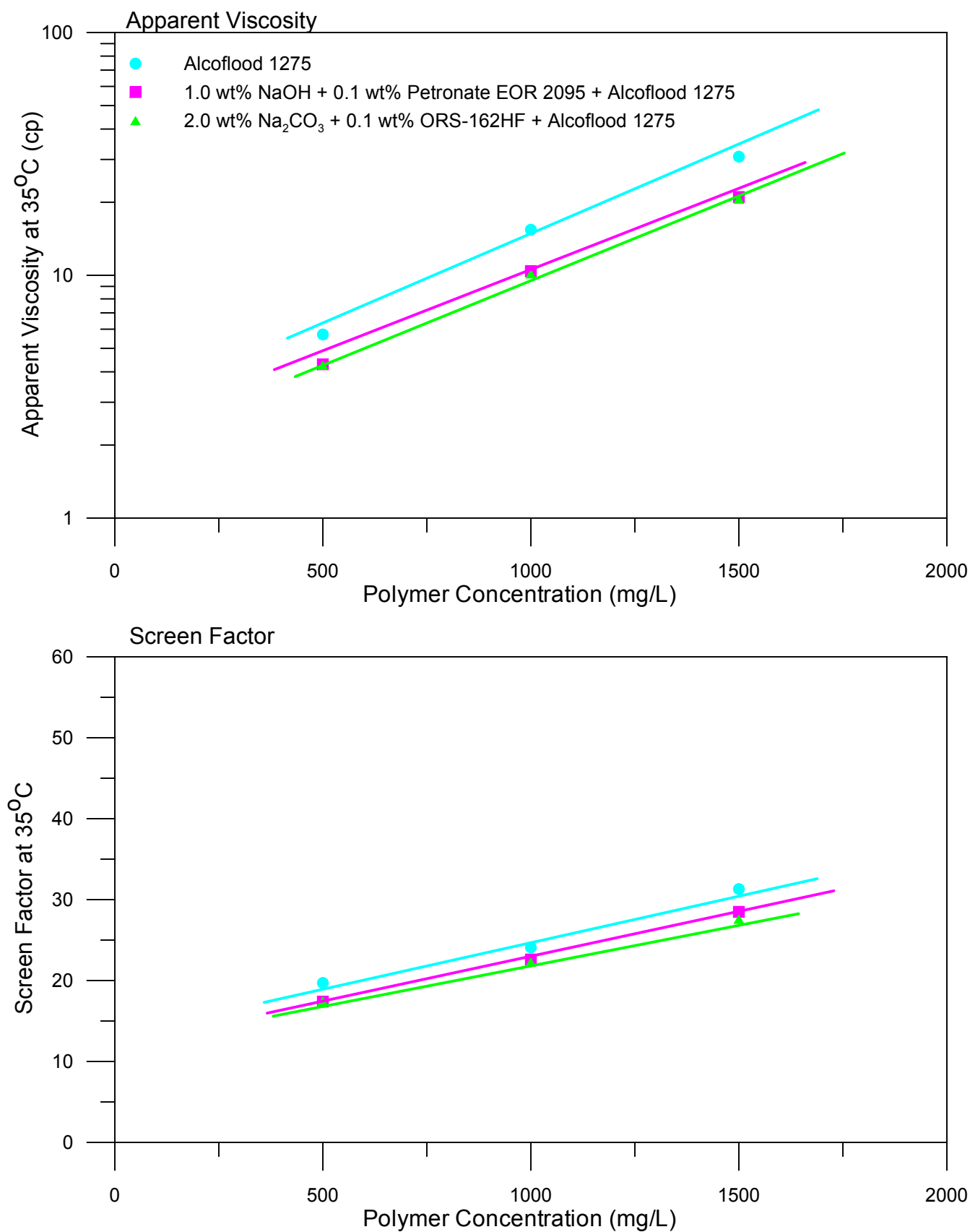
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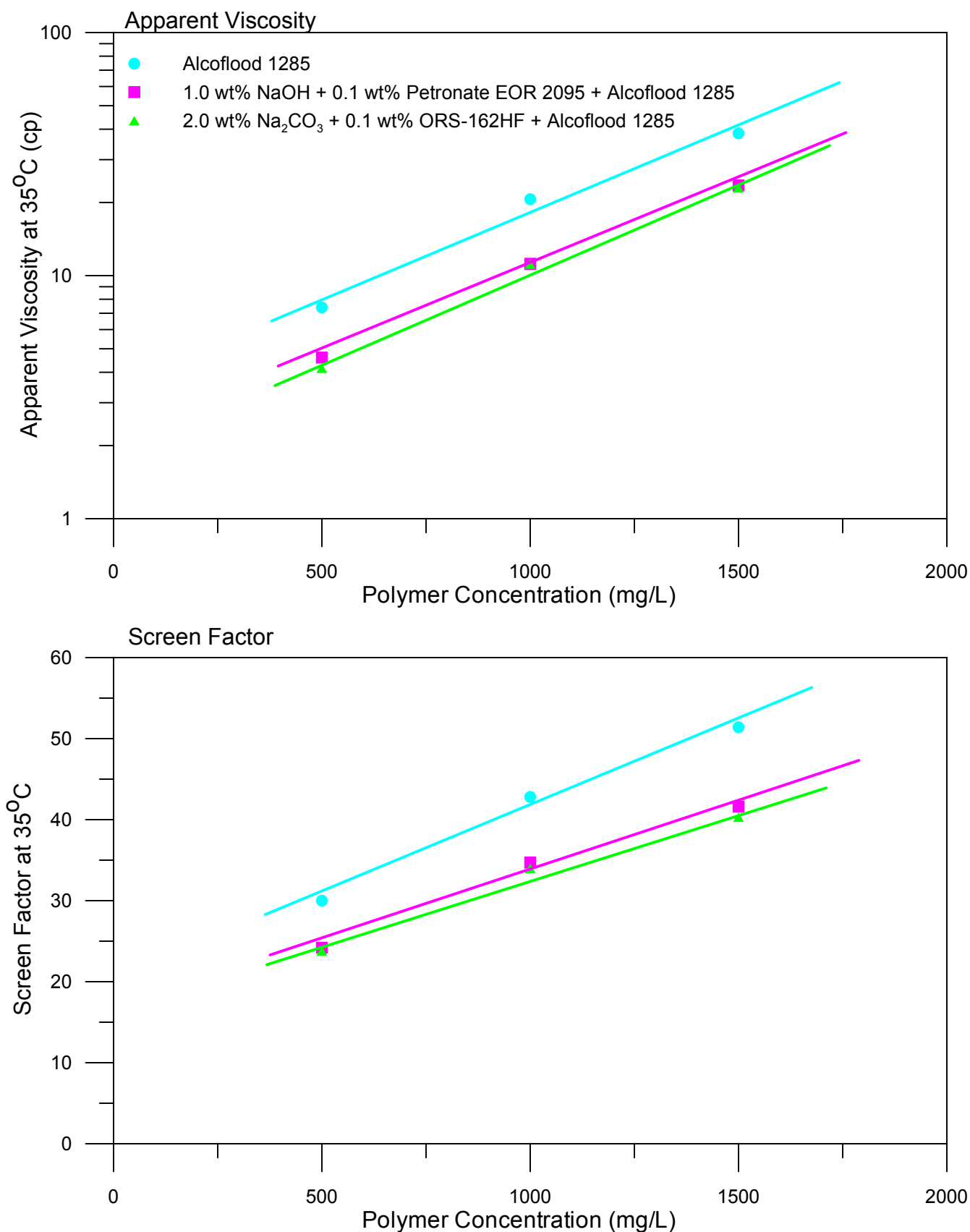
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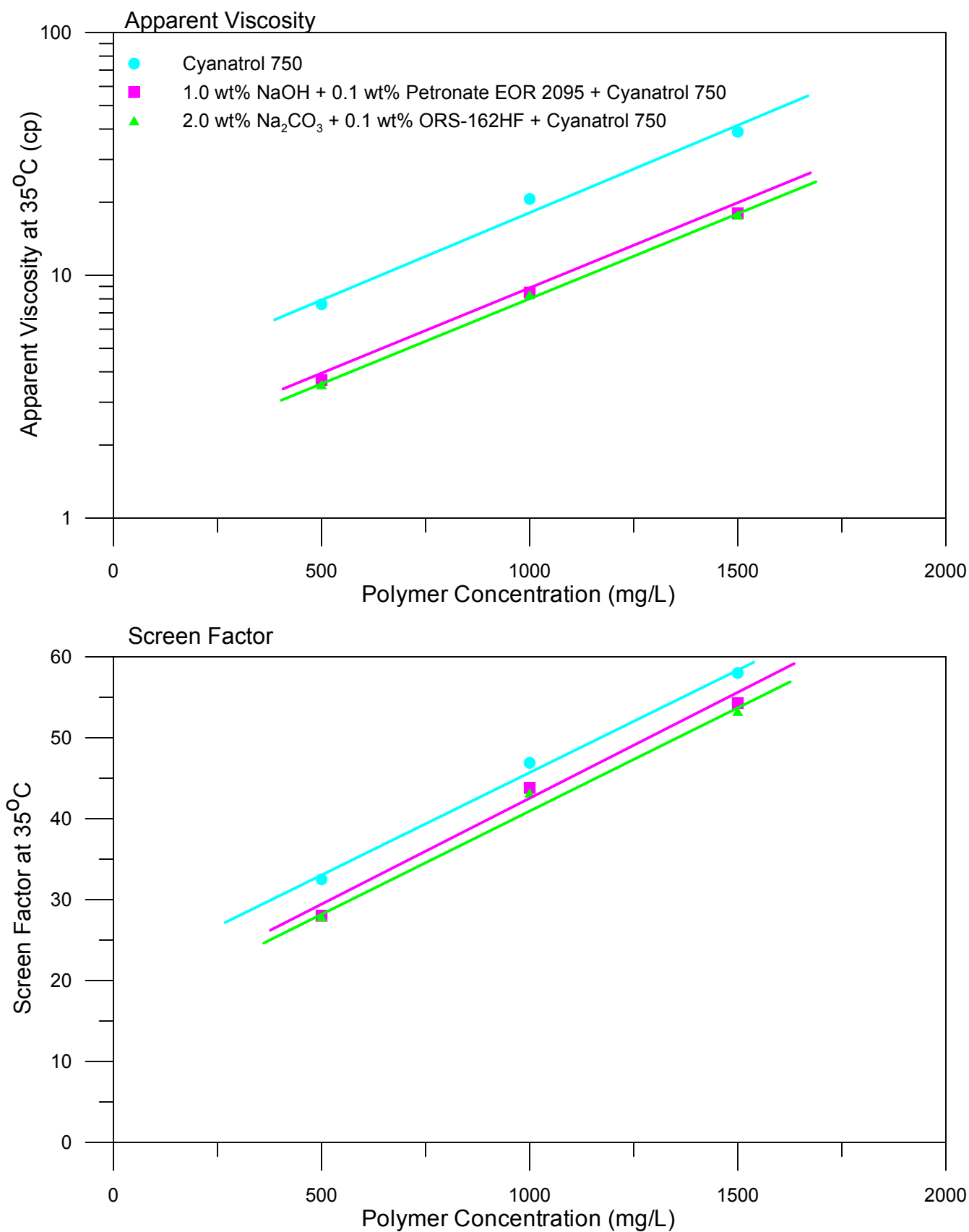
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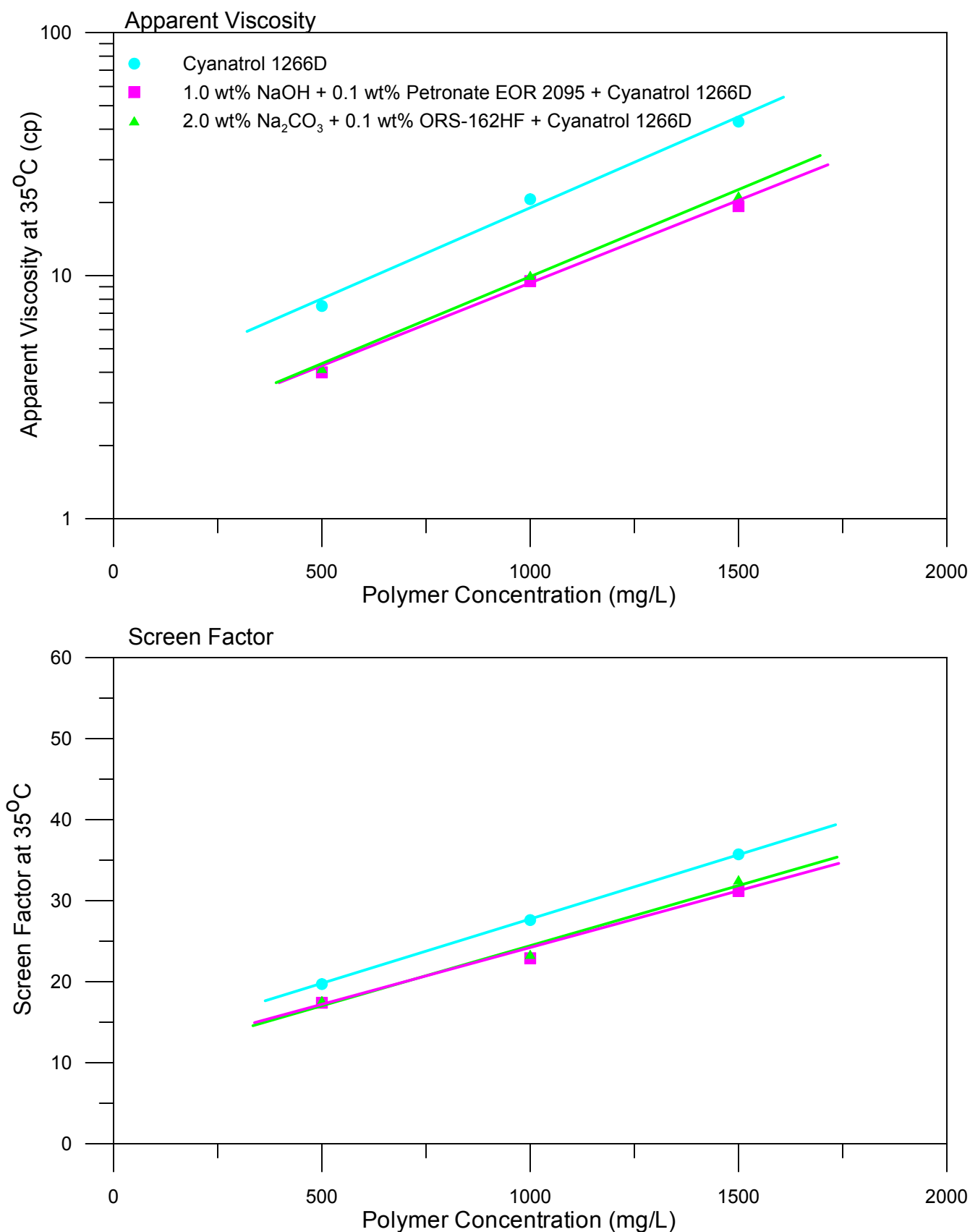
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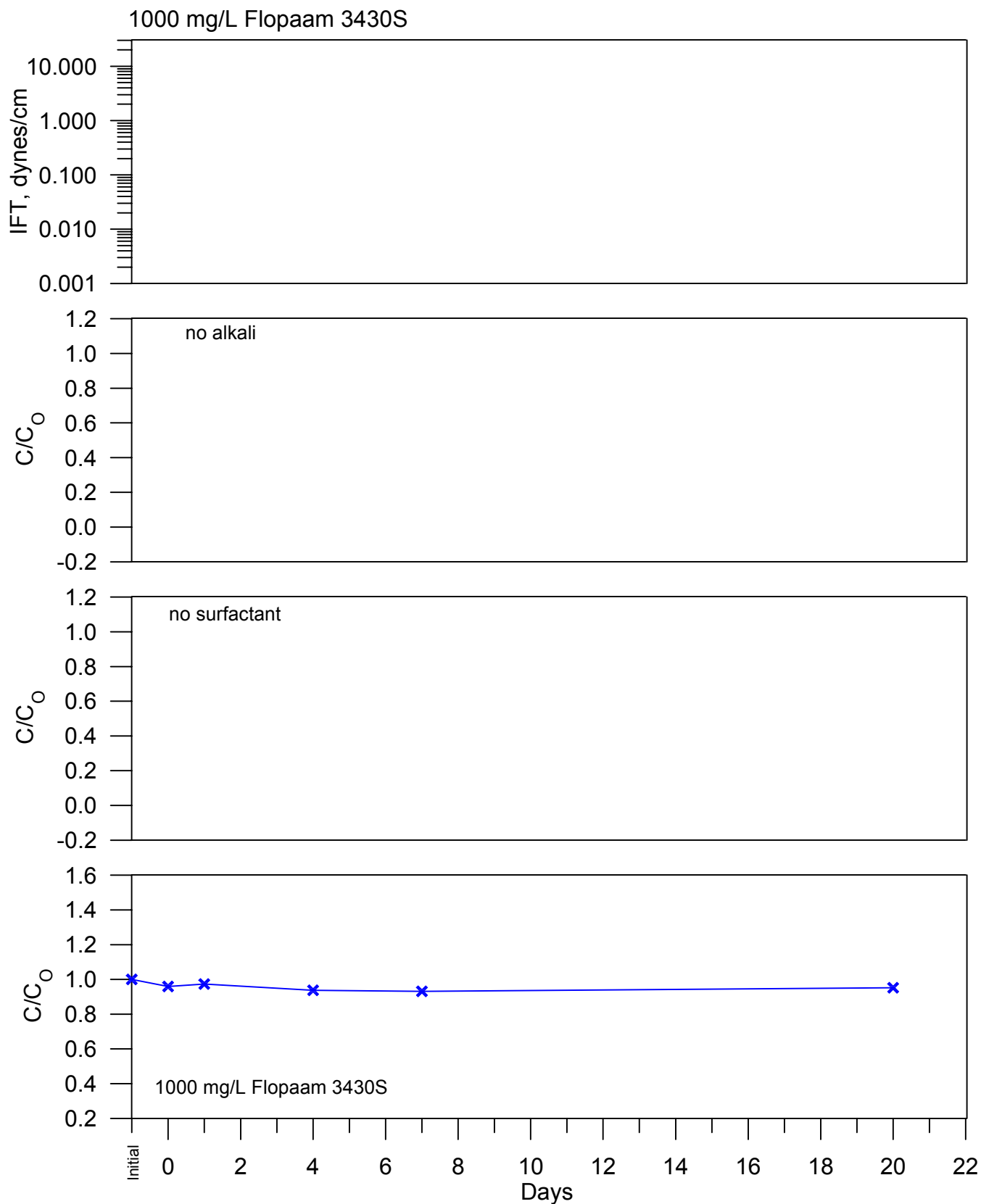


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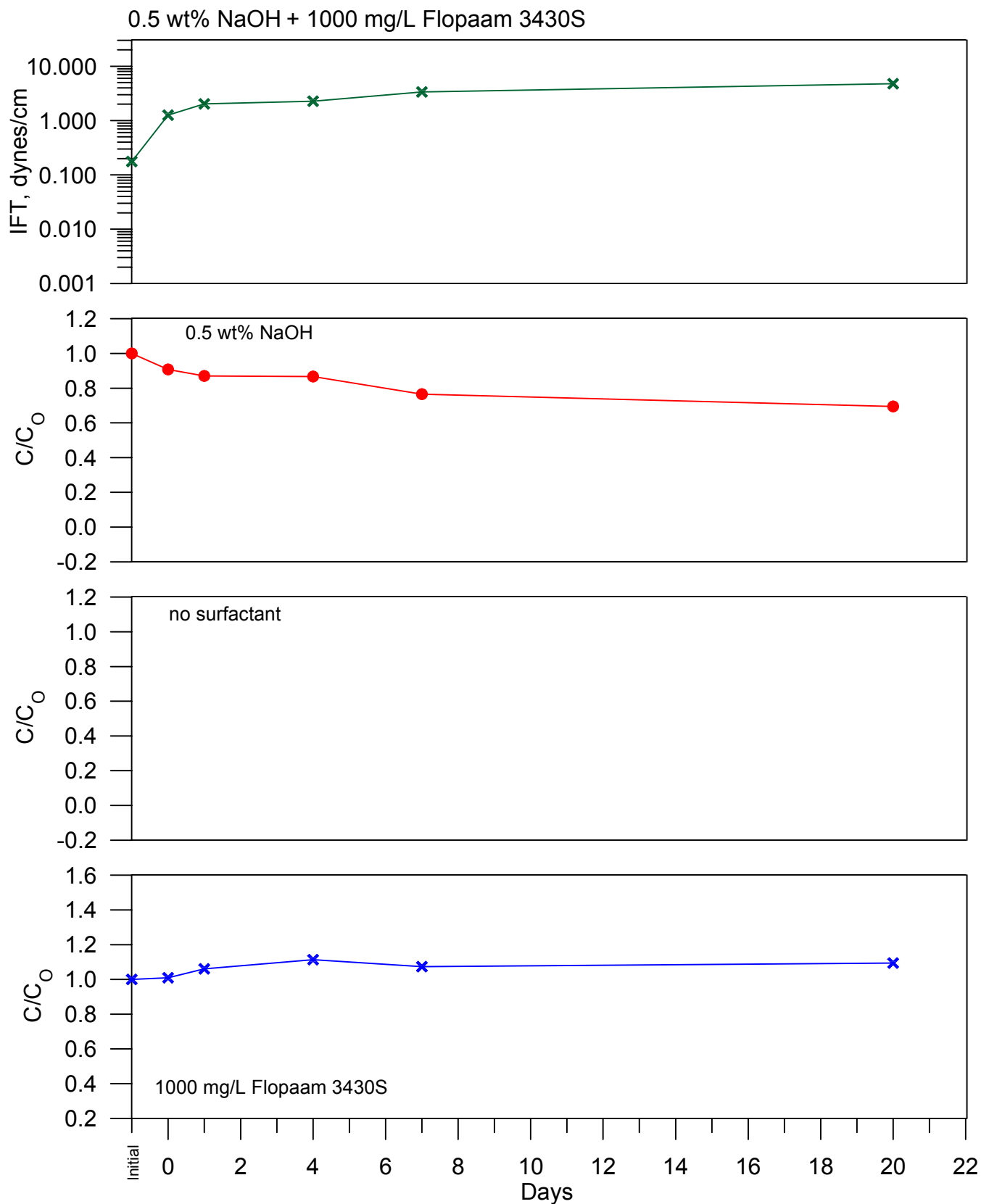
Static Alkali, Surfactant, and Polymer Changes in Aqueous Phase Chemical Concentration

(Well: Warner (Various))

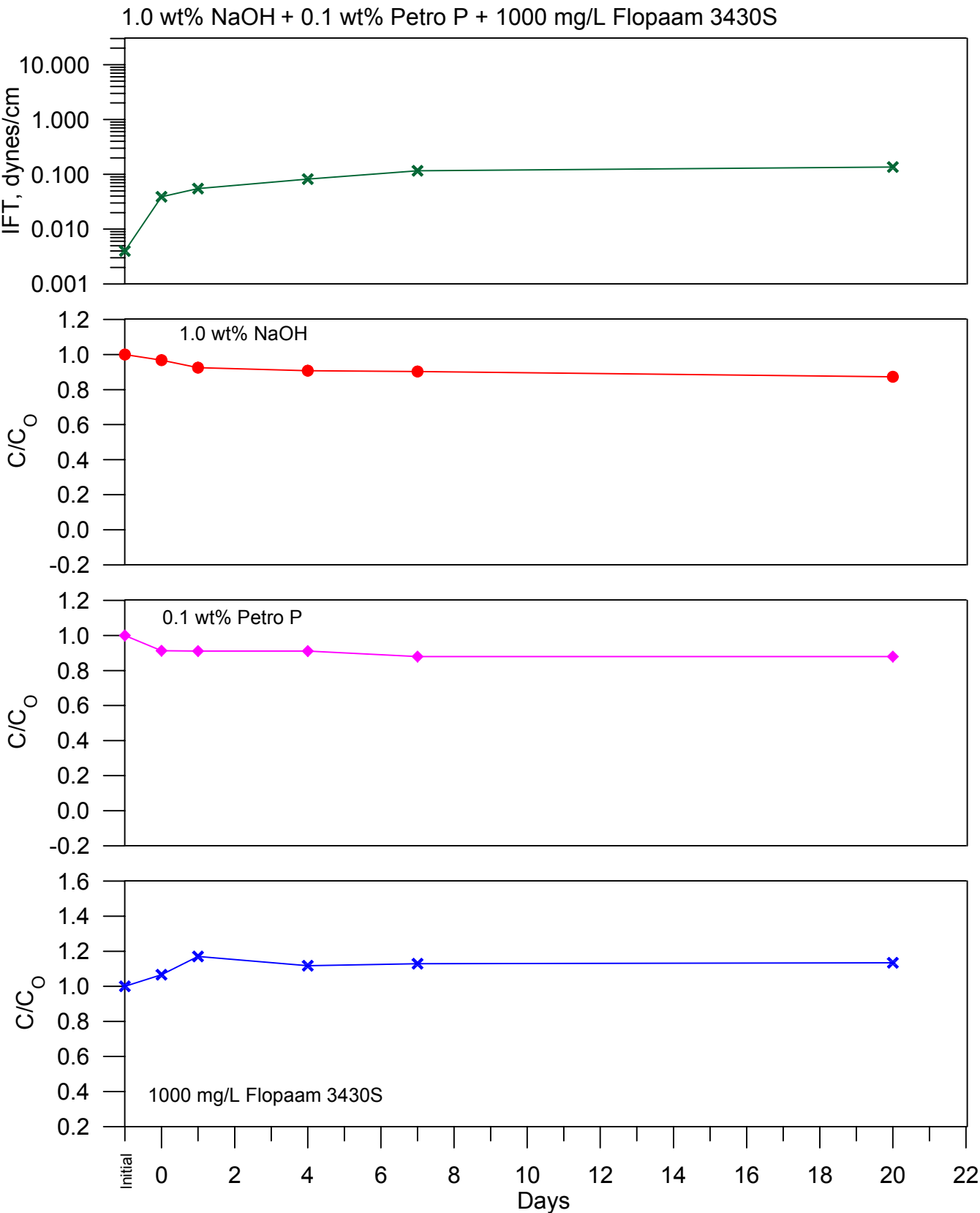


Static Alkali, Surfactant, and Polymer Changes in Aqueous Phase Chemical Concentration

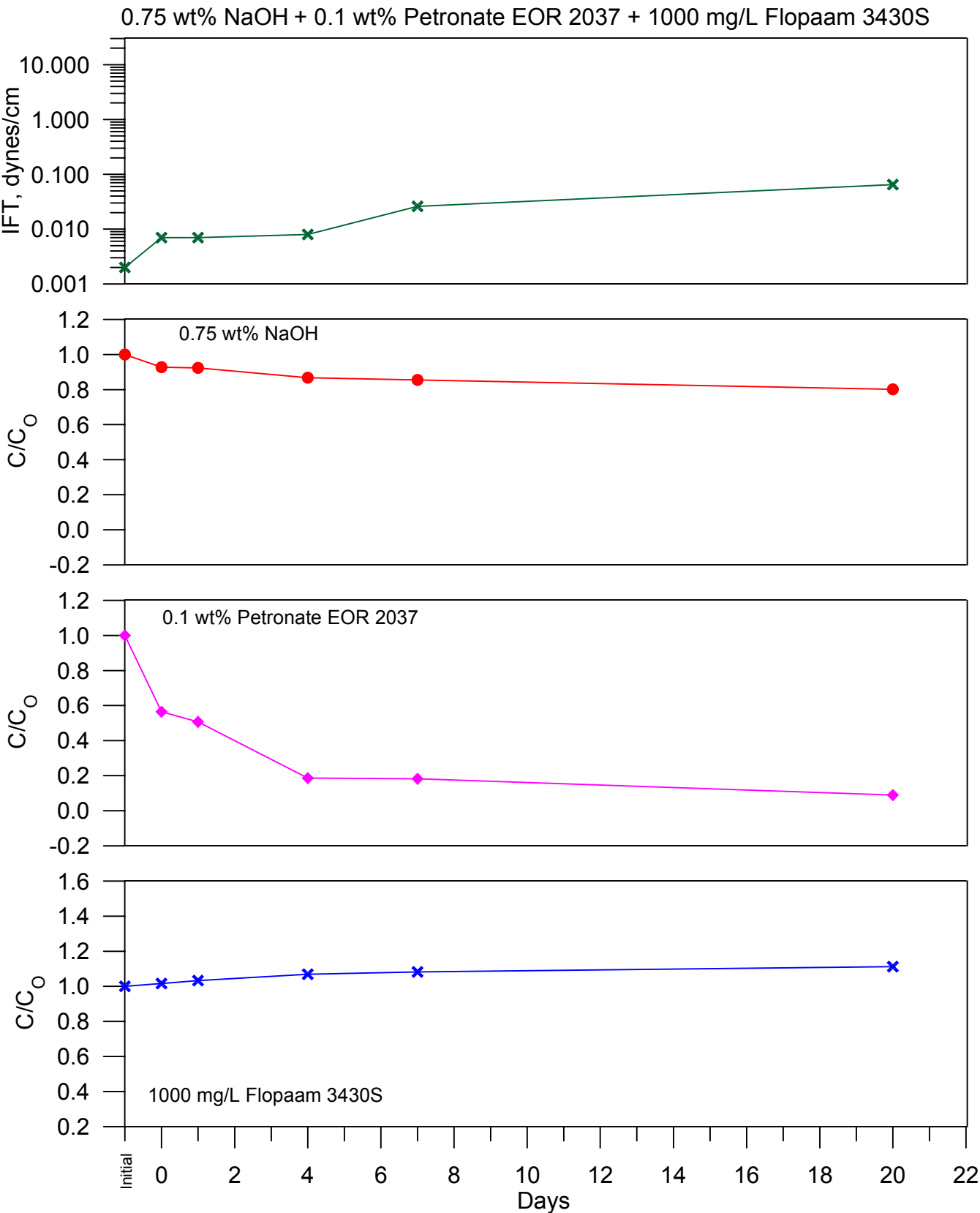
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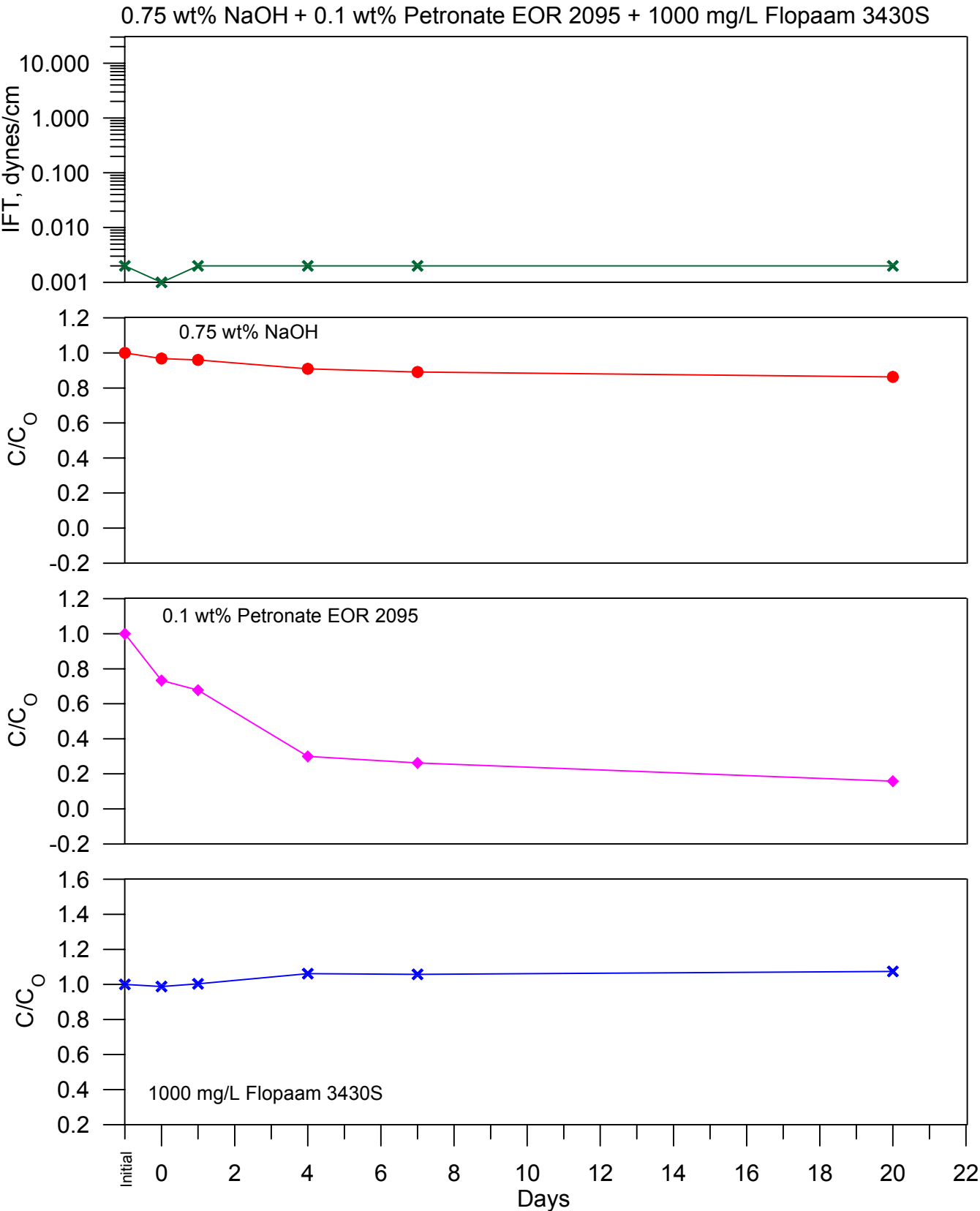
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



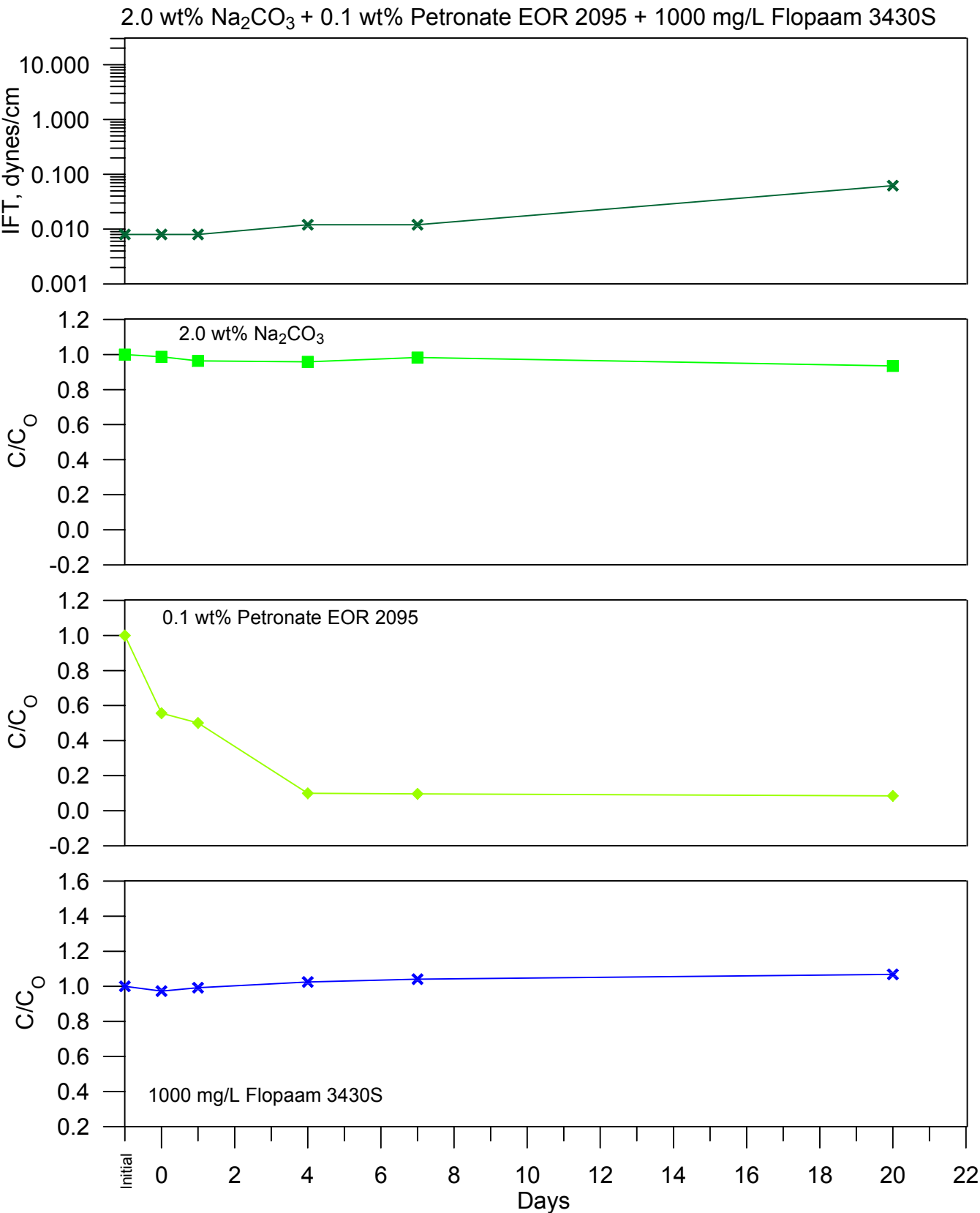
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



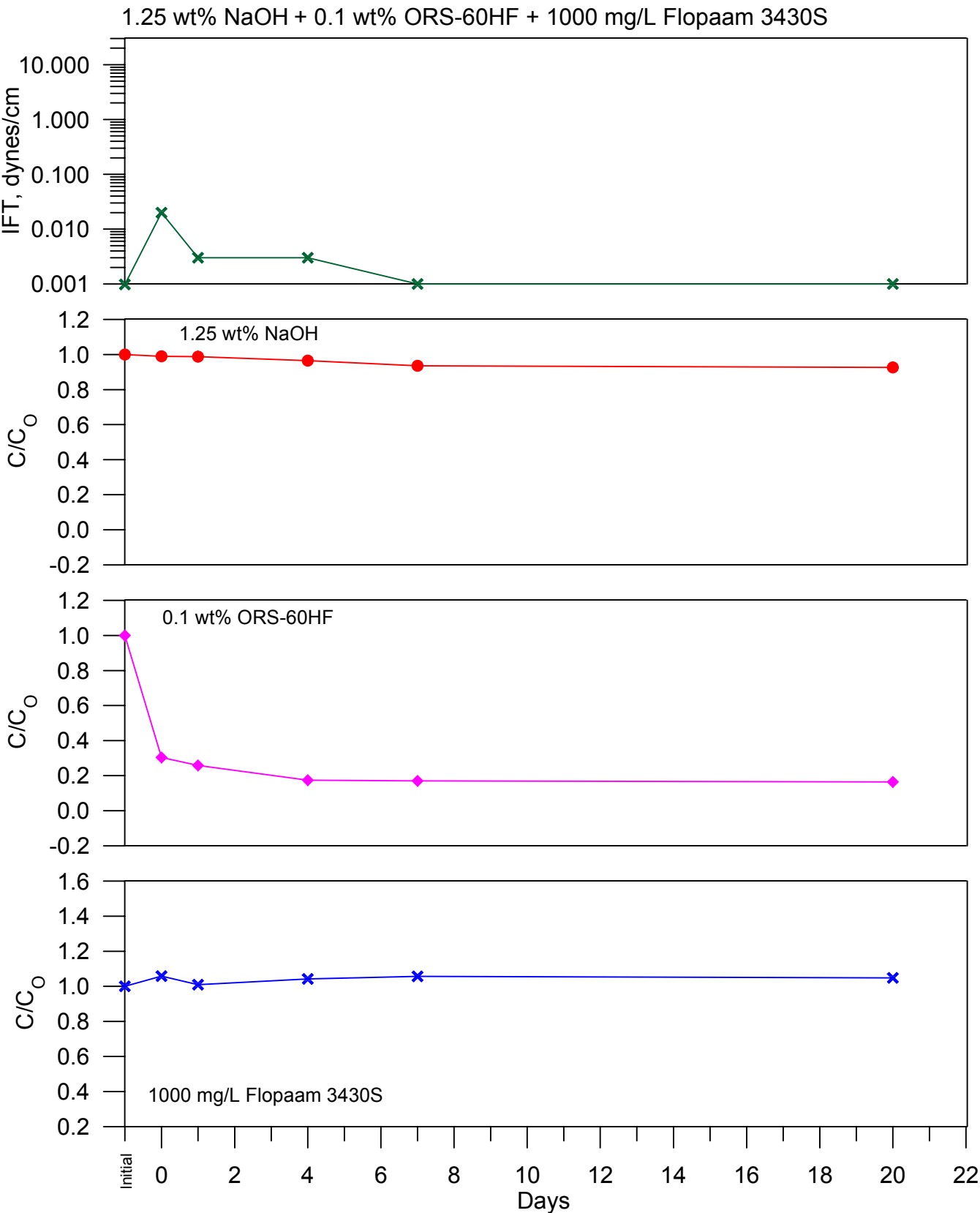
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



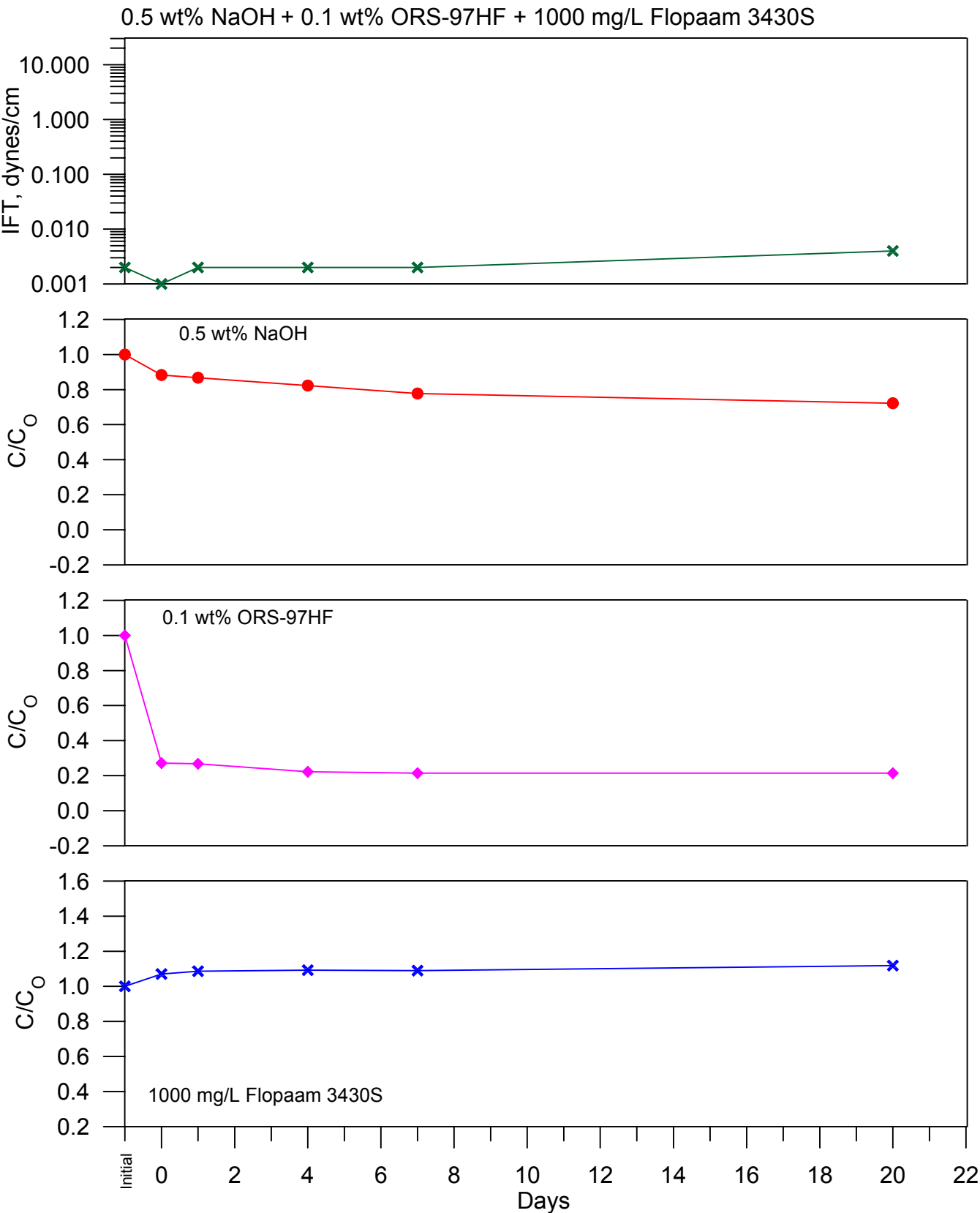
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



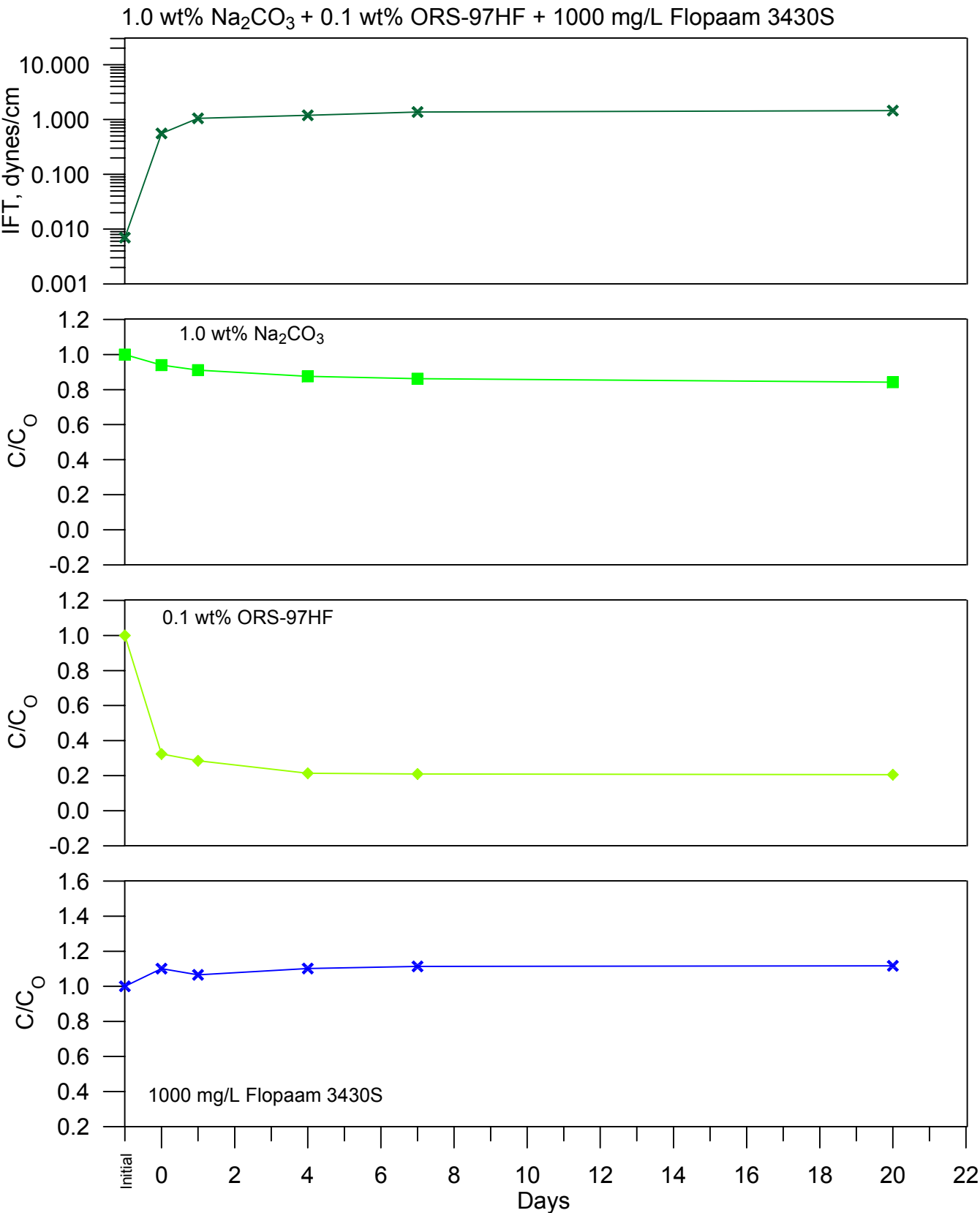
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



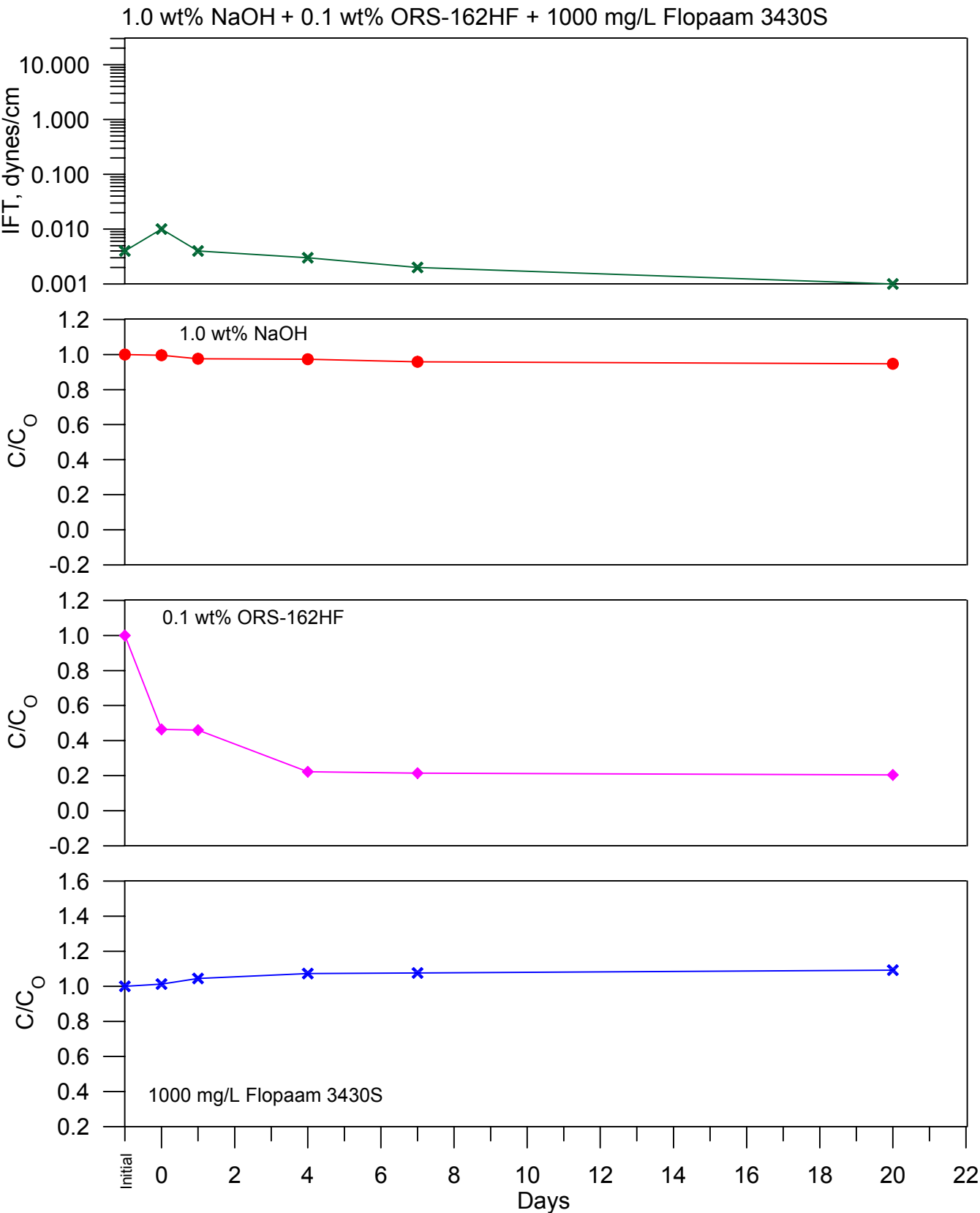
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



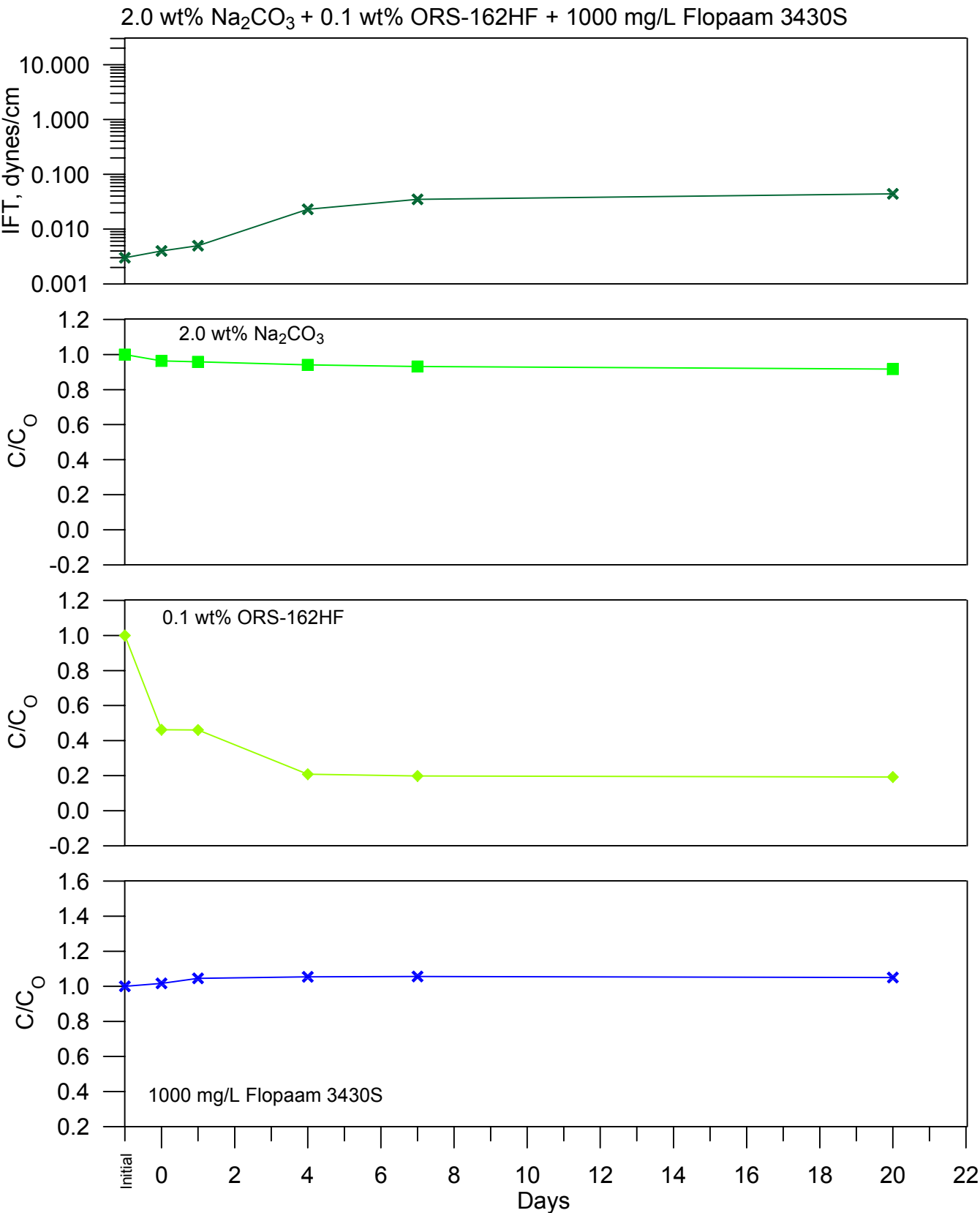
Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))



Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
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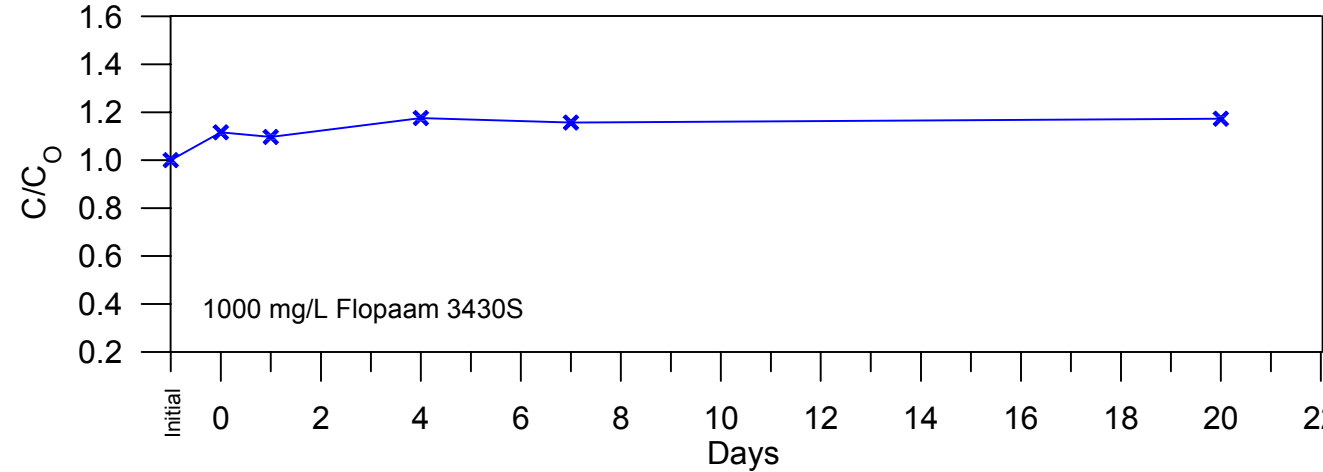
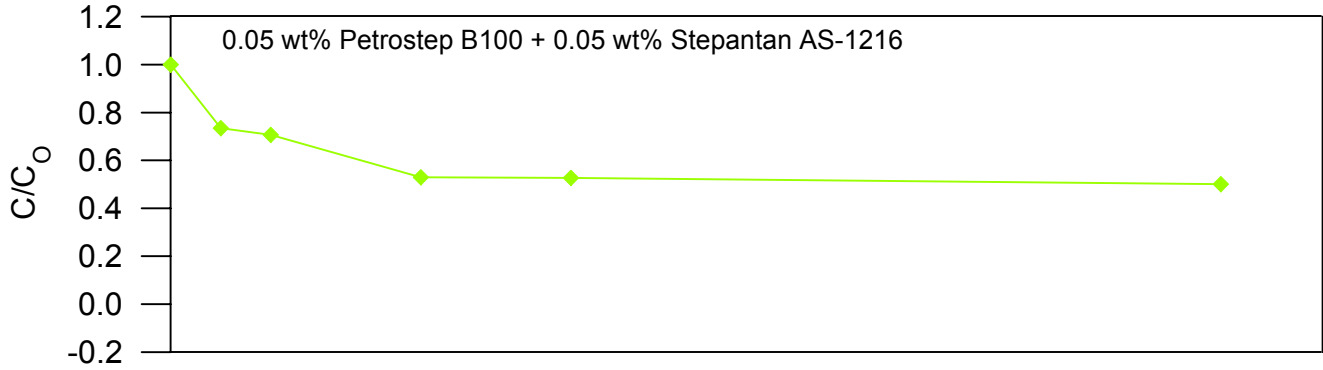
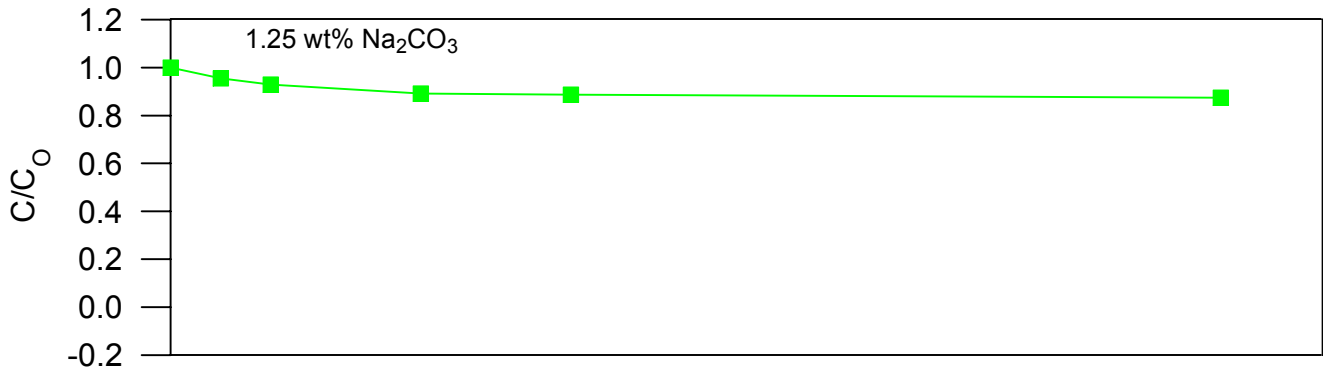
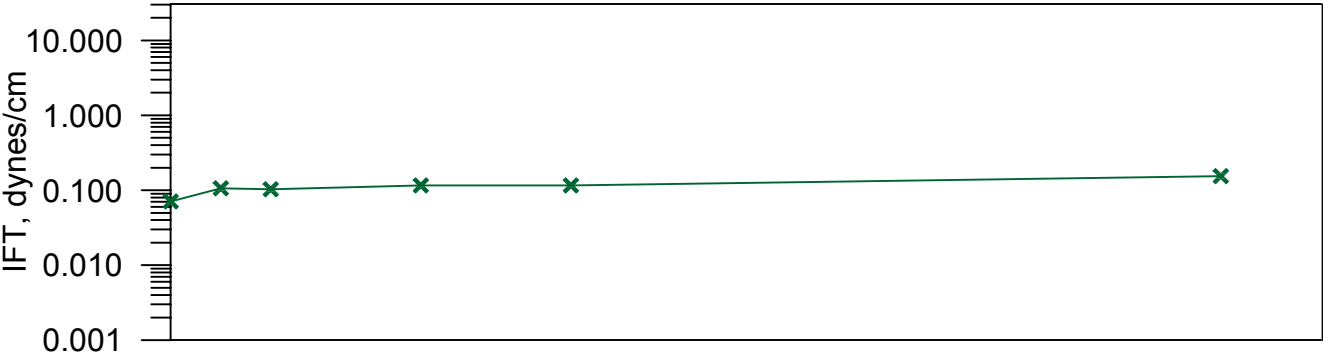


Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))

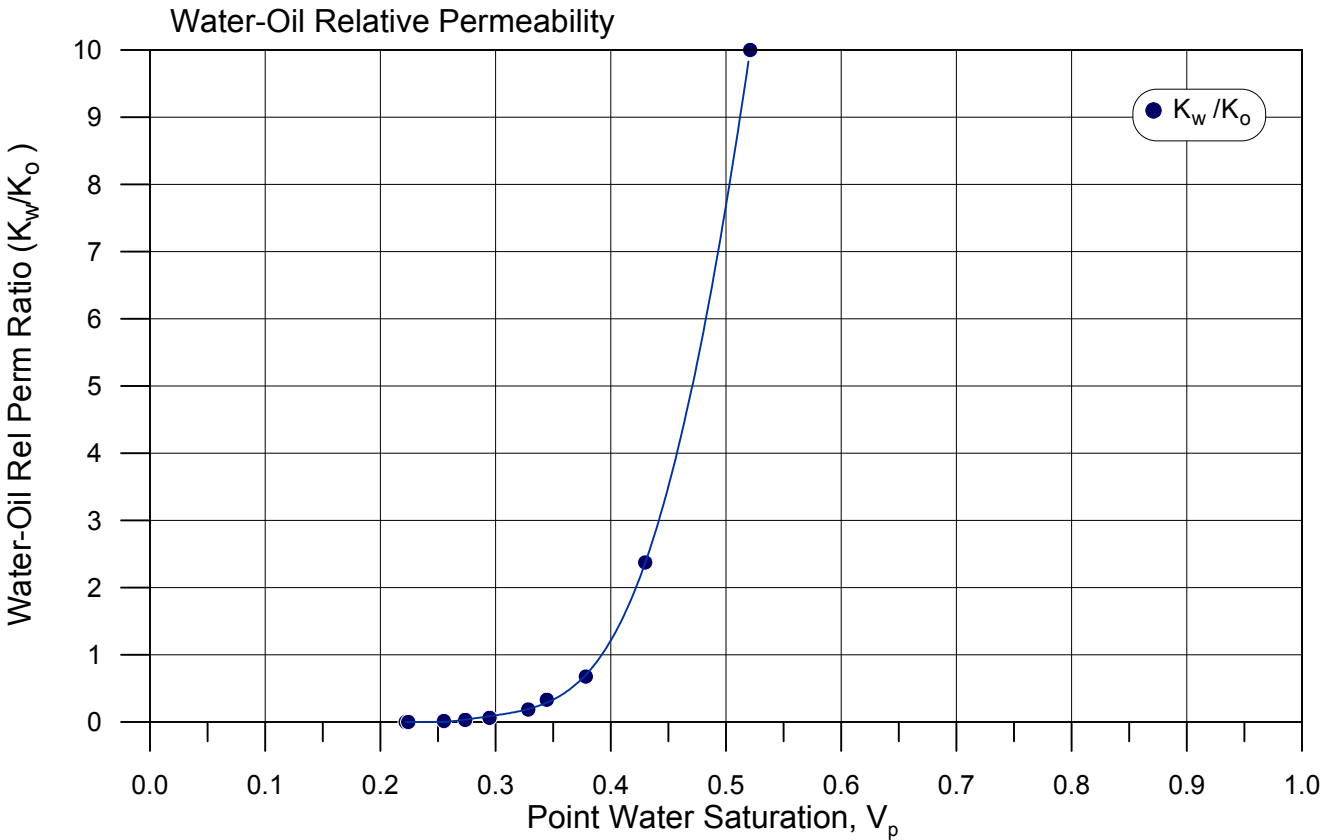
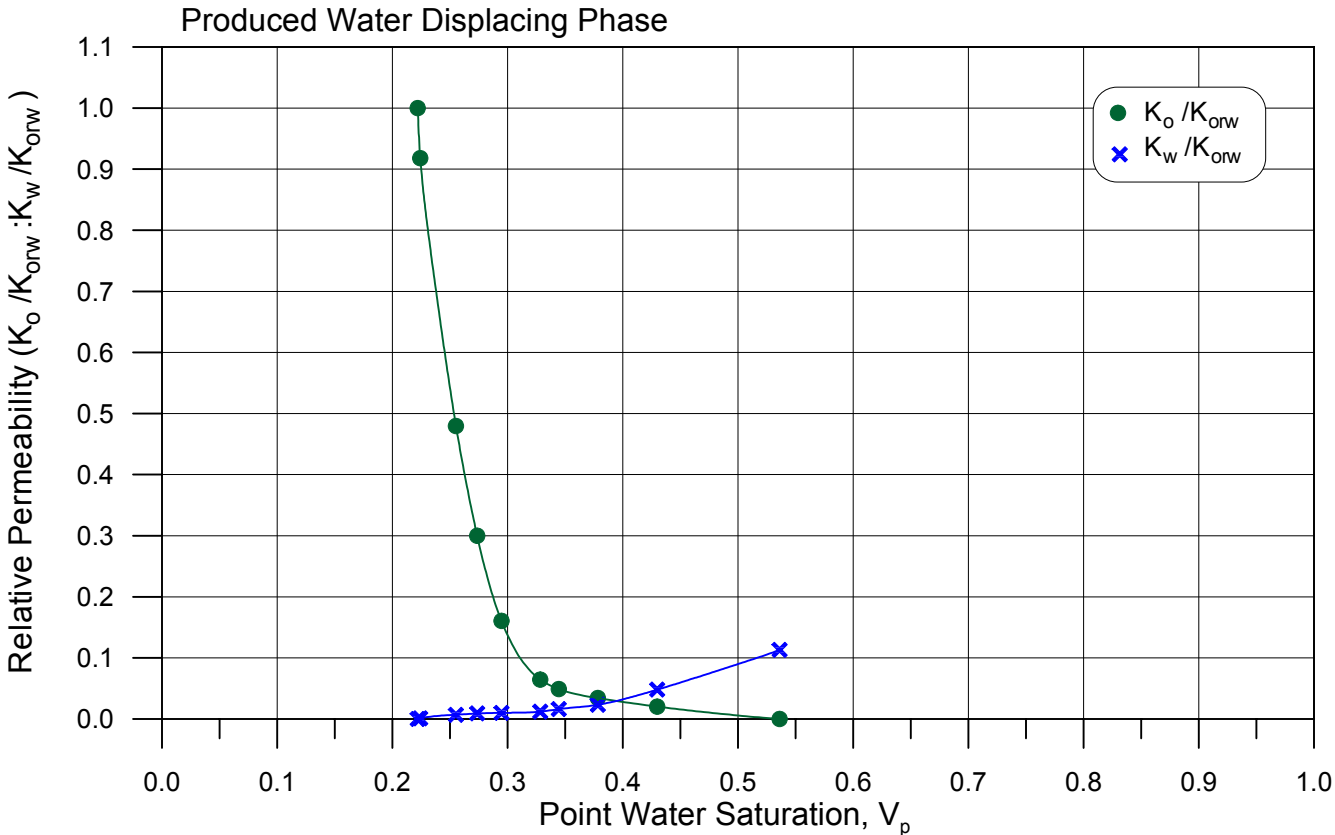


Static Alkali, Surfactant, and Polymer
Changes in Aqueous Phase Chemical Concentration
(Well: Warner (Various))

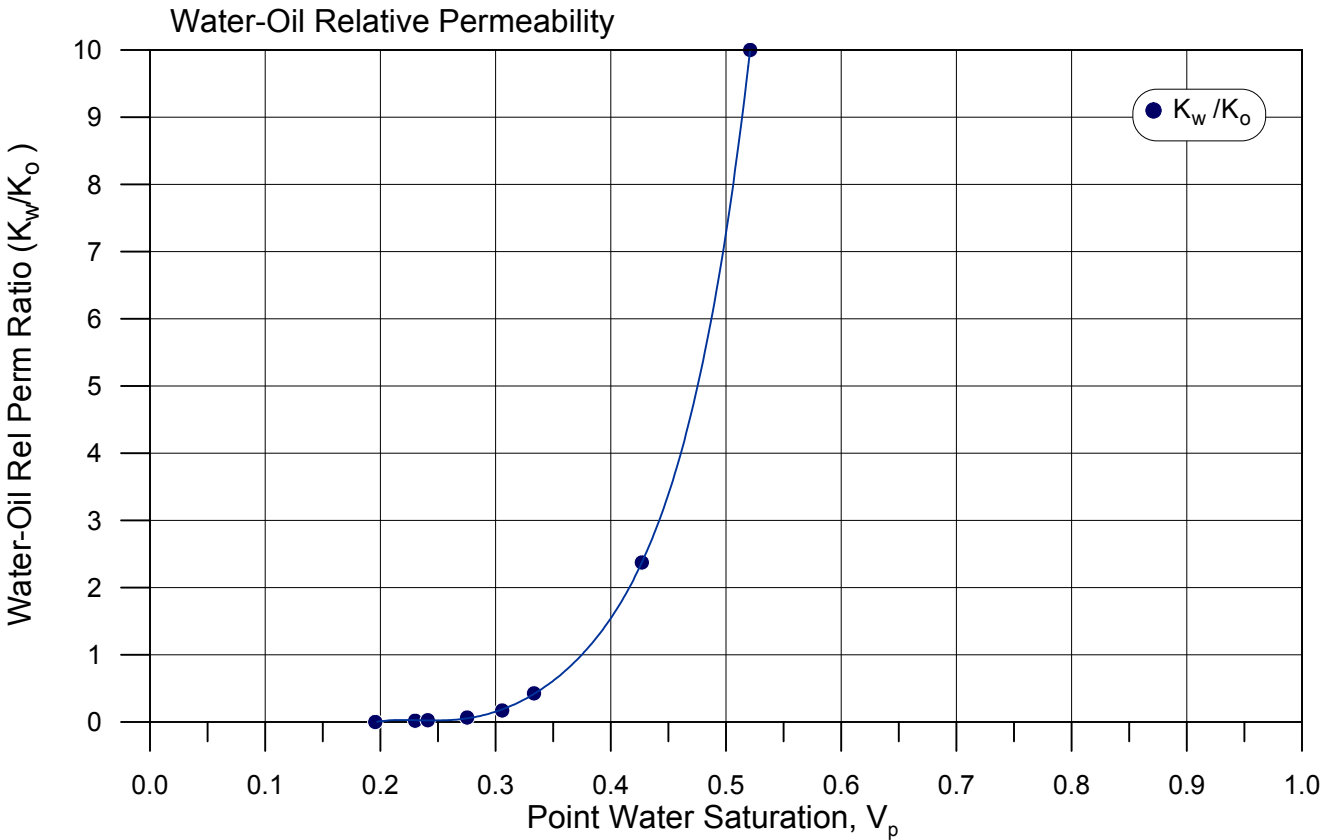
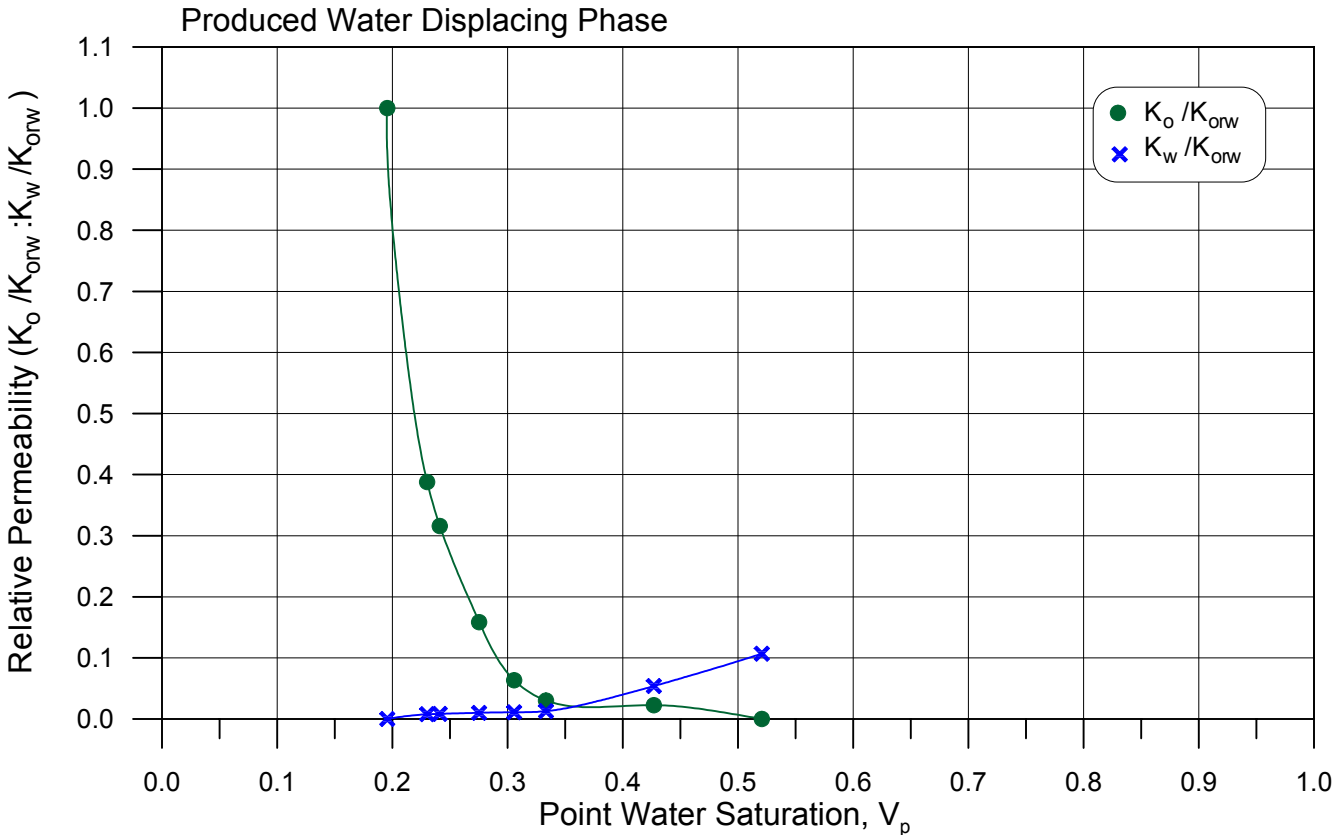
1.25 wt% Na₂CO₃ + 0.05 wt% Petrostep B100
+ 0.05 wt% Stepantan AS-1216 + 1000 mg/L Flopaam 3430S



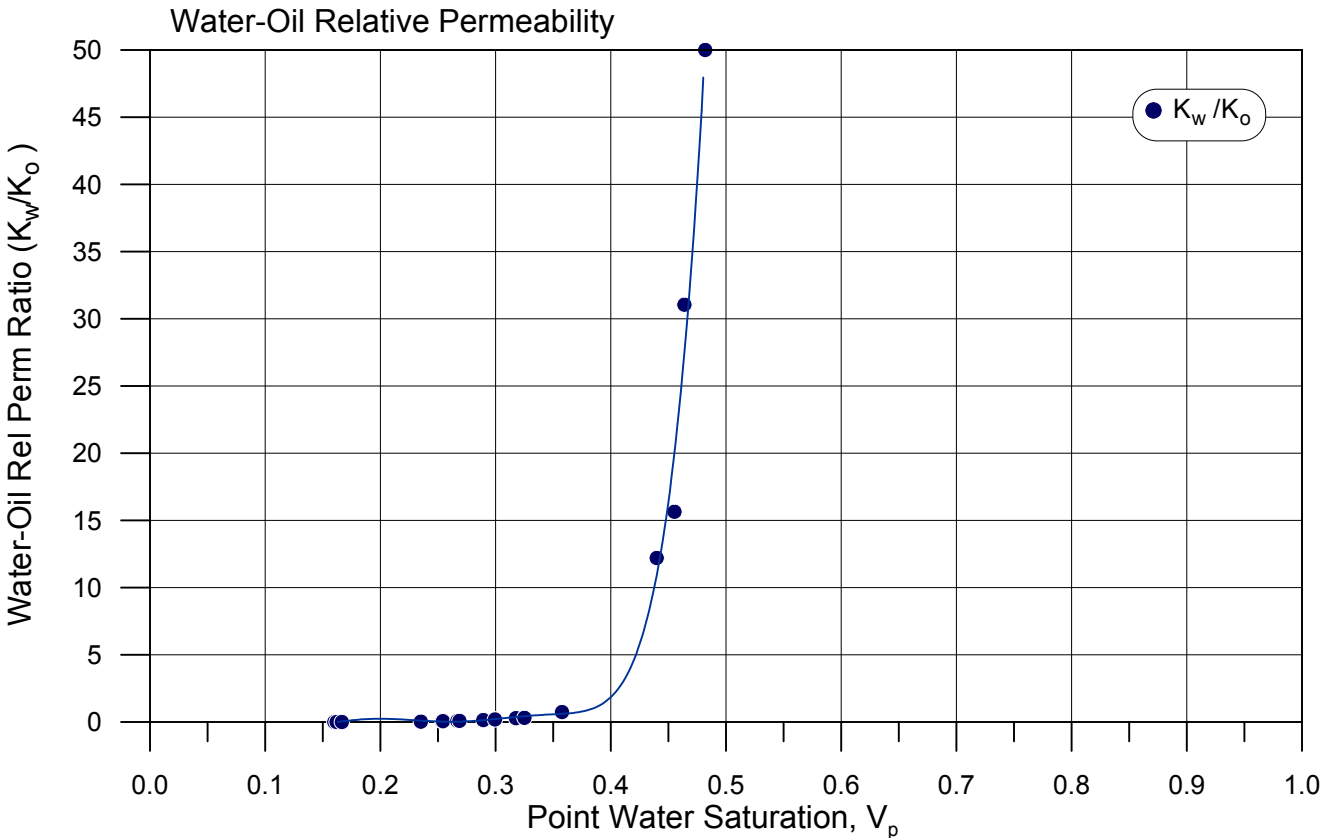
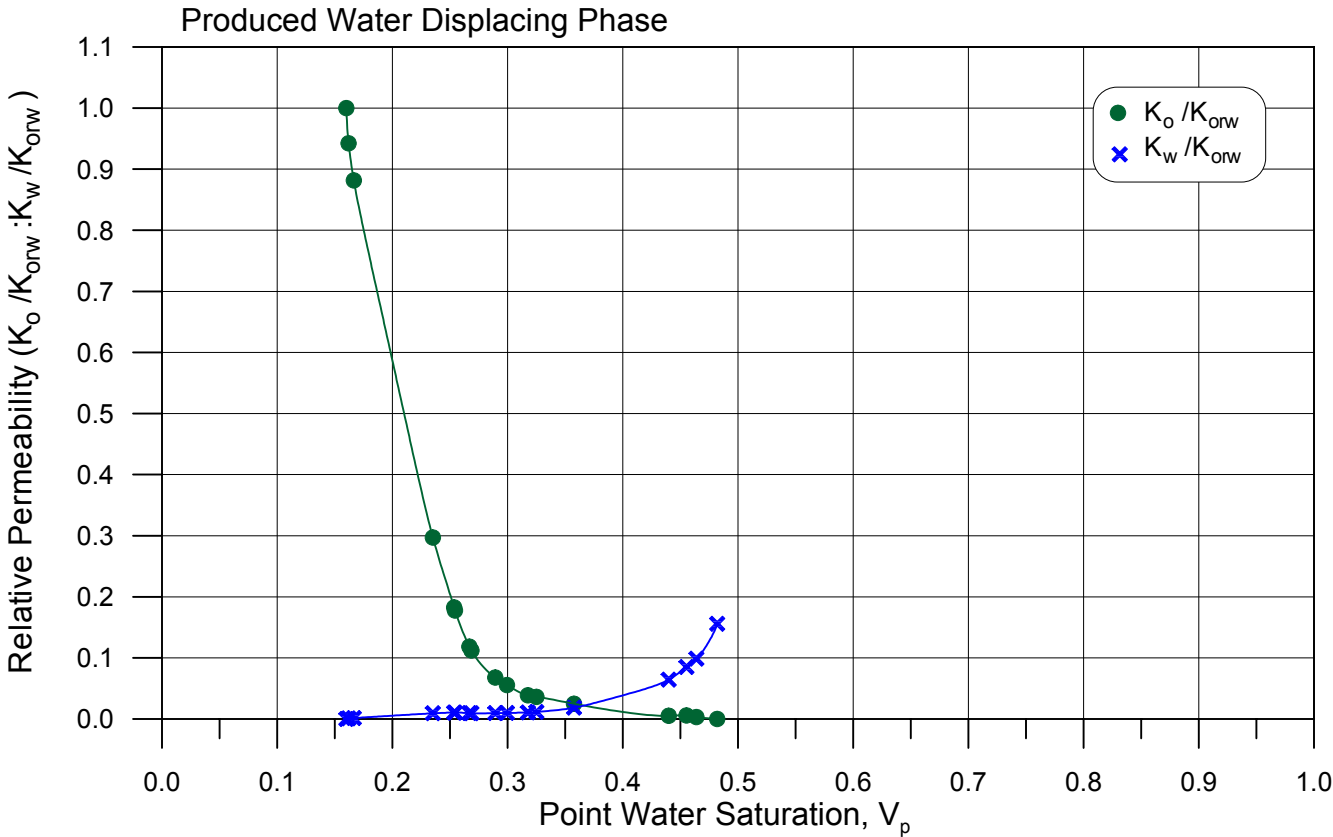
Warner 00/04-21-007-16W4
Relative Permeability #1



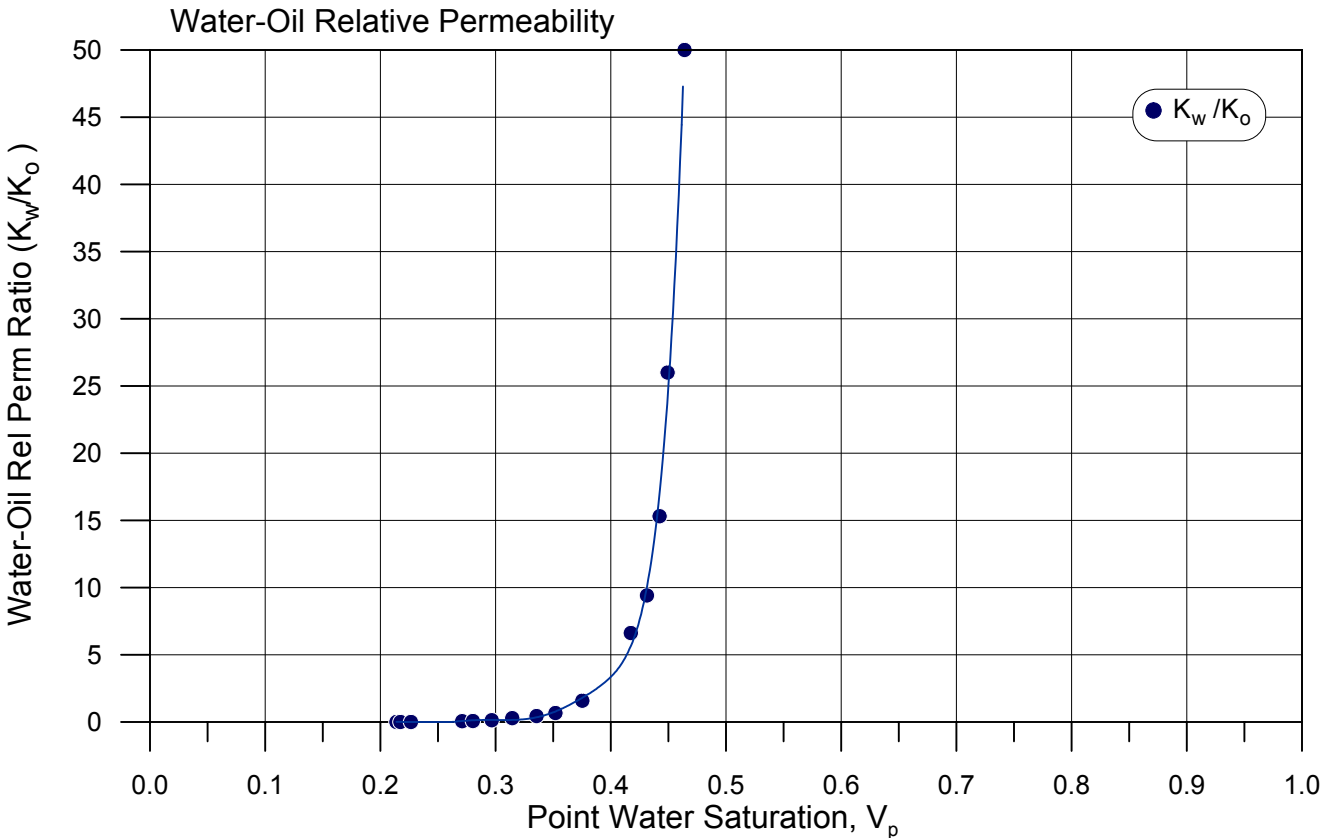
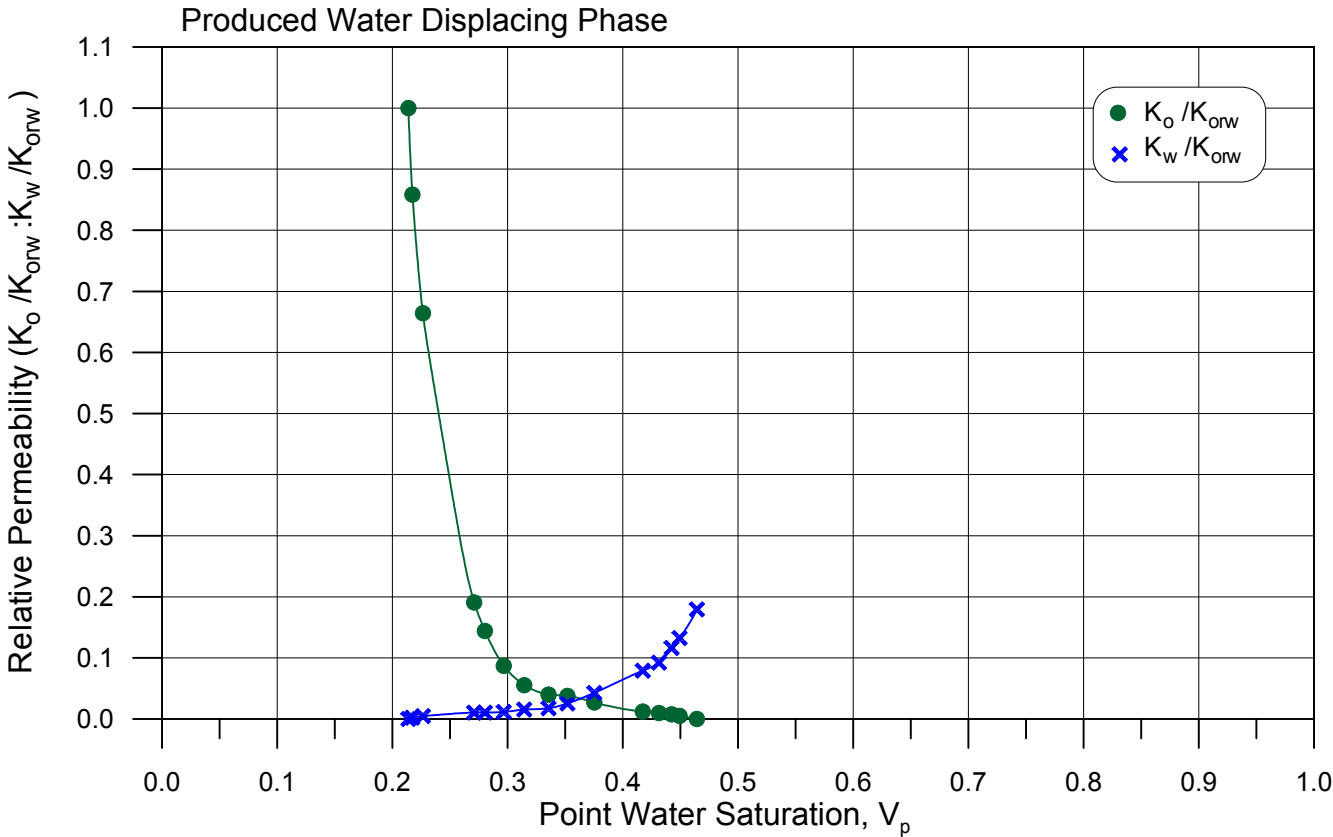
Warner 00/04-21-007-16W4
Relative Permeability #2



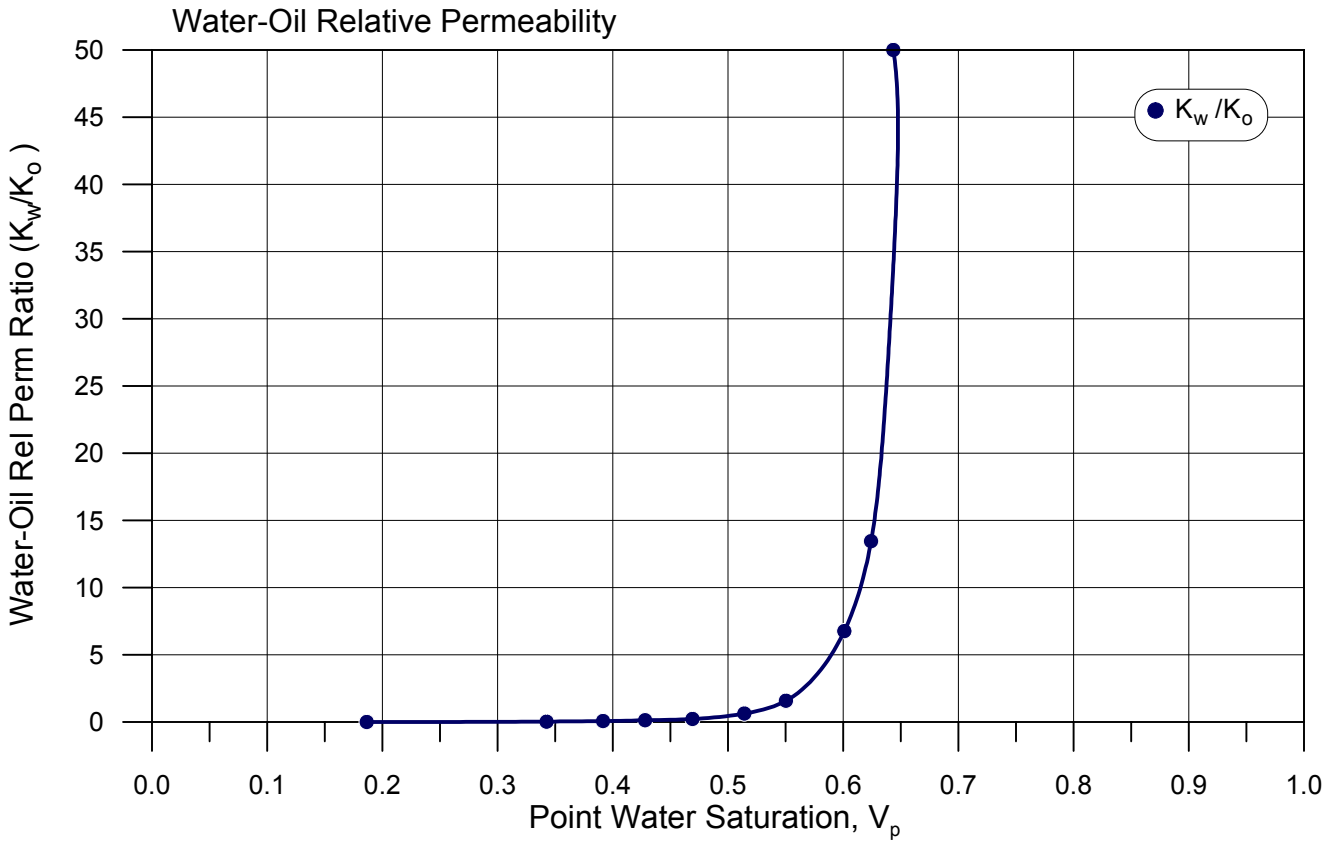
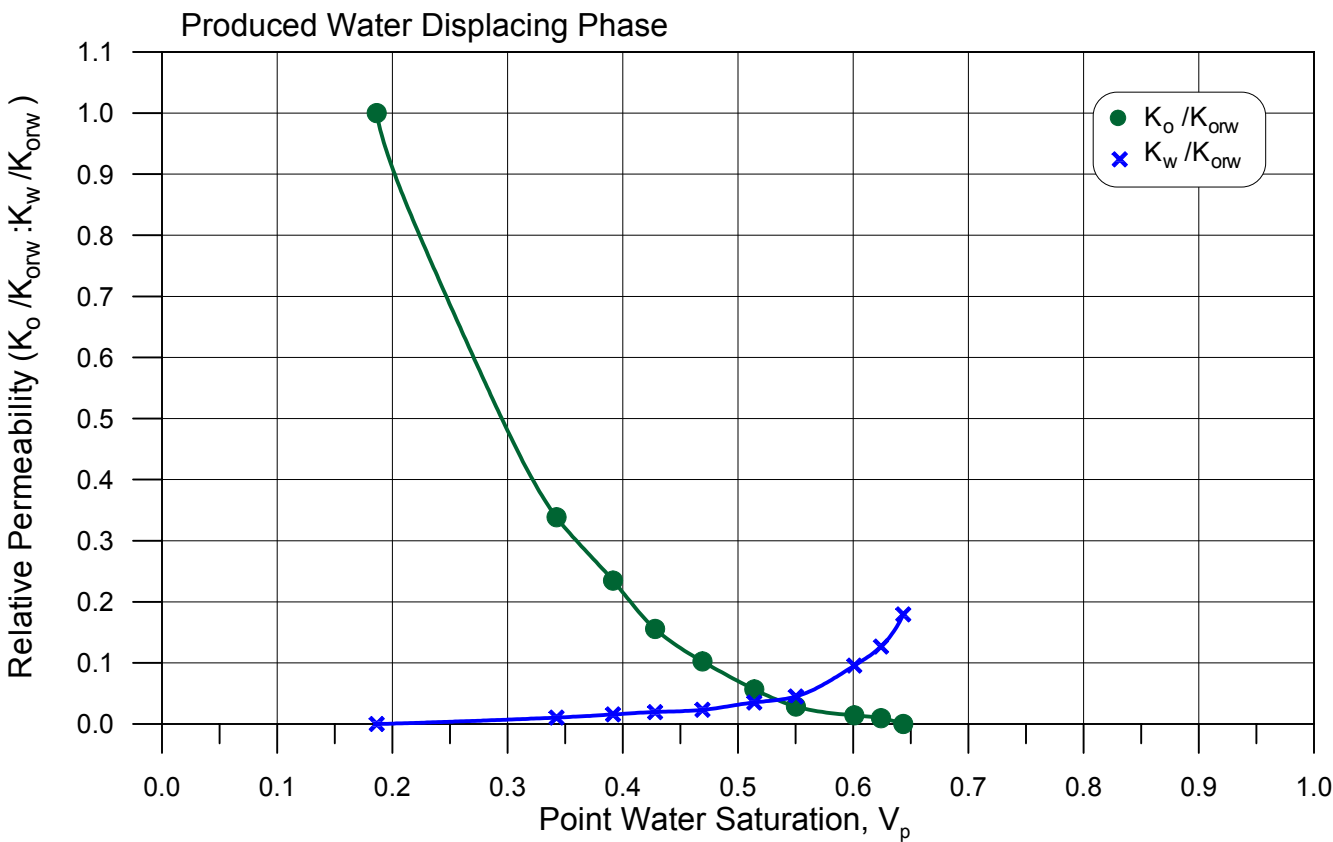
Warner 02/09-20-007-16W4
Relative Permeability #3



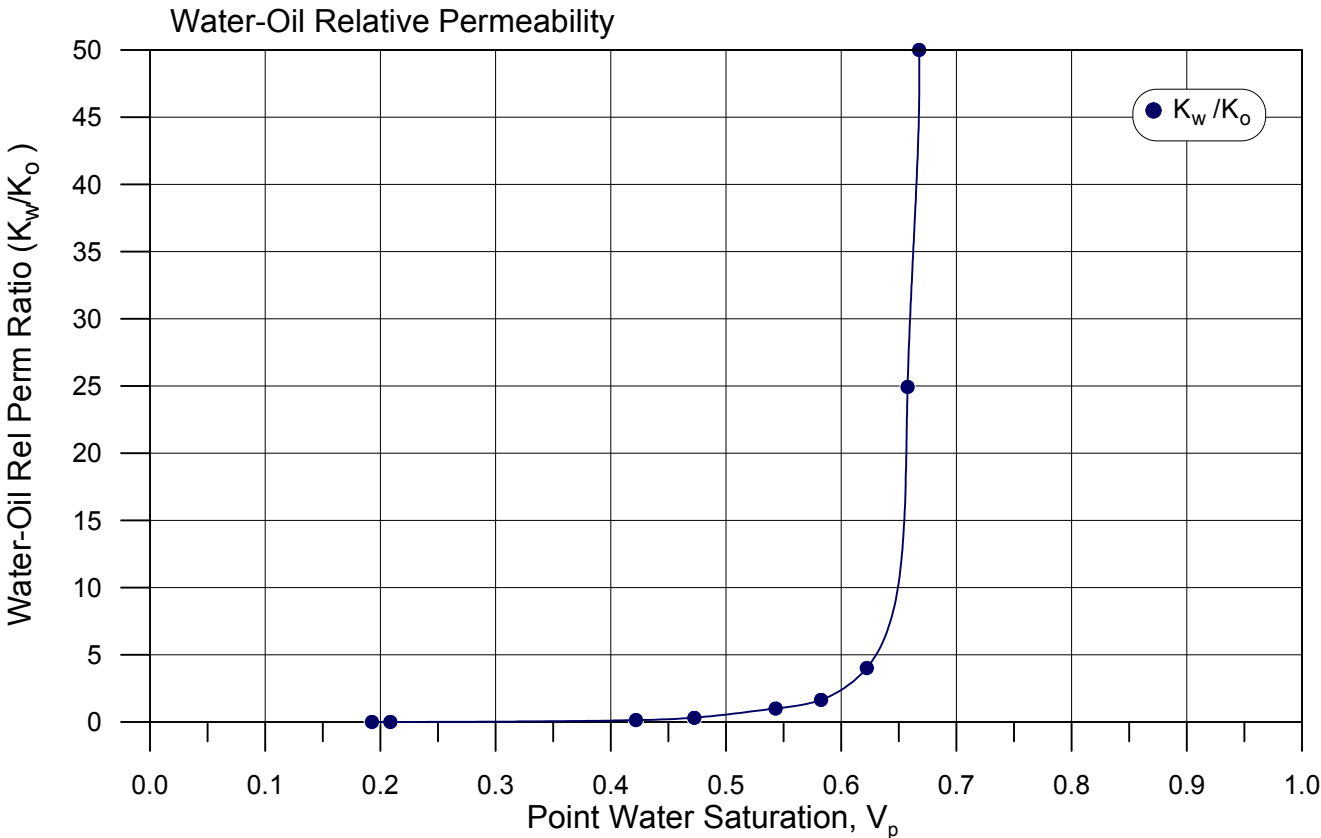
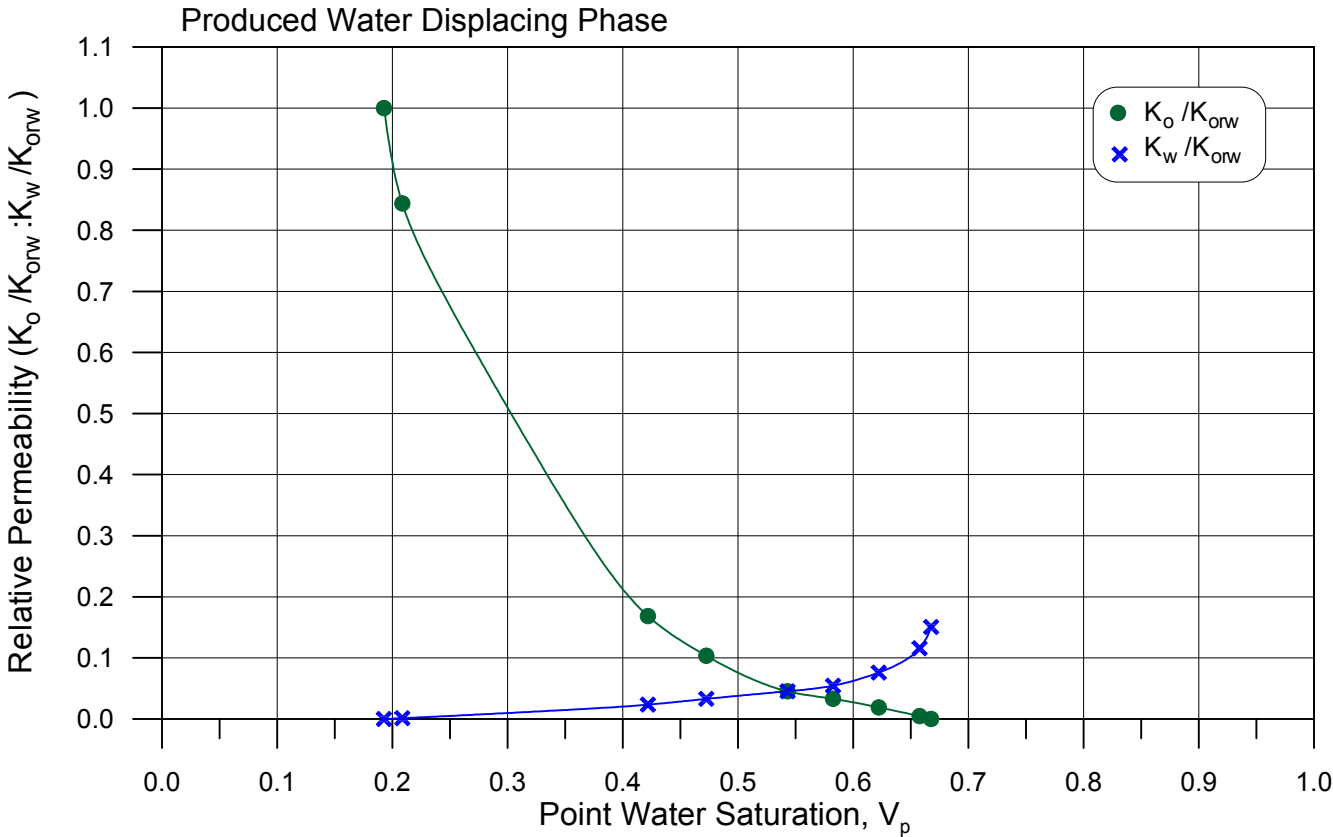
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Relative Permeability #4

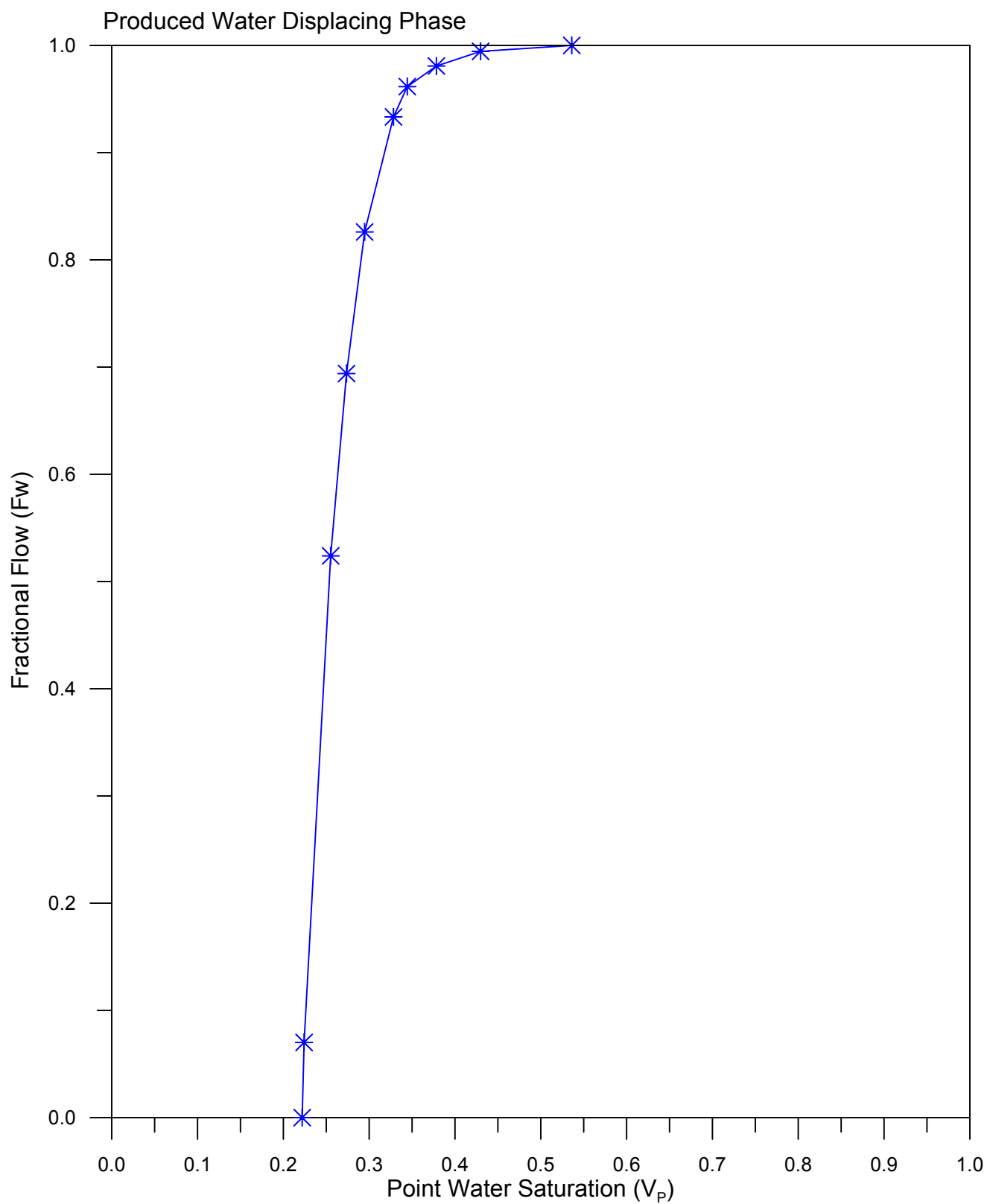


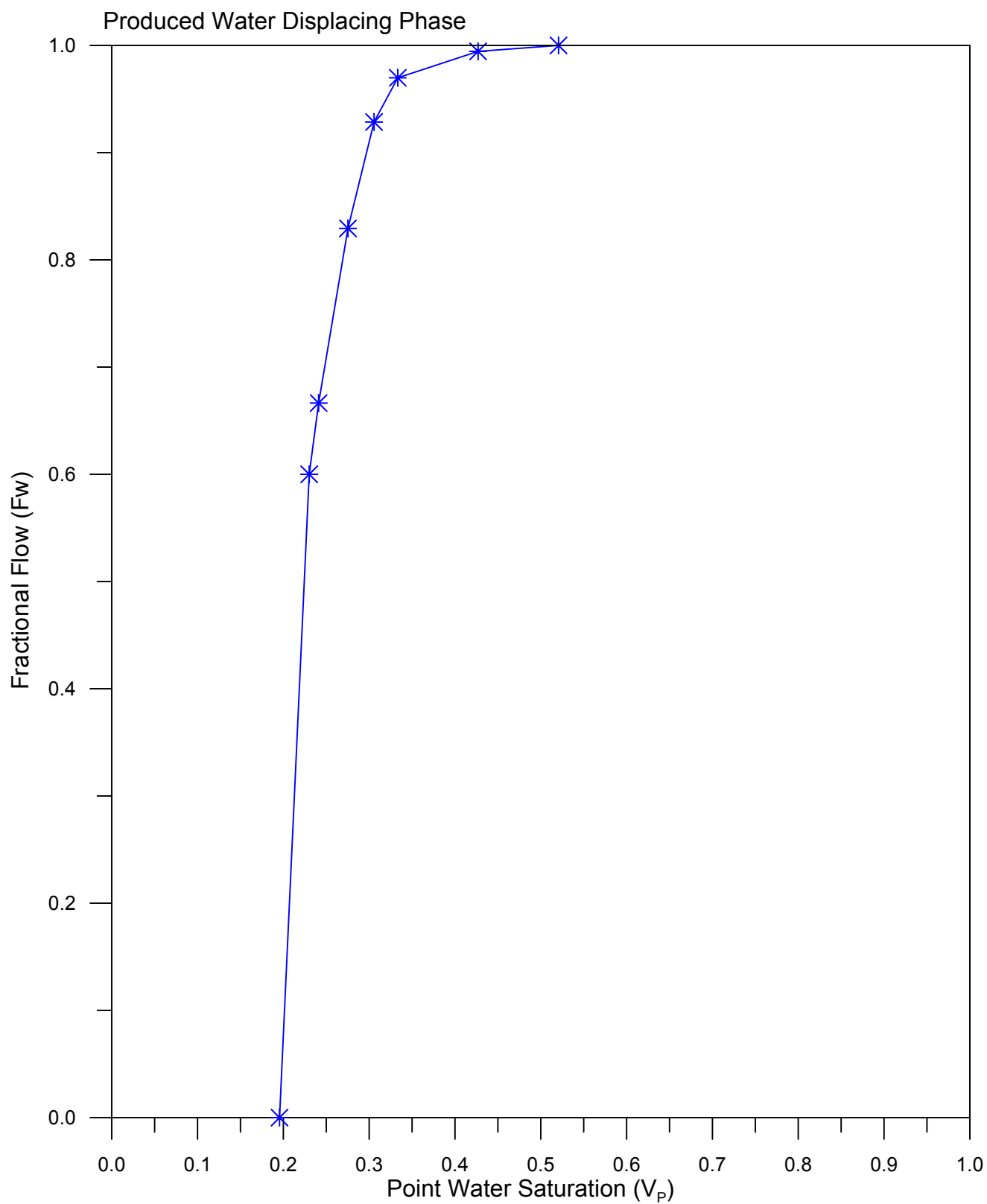
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Relative Permeability #5

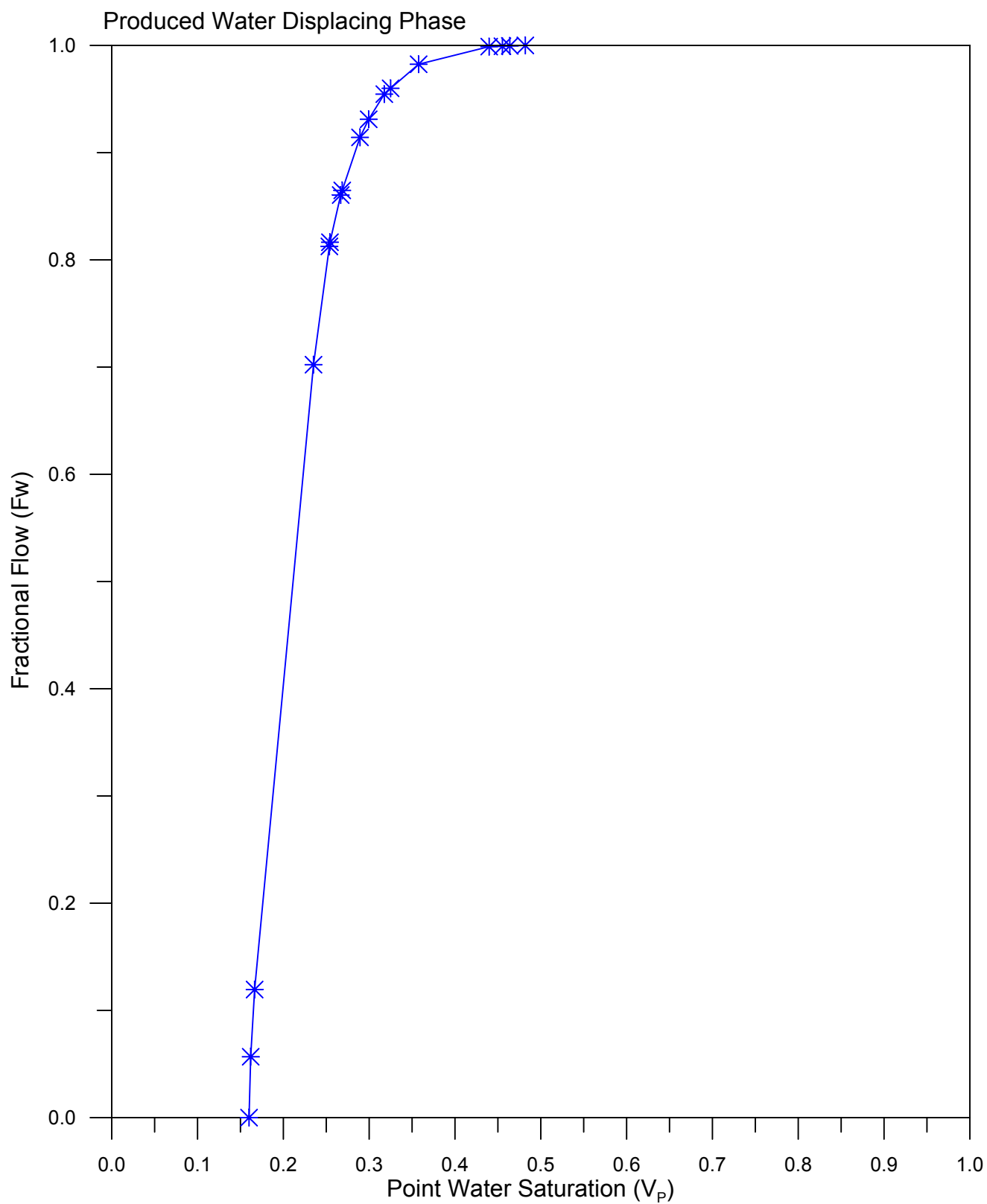


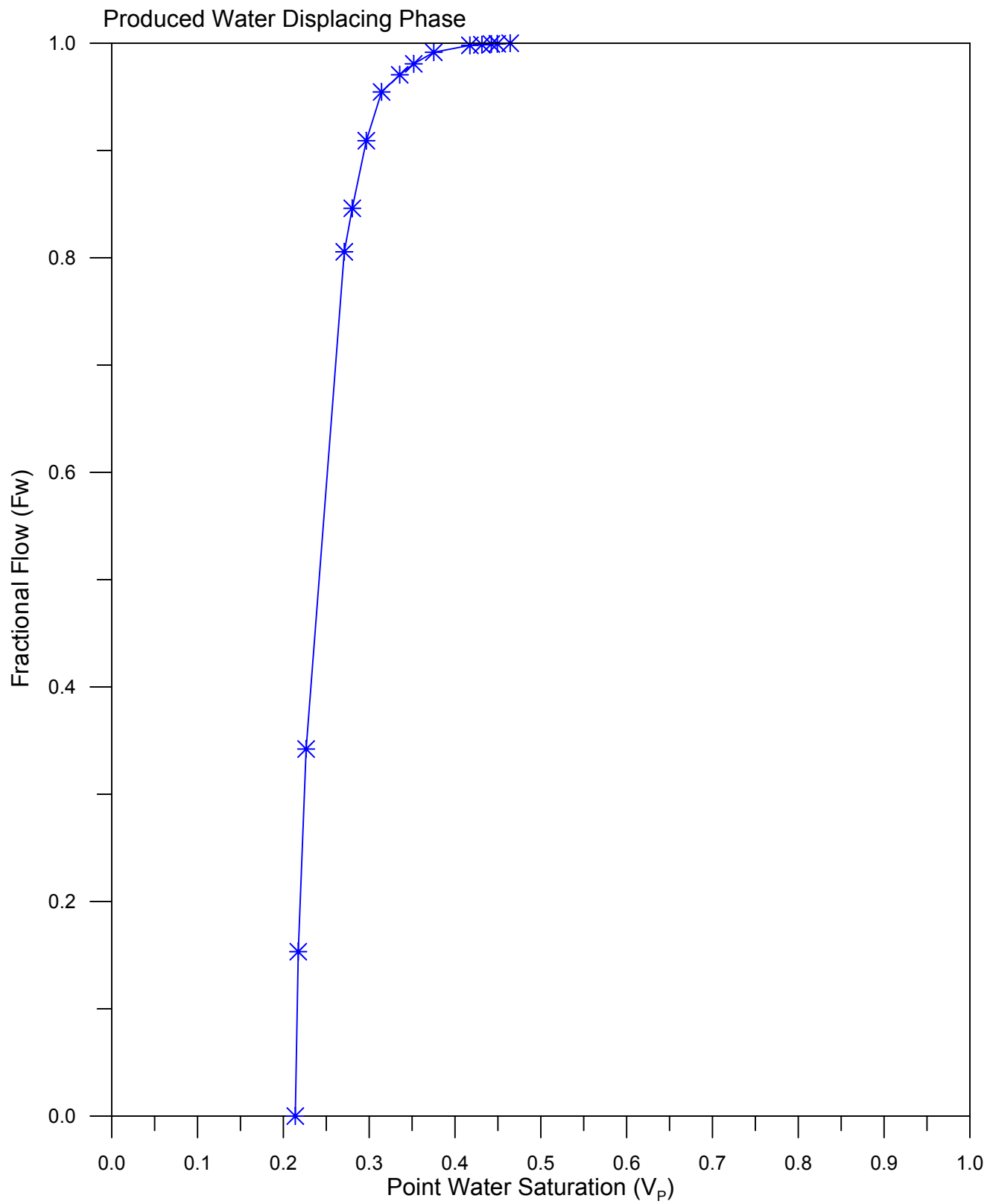
Warner 00/16-20-007-16W4
Relative Permeability #6

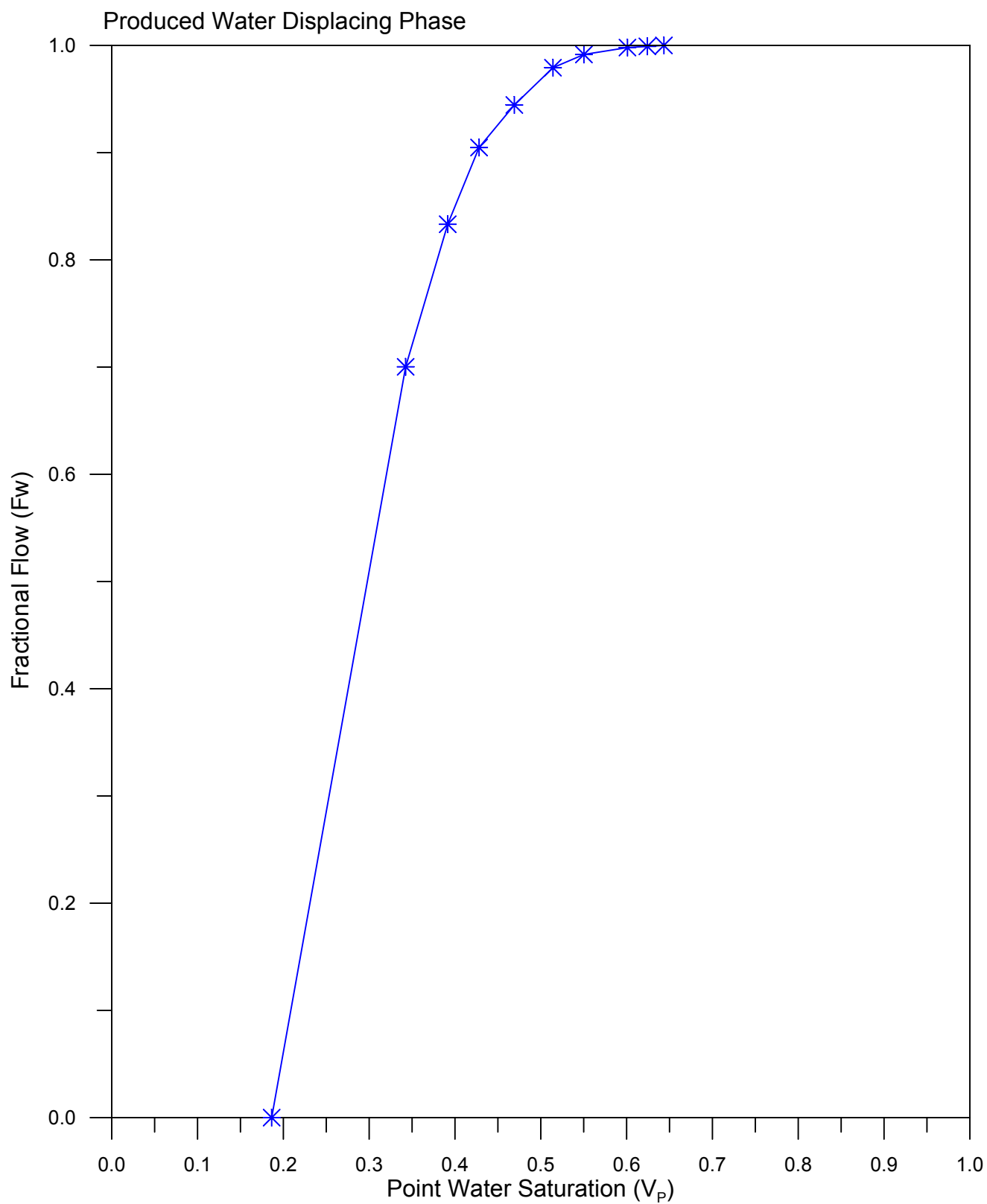


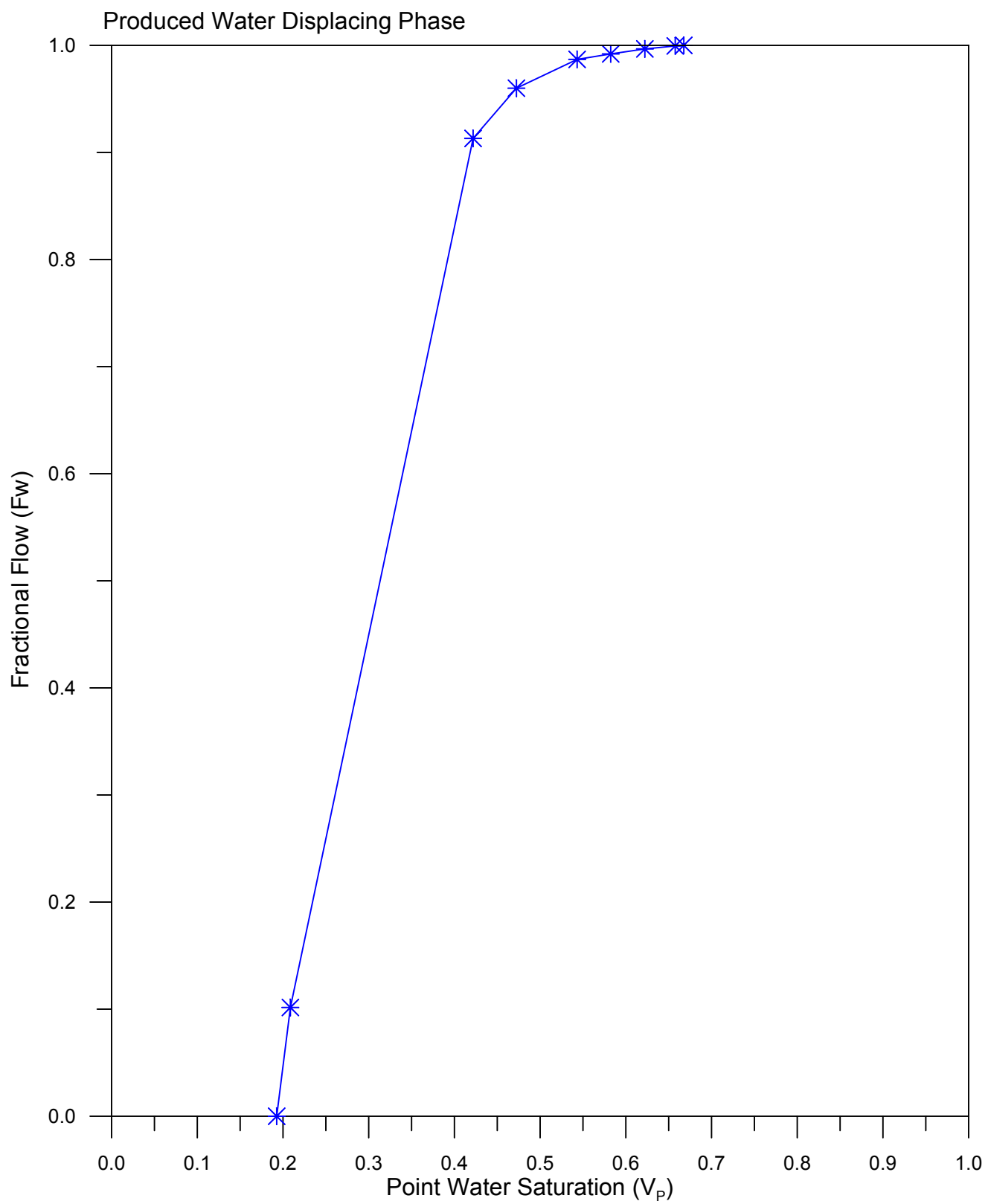




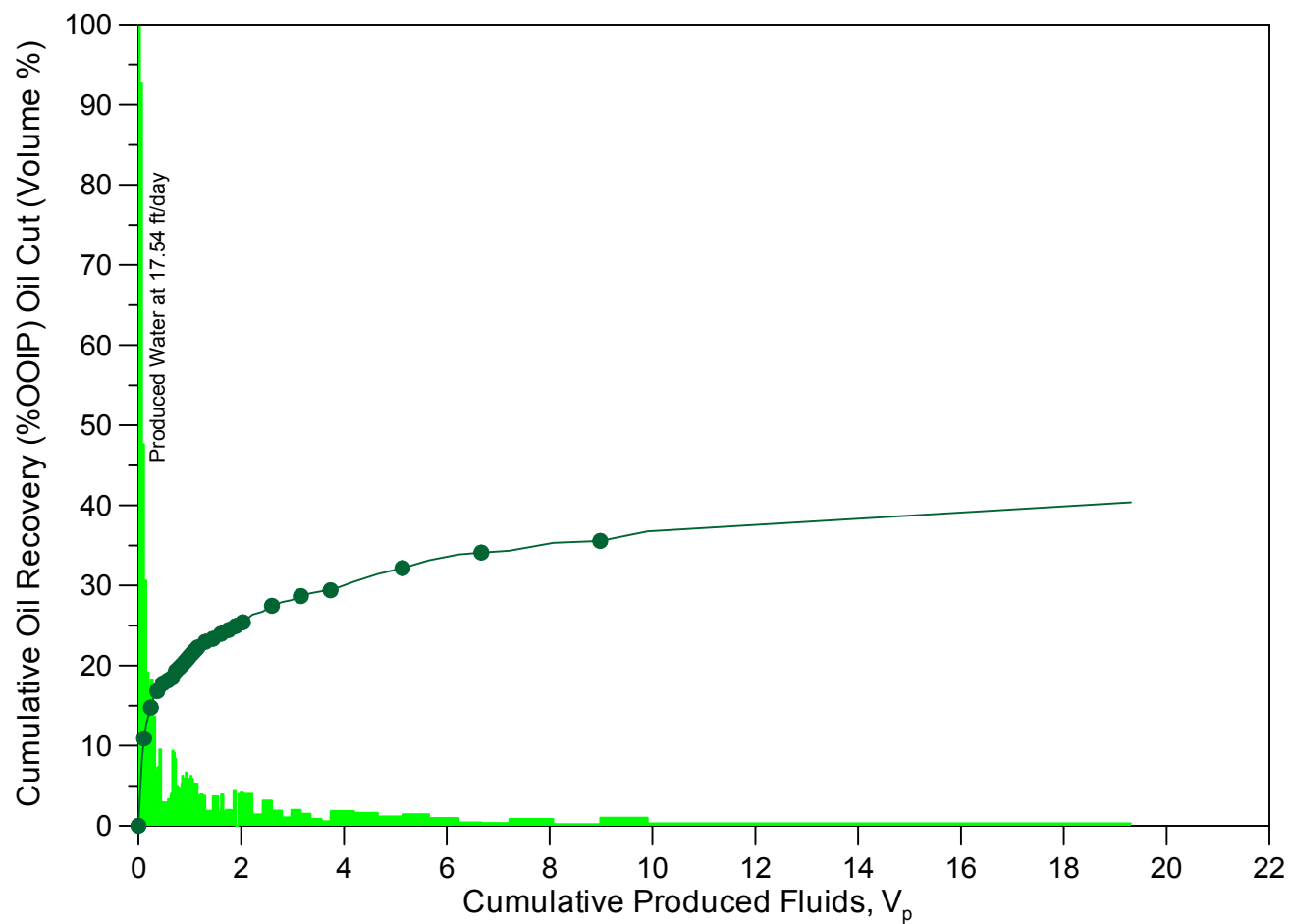
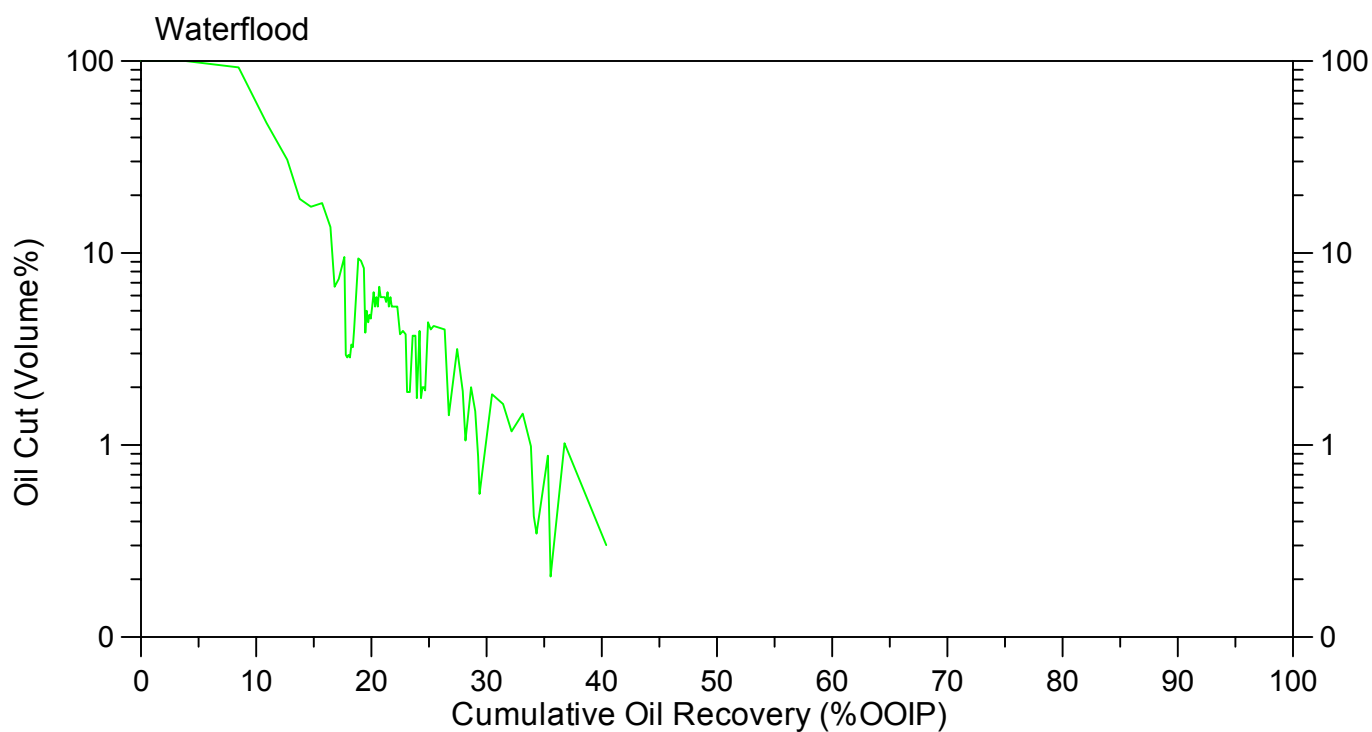




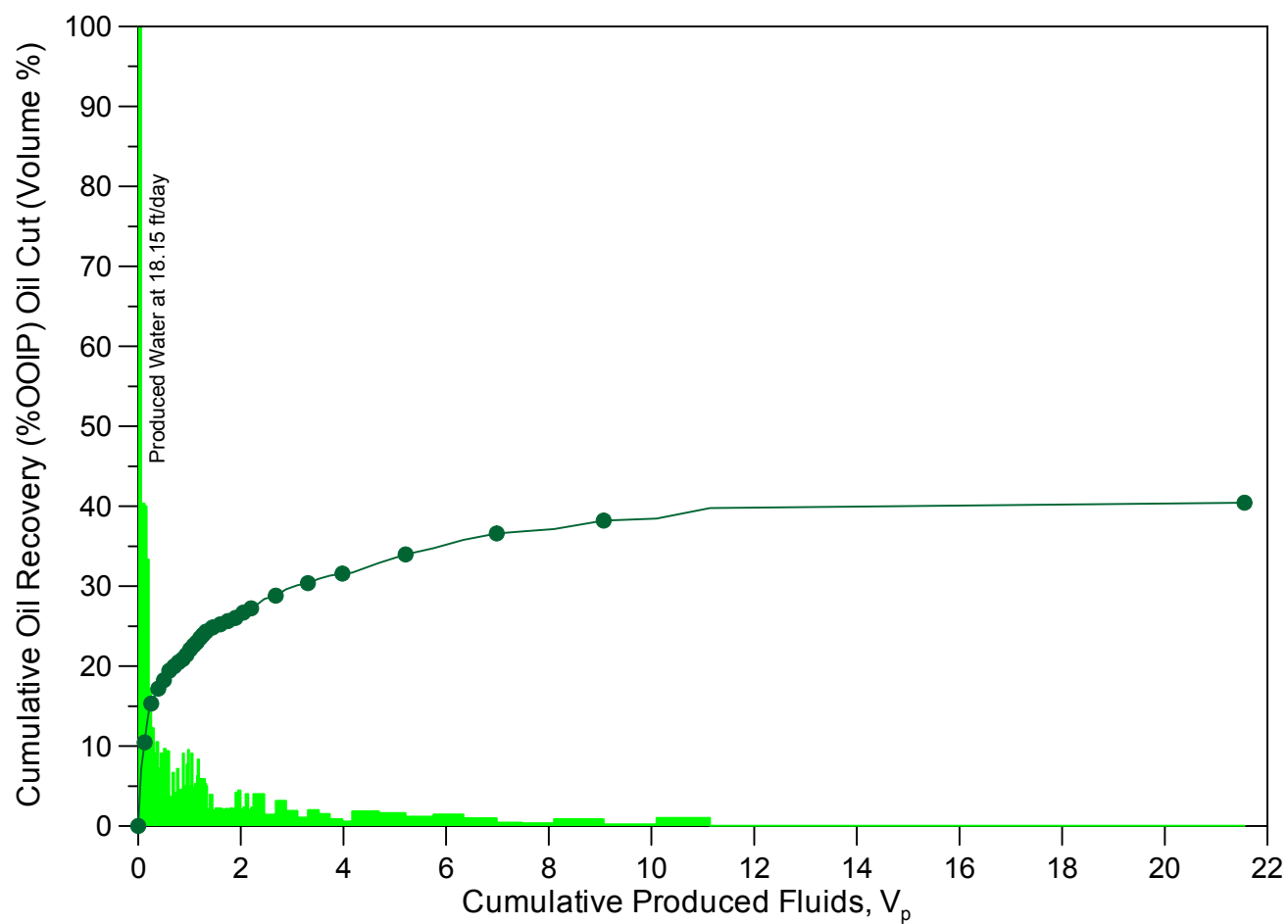
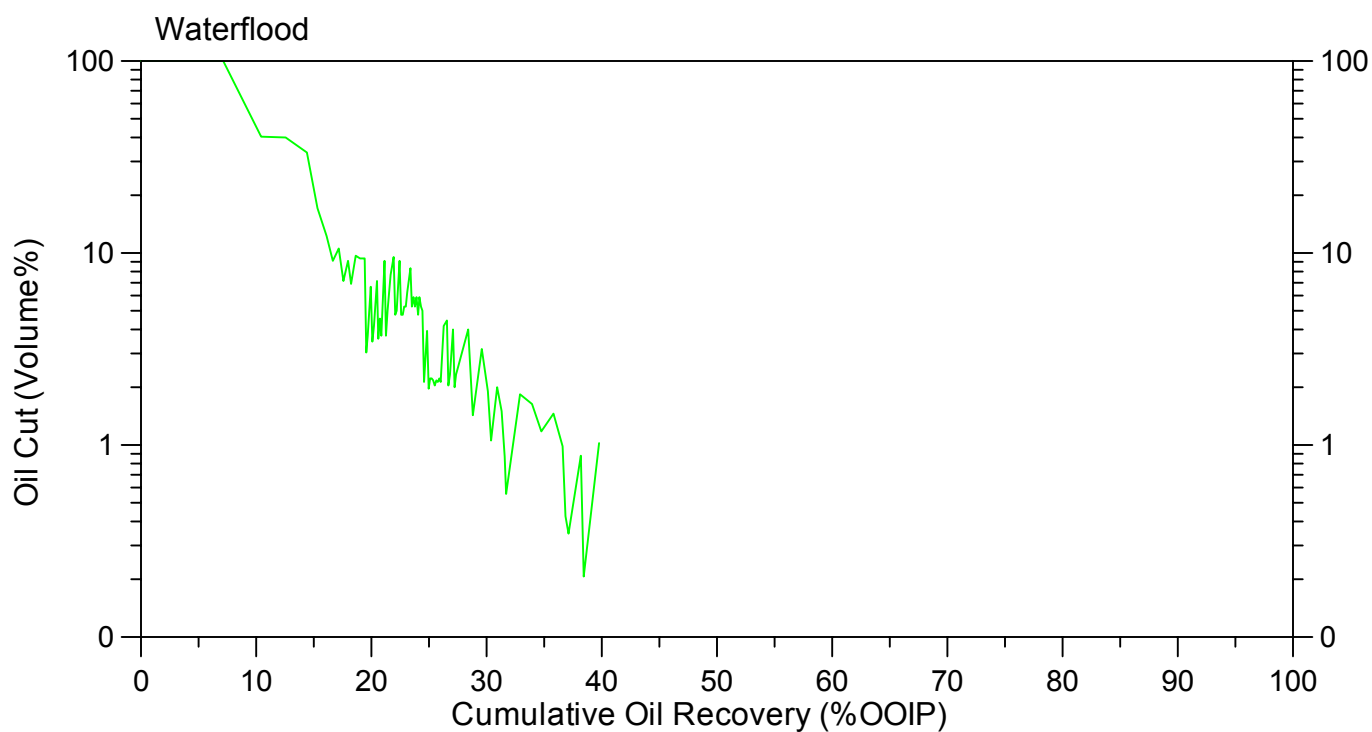




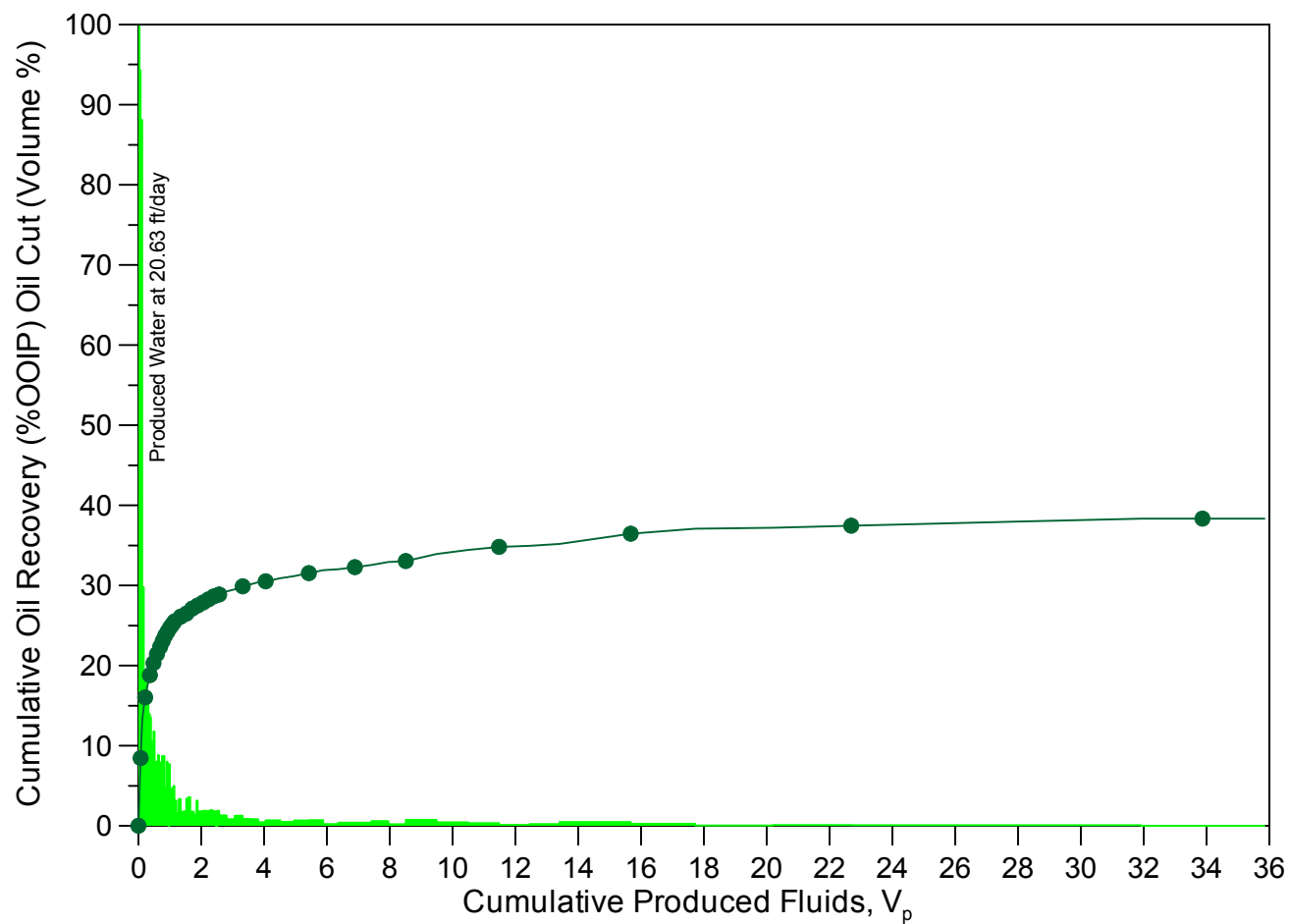
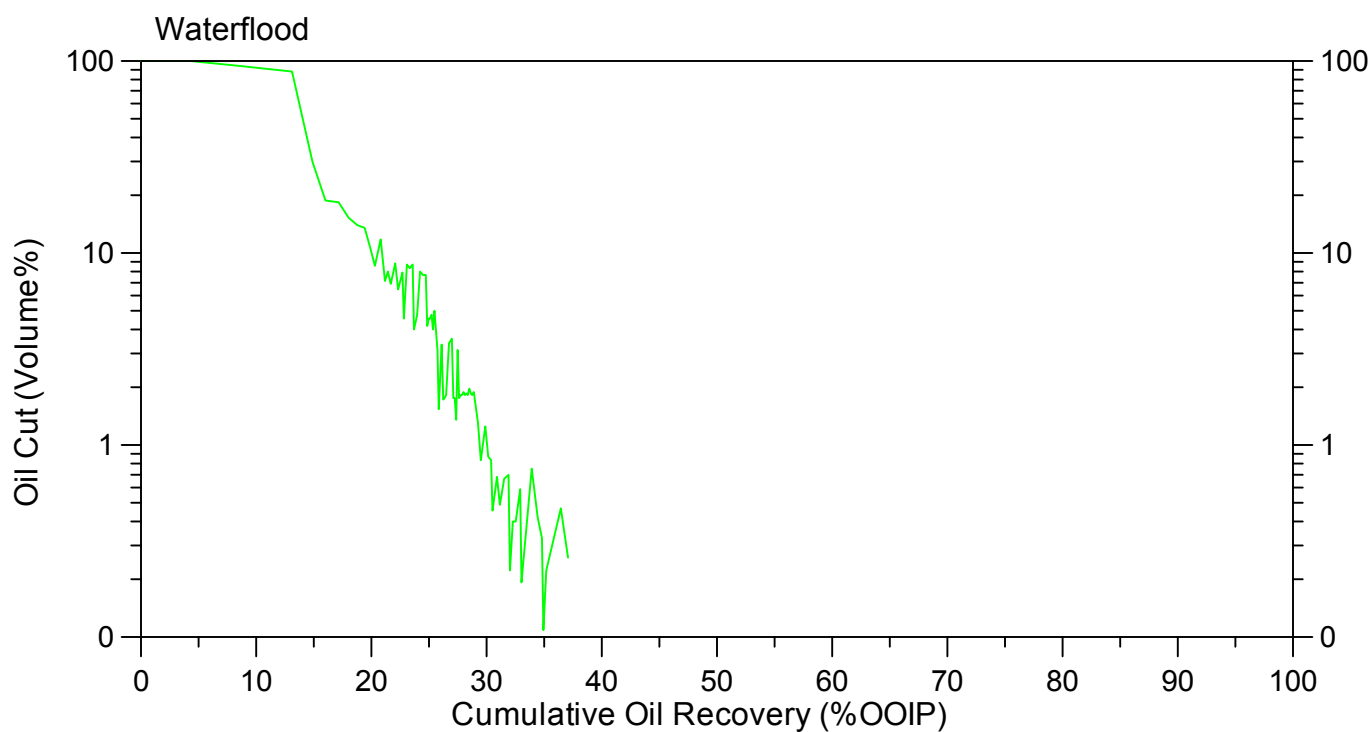
Warner Linear Coreflood 1L



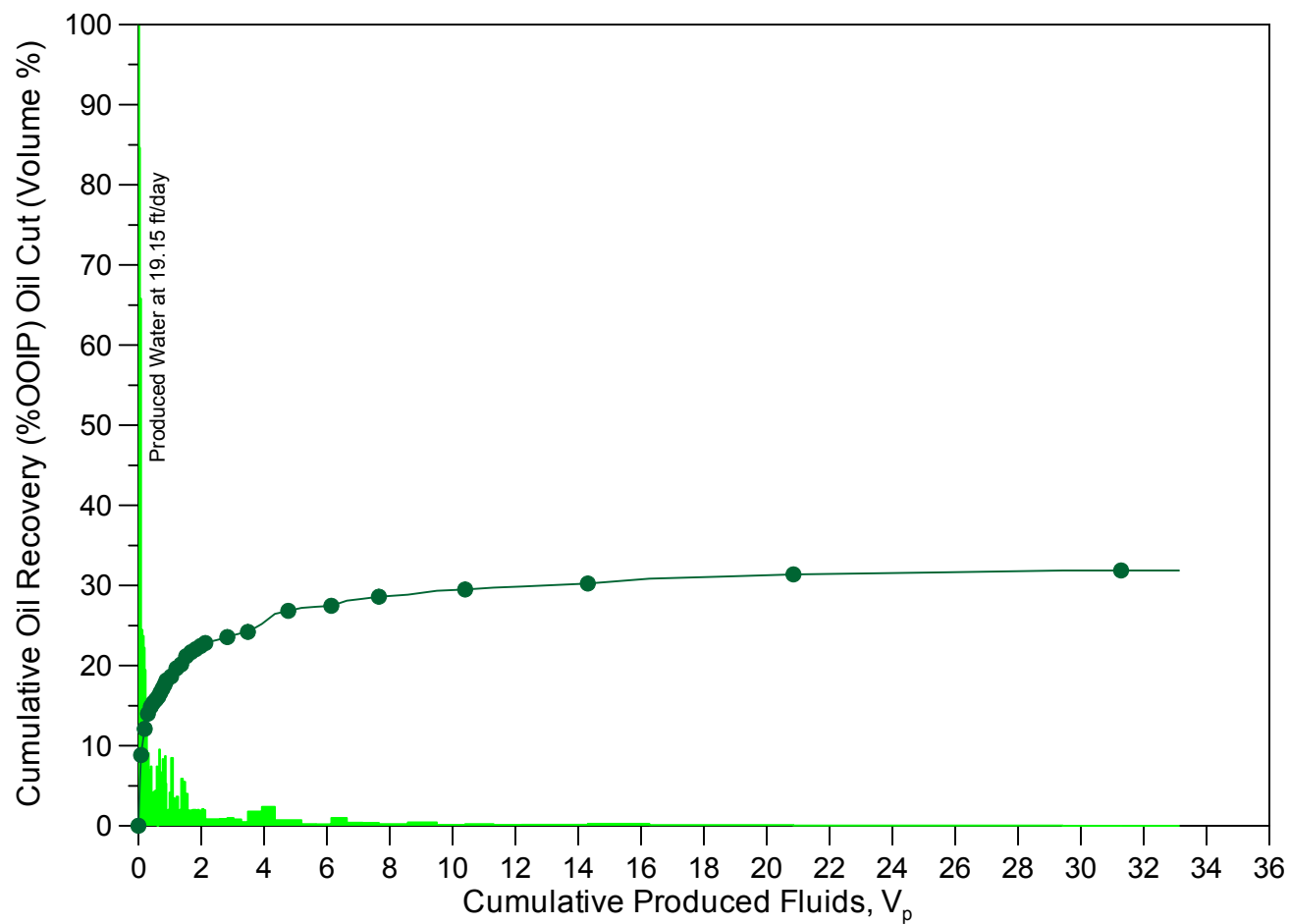
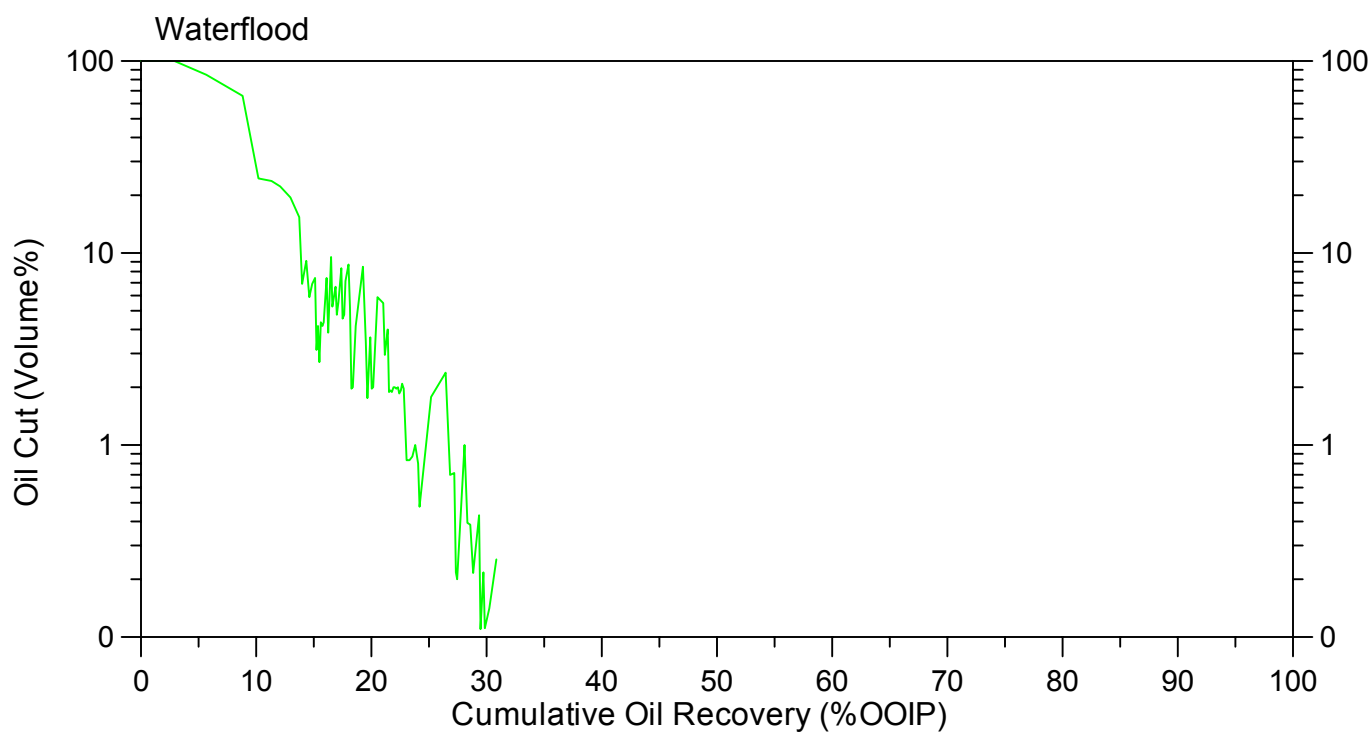
Warner Linear Coreflood 2L



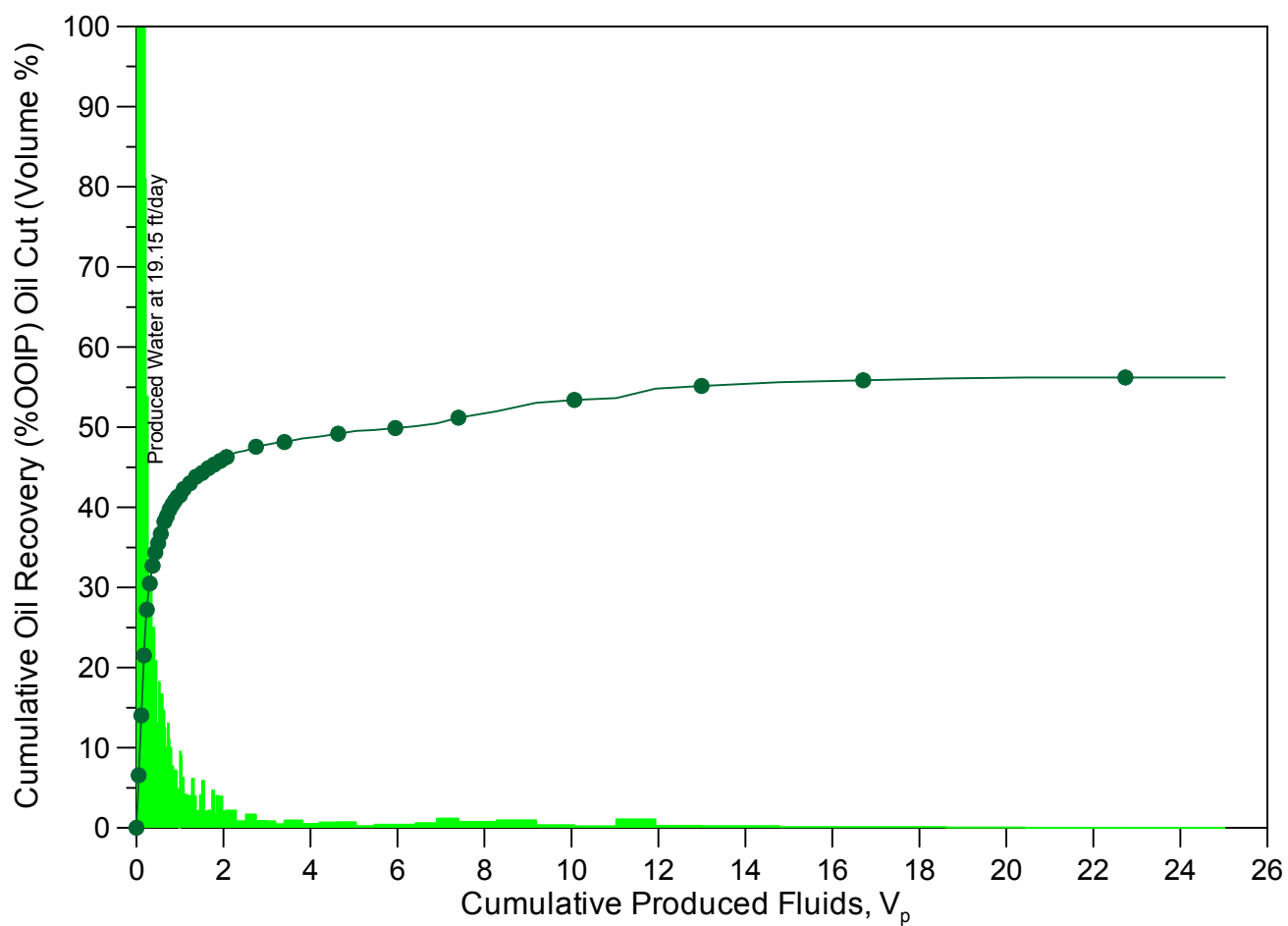
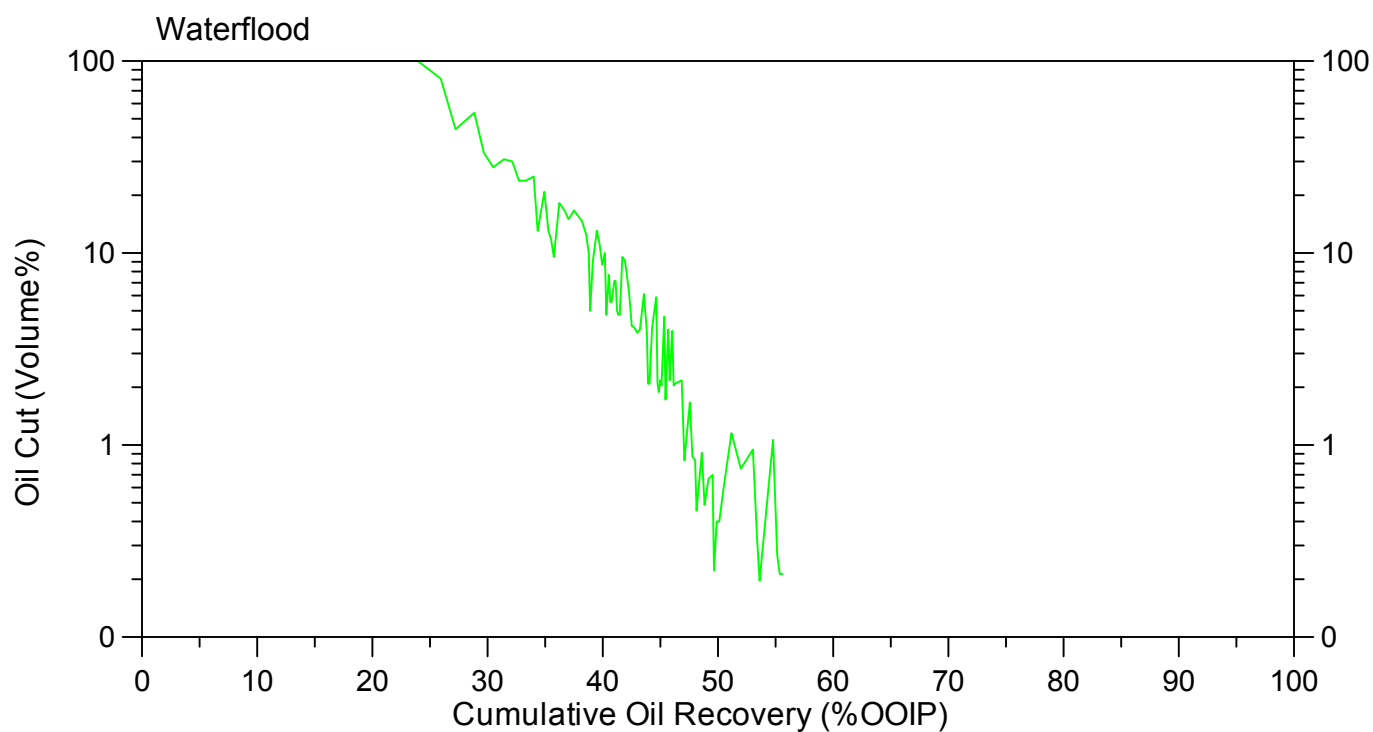
Warner Linear Coreflood 3L



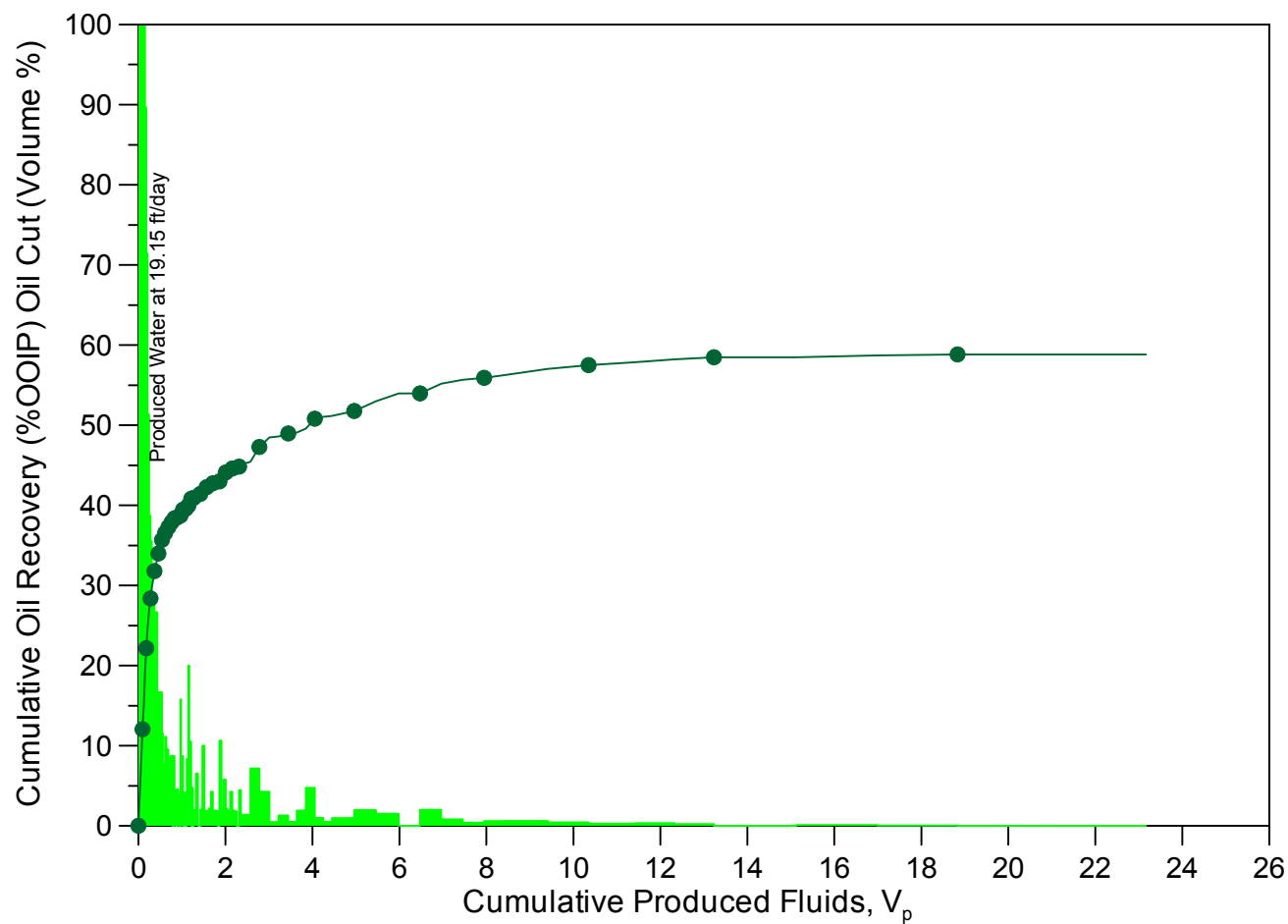
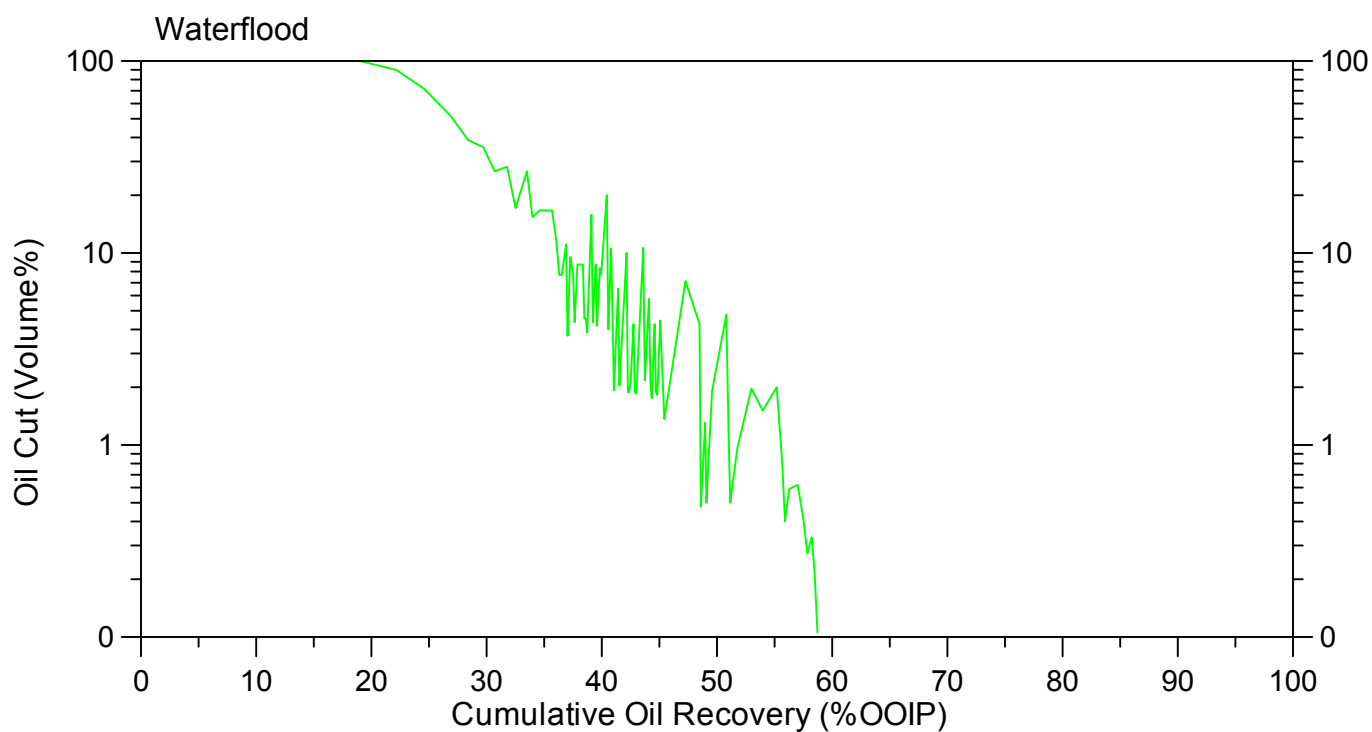
Warner Linear Coreflood 4L



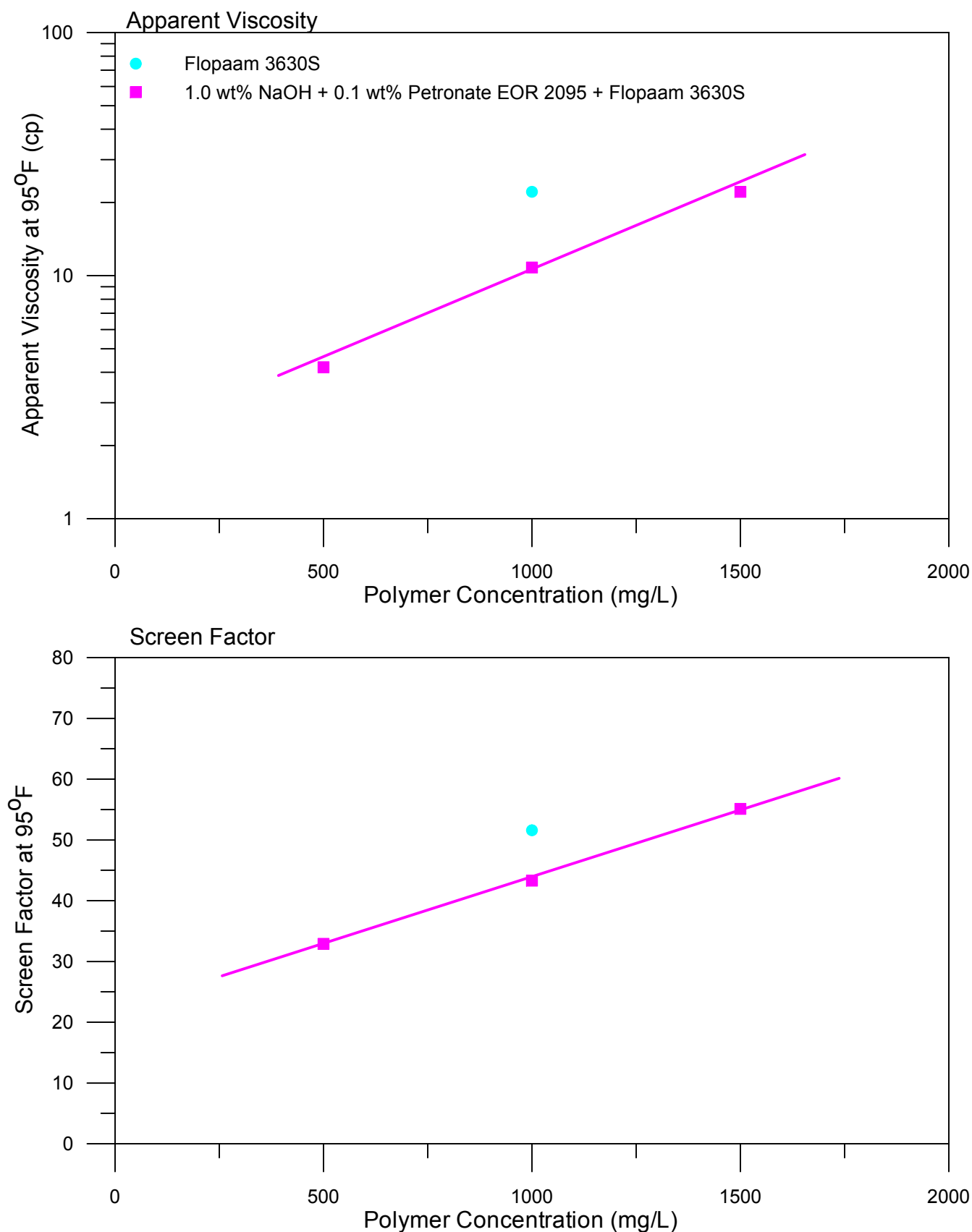
Warner Linear Coreflood 5L



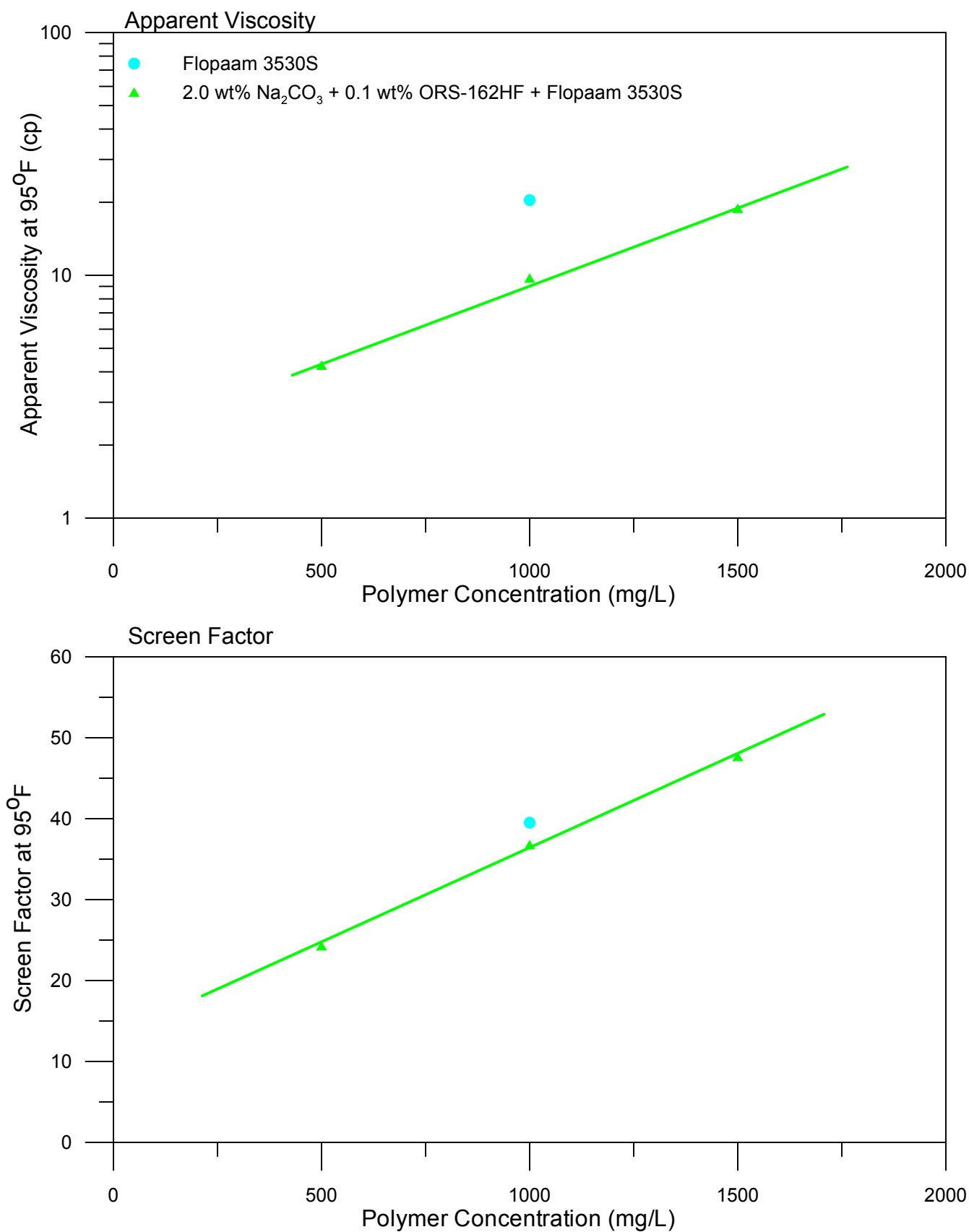
Warner Linear Coreflood 6L



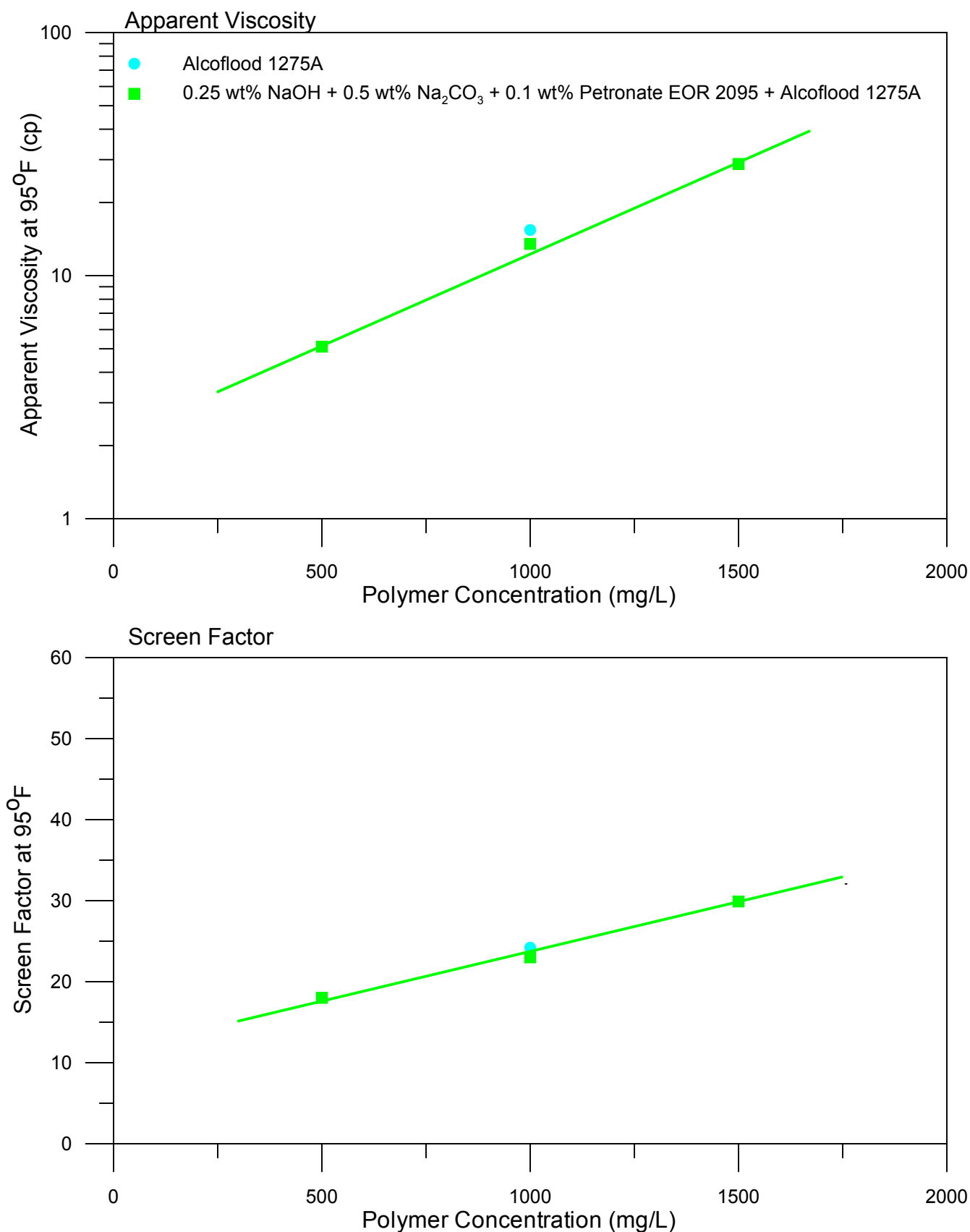
Warner Linear Run 1
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



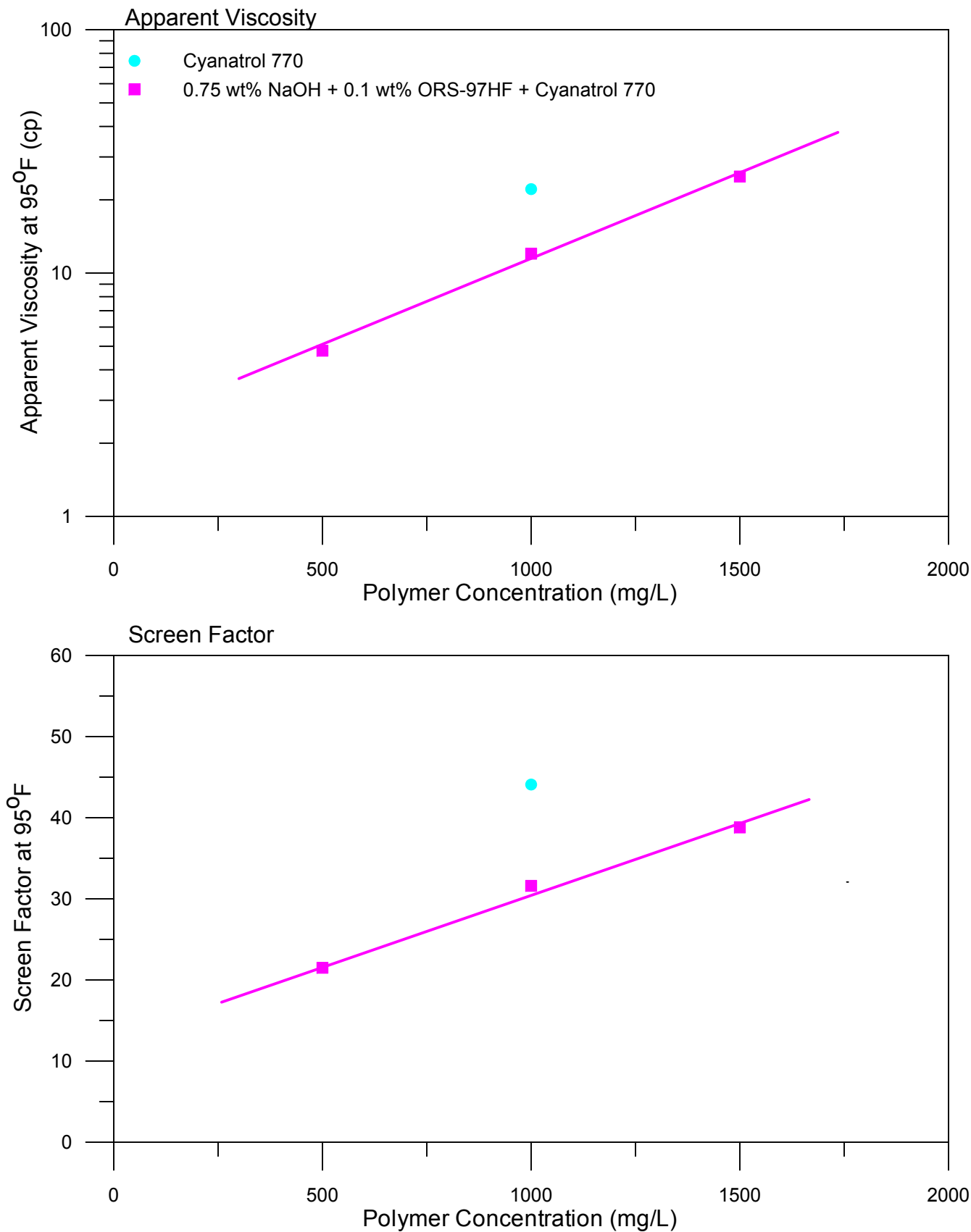
Warner Linear Run 2
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



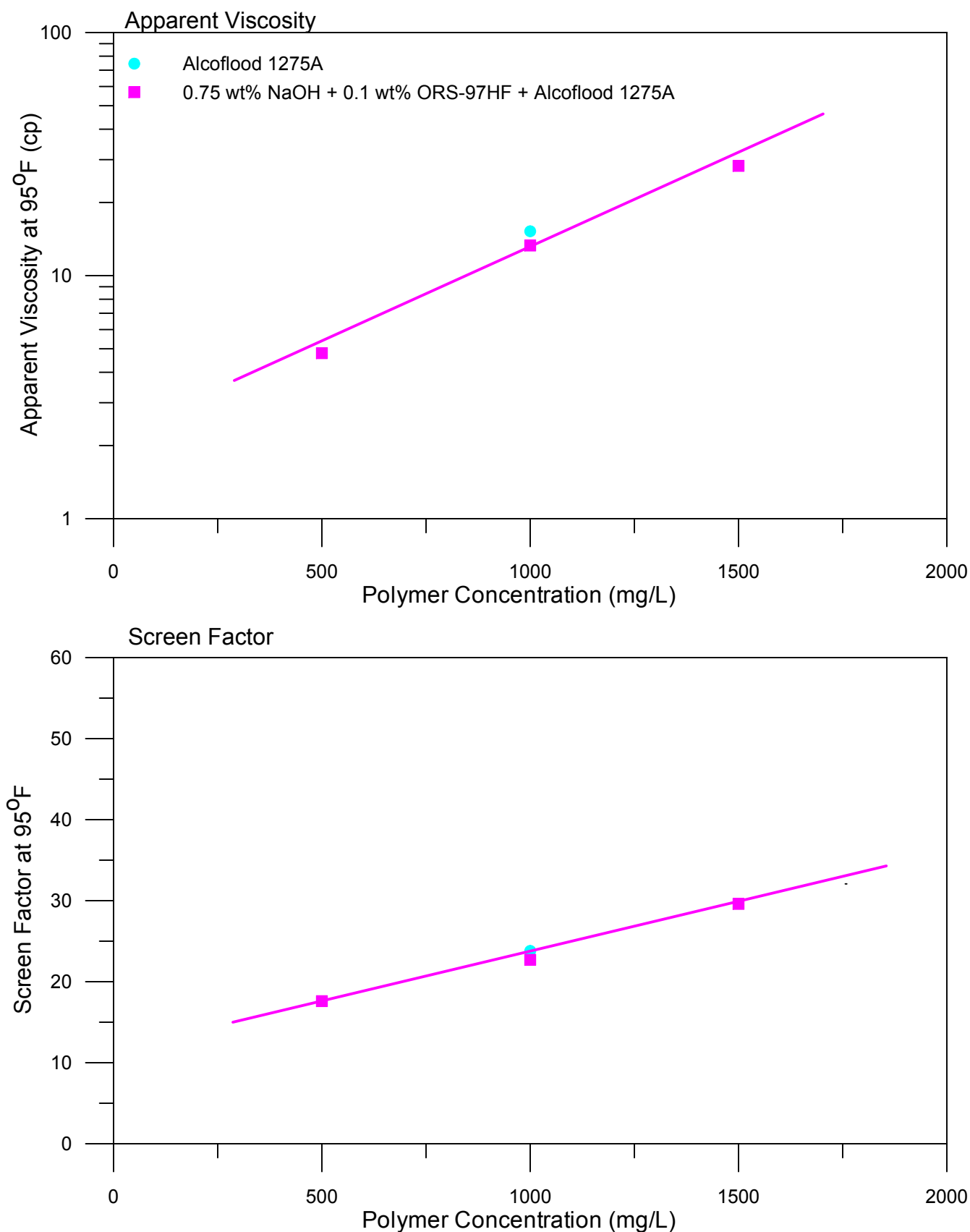
Warner Linear Run 3
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



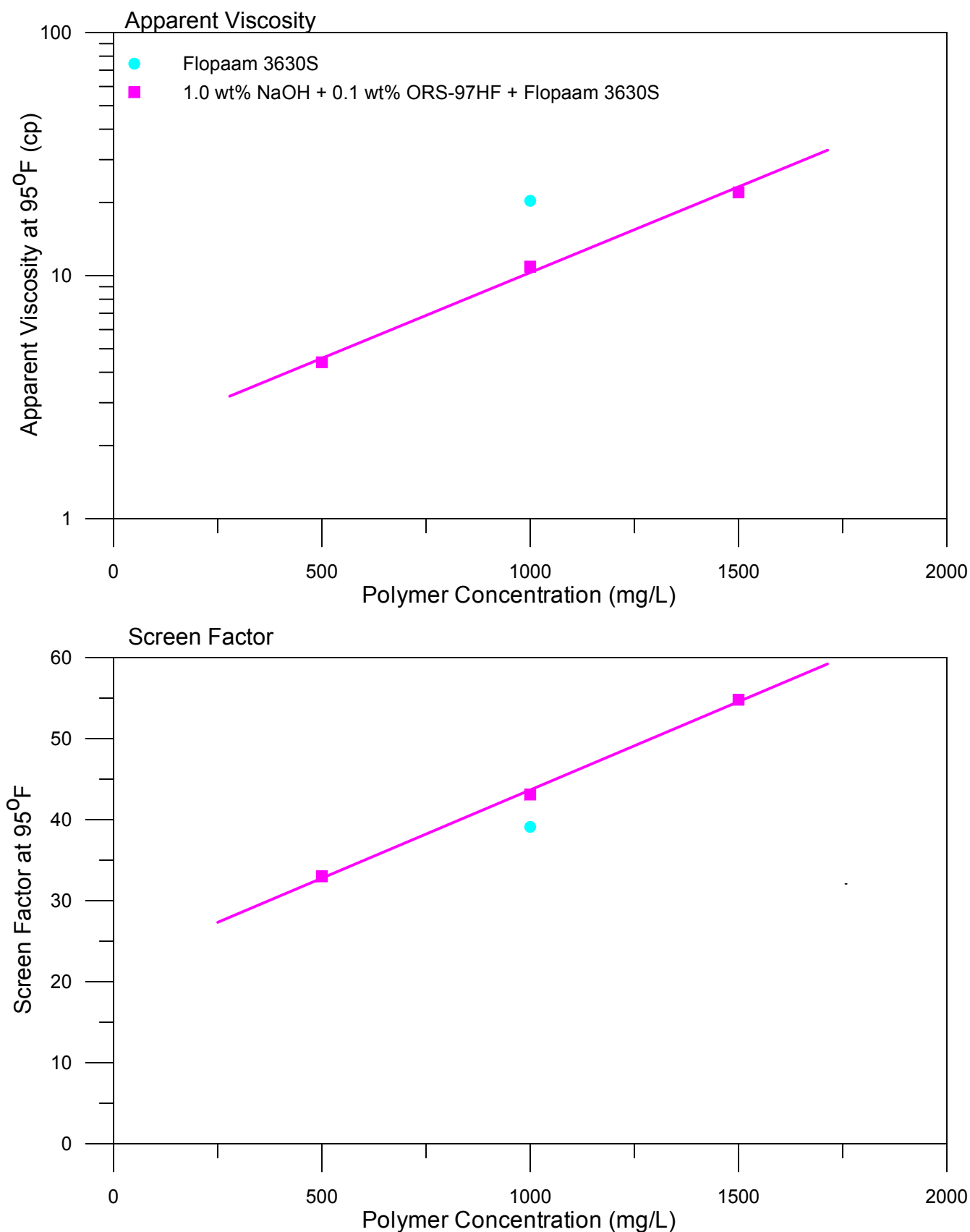
Warner Linear Run 4
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



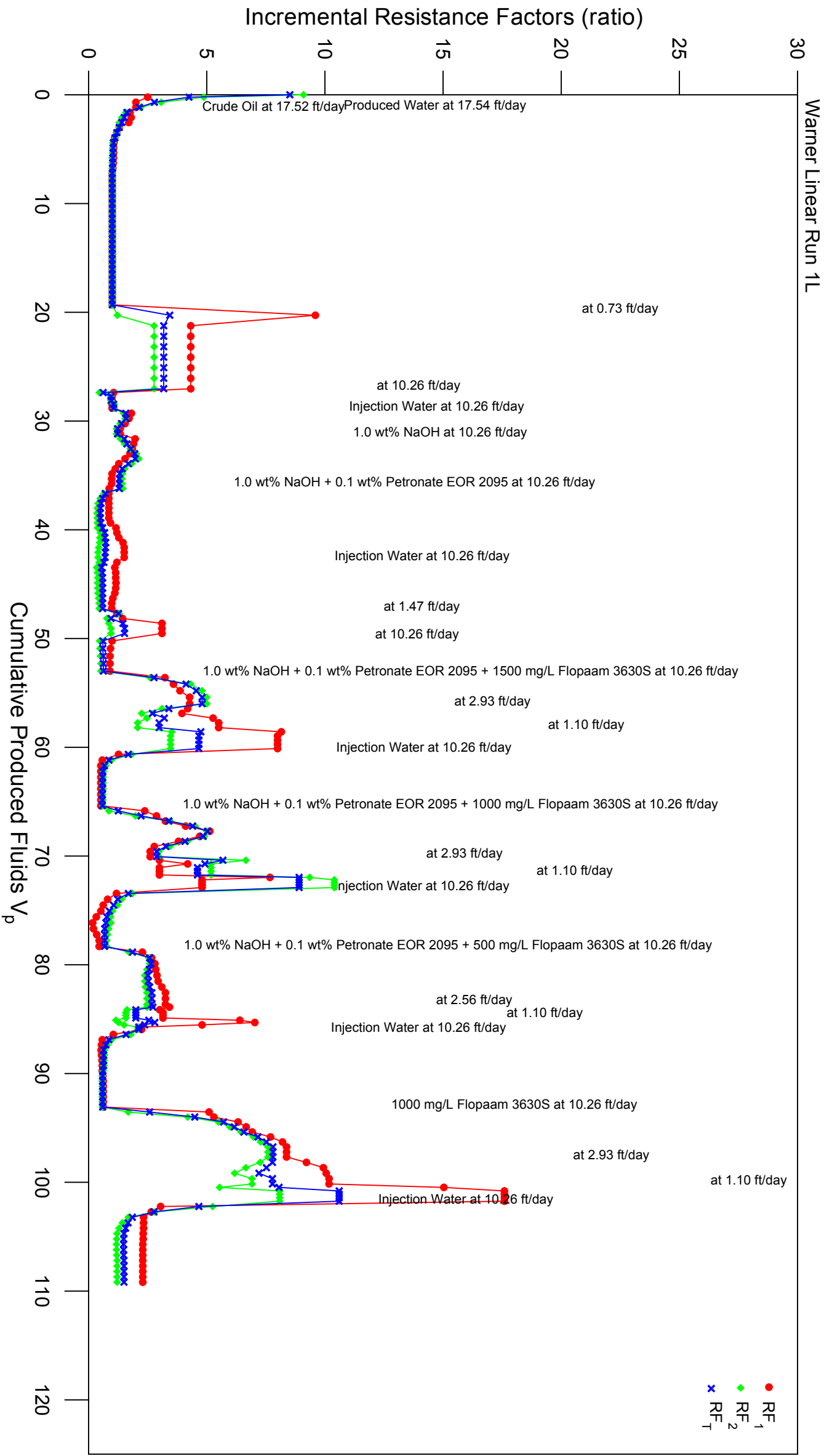
Warner Linear Run 5
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



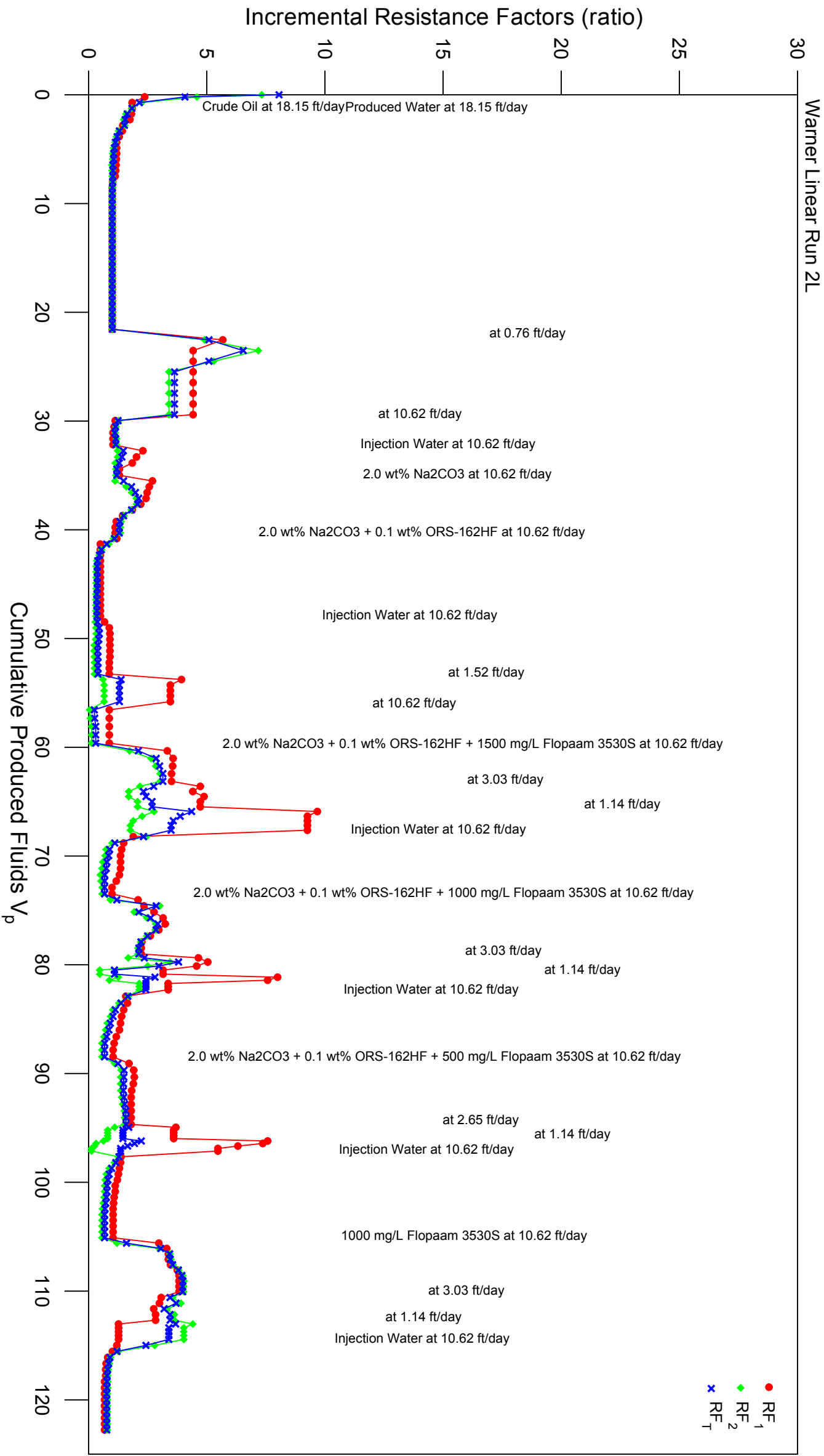
Warner Linear Run 6
Apparent Viscosity and Screen Factor
versus Polymer Concentration at 95°F
dissolved in Warner Softened Injection Water



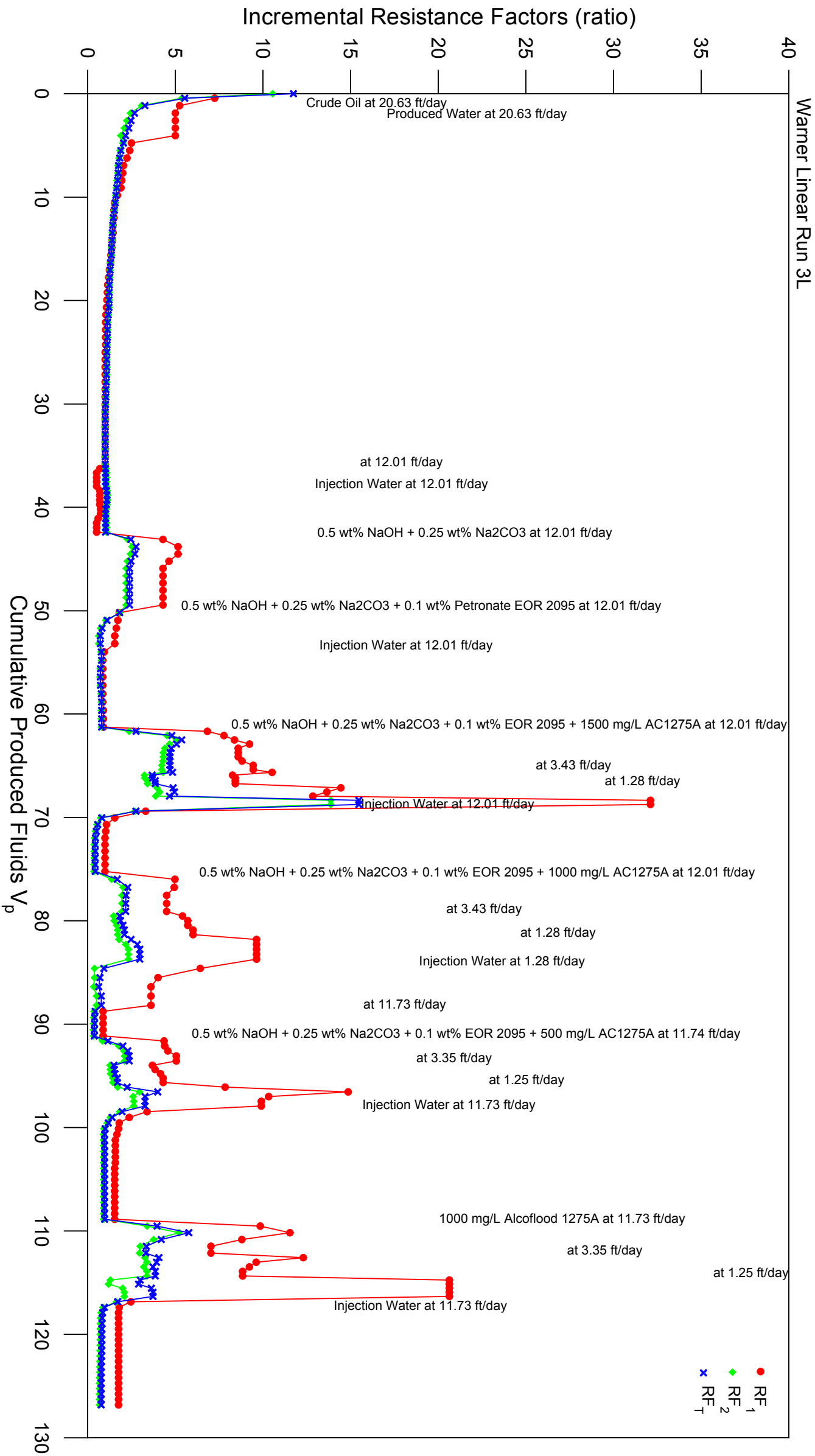
Incremental Resistance Factors versus Cumulative Produced Fluids

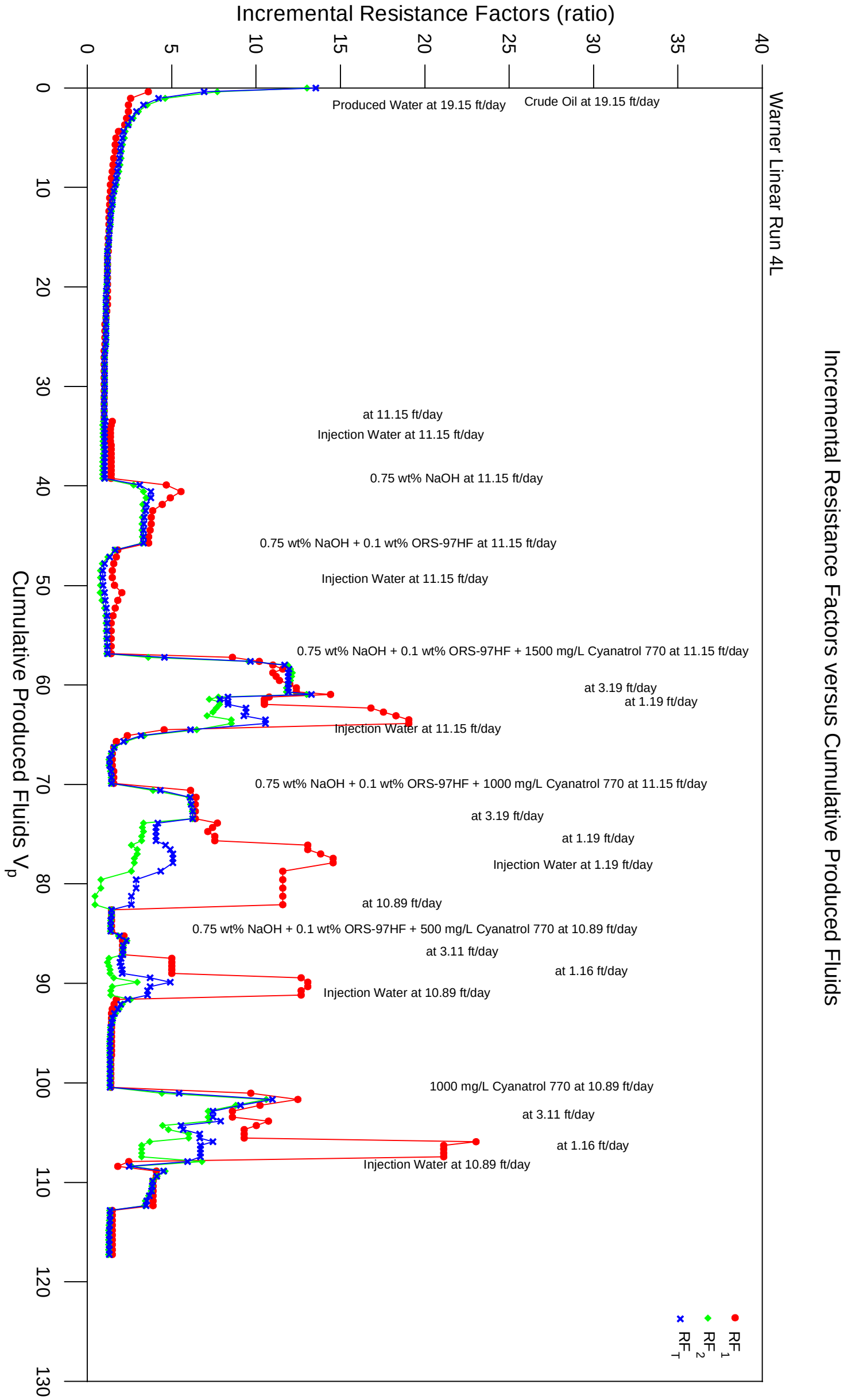


Incremental Resistance Factors versus Cumulative Produced Fluids

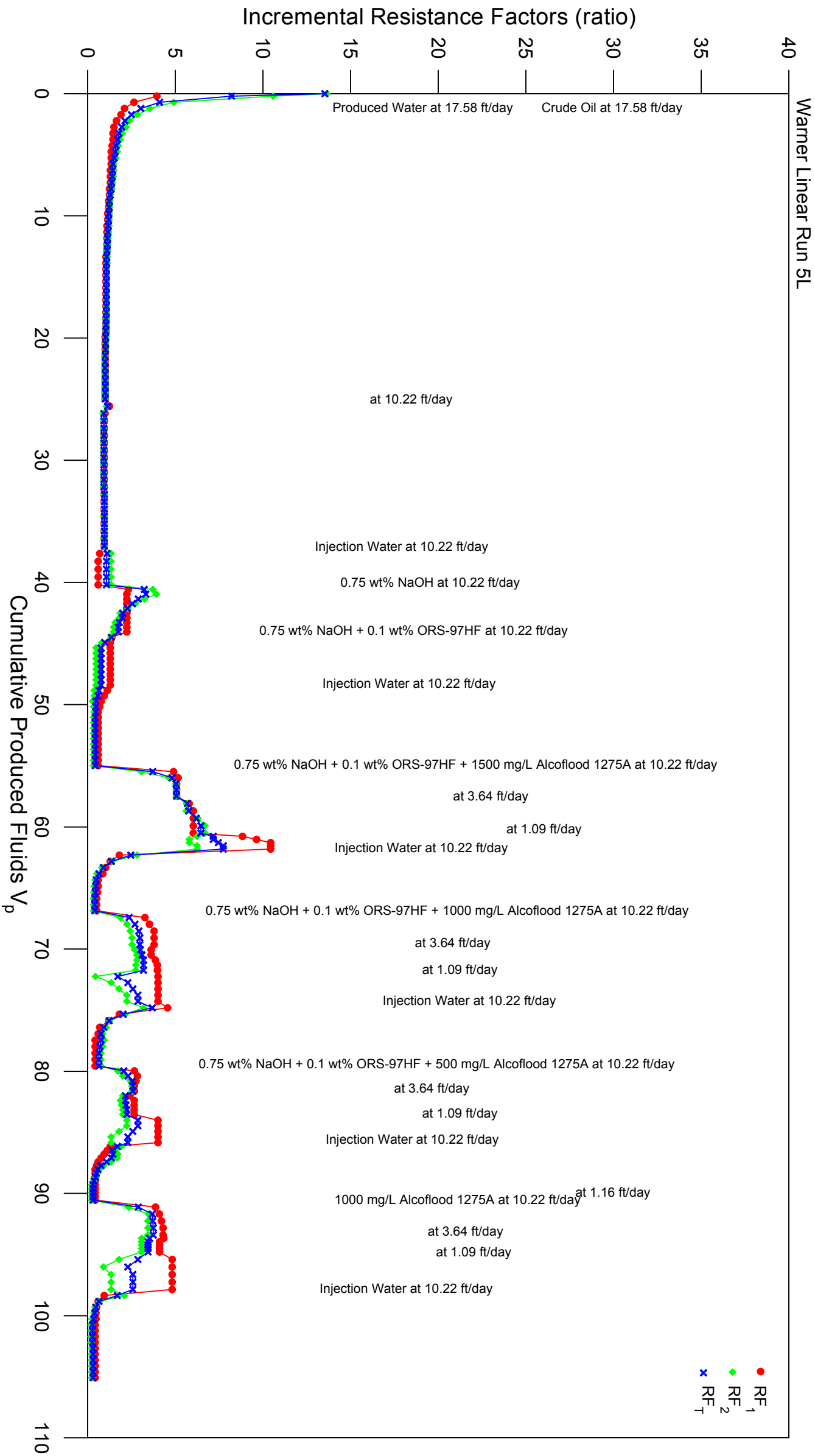


Incremental Resistance Factors versus Cumulative Produced Fluids

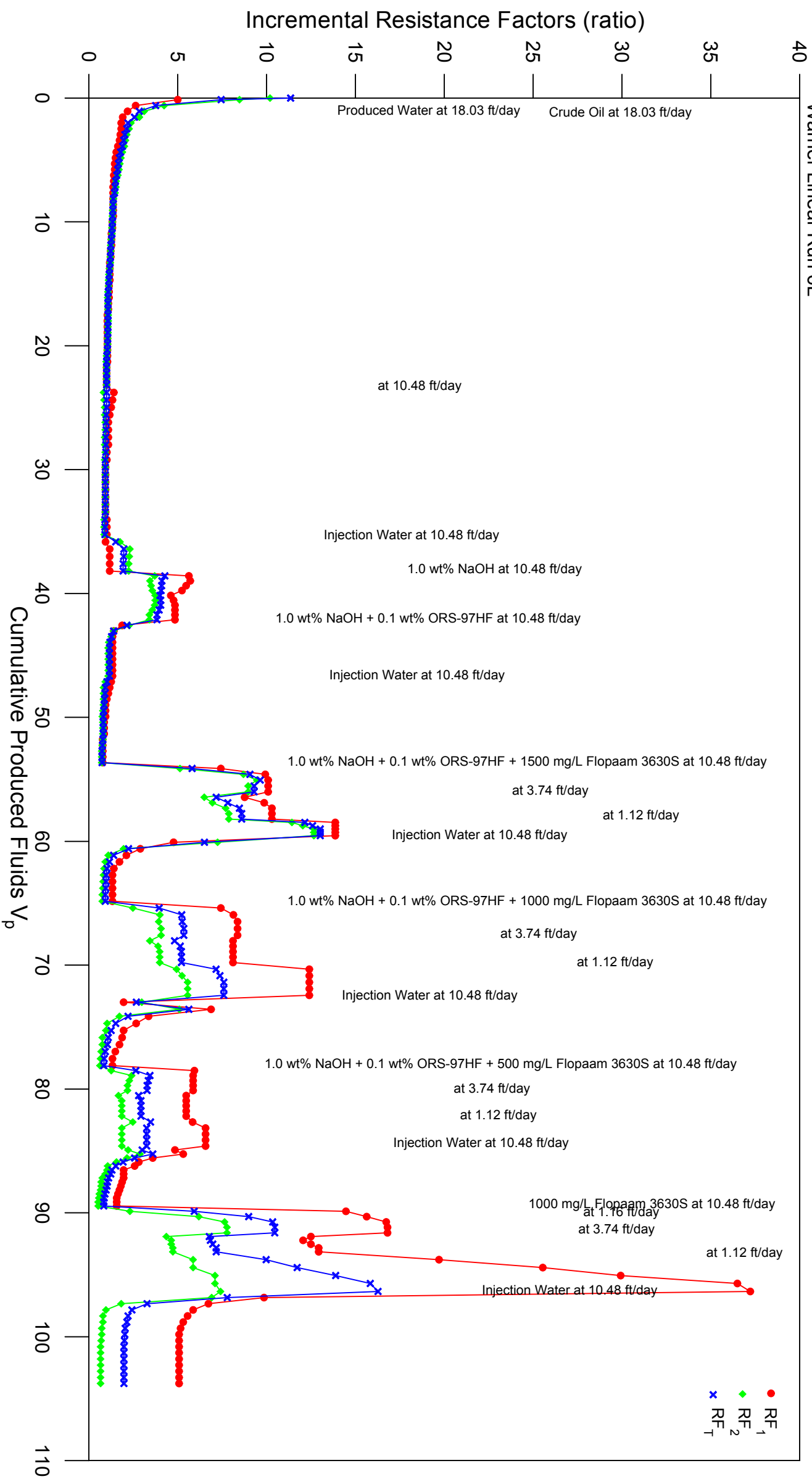




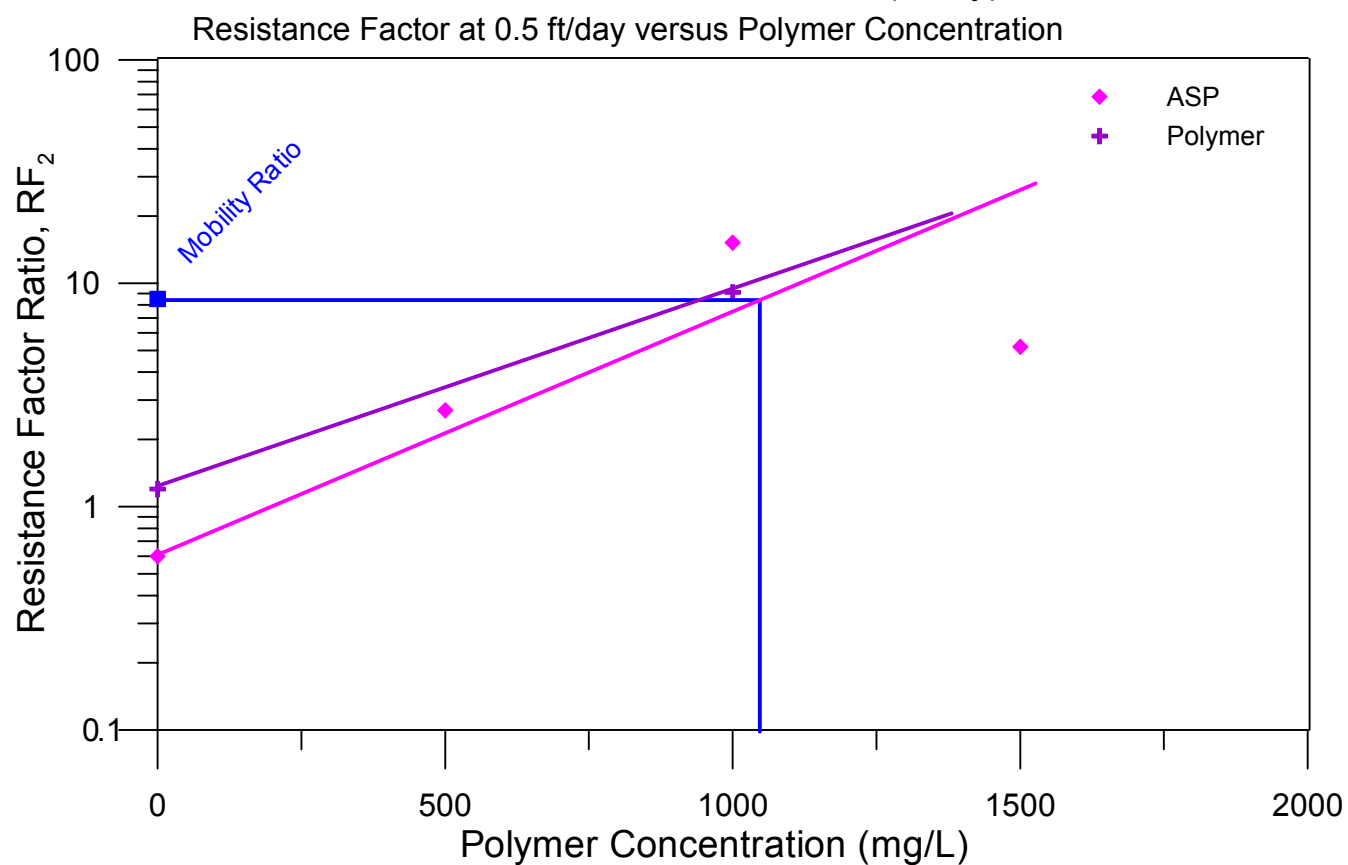
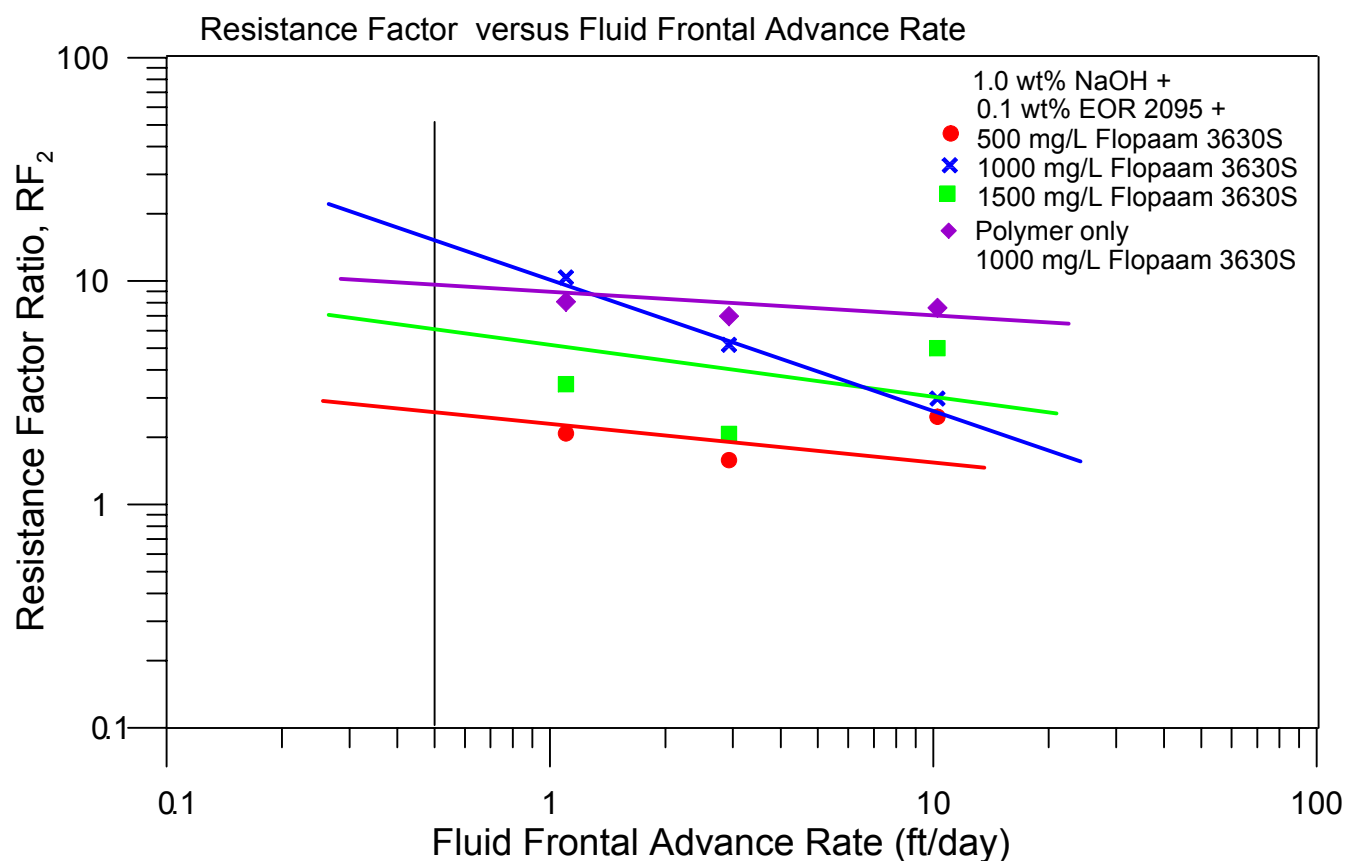
Incremental Resistance Factors versus Cumulative Produced Fluids



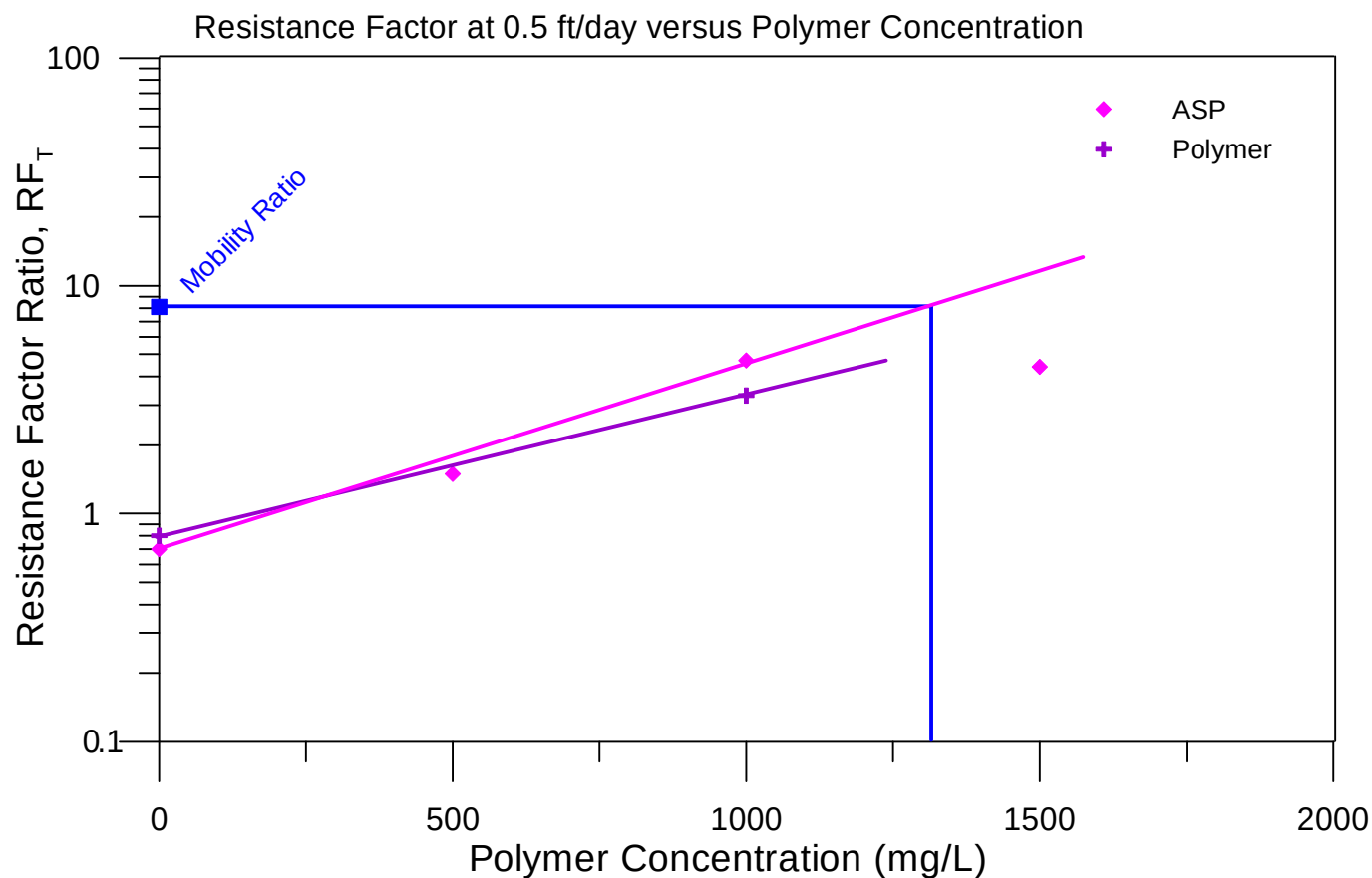
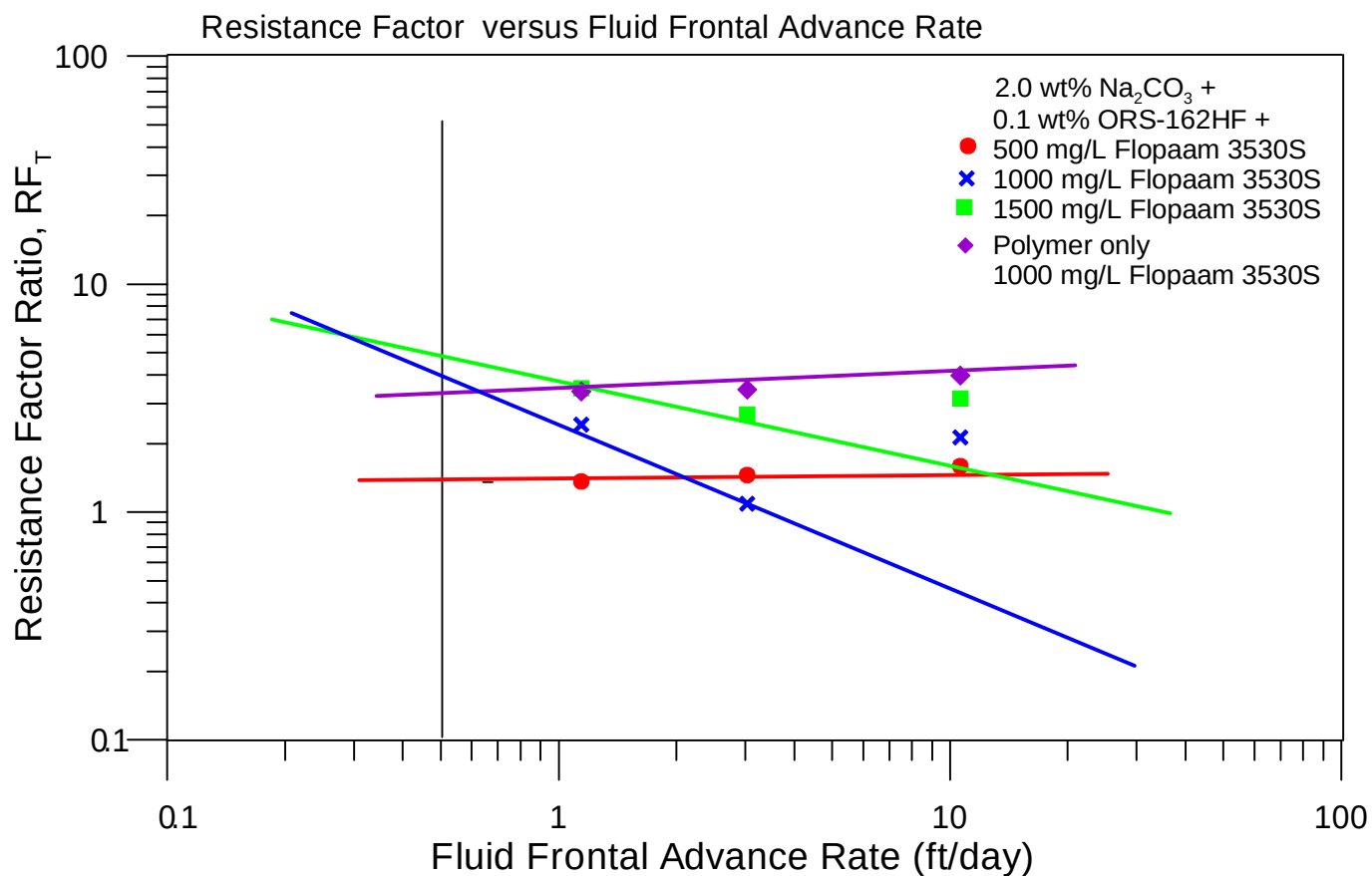
Warner Linear Run 6L



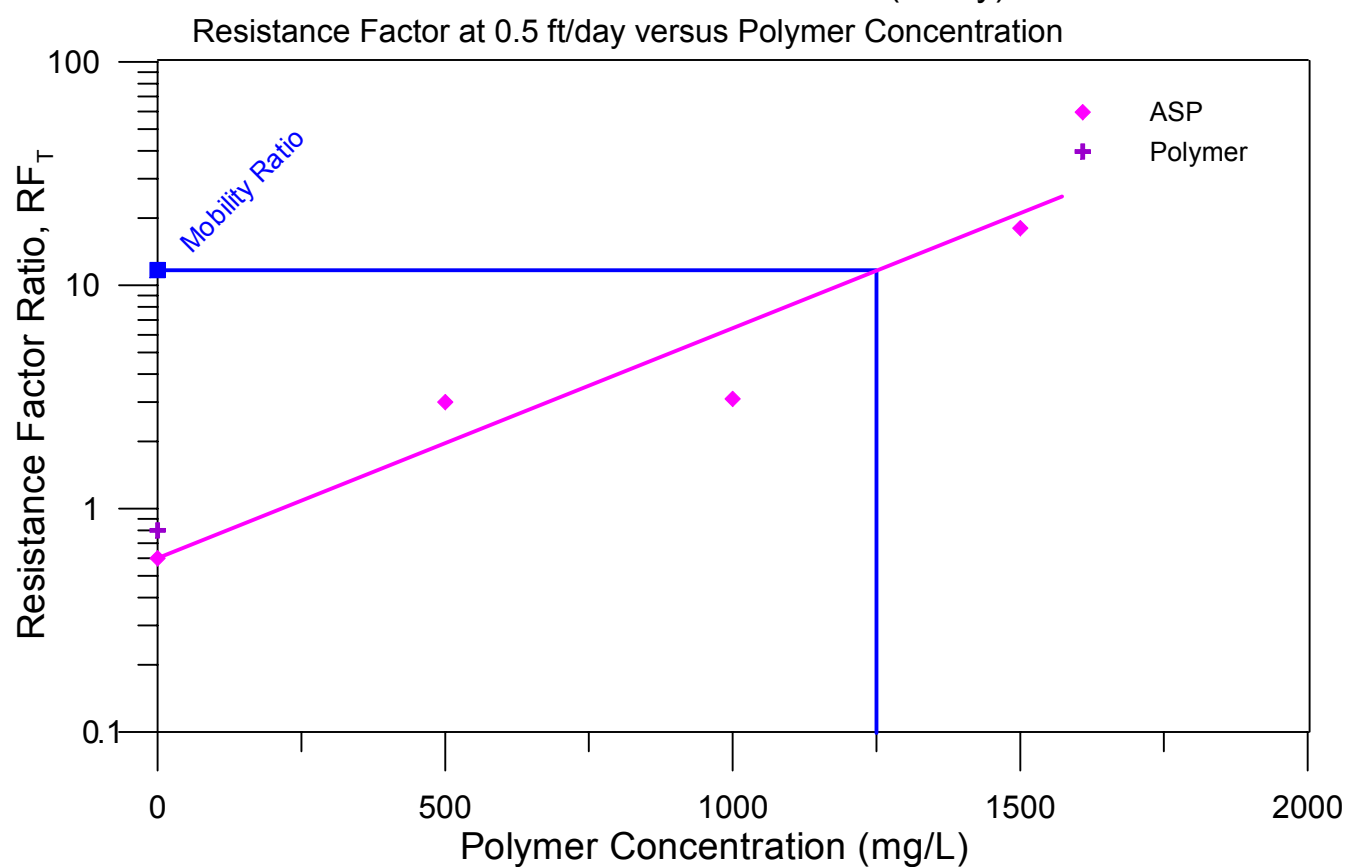
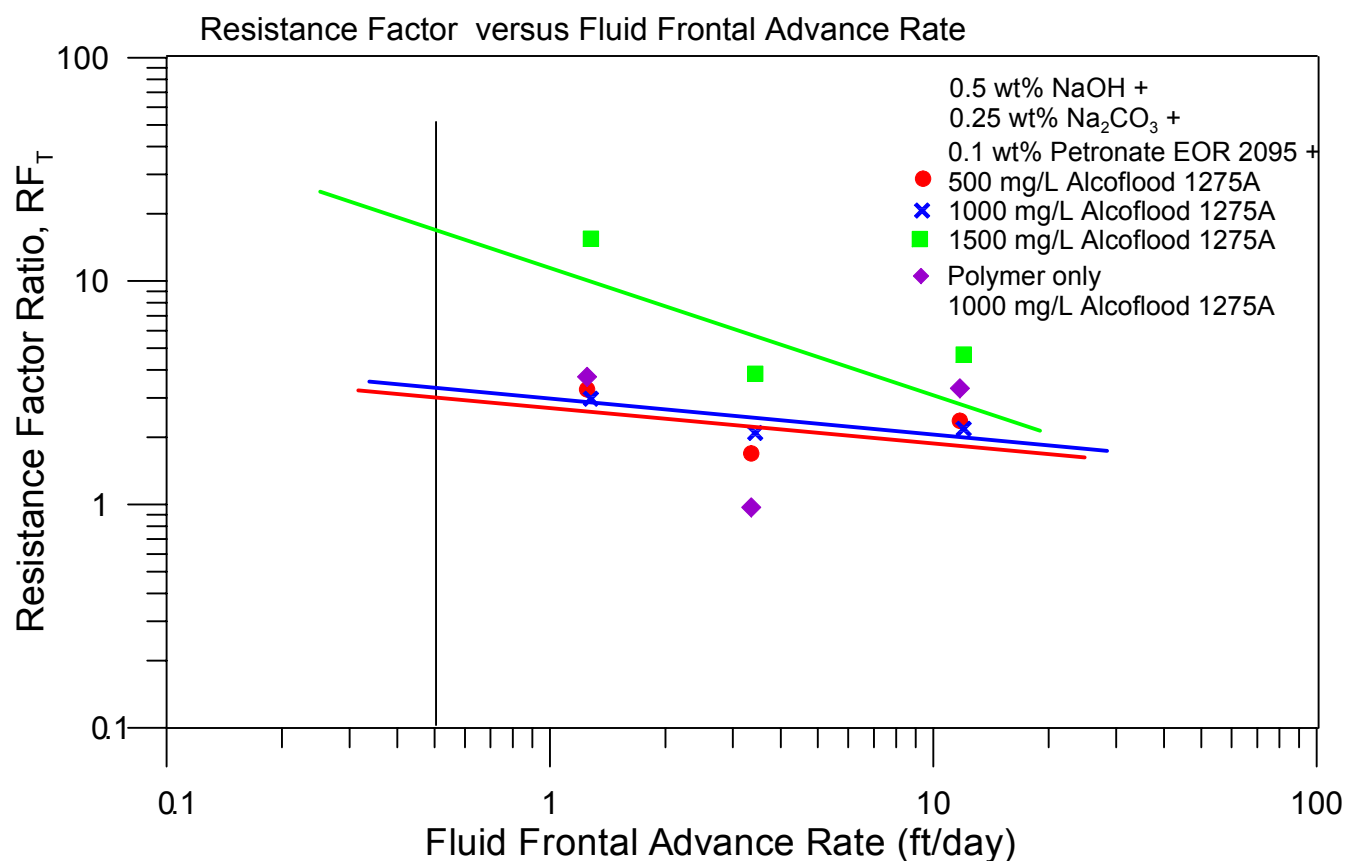
Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 1L



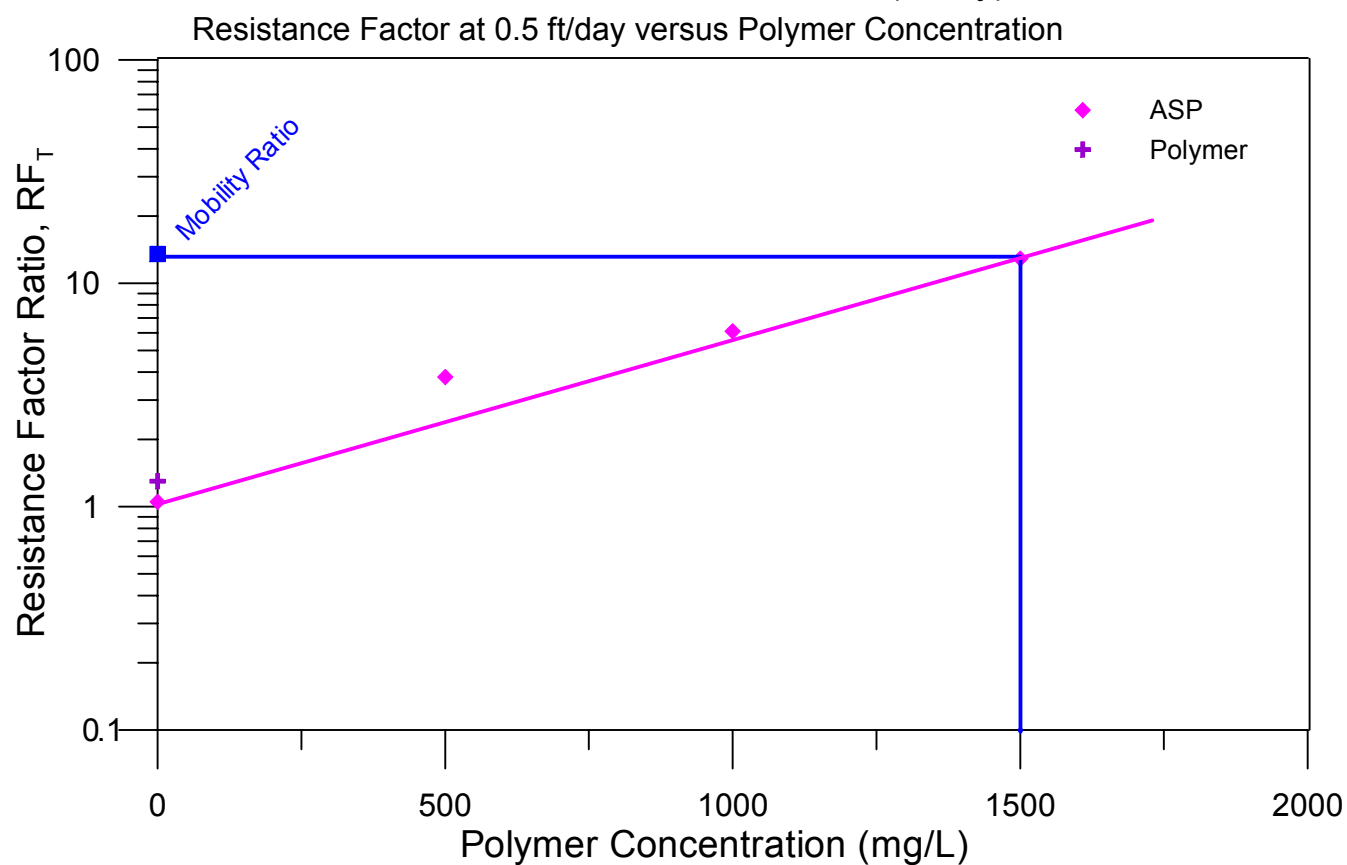
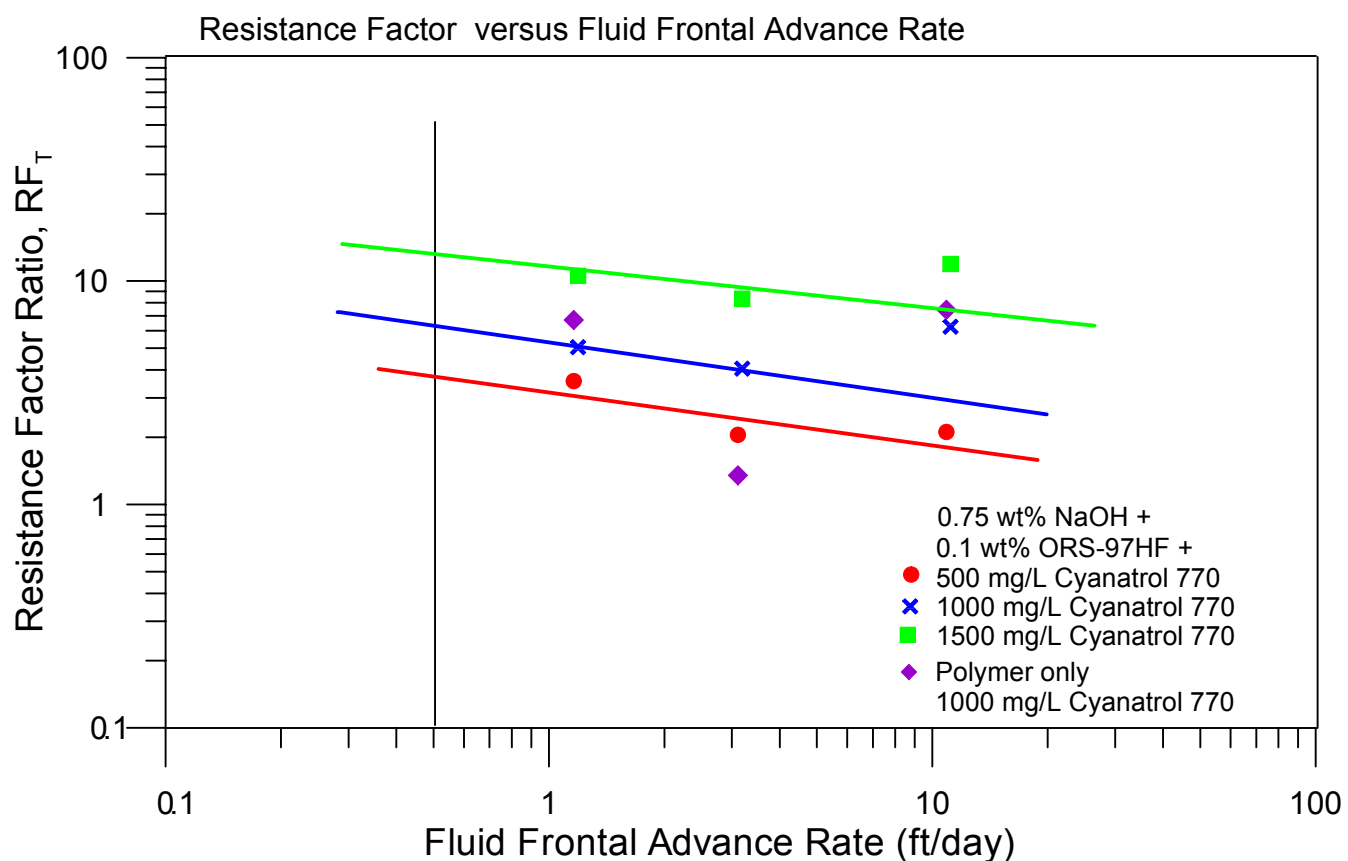
Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 2L



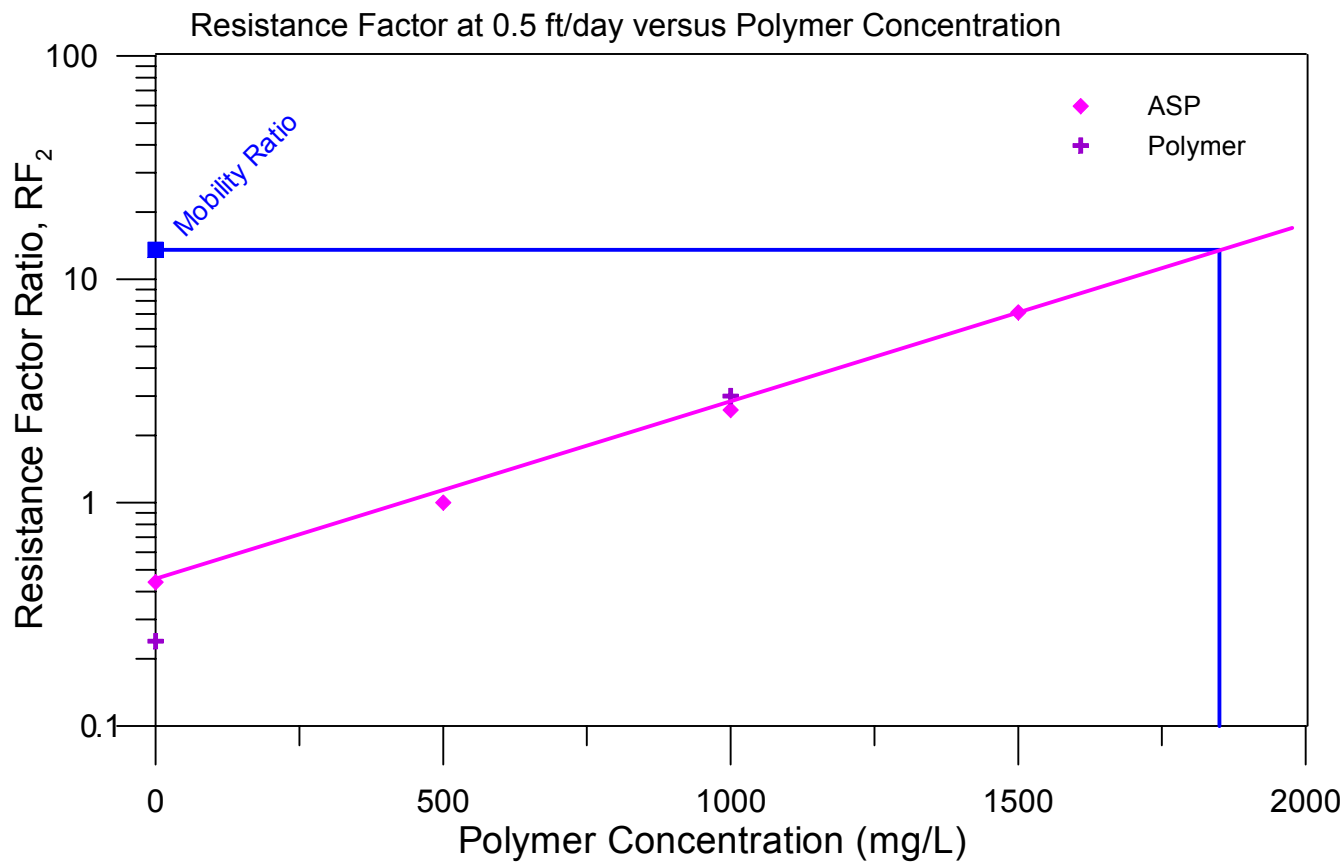
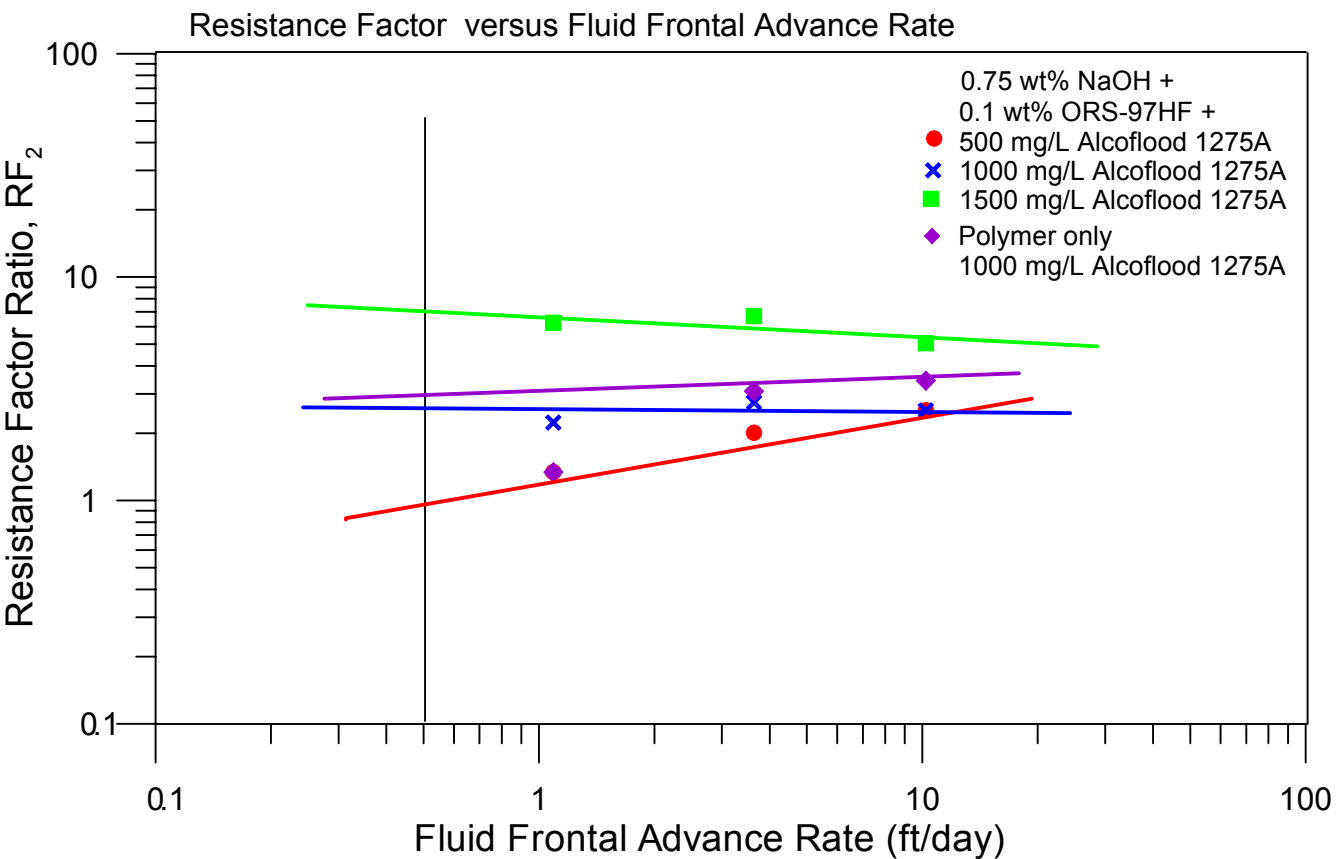
Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 3L



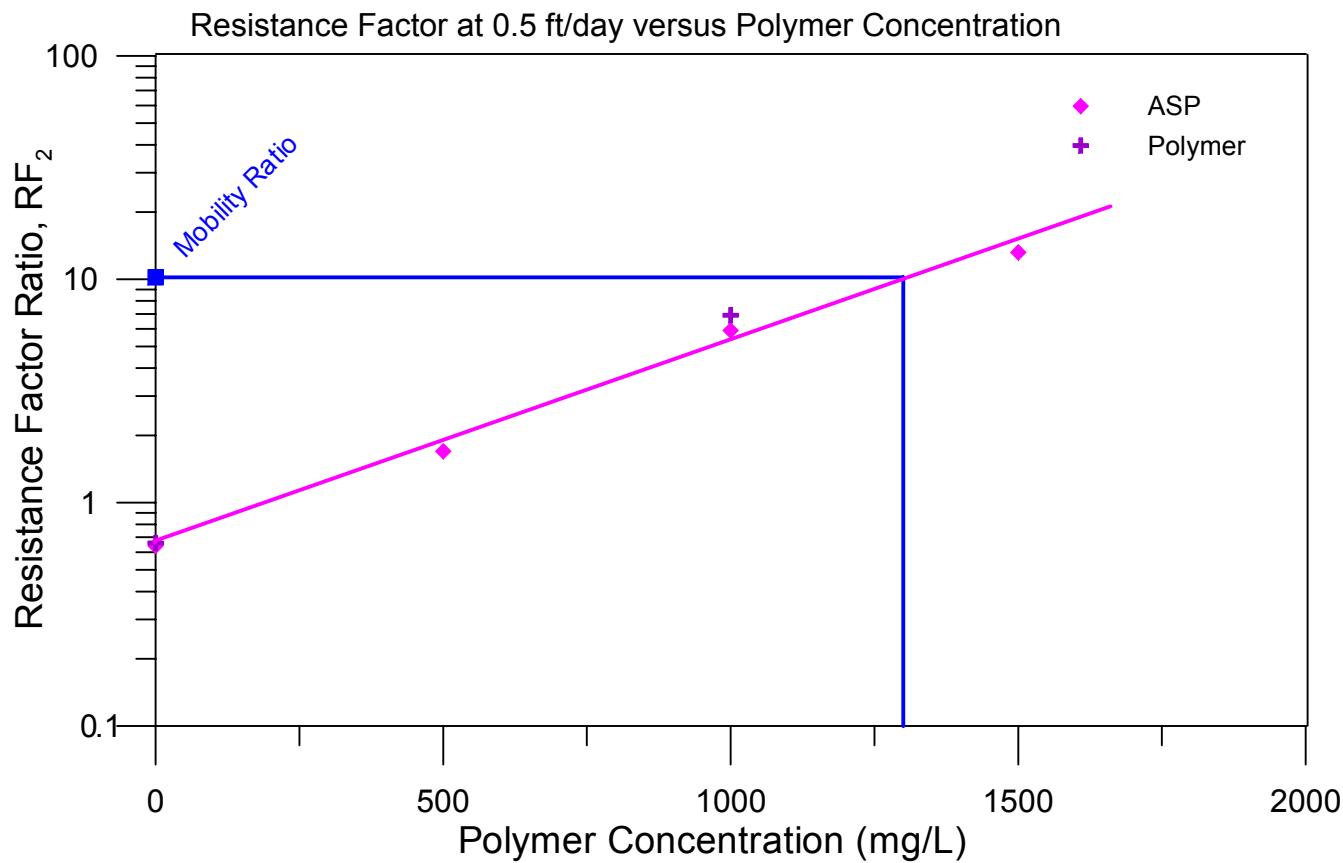
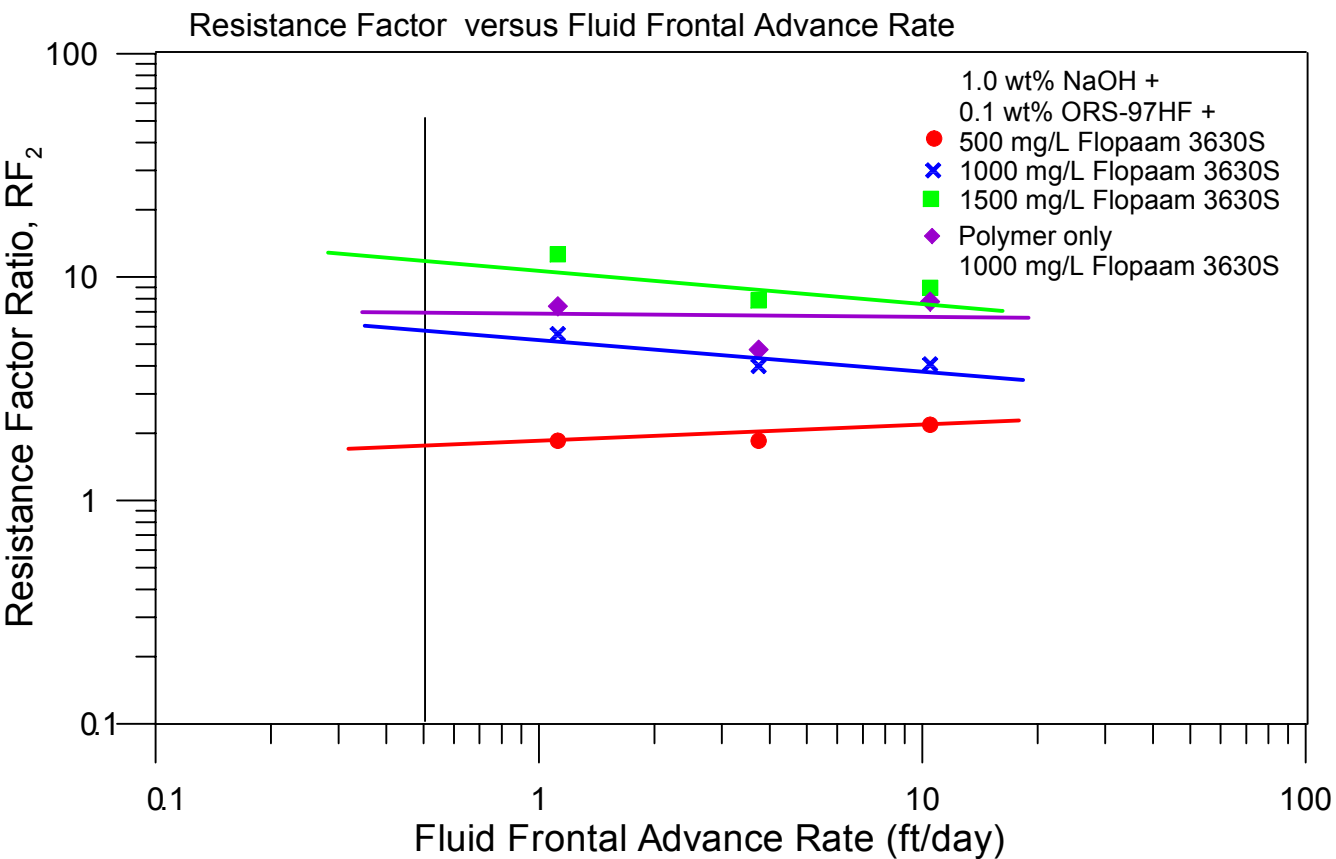
Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 4L



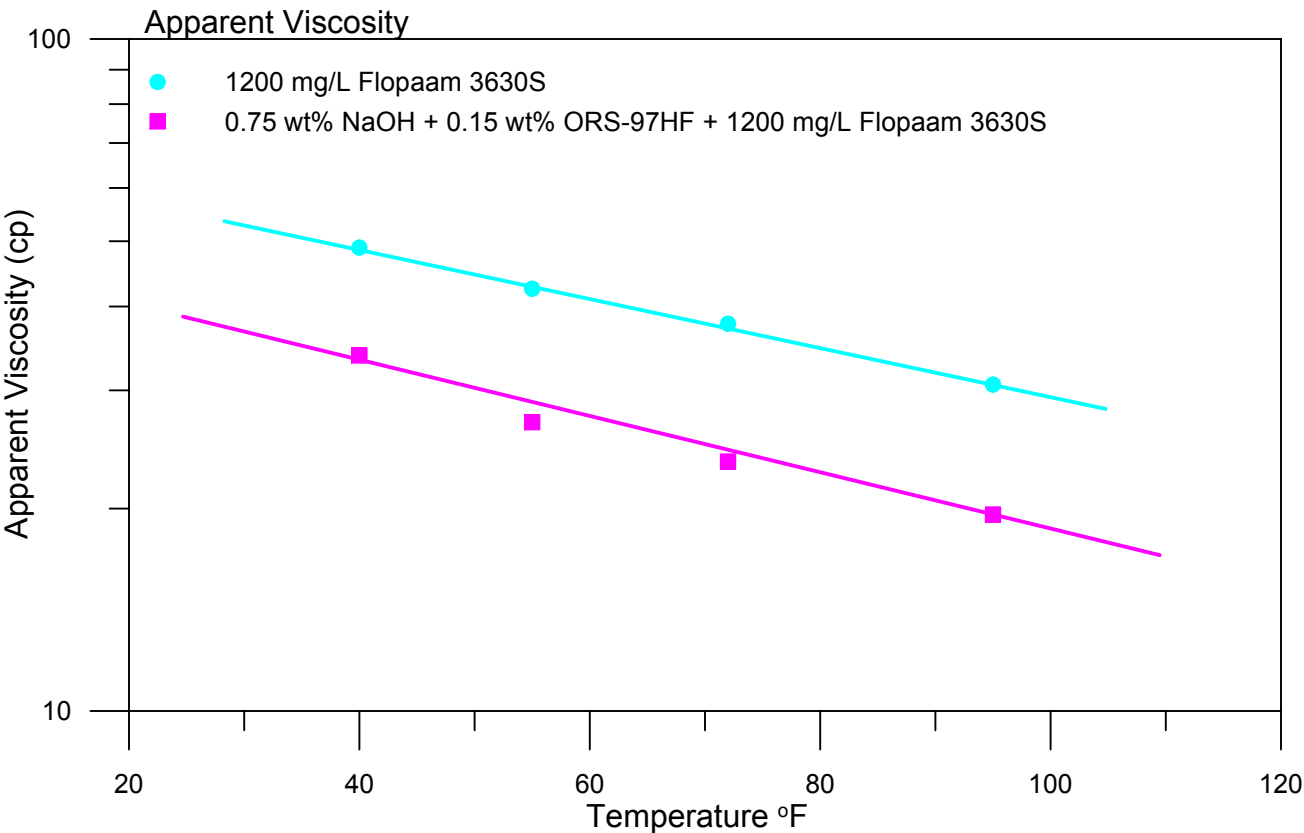
Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 5L



Resistance Factor, Polymer Concentration
and Fluid Frontal Advance Rate
Warner Linear Coreflood 6L

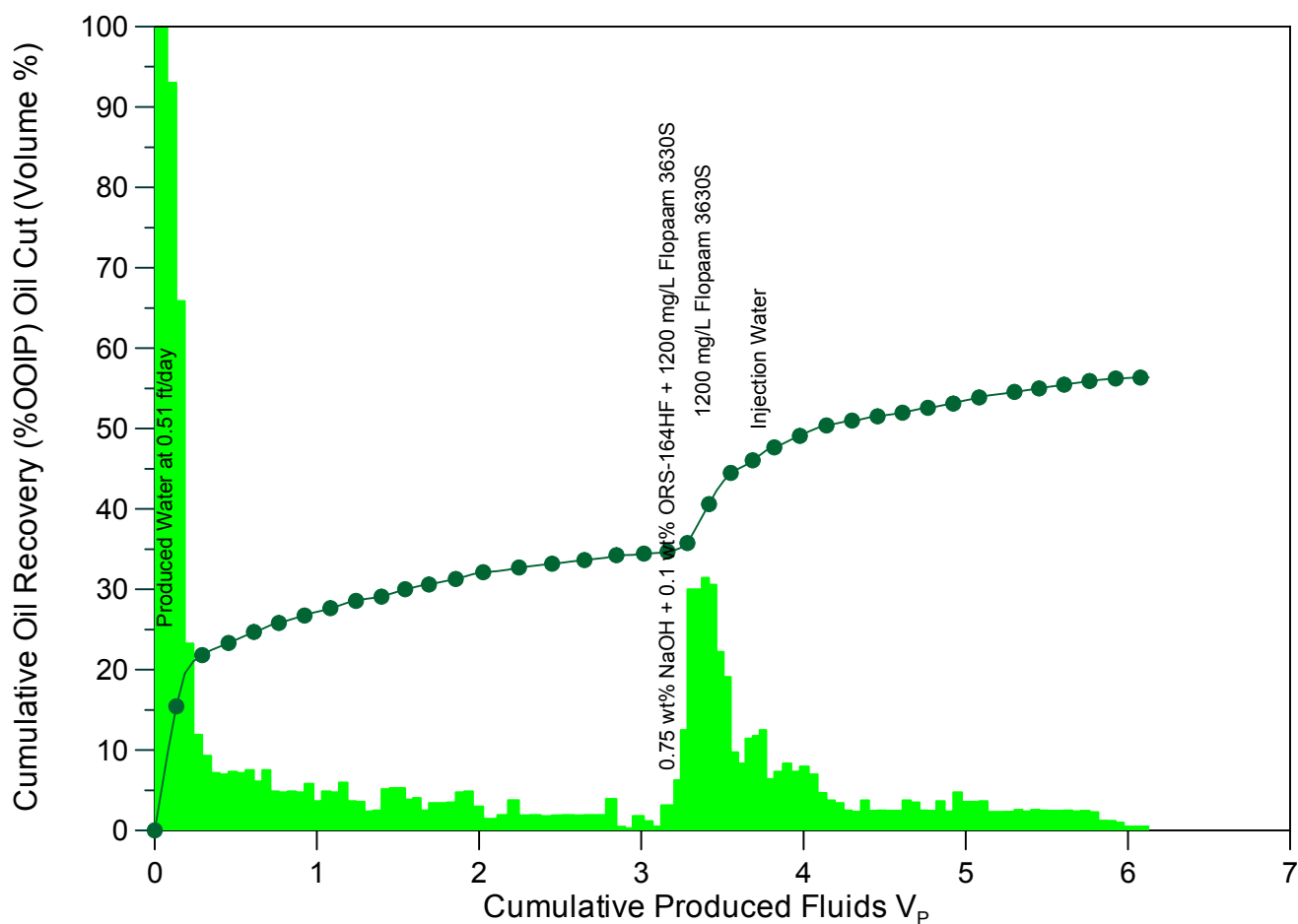
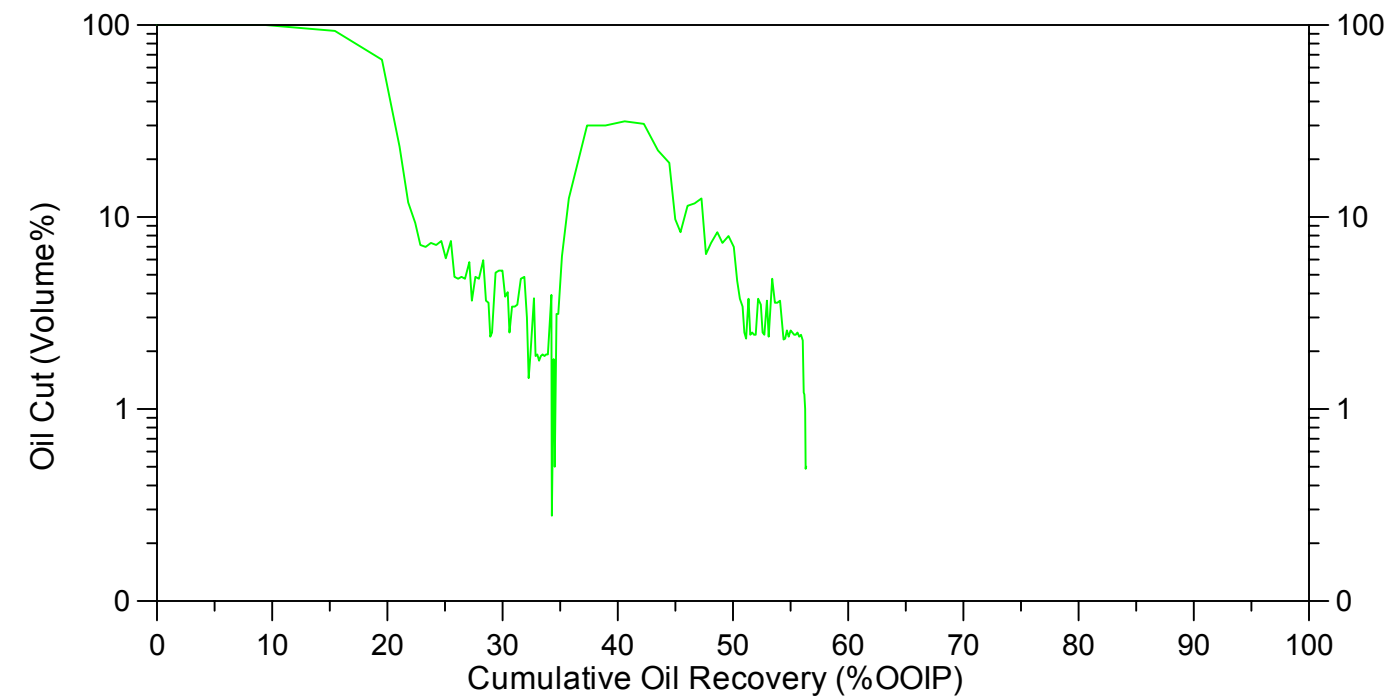


Apparent Viscosity versus Temperature
Alkaline-Surfactant-Polymer Solution
dissolved in Warner Softened Injection Water

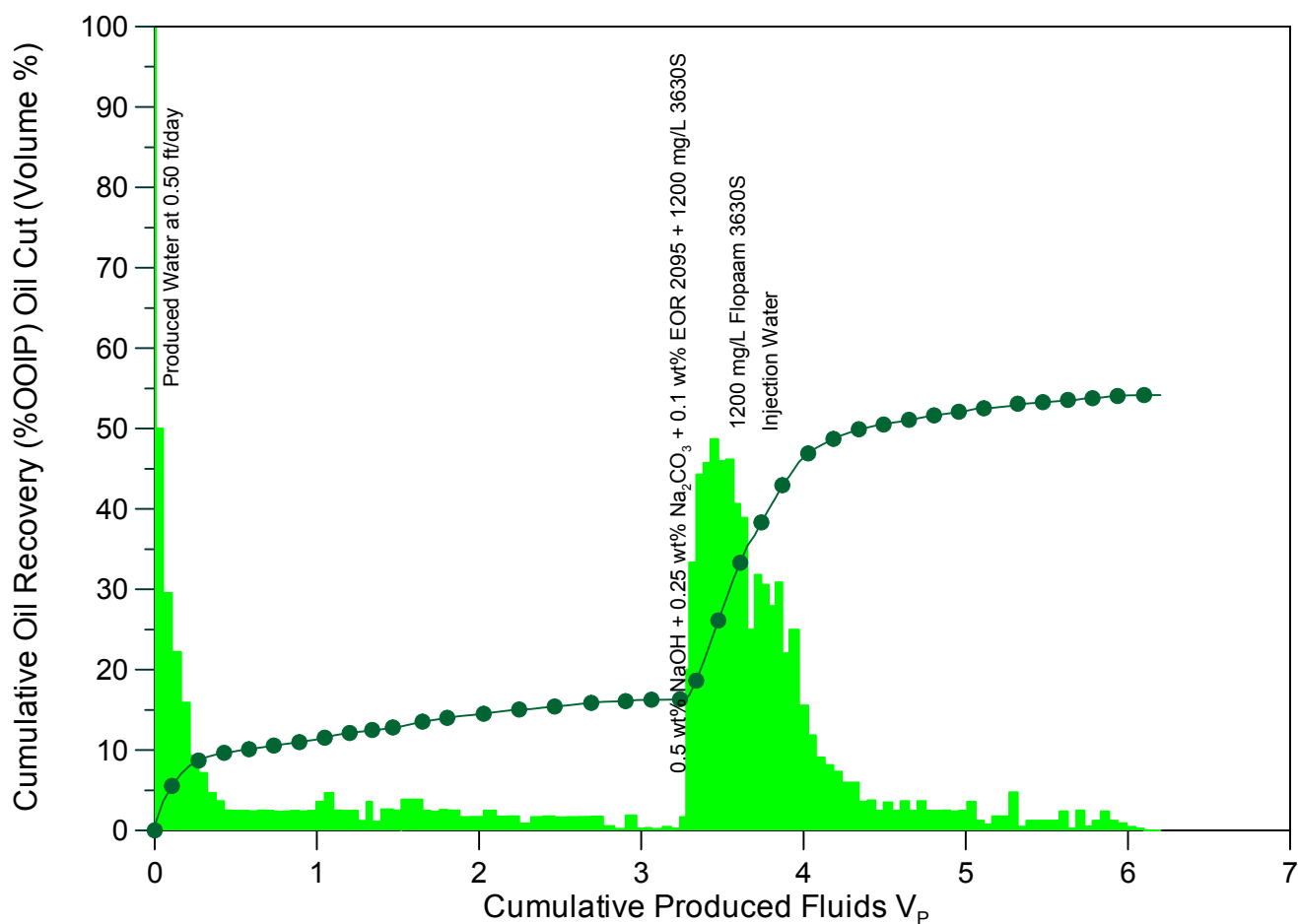
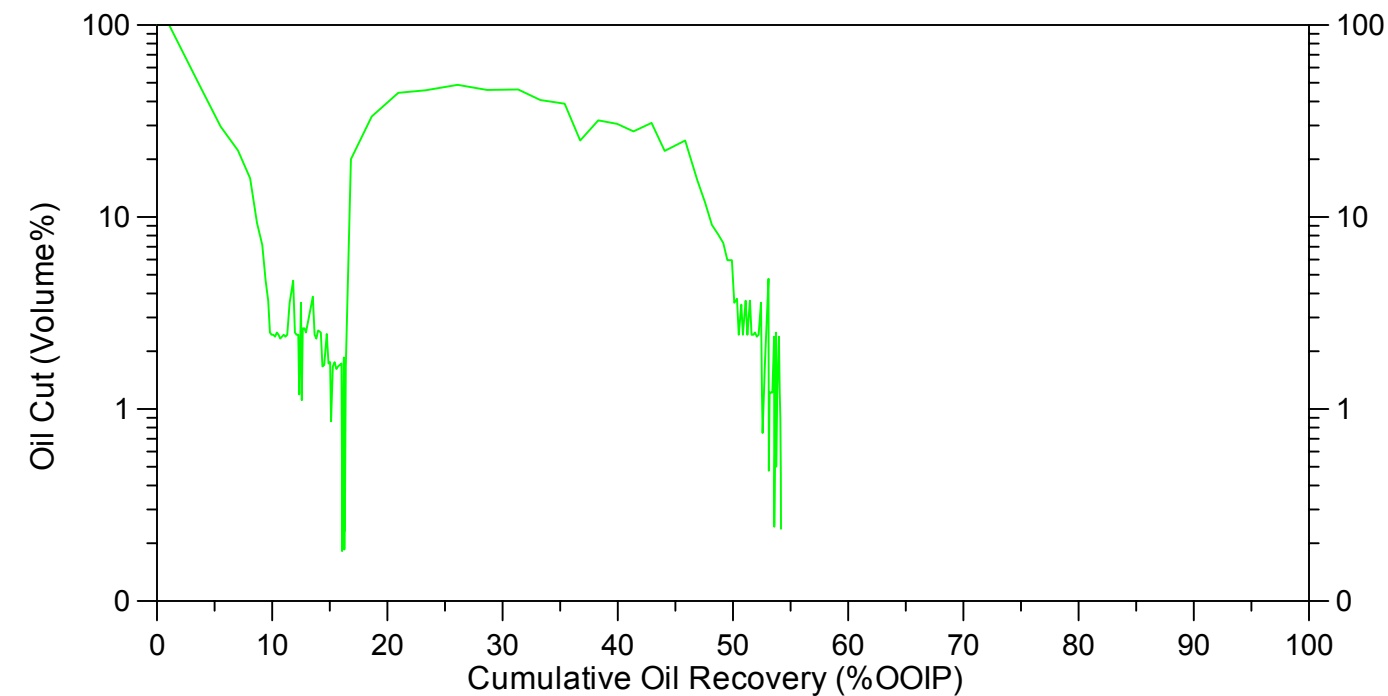


Temp °F	Viscosity (cp) Brookfield	
	Polymer	ASP
40	48.9	33.8
55	42.5	26.9
72	37.7	23.5
95	30.6	19.6

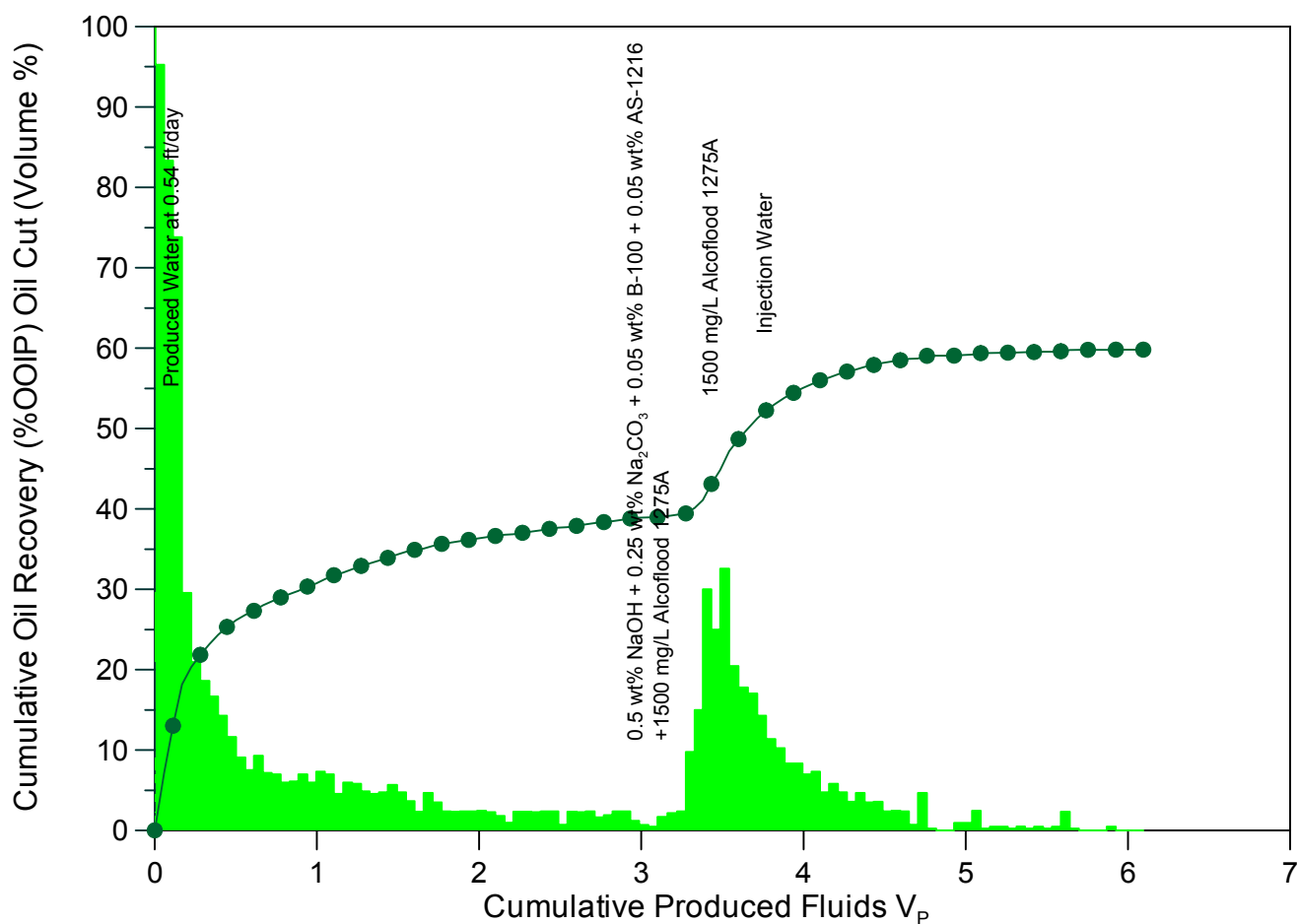
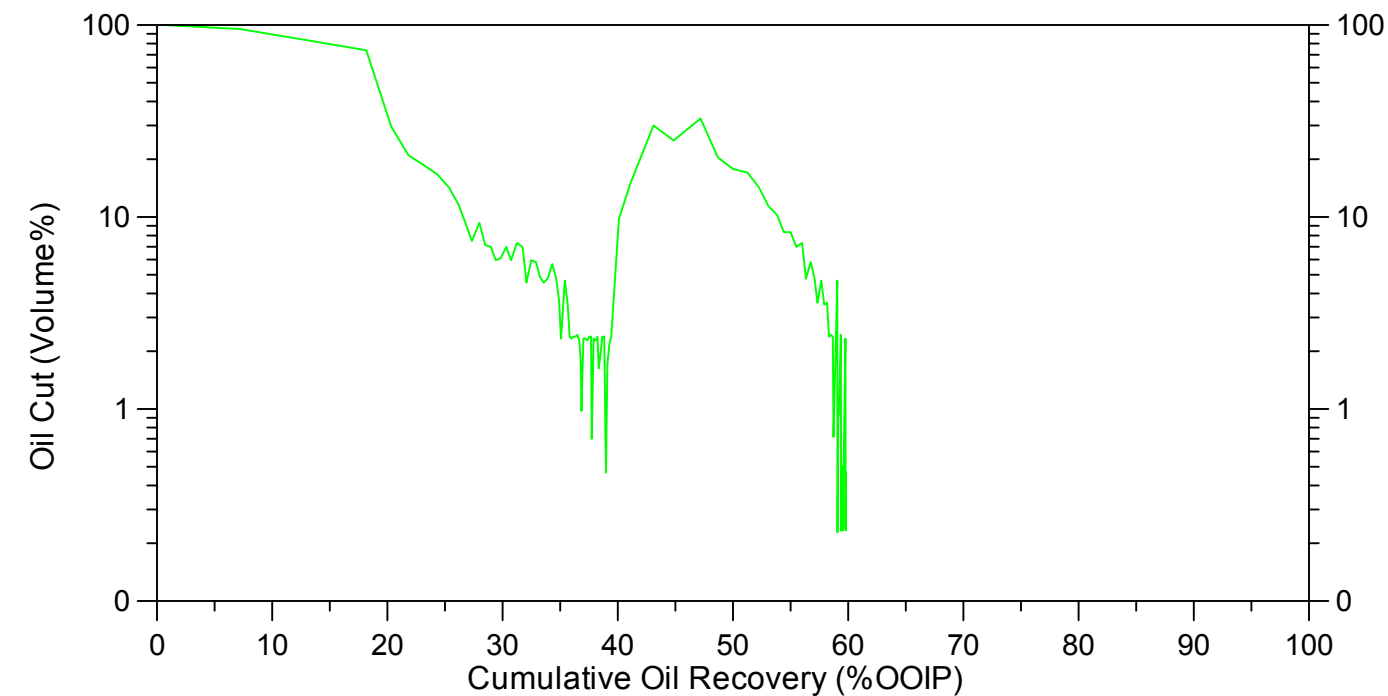
Warner Radial Coreflood 1R



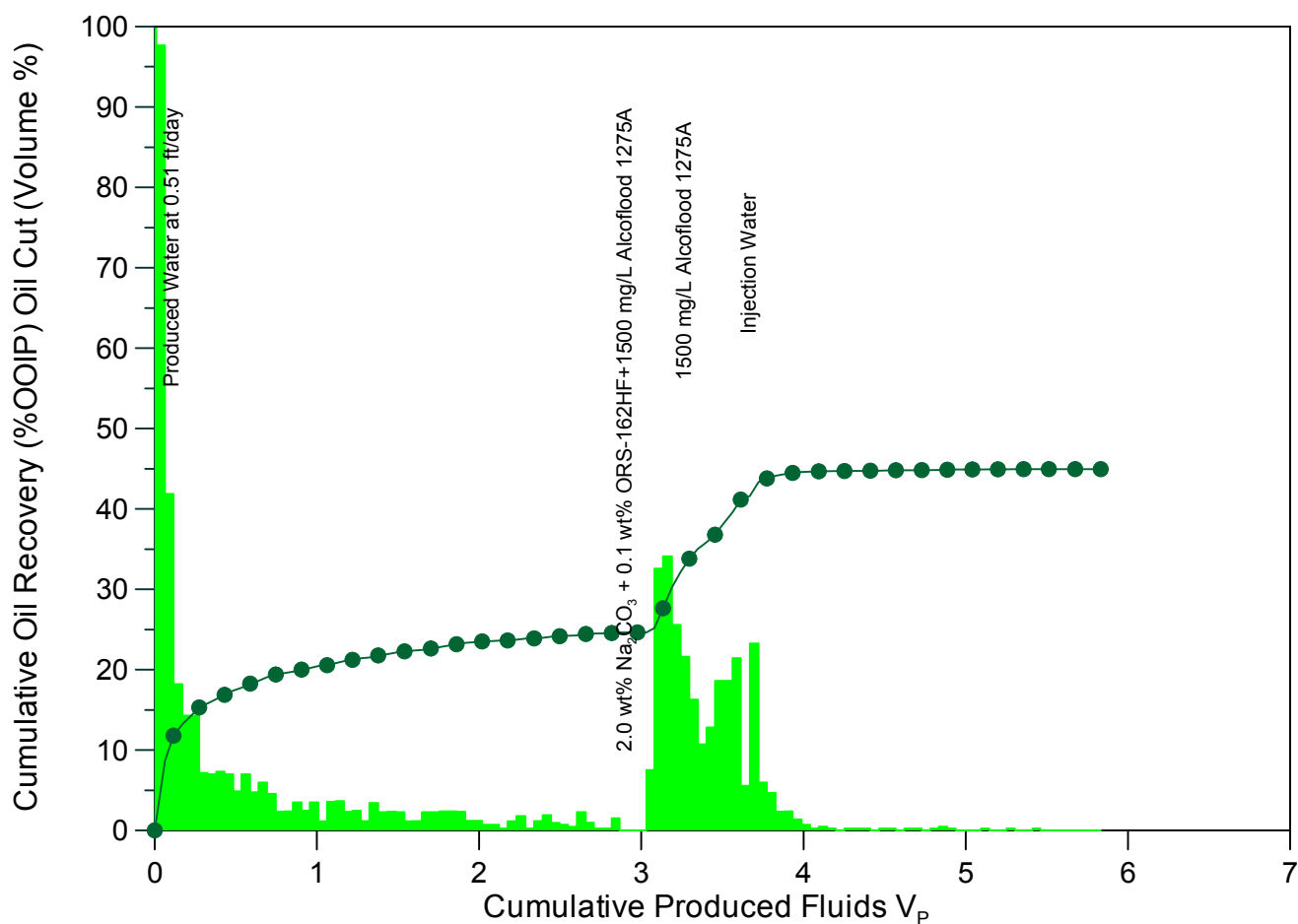
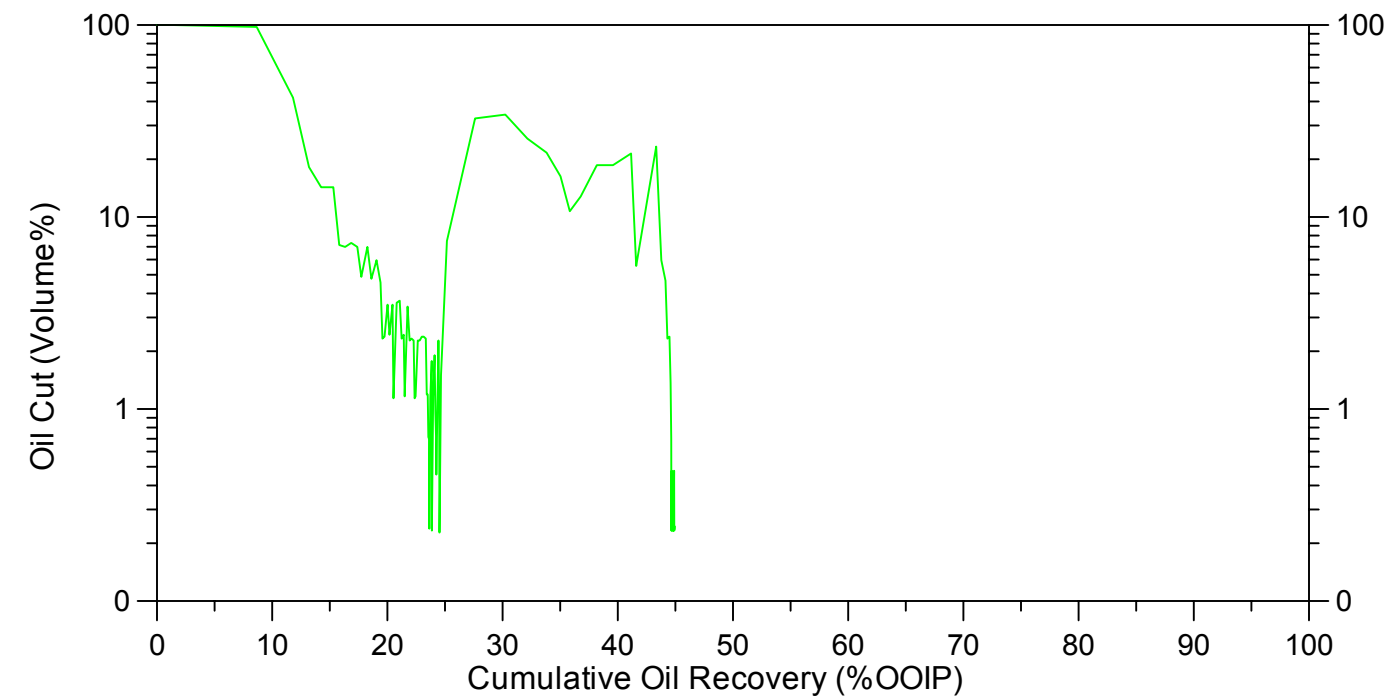
Warner Radial Coreflood 2R



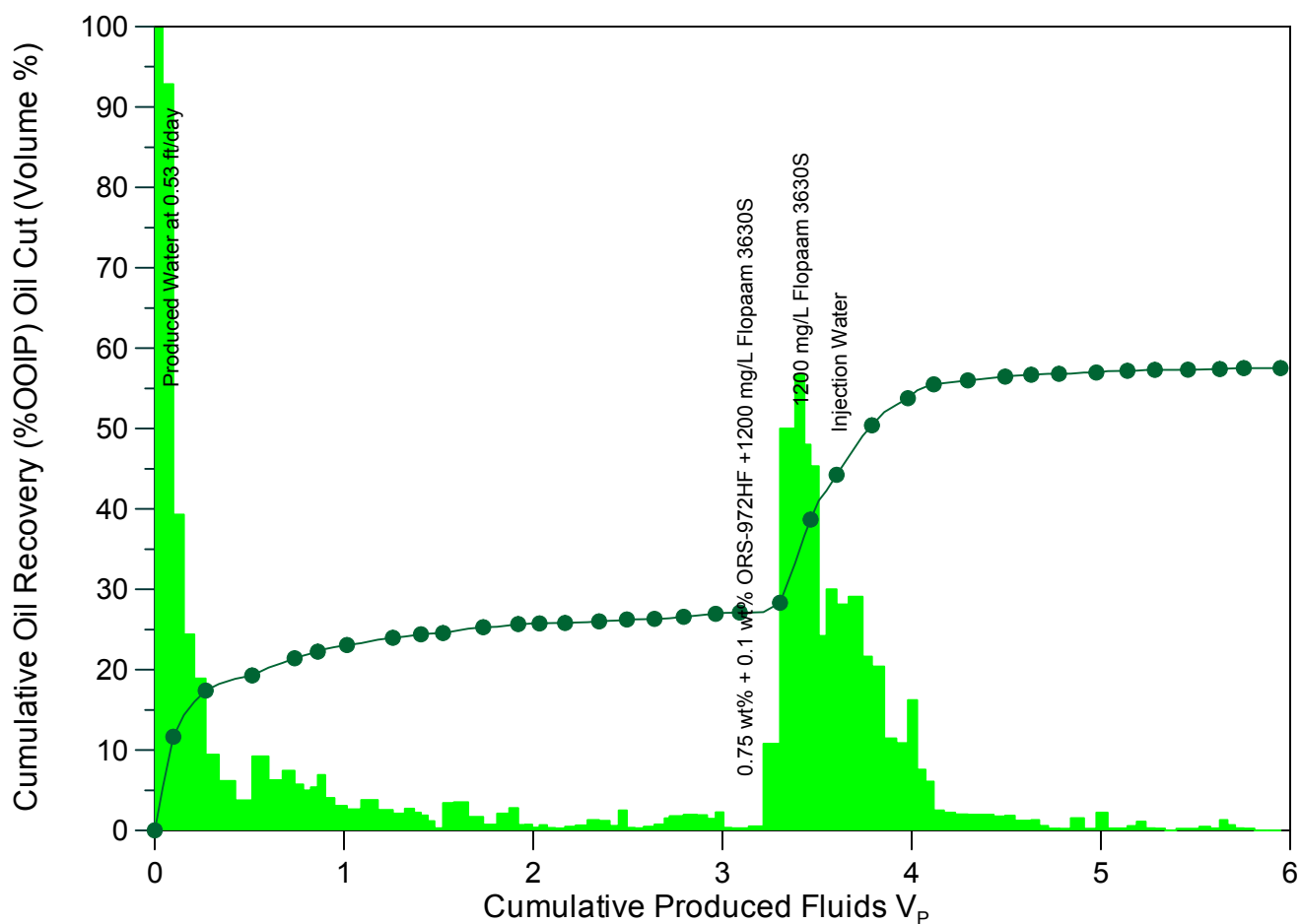
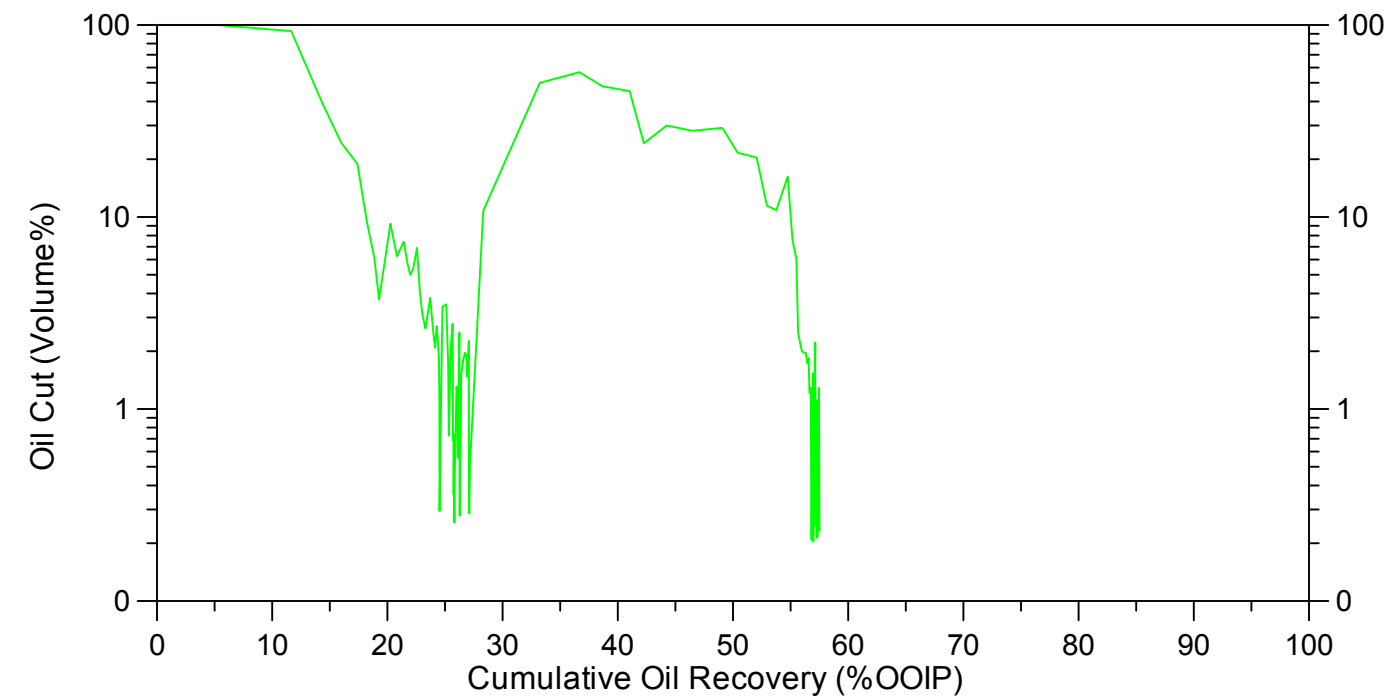
Warner Radial Coreflood 3R



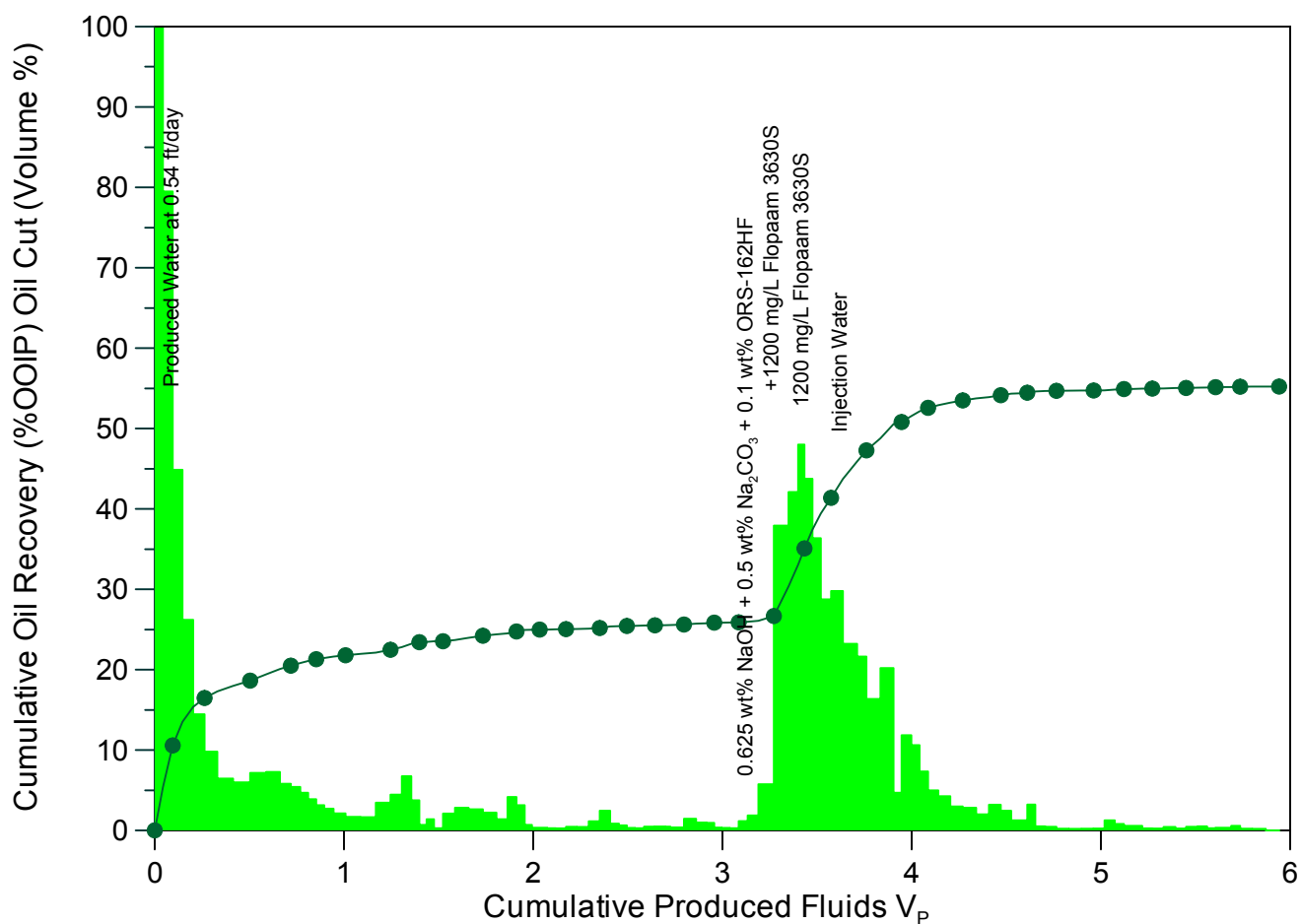
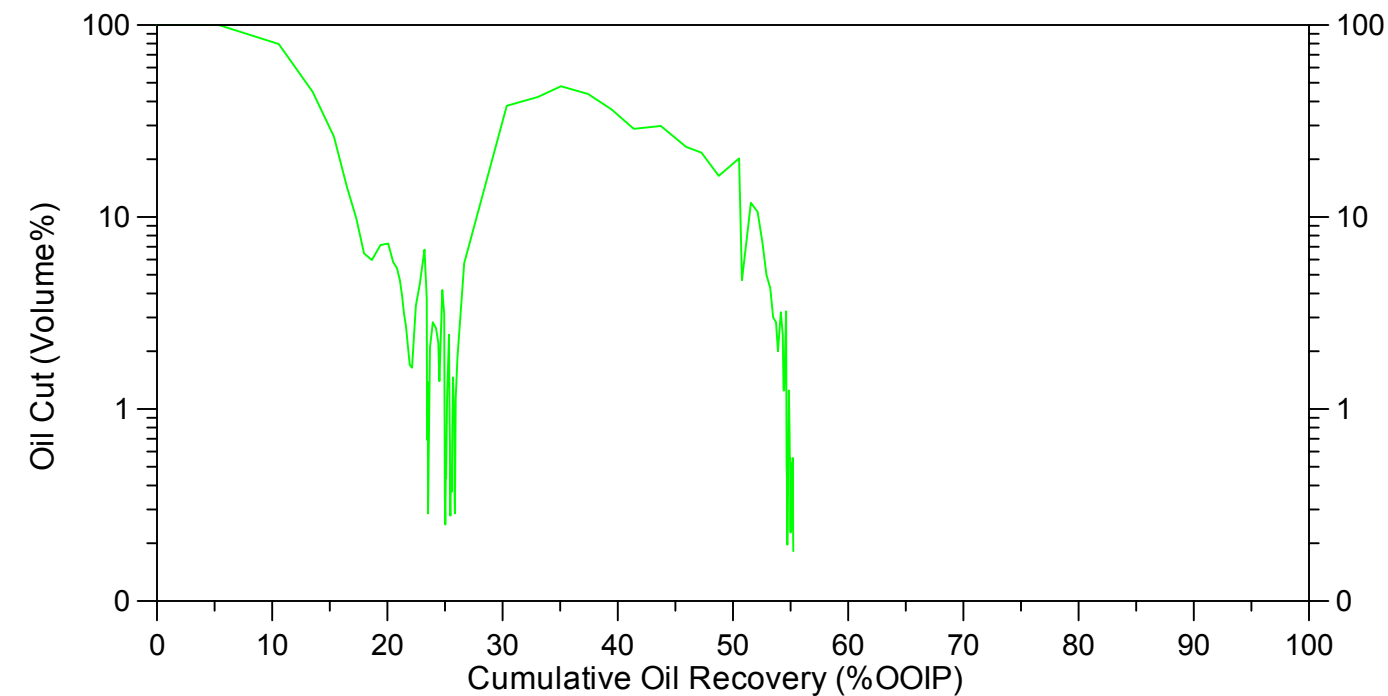
Warner Radial Coreflood 4R



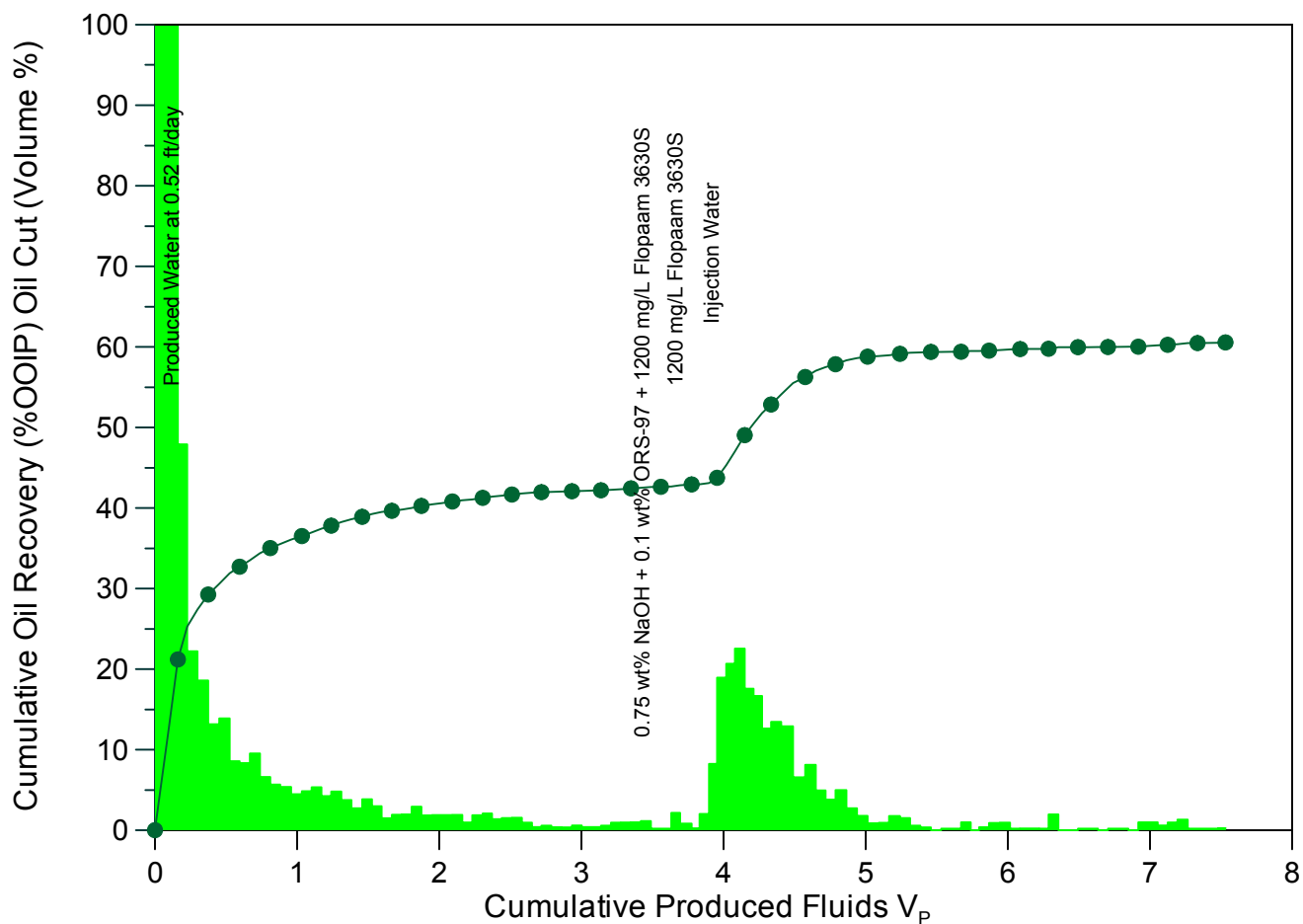
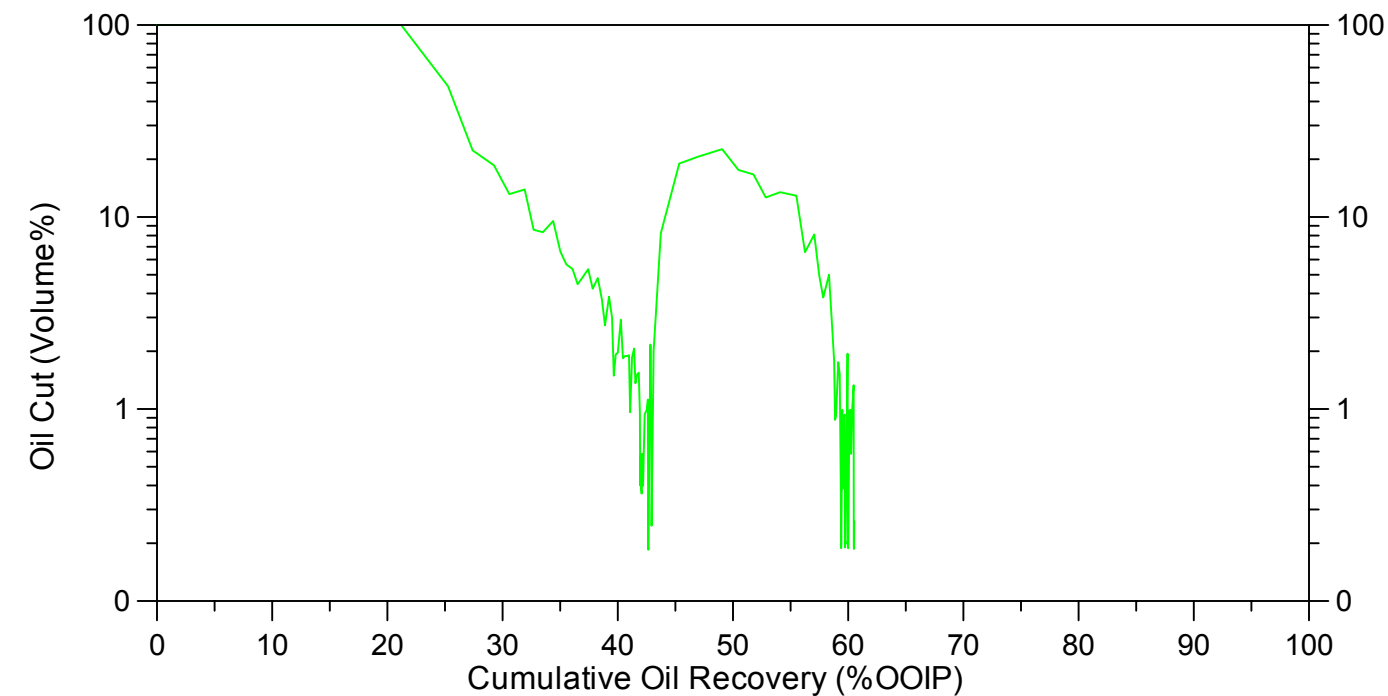
Warner Radial Coreflood 5R



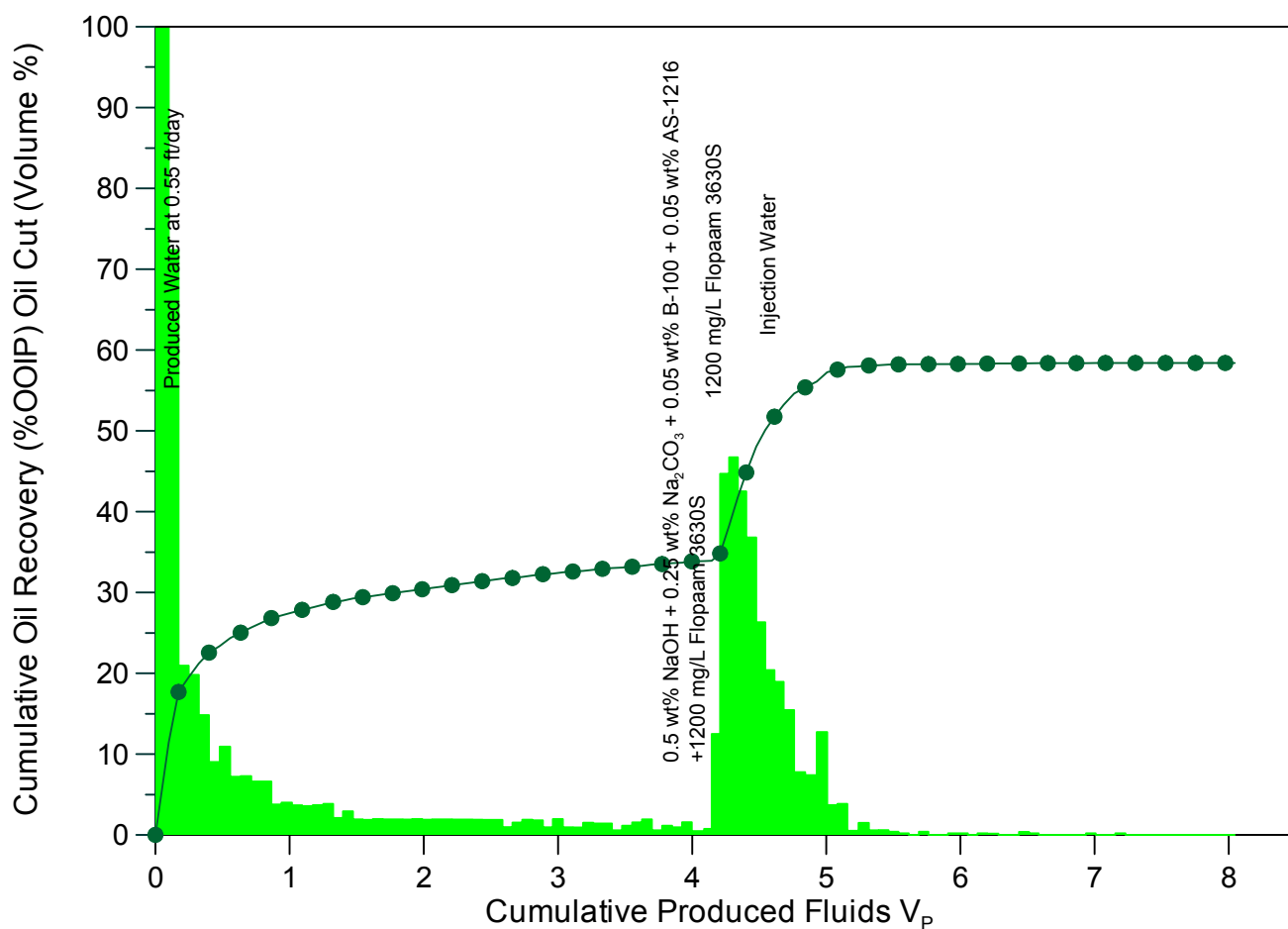
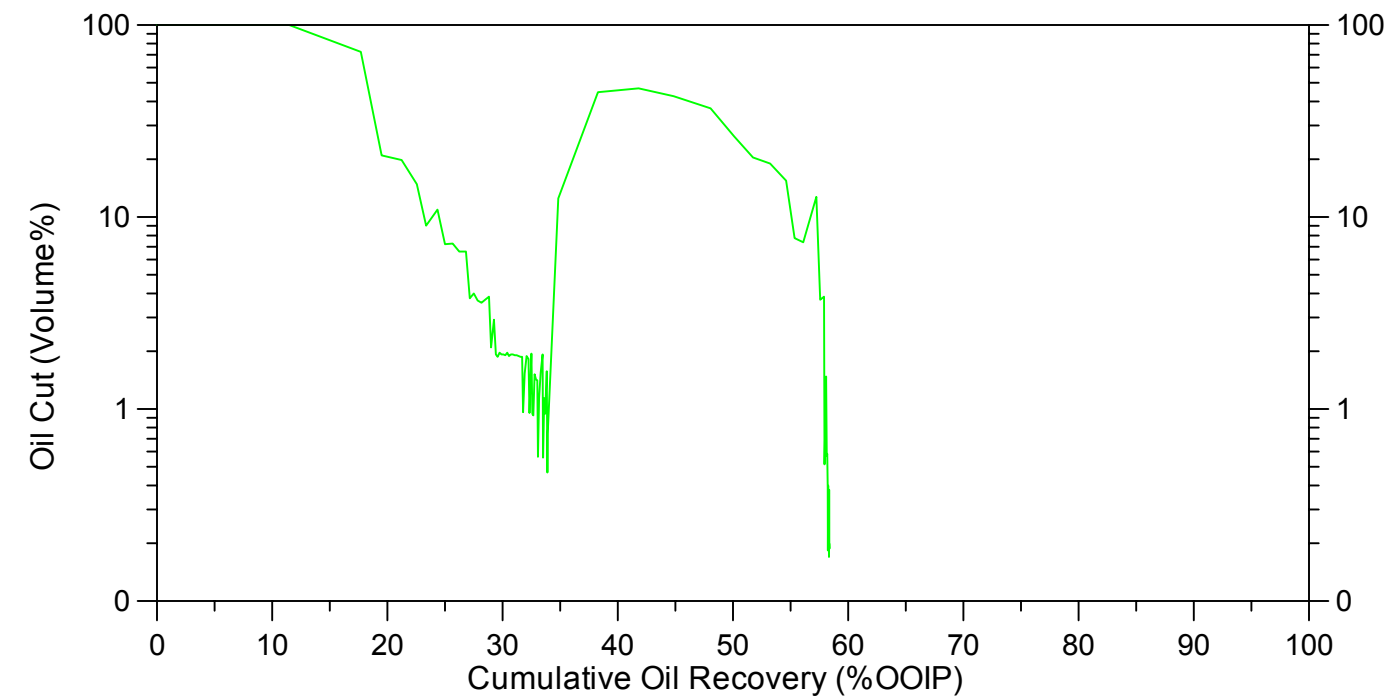
Warner Radial Coreflood 6R



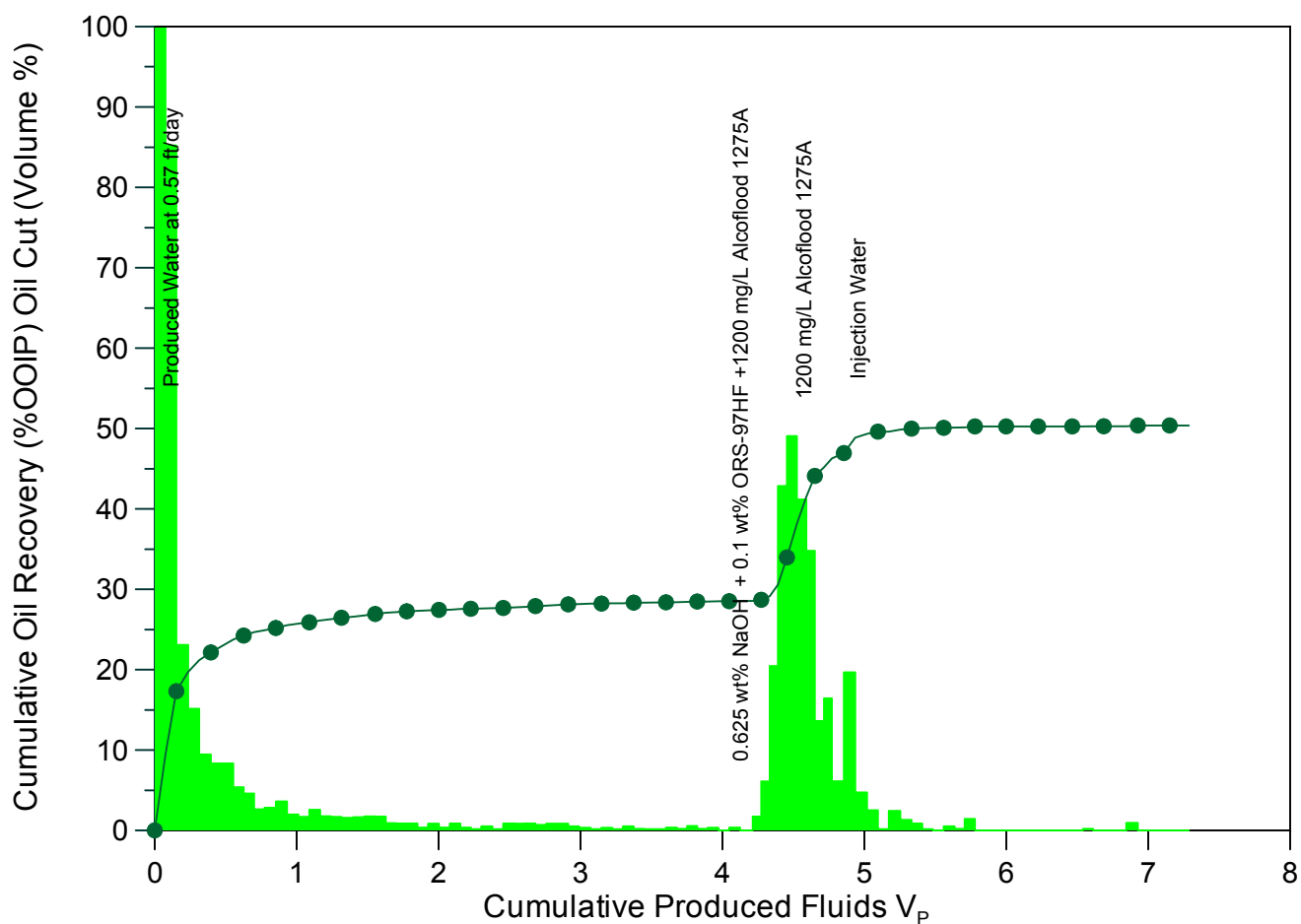
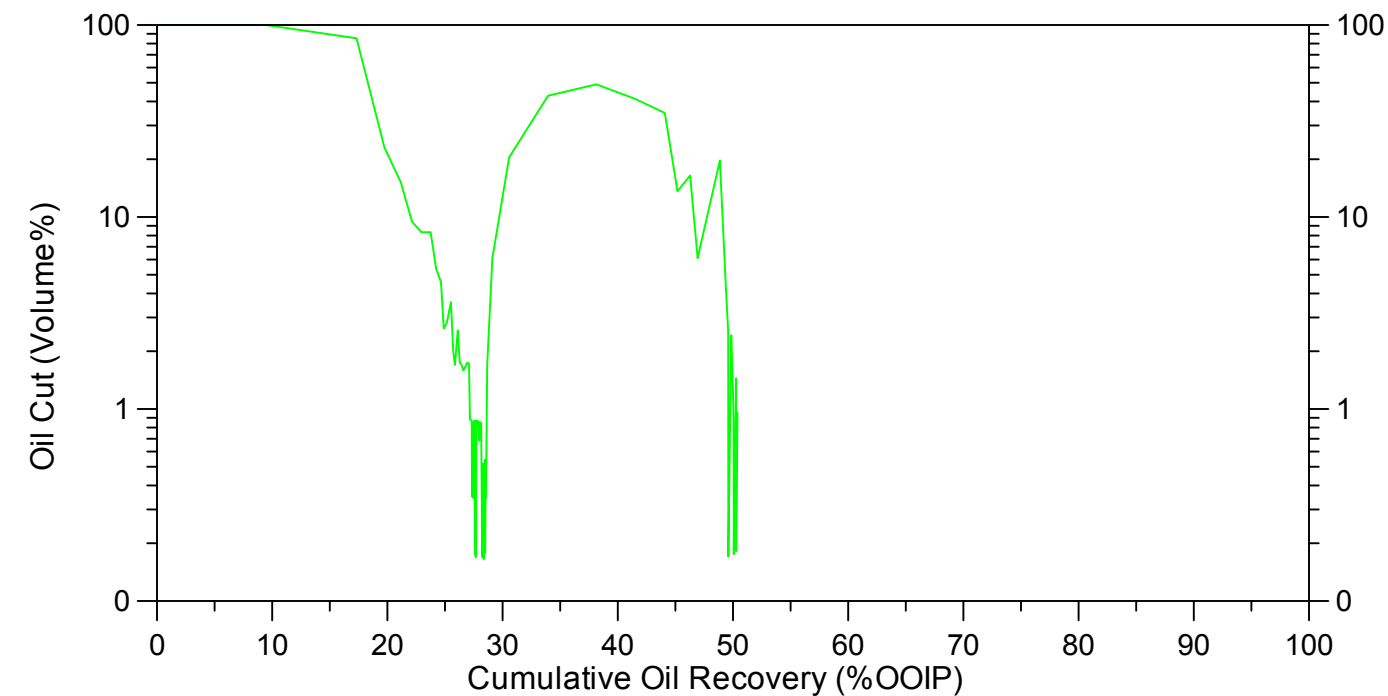
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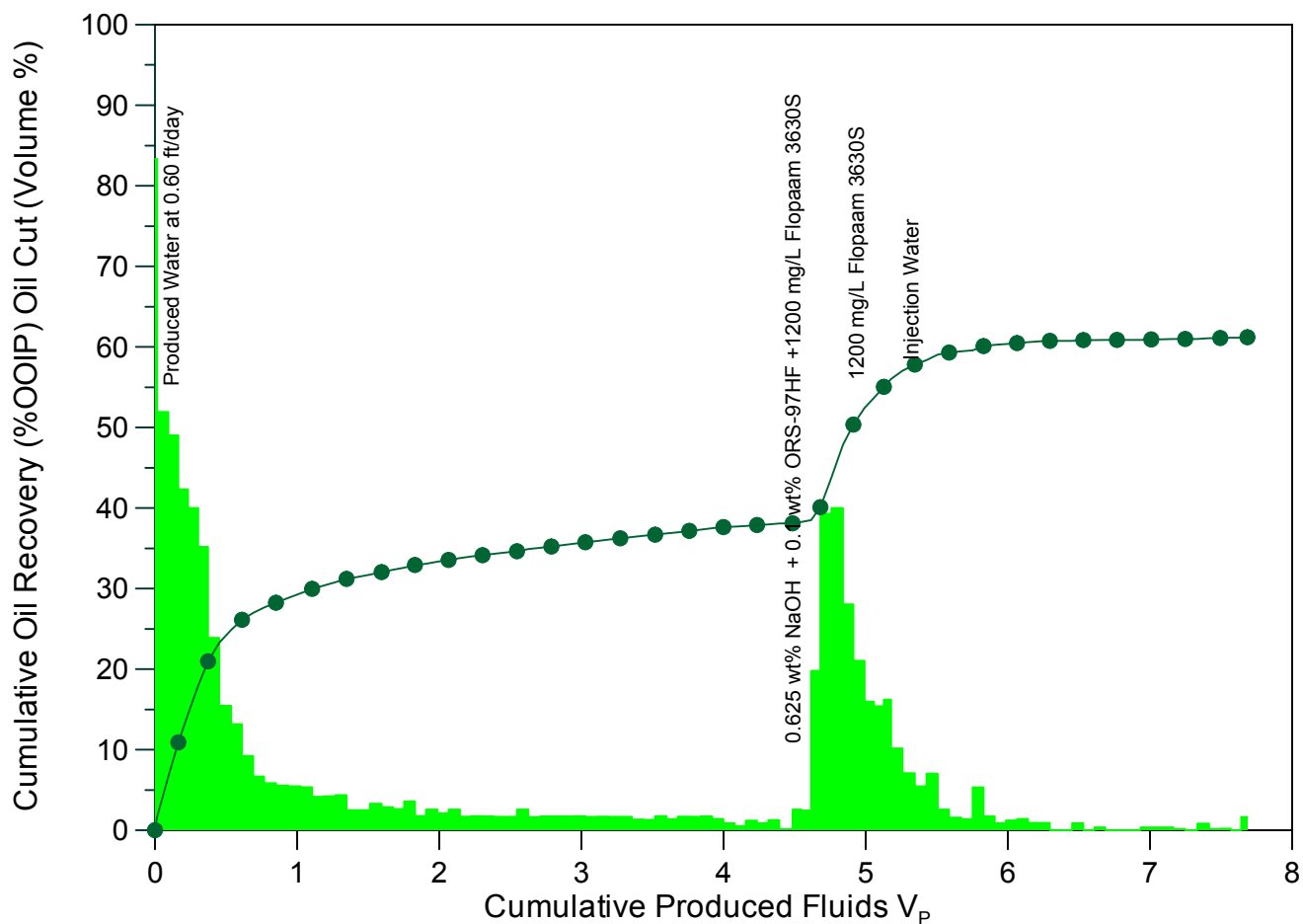
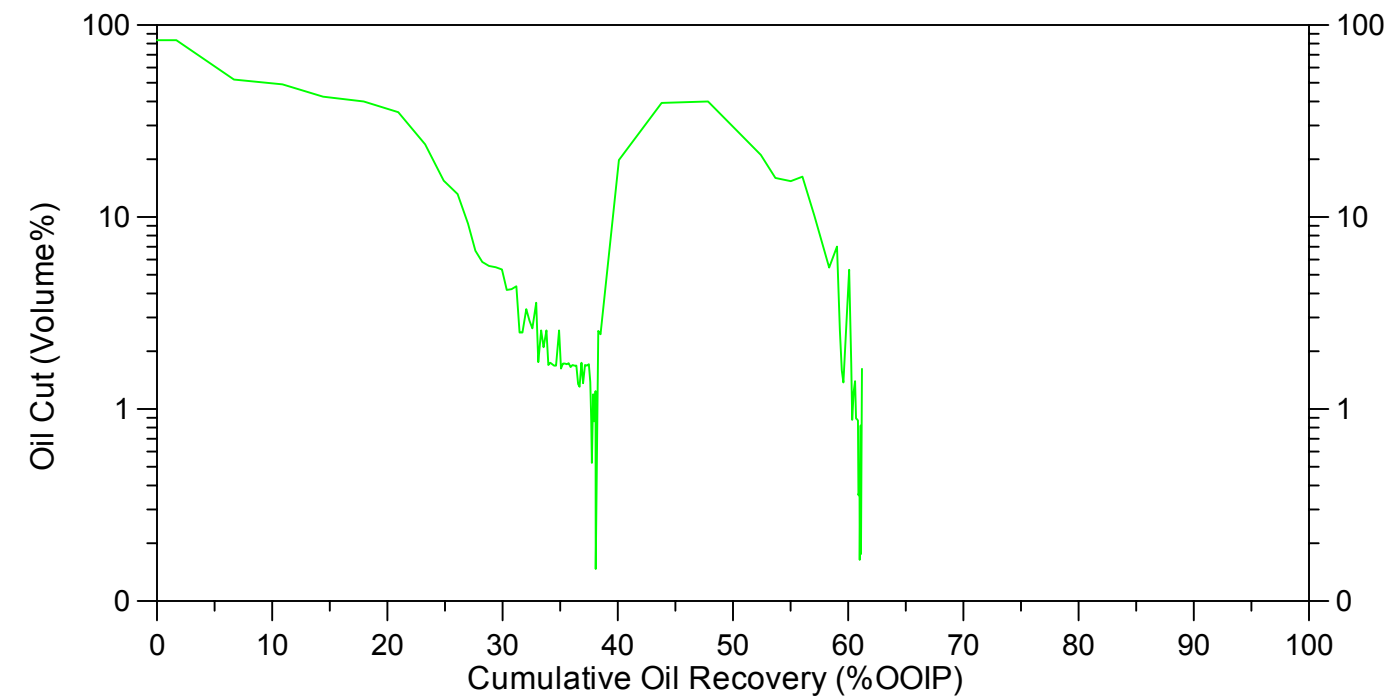
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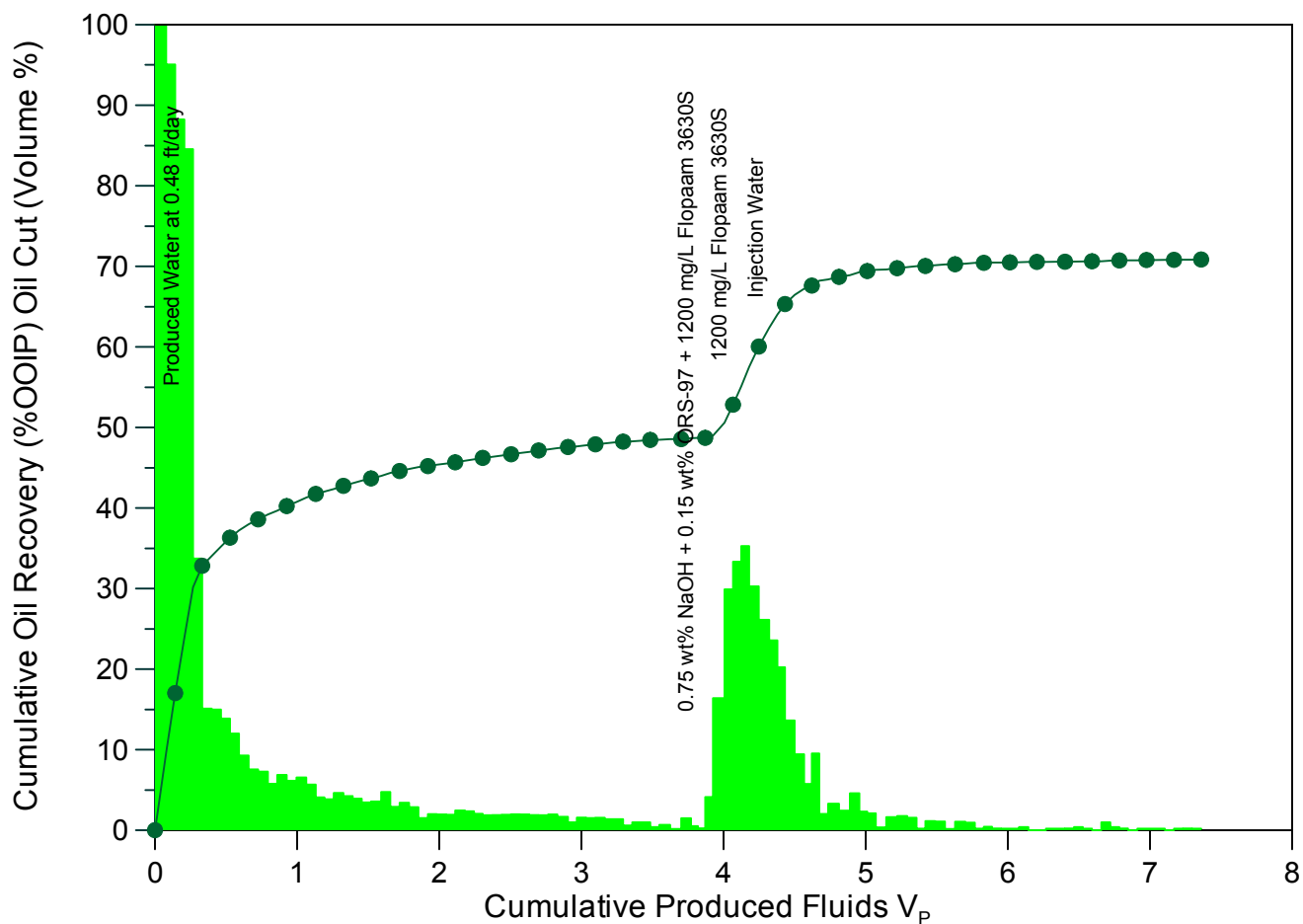
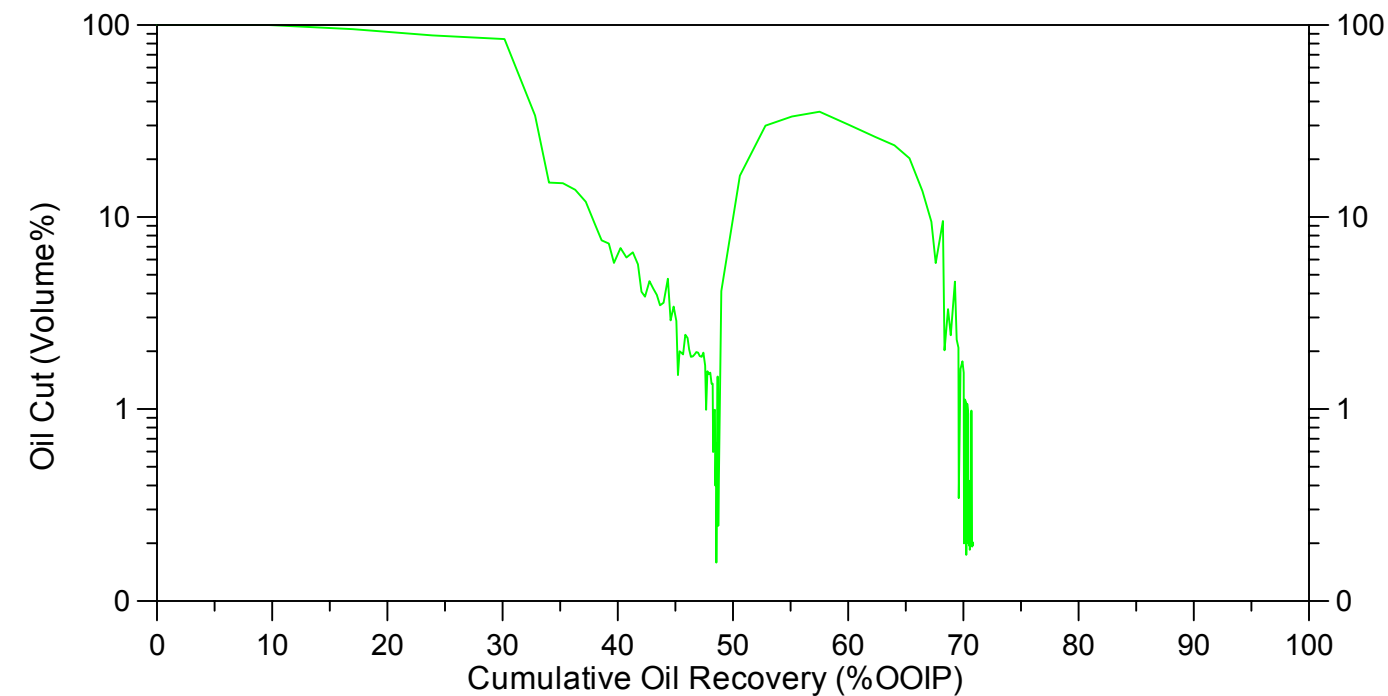
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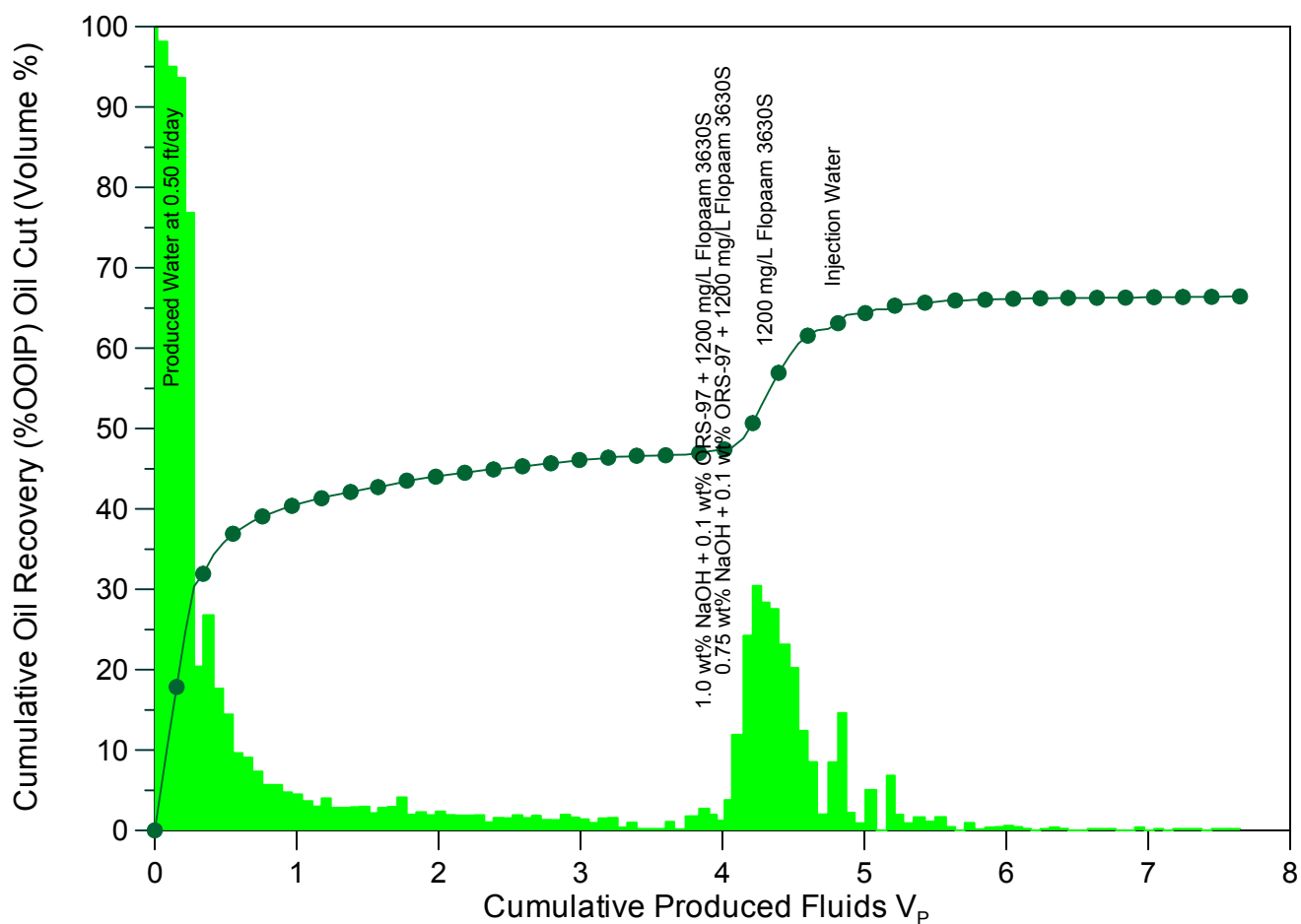
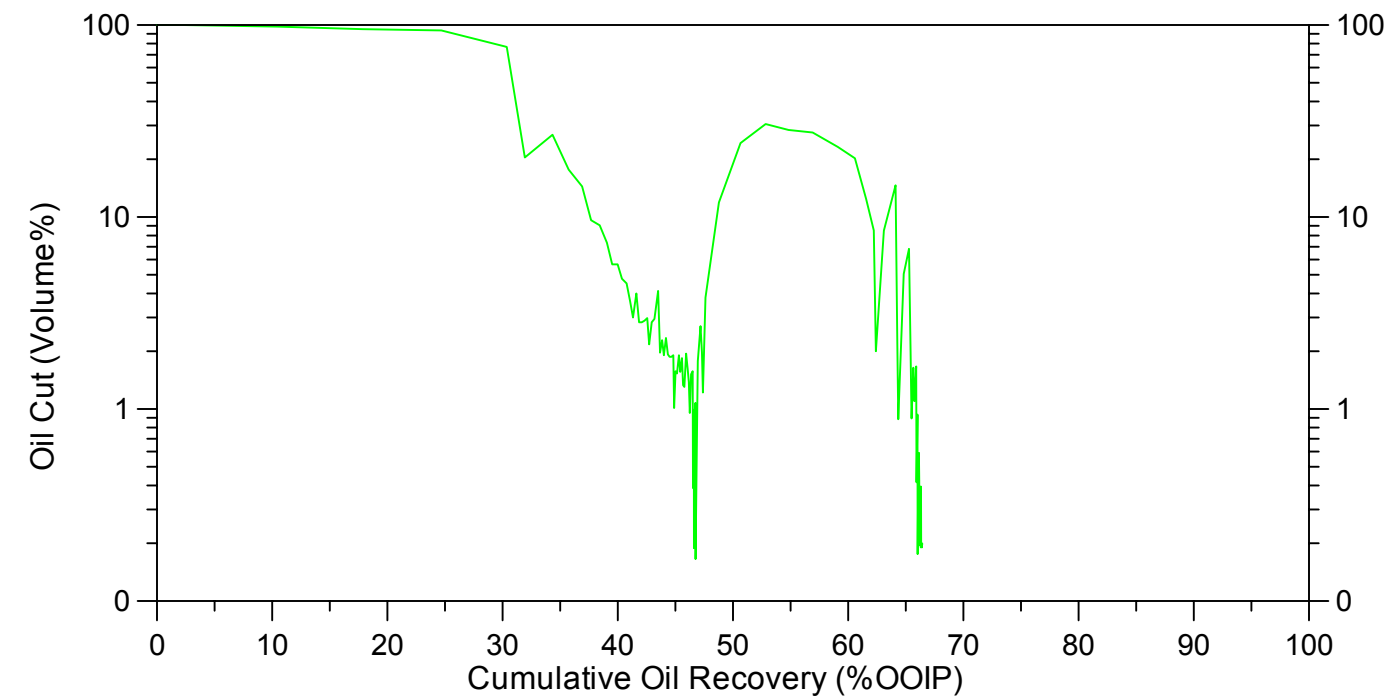
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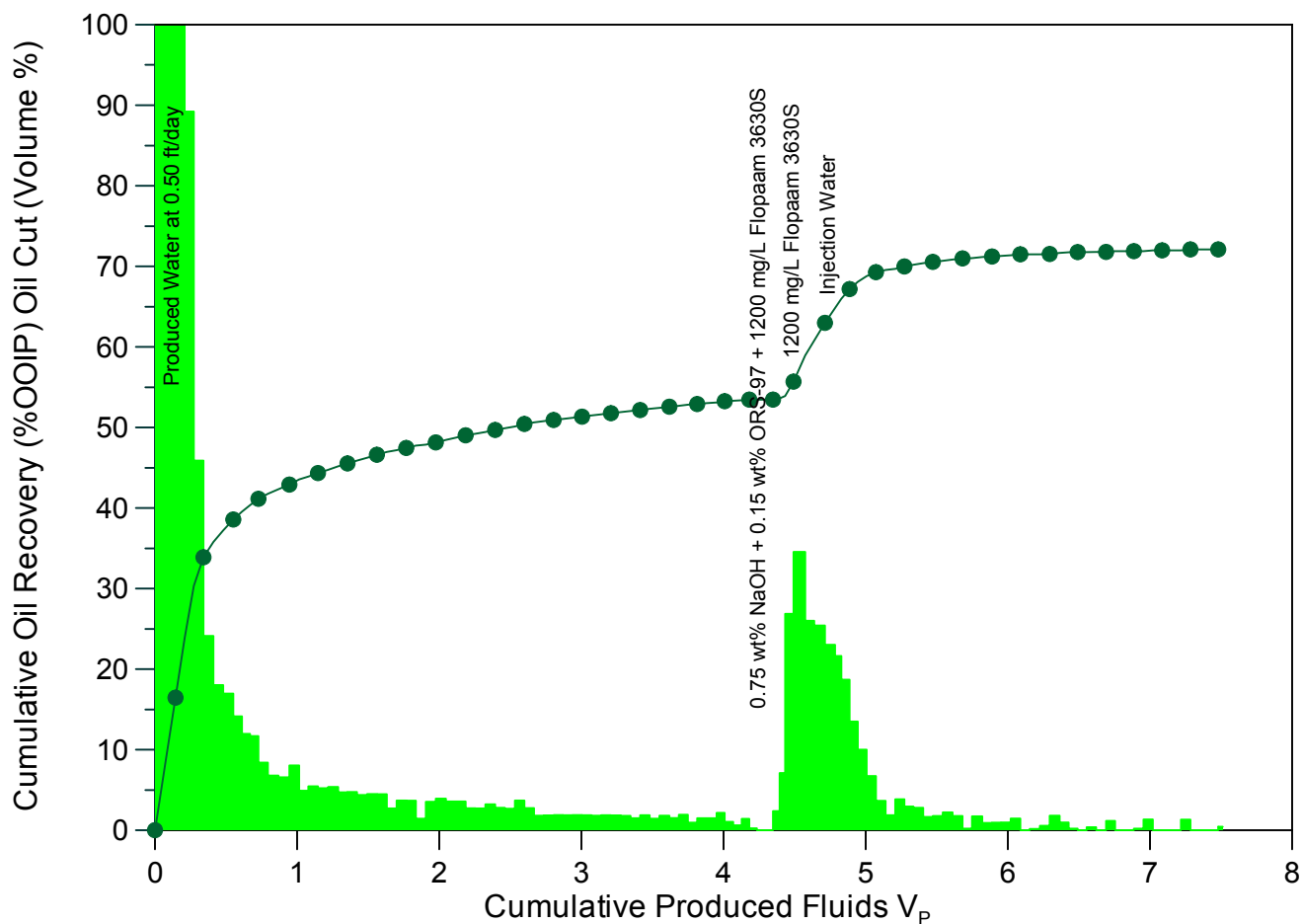
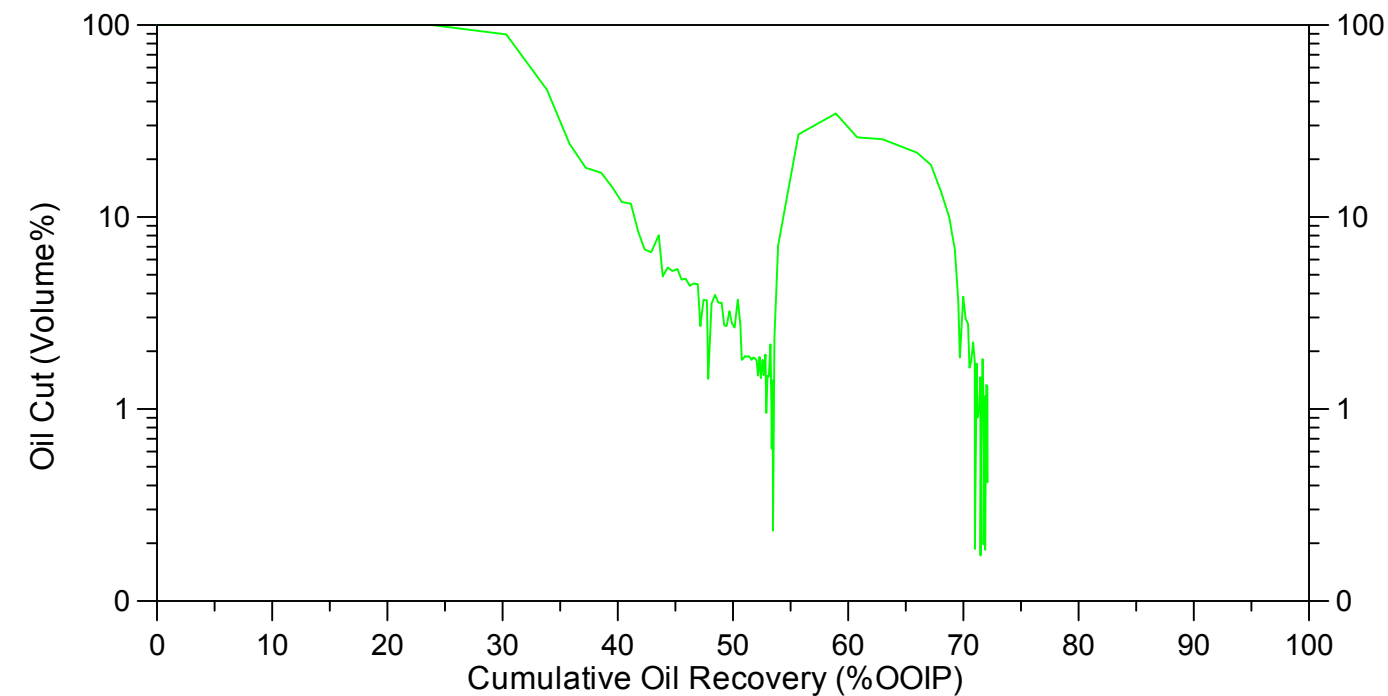
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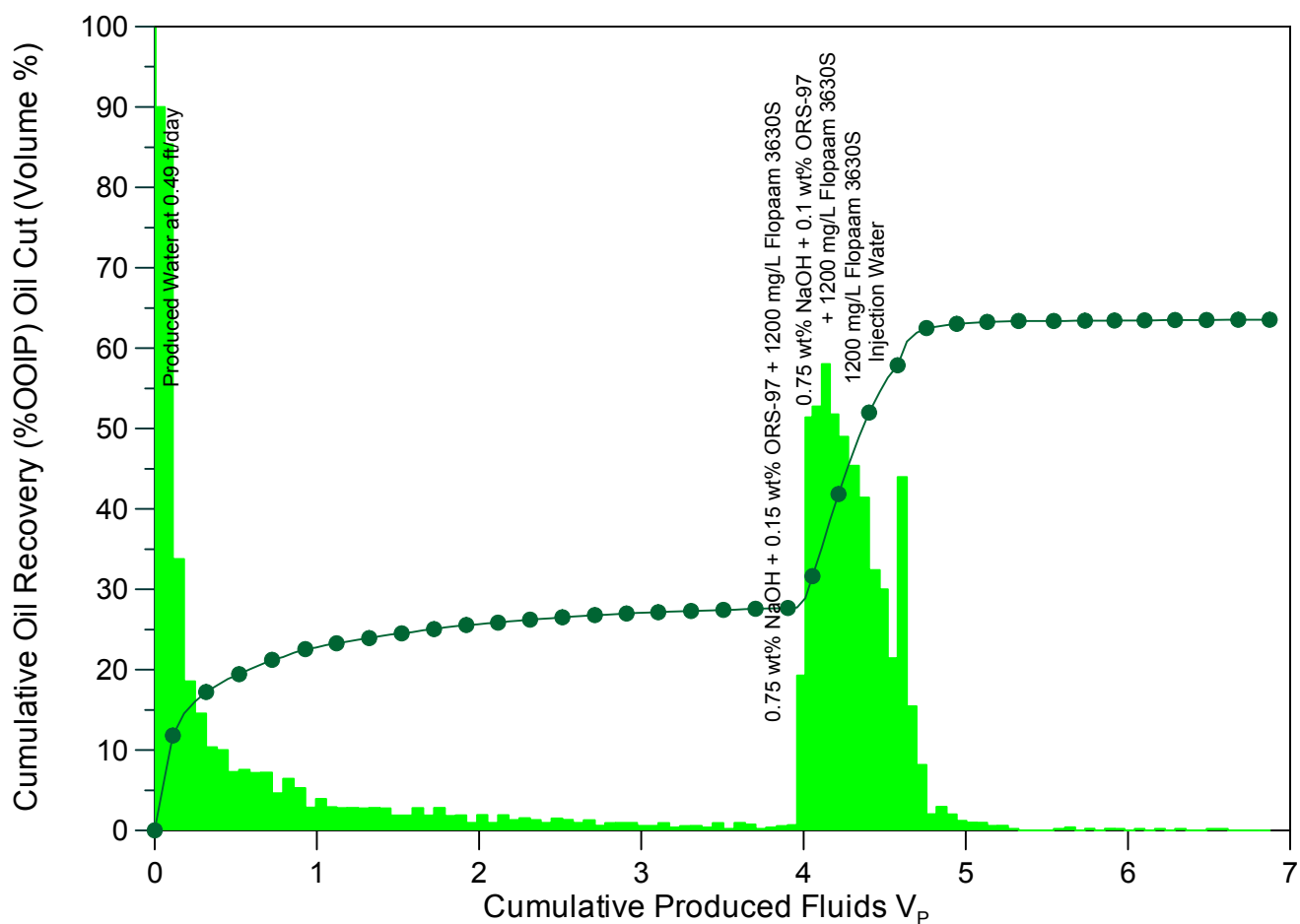
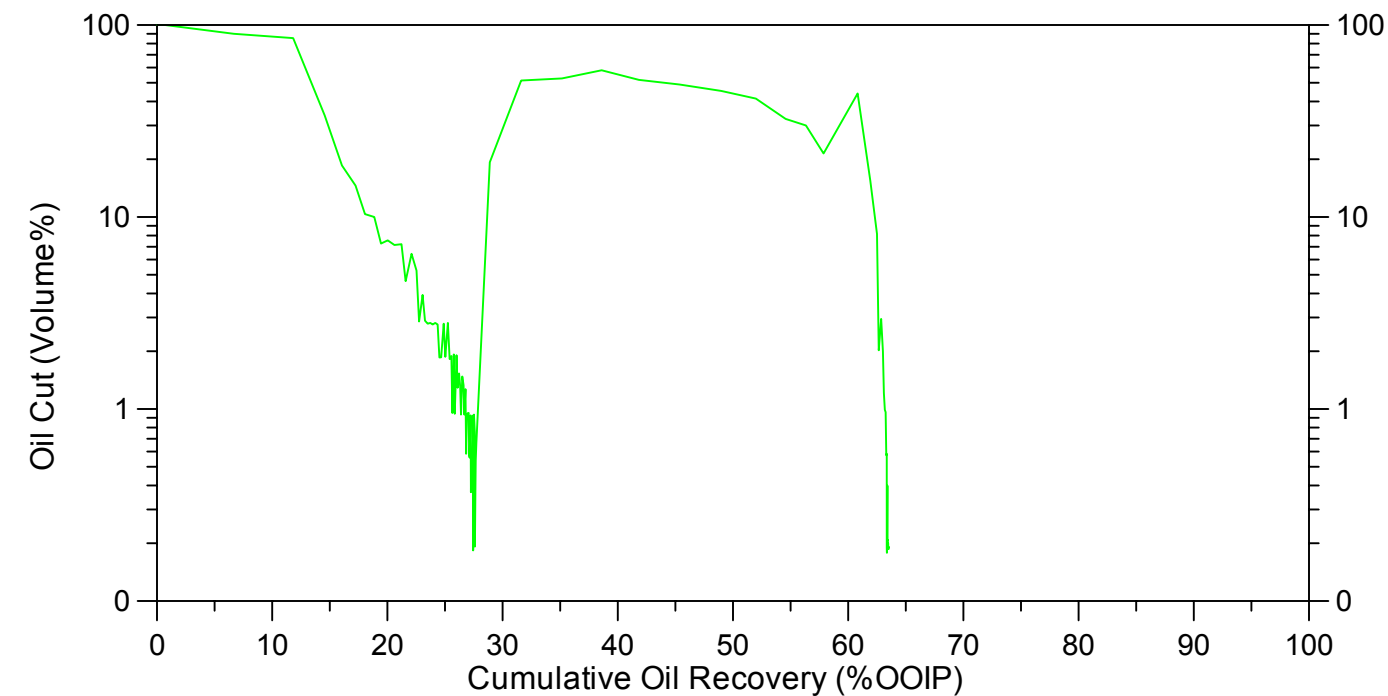
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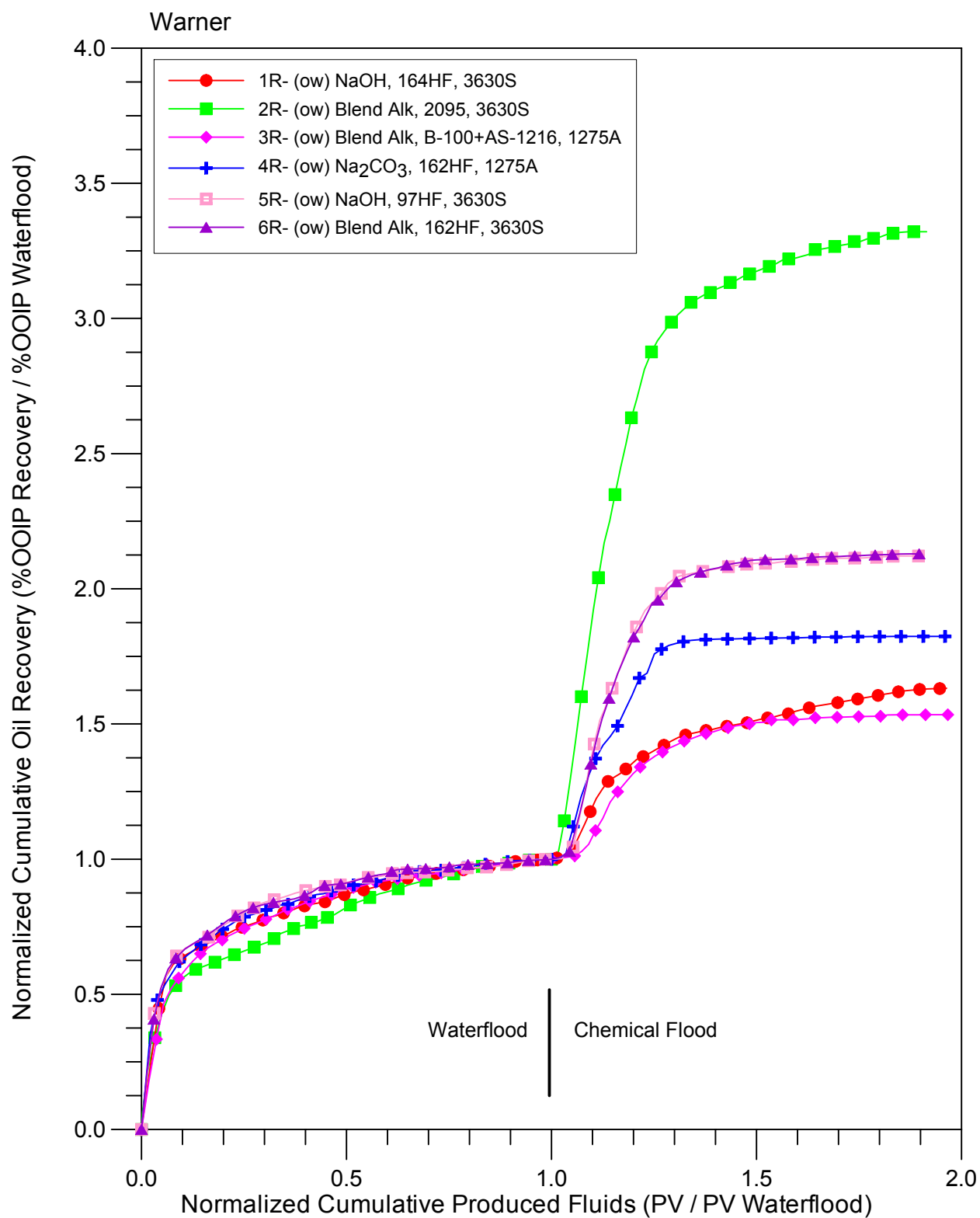
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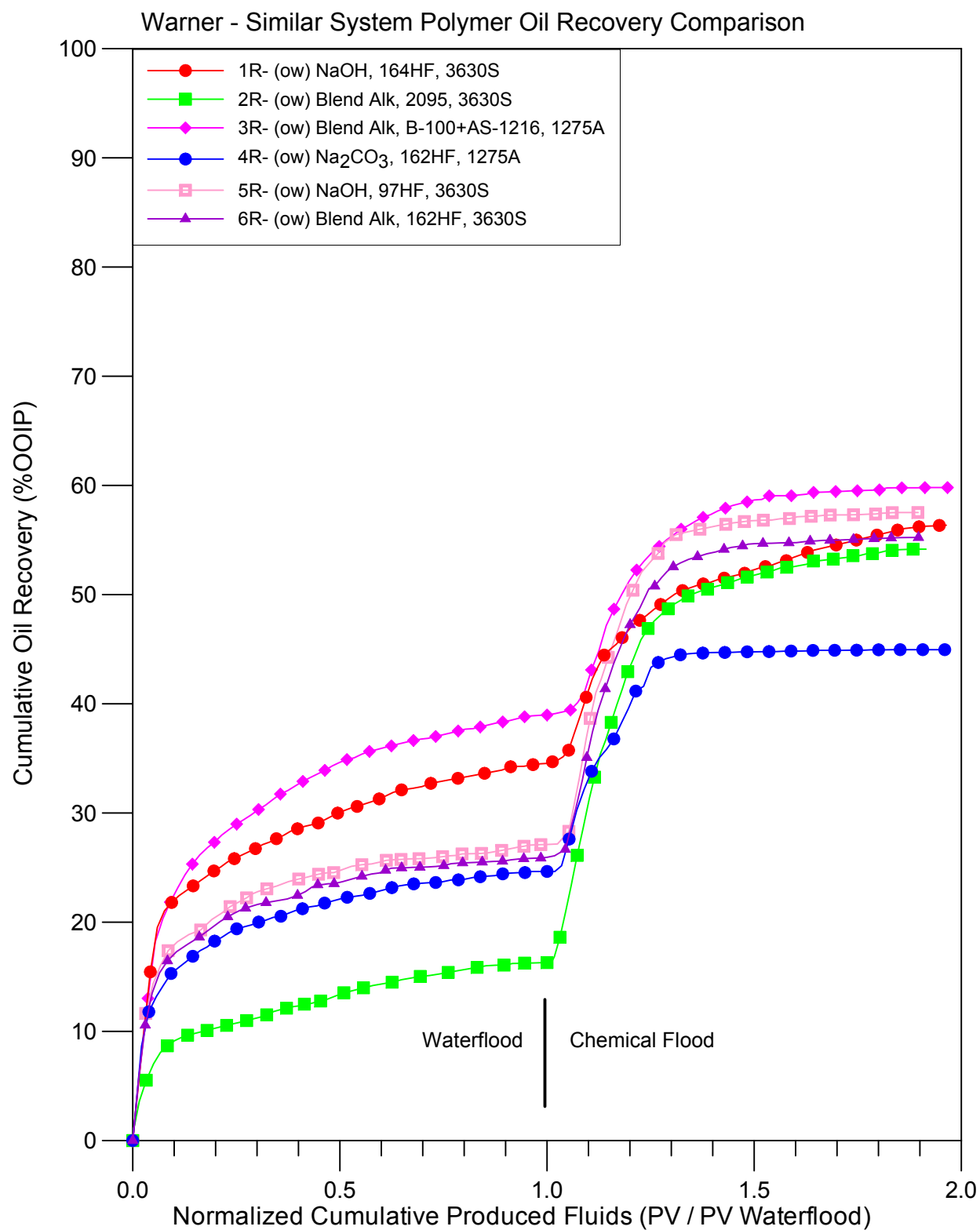
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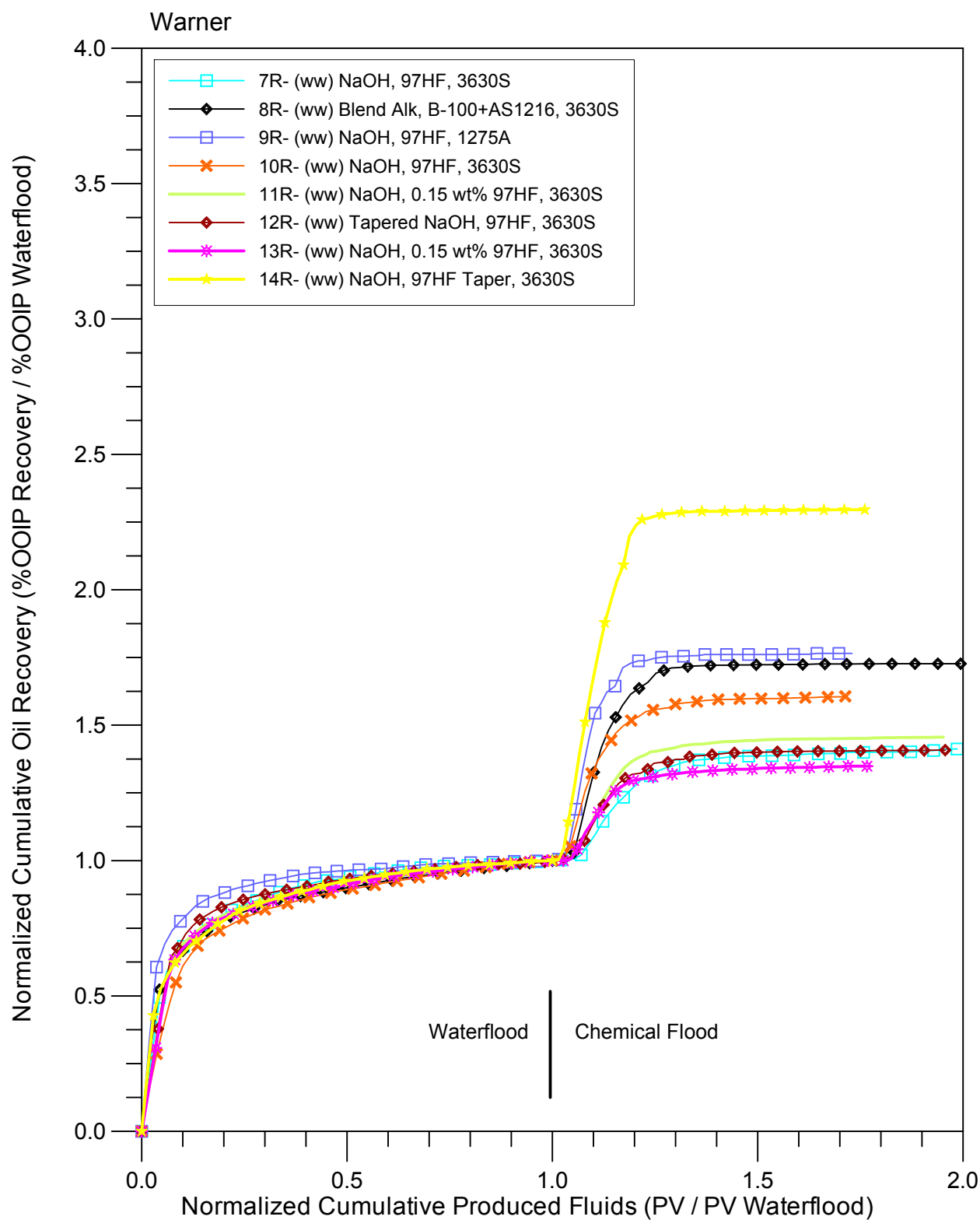
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Oil-Wet Treated Core



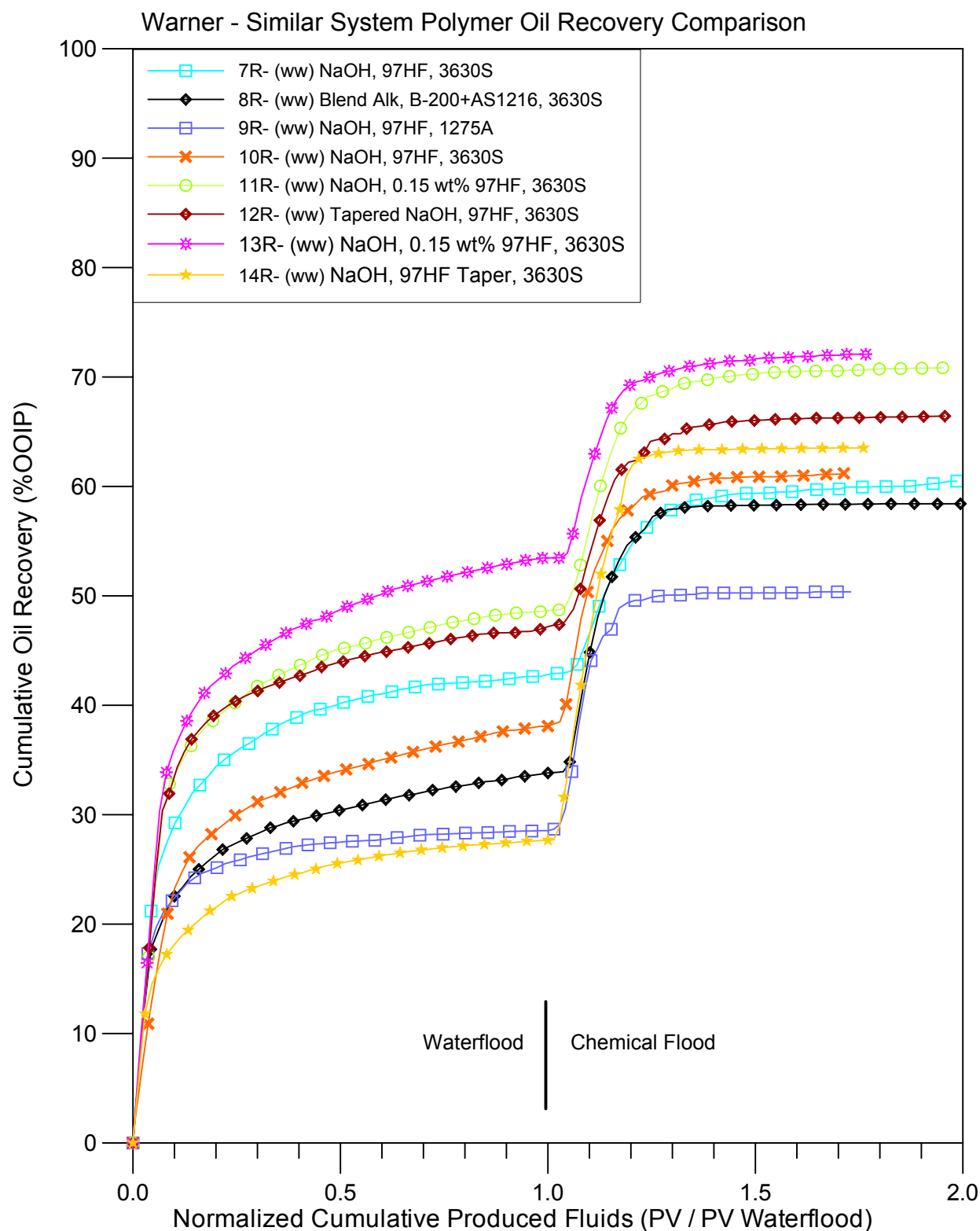
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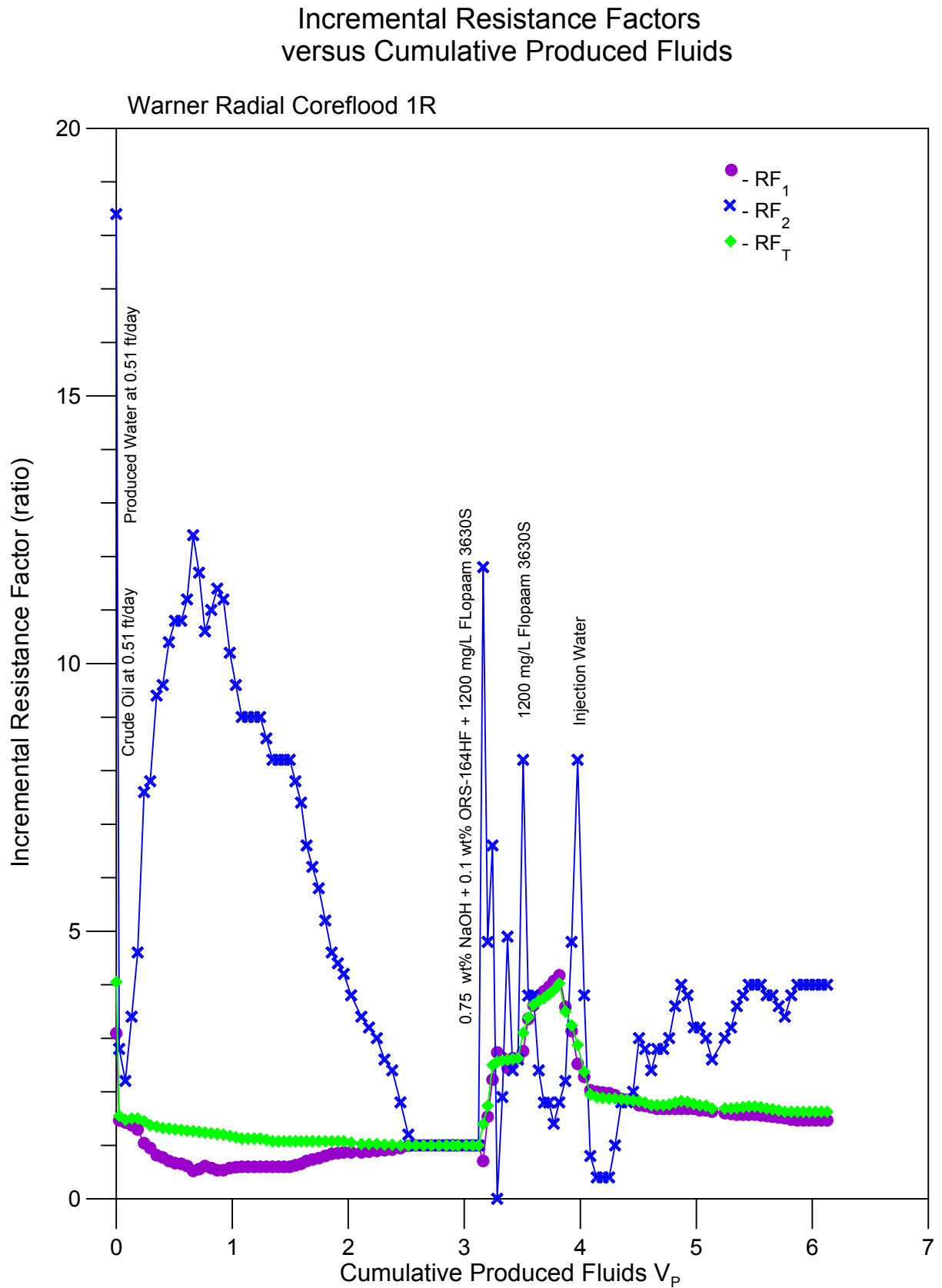


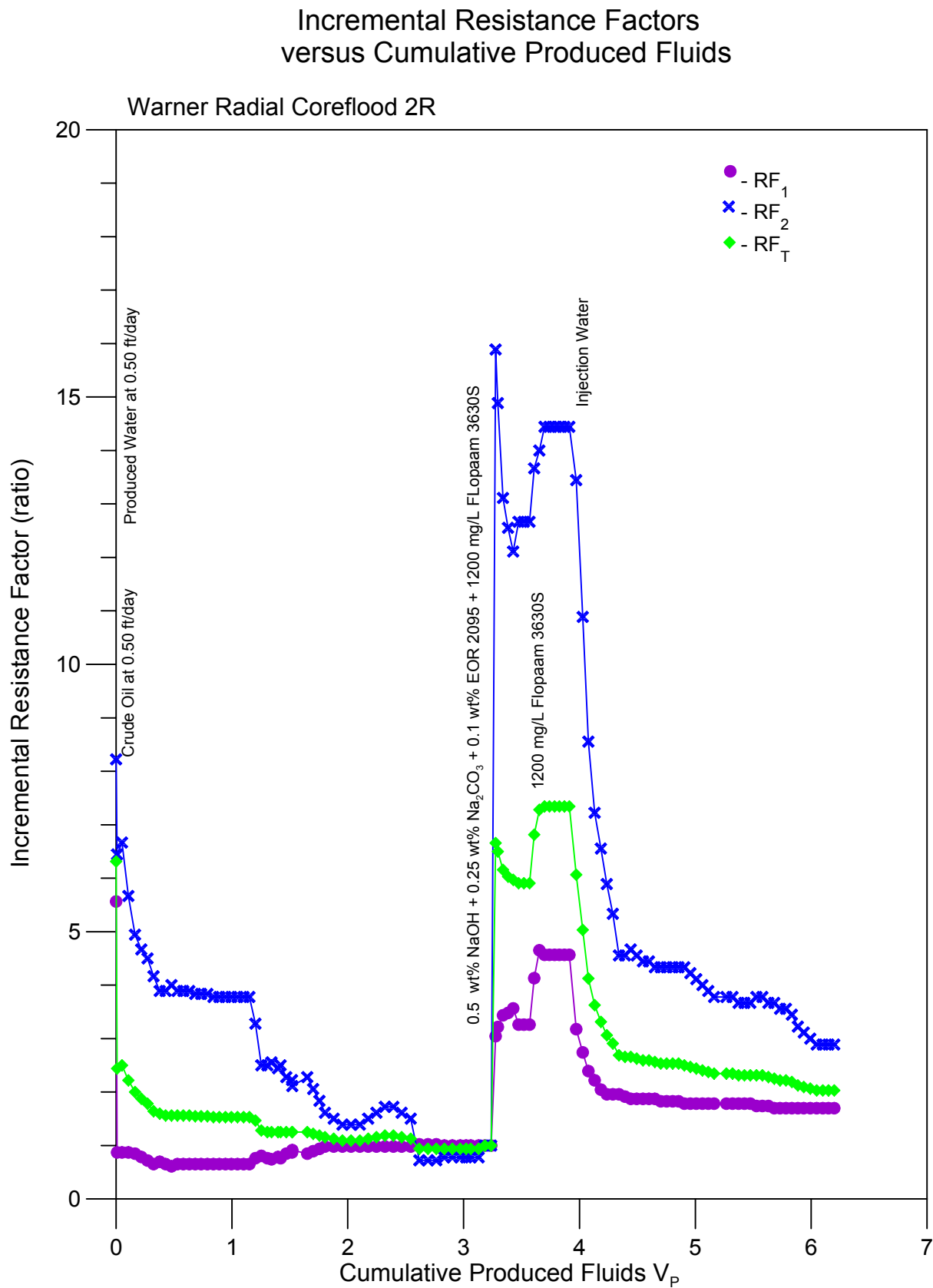
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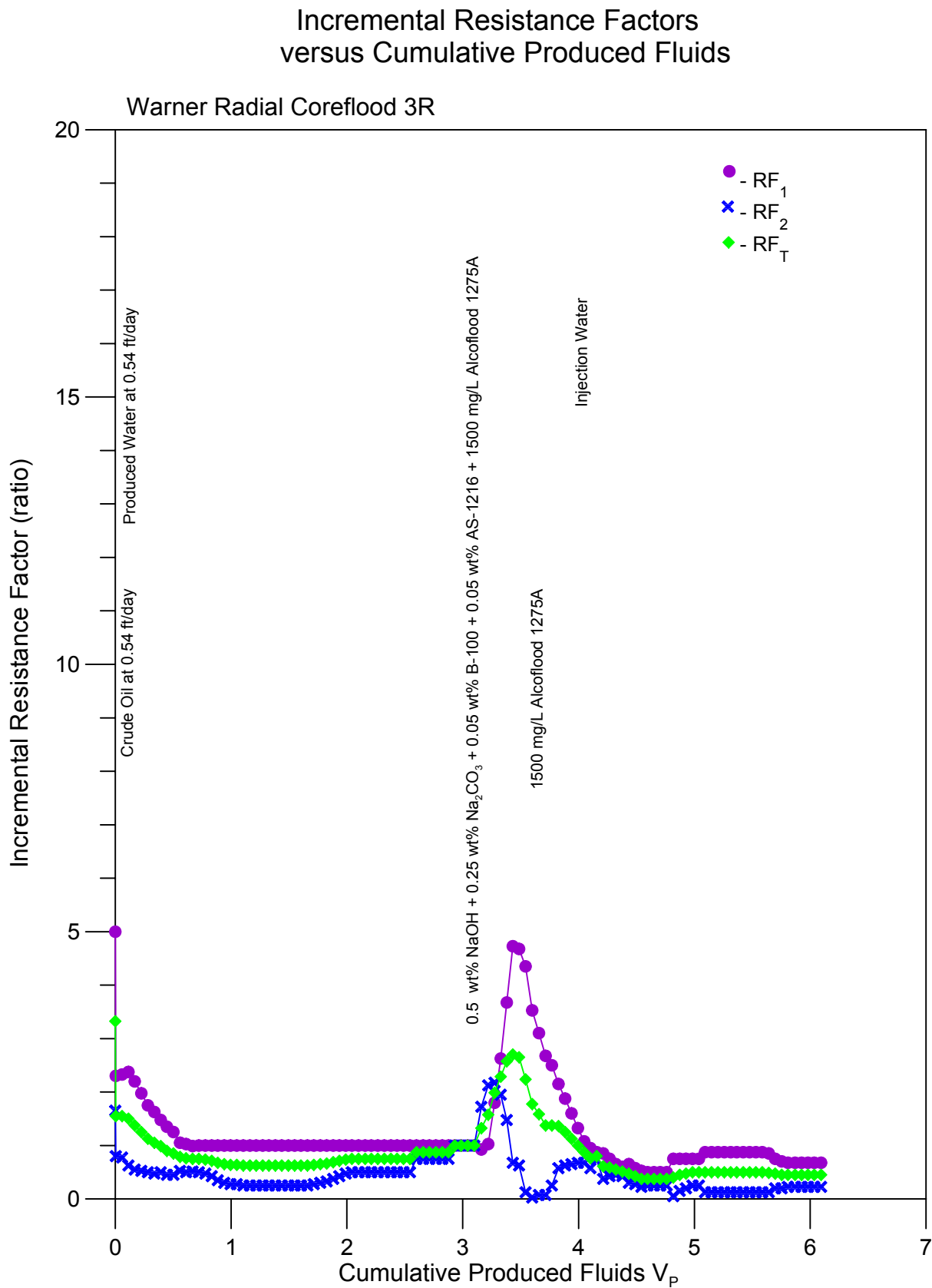


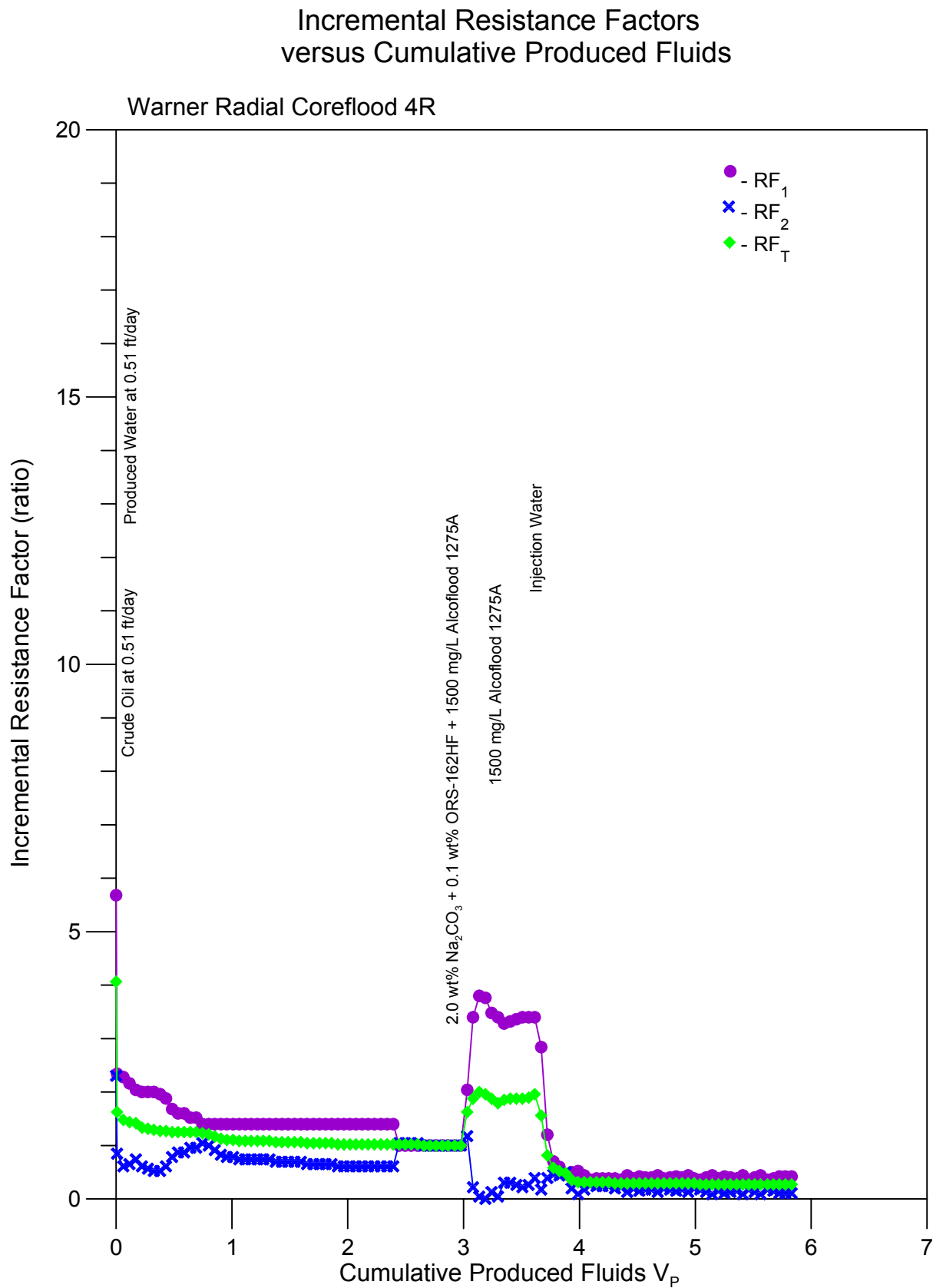
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versus Normalized Cumulative Produced Fluids
Water-Wet Corefloods

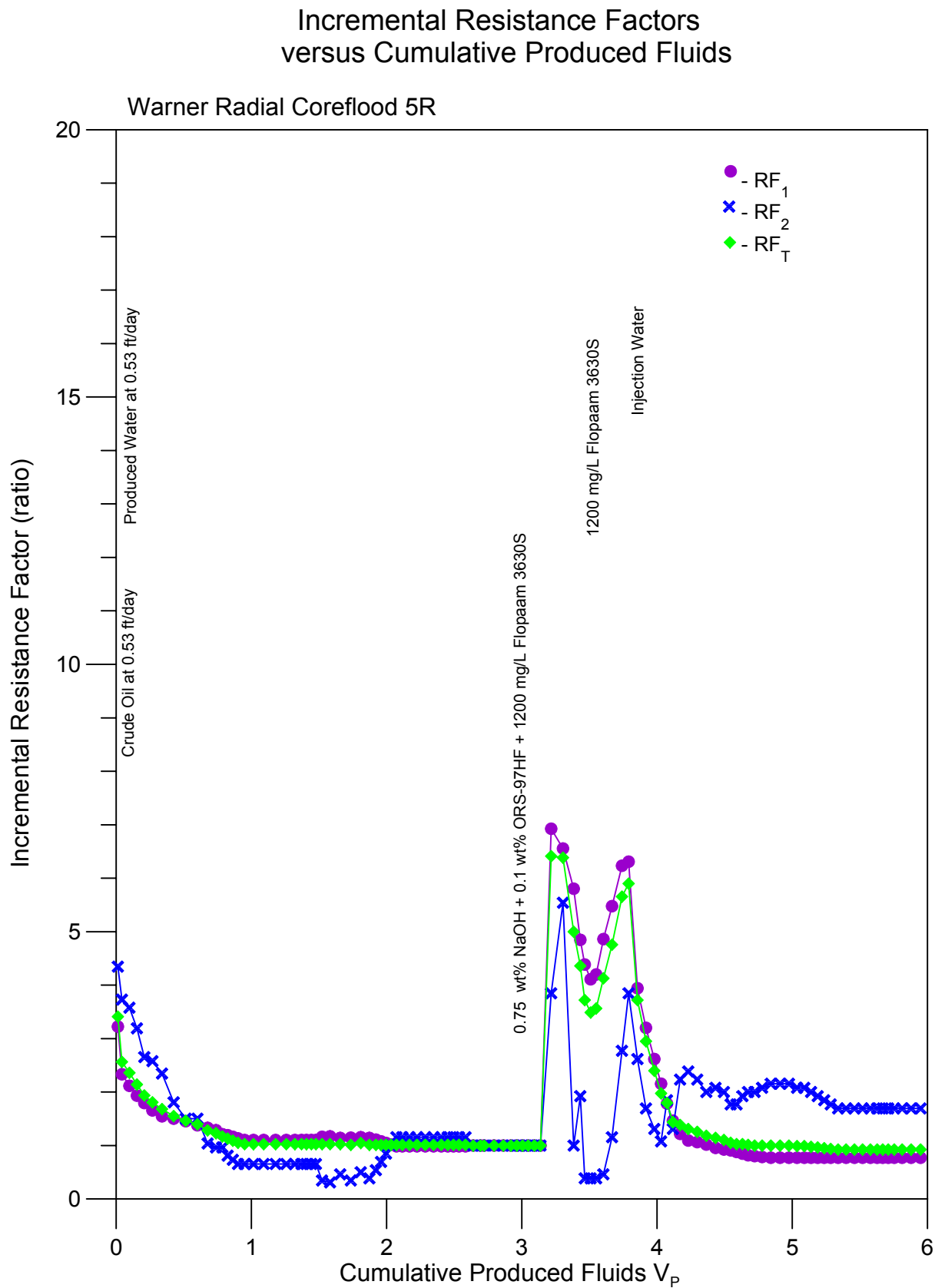


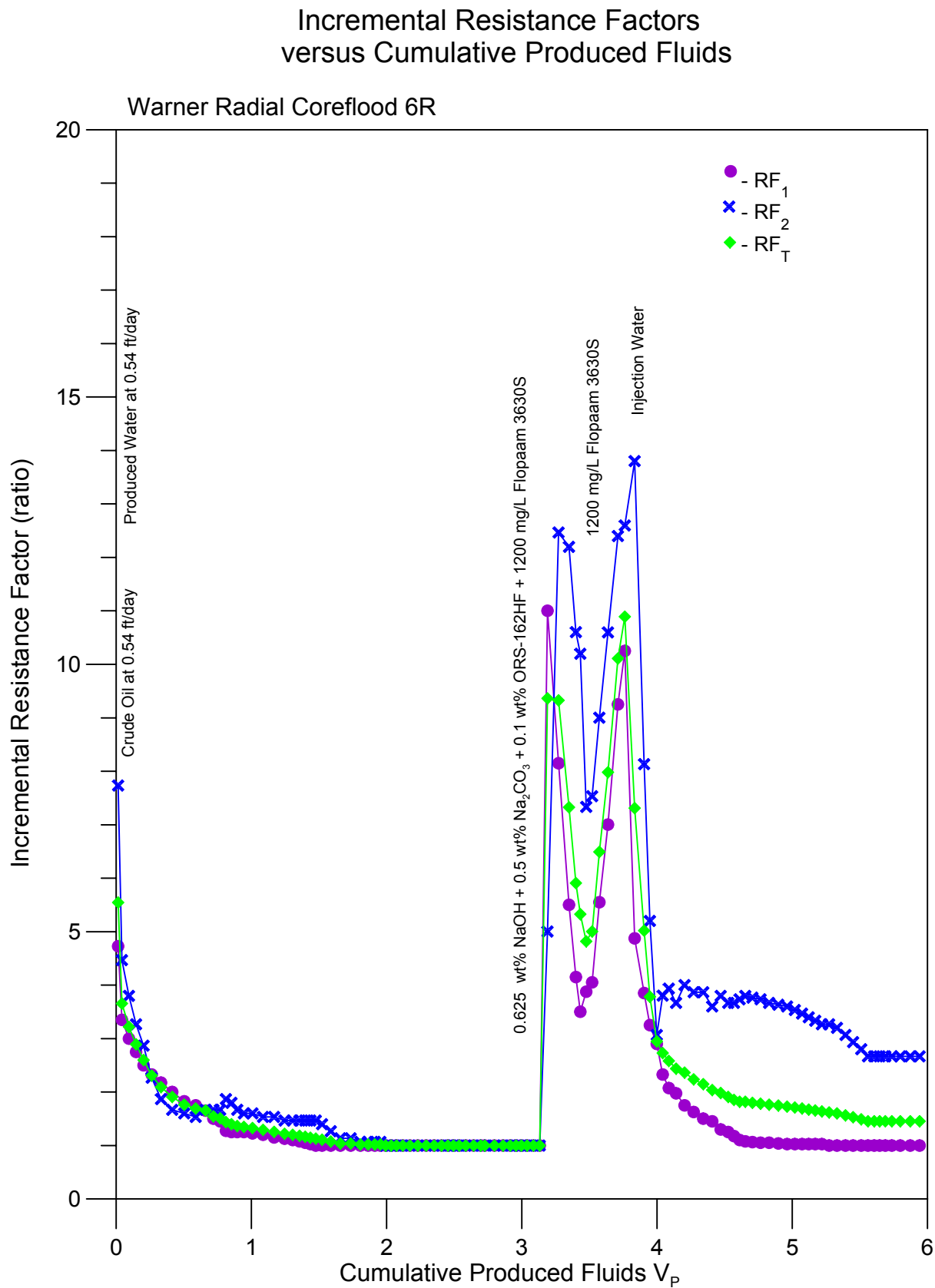


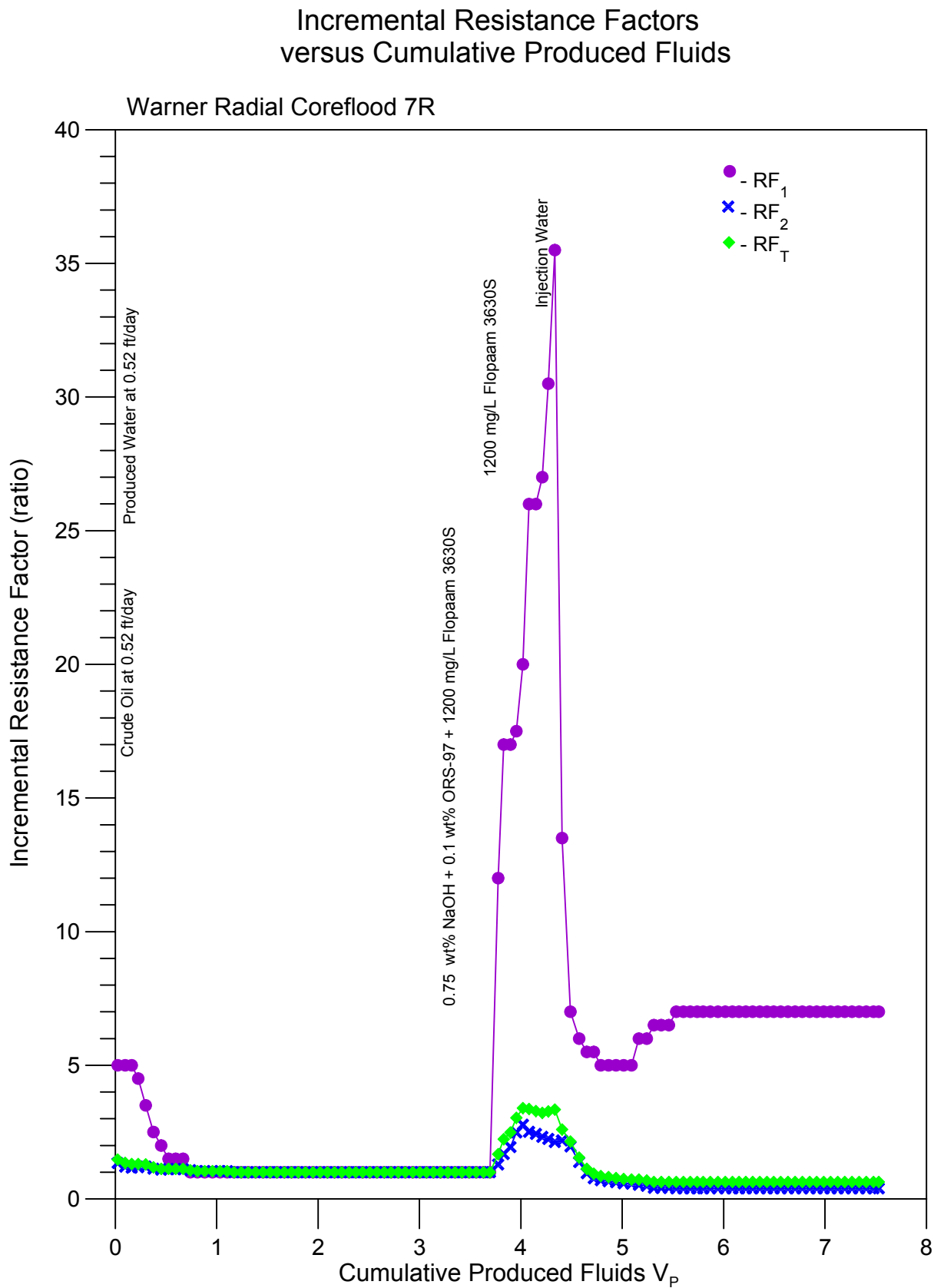


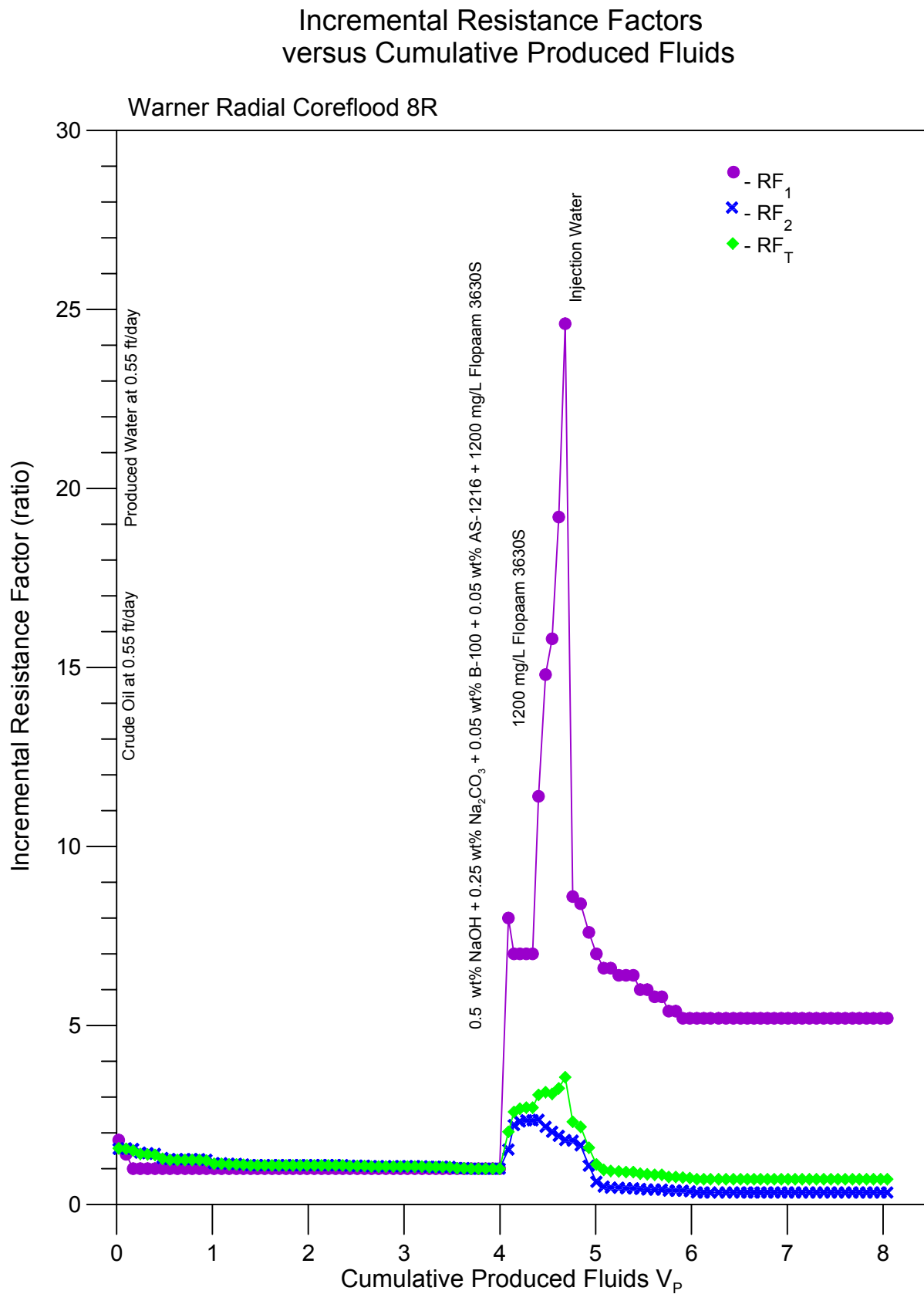


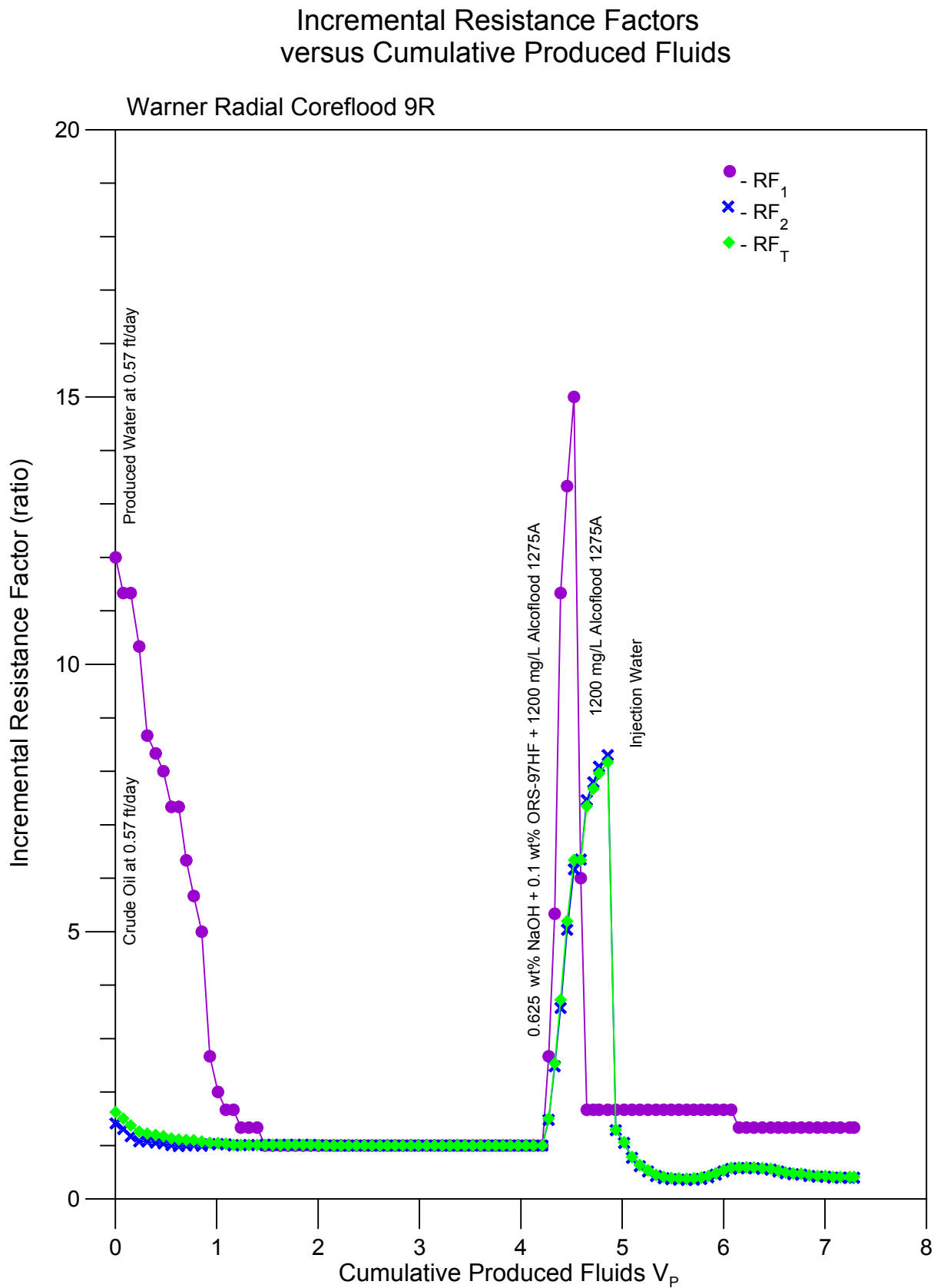


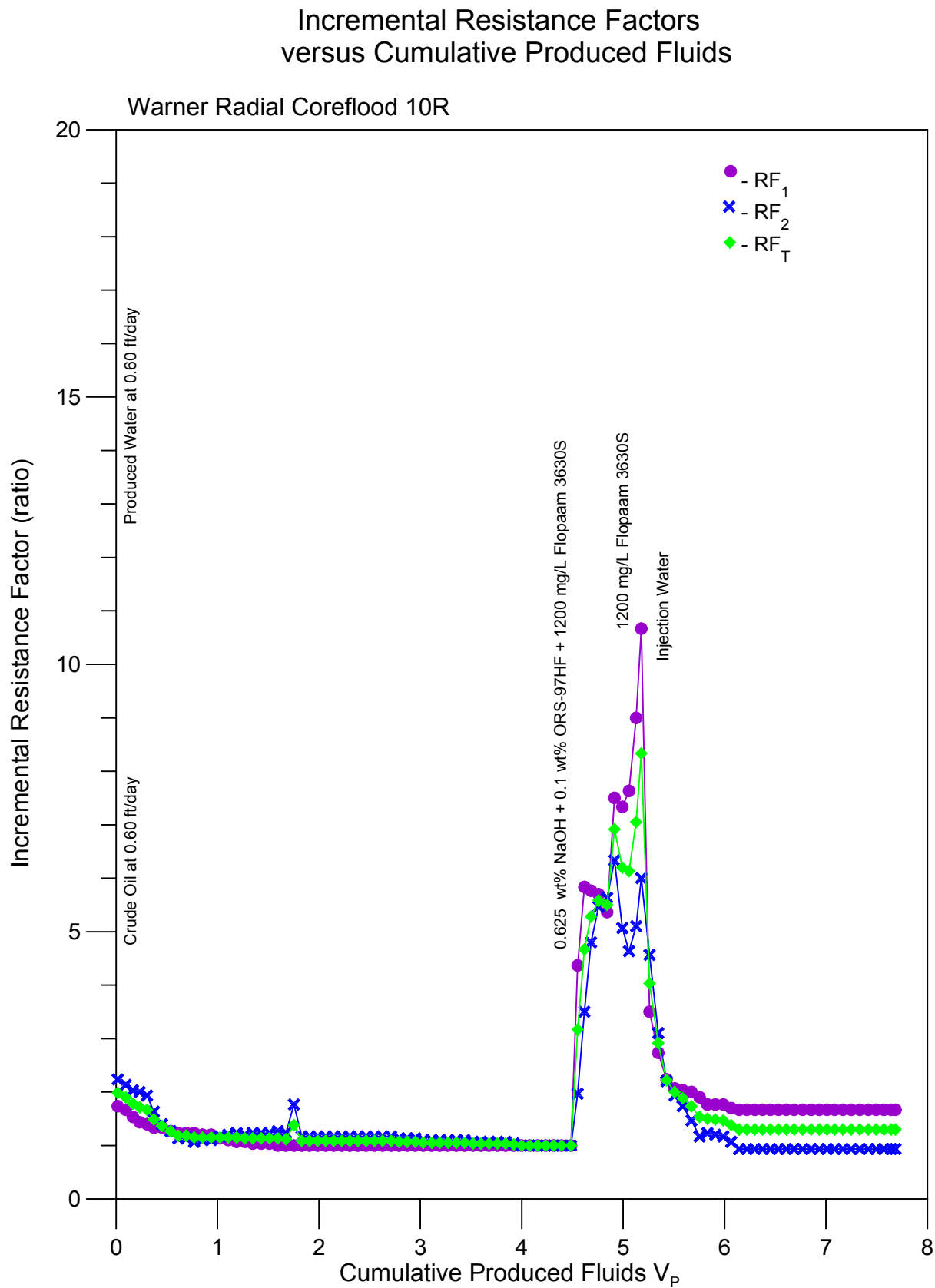


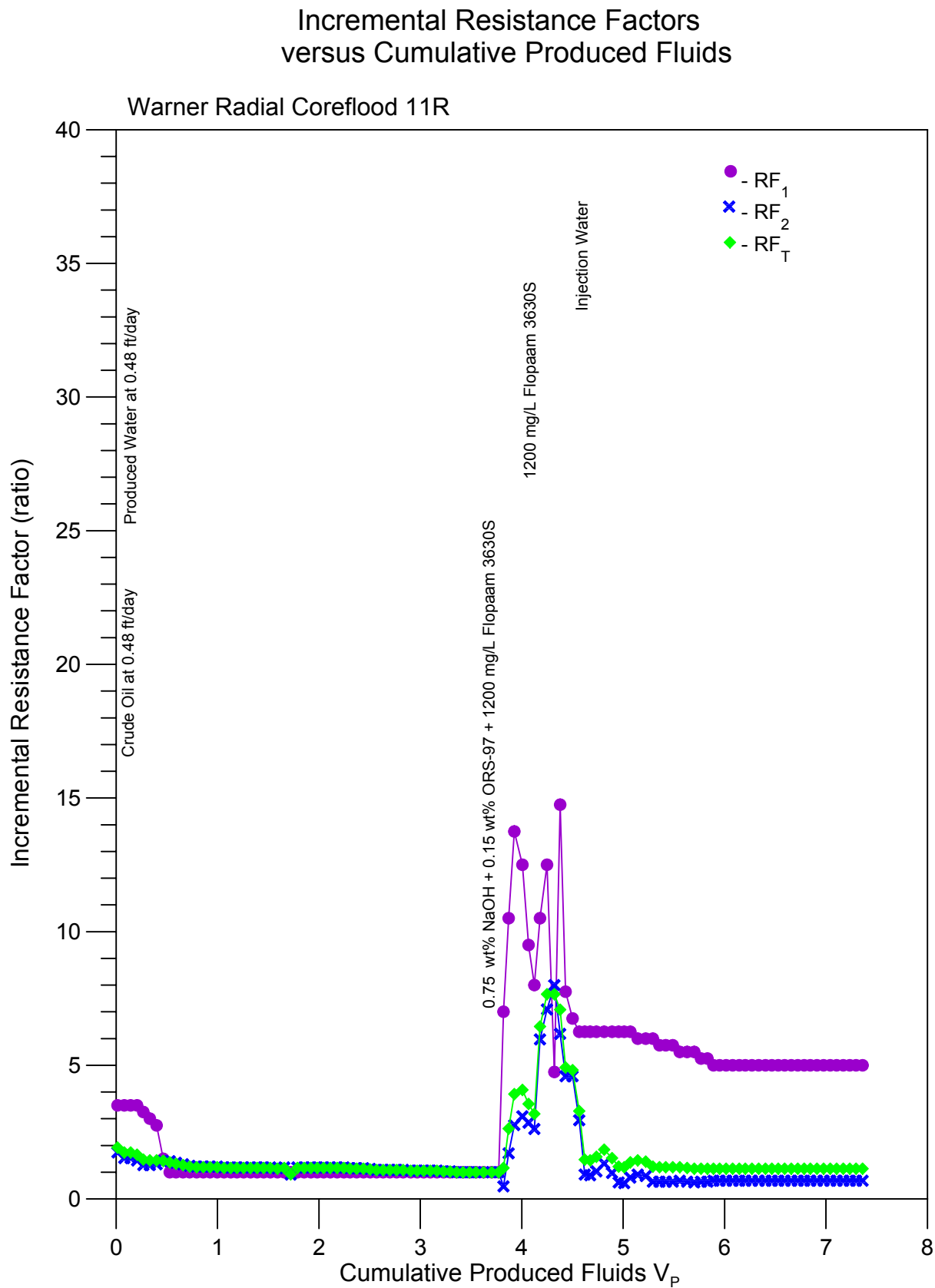


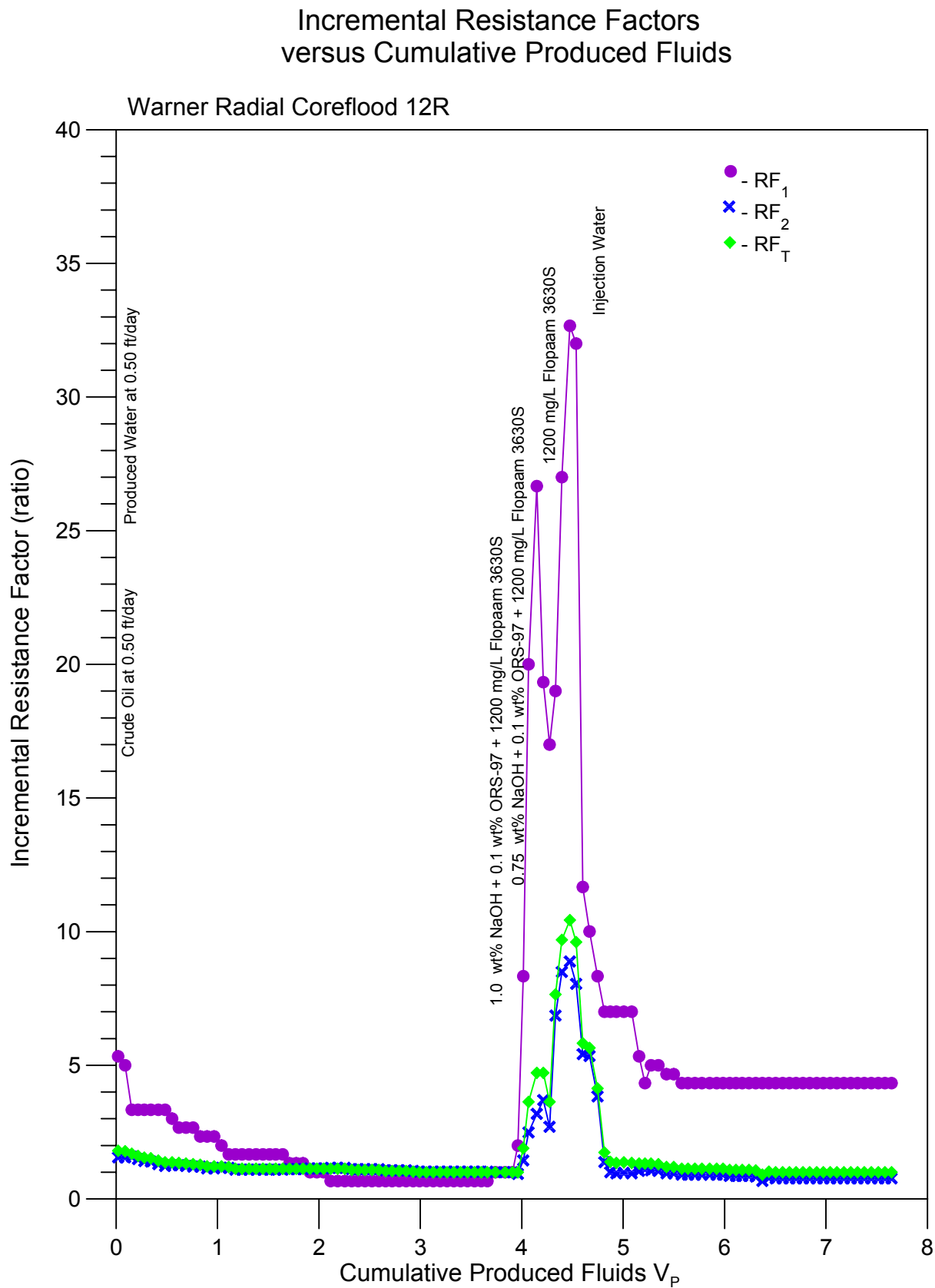


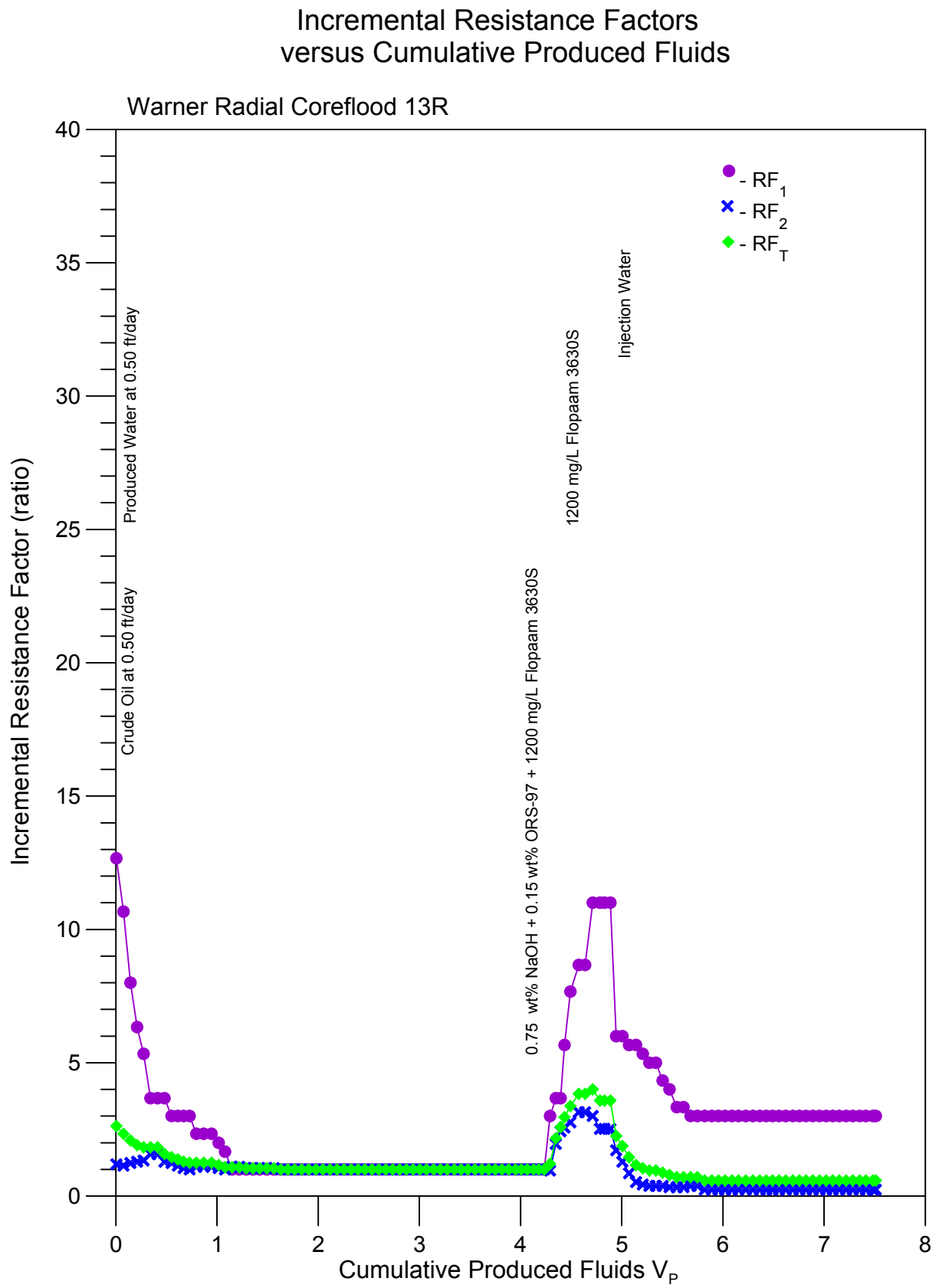


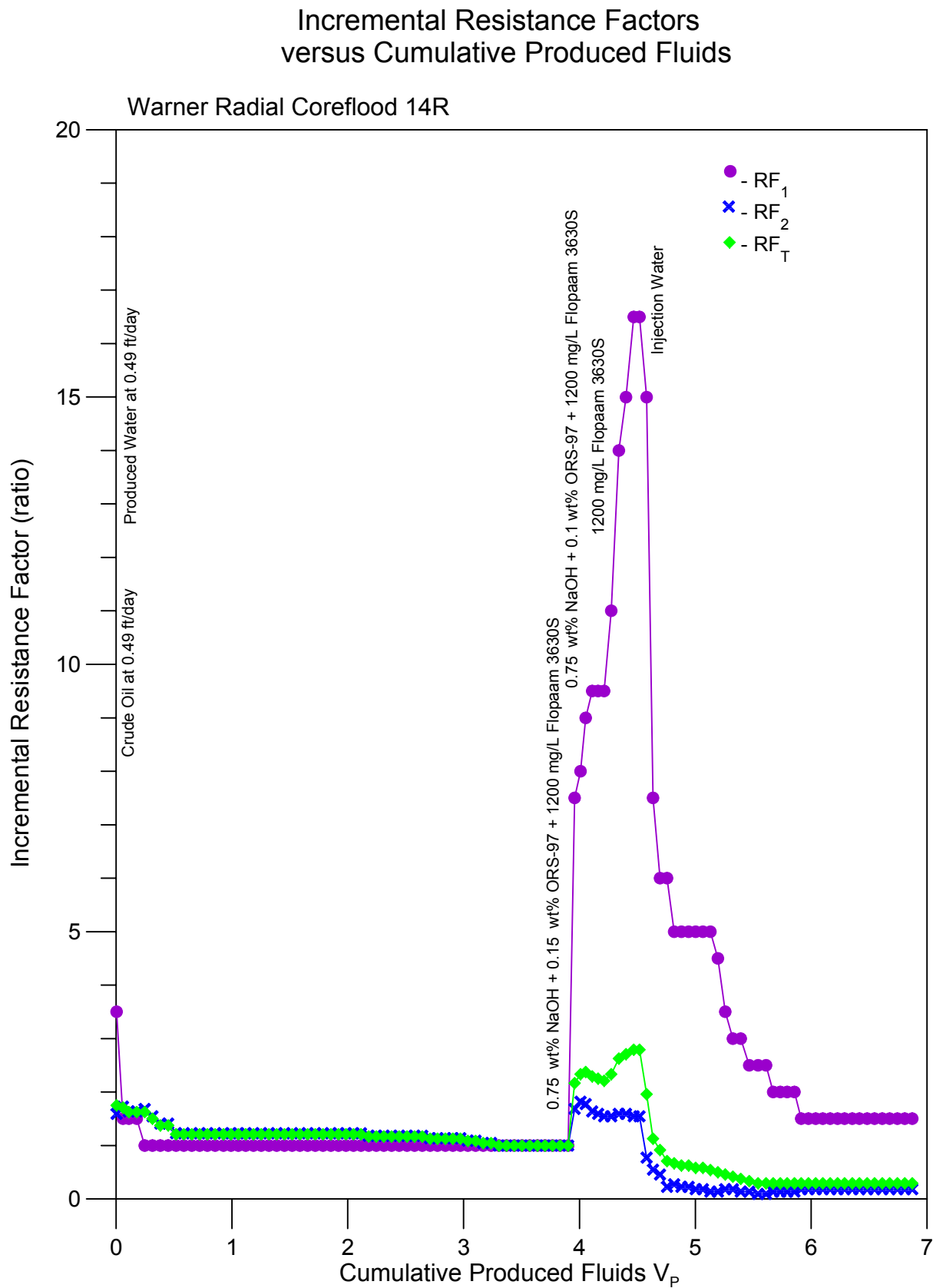


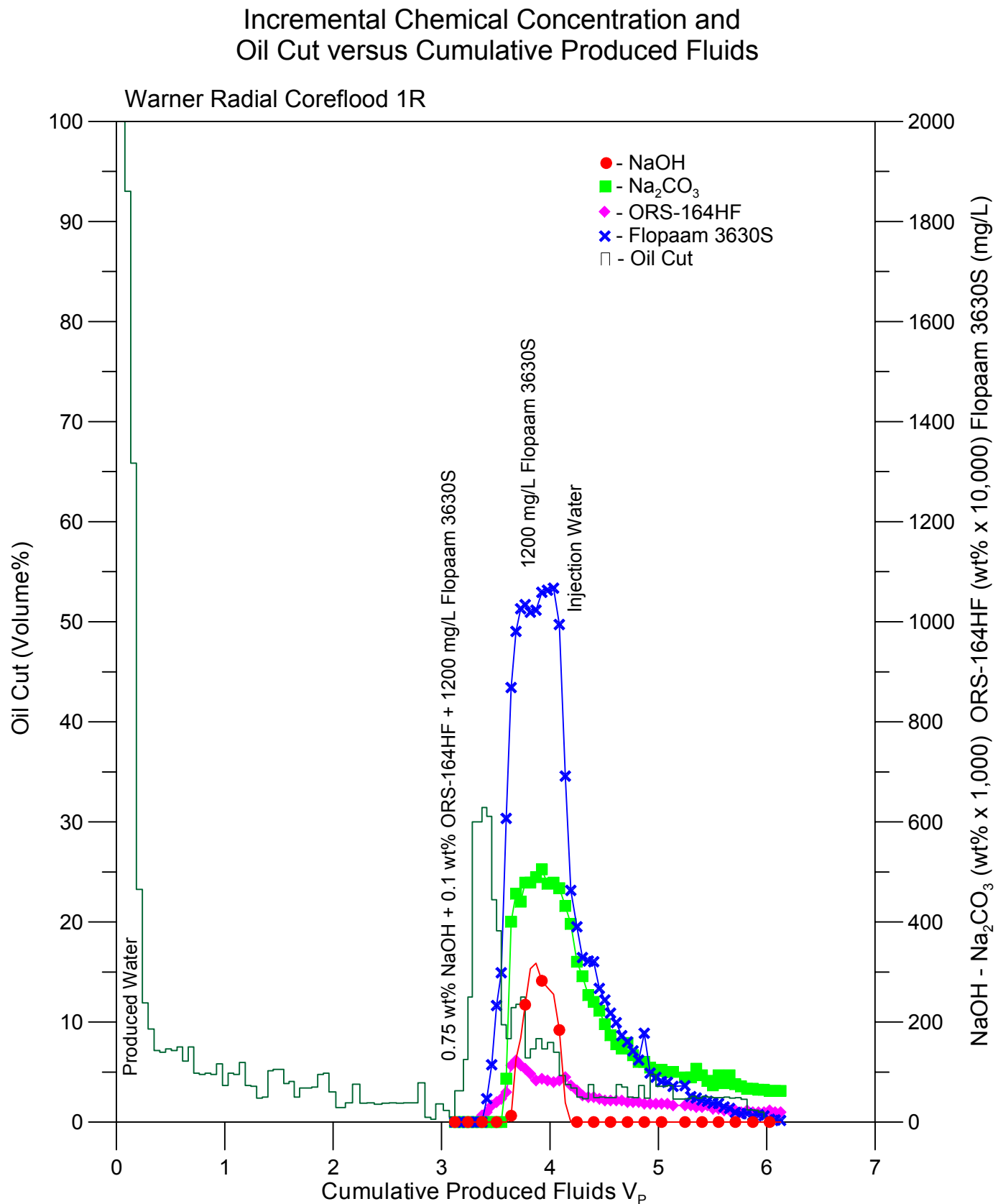


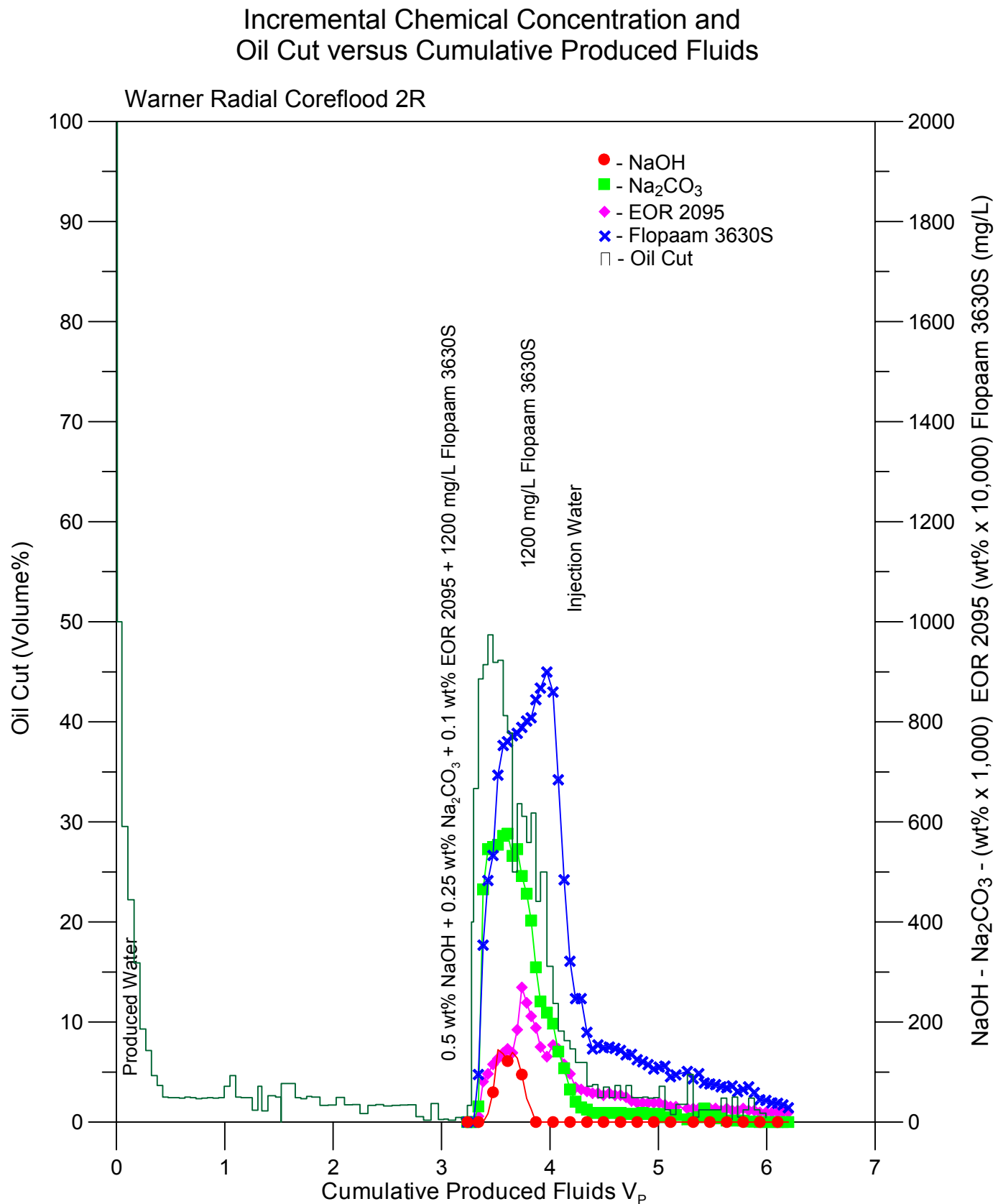


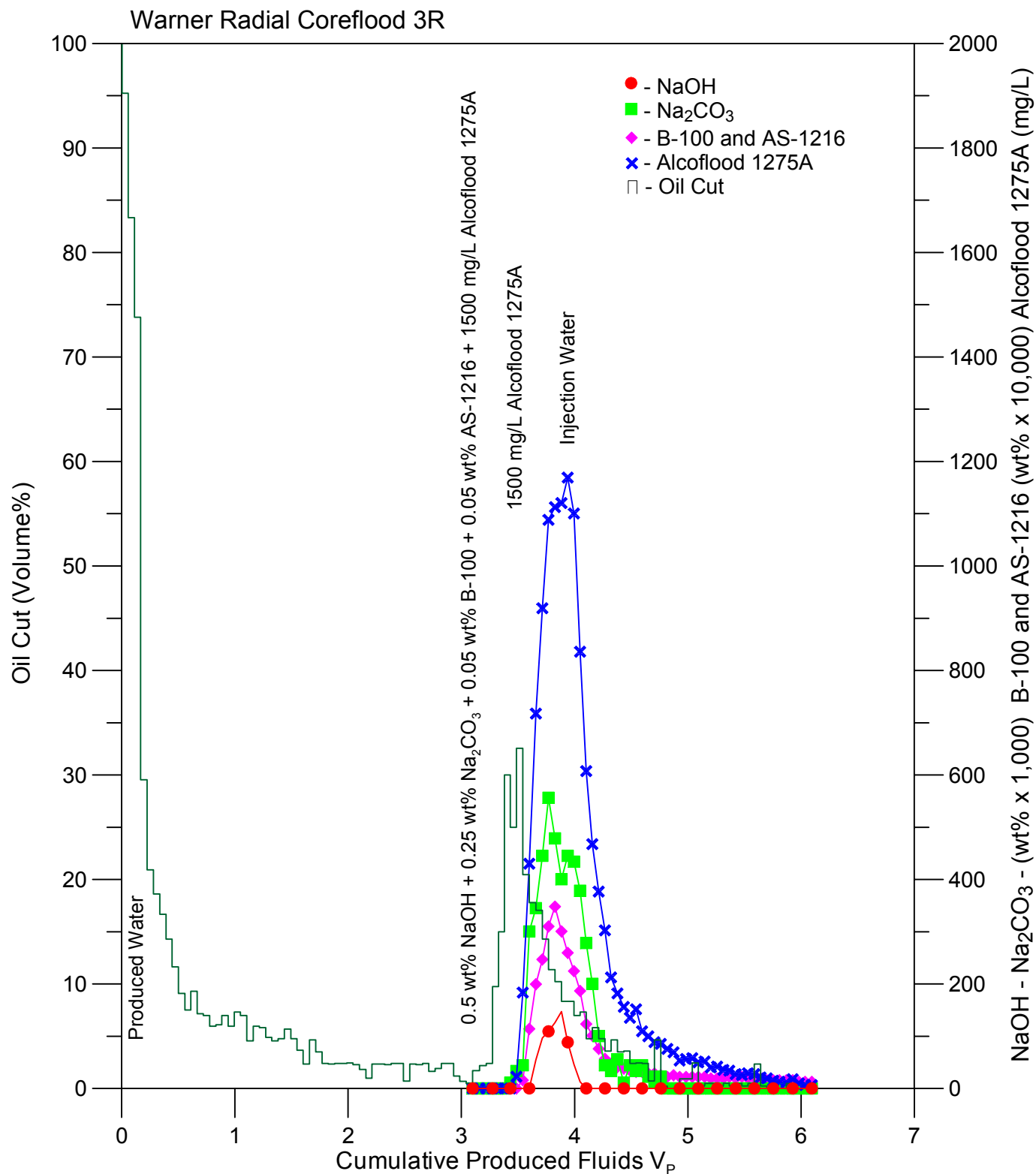


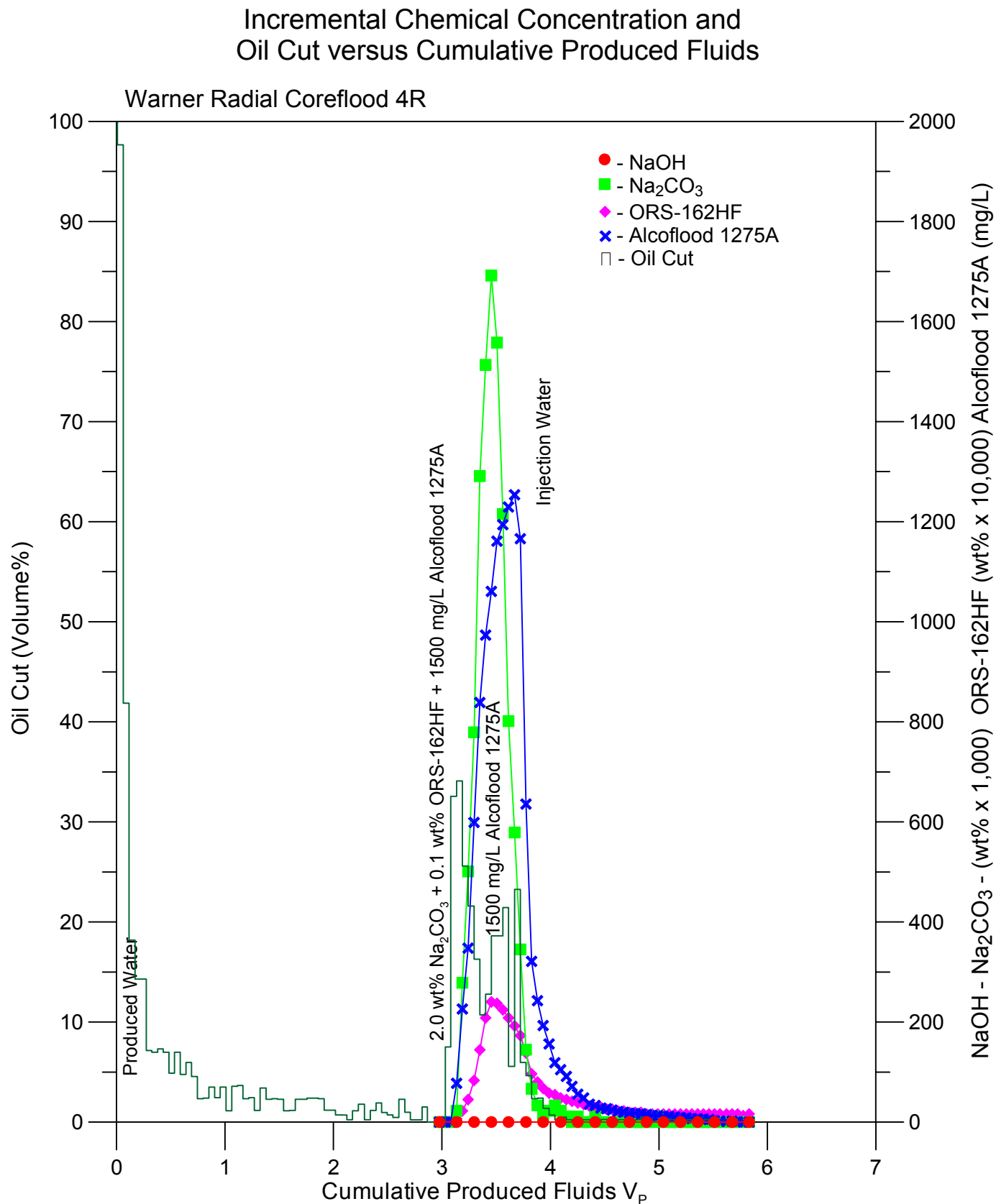


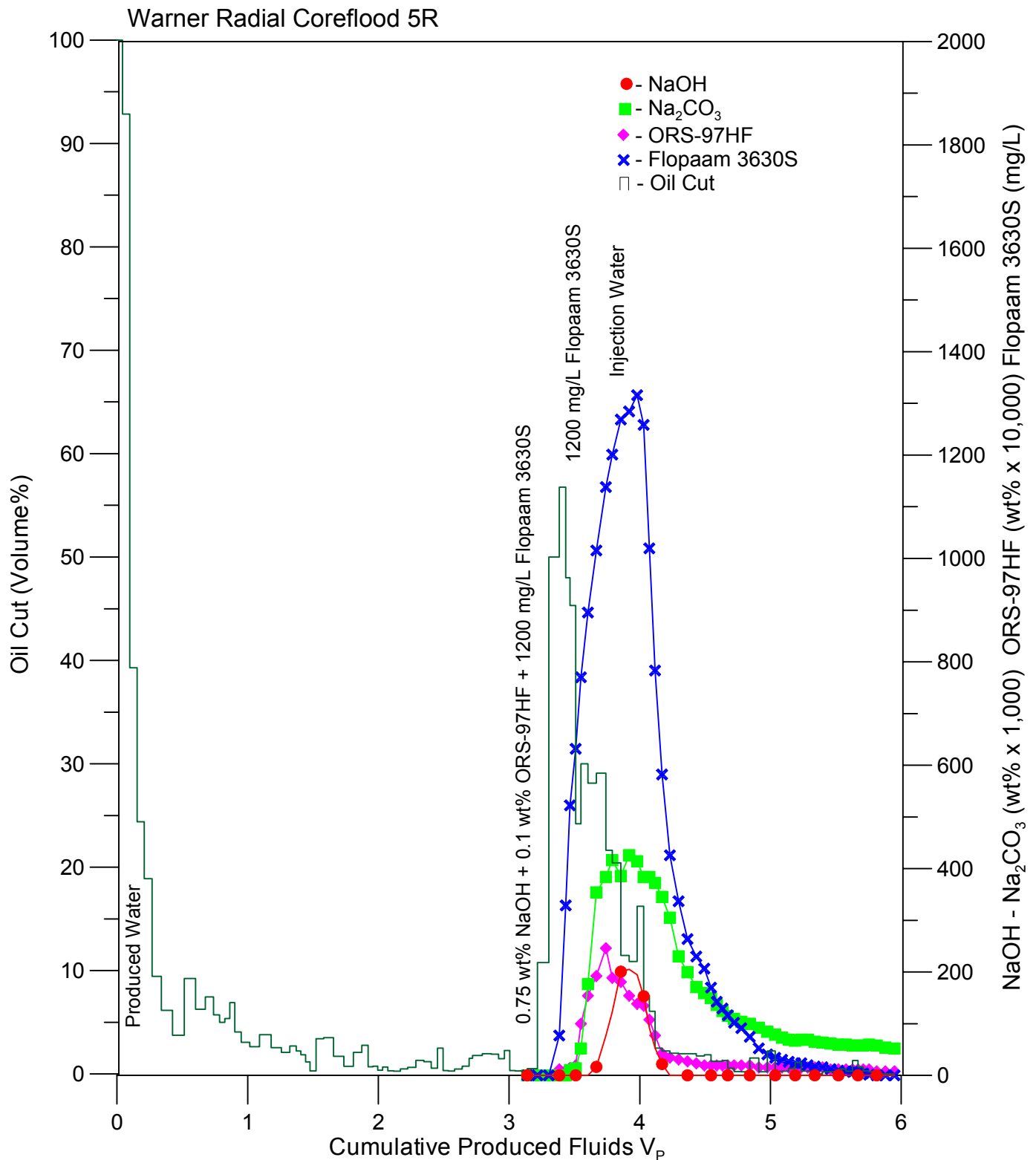


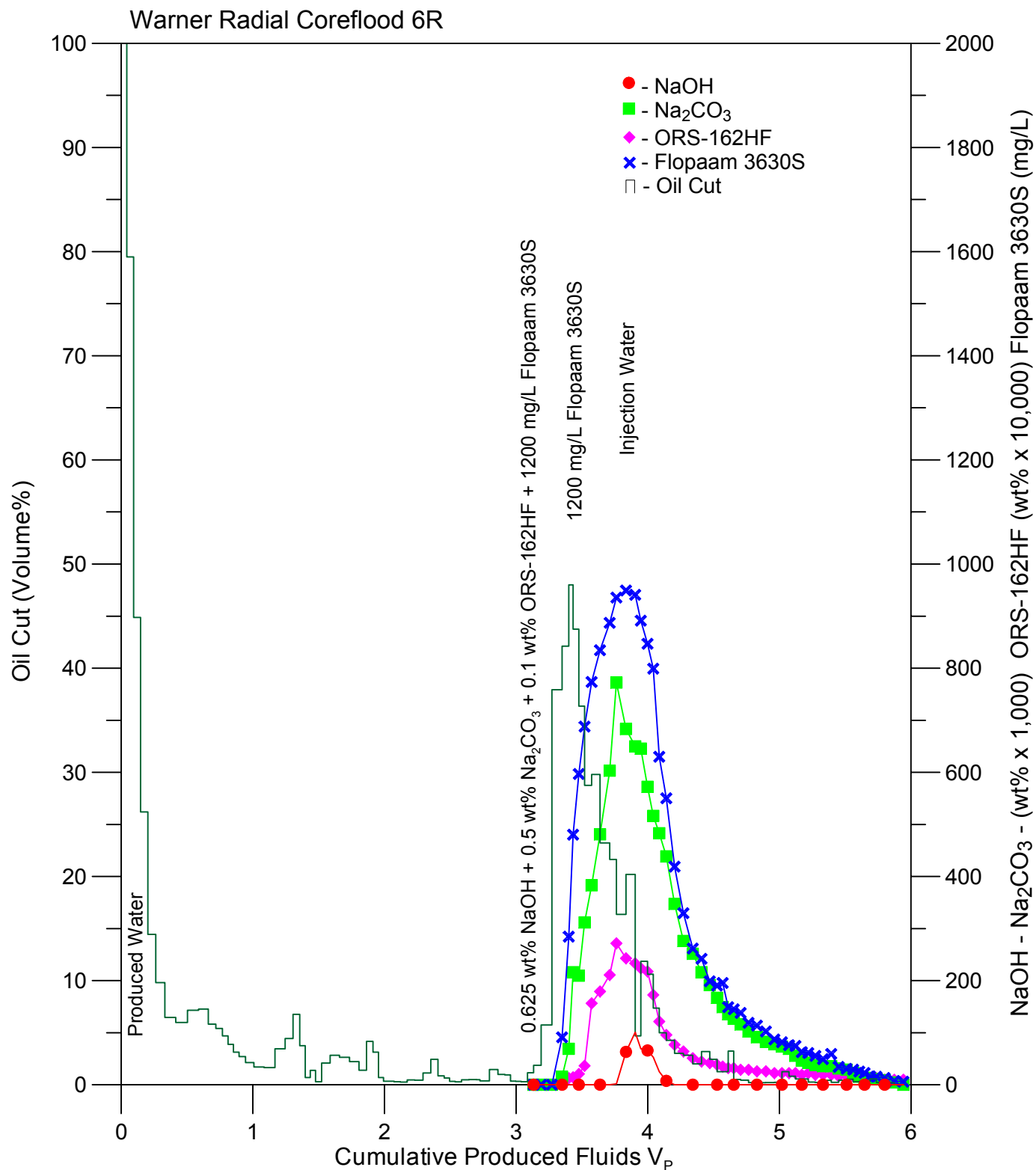


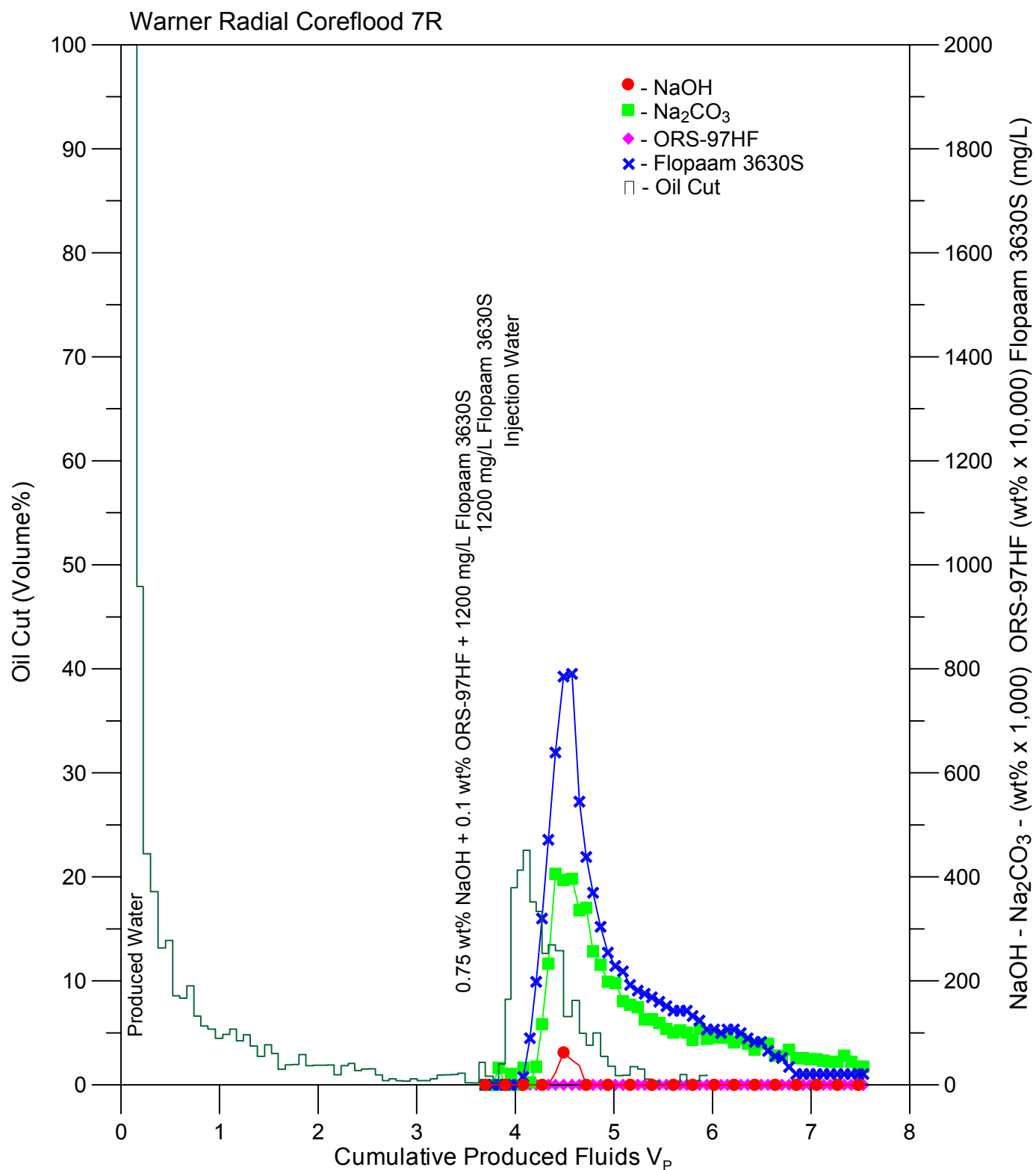


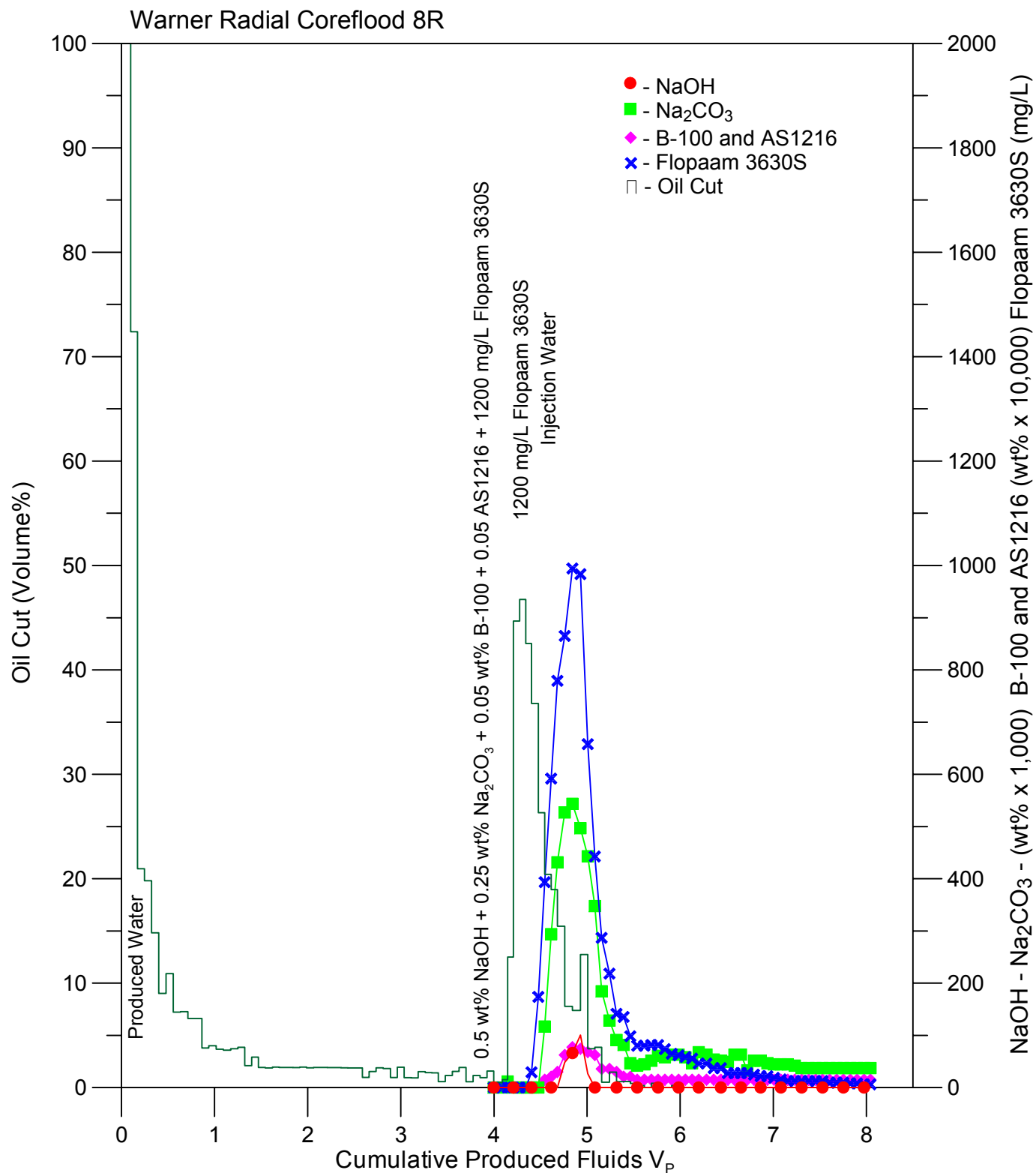
Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids

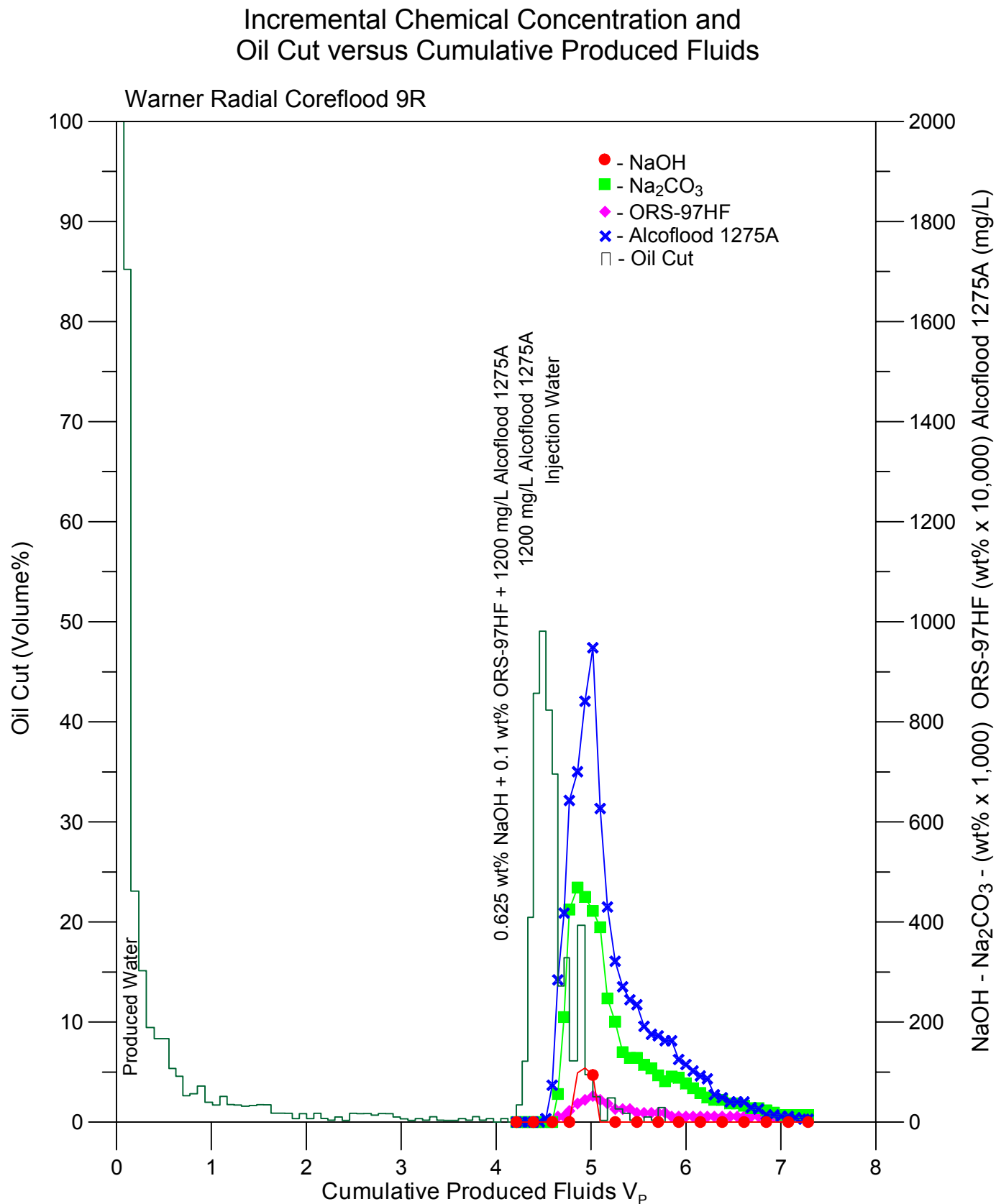


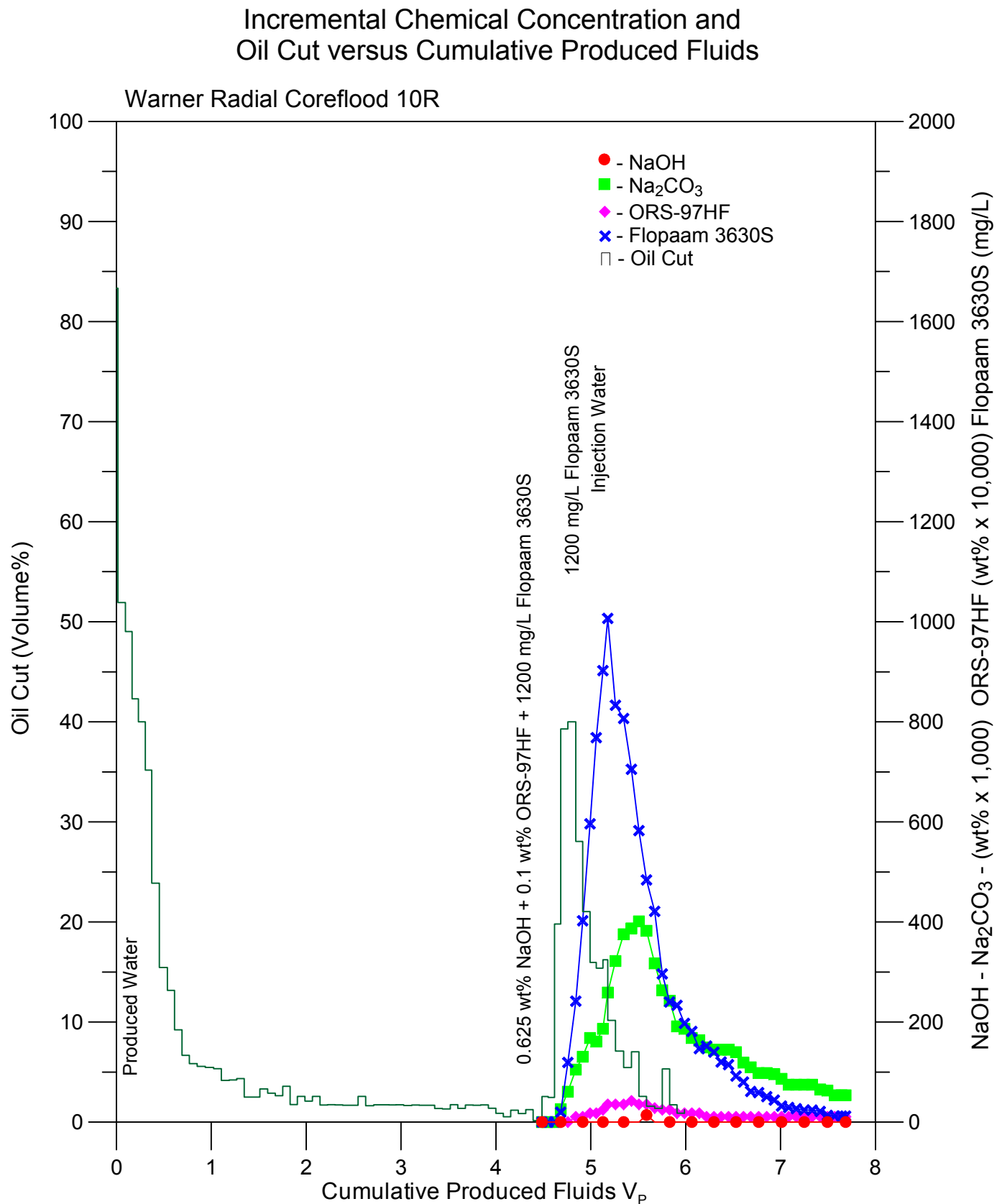
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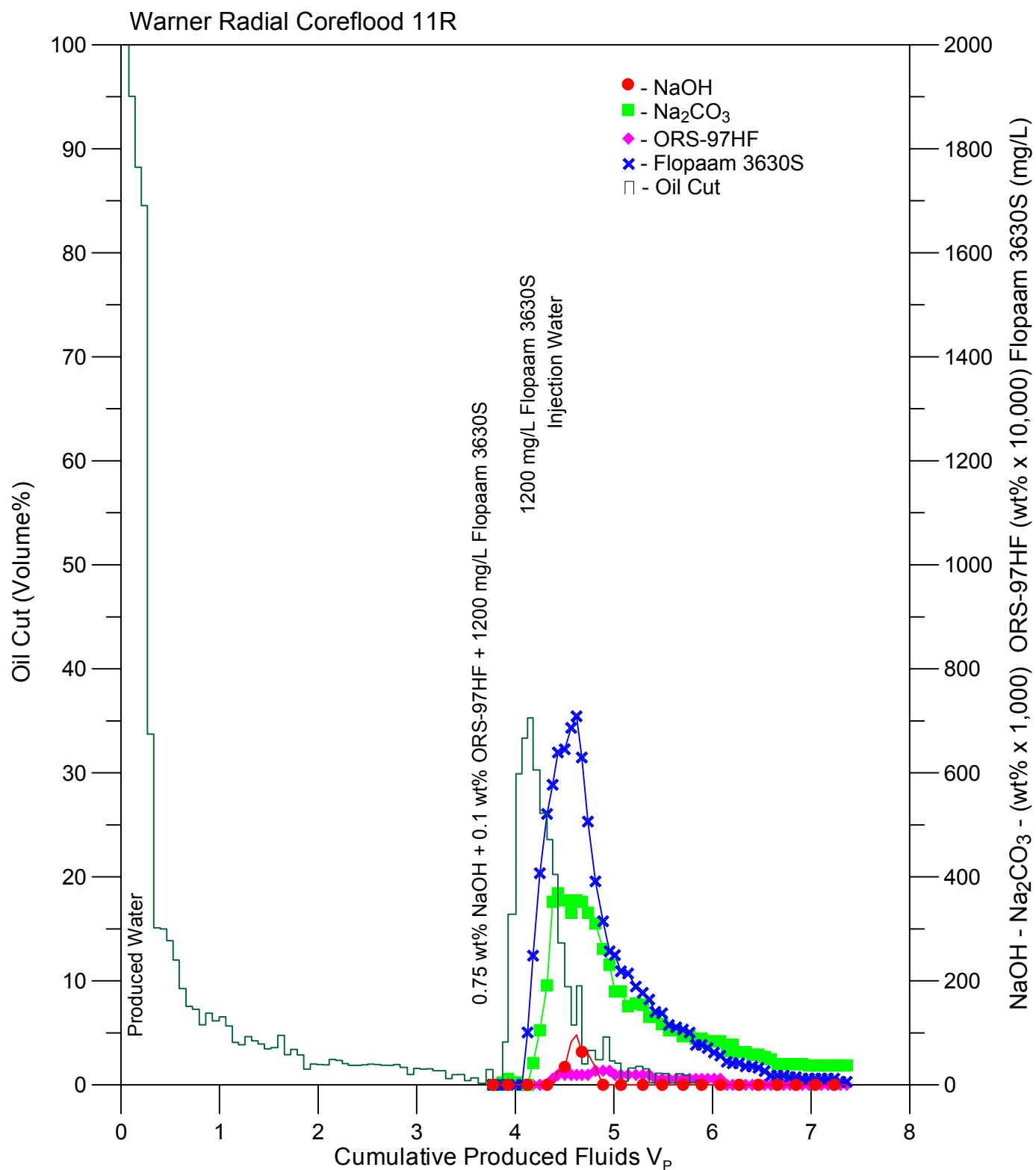
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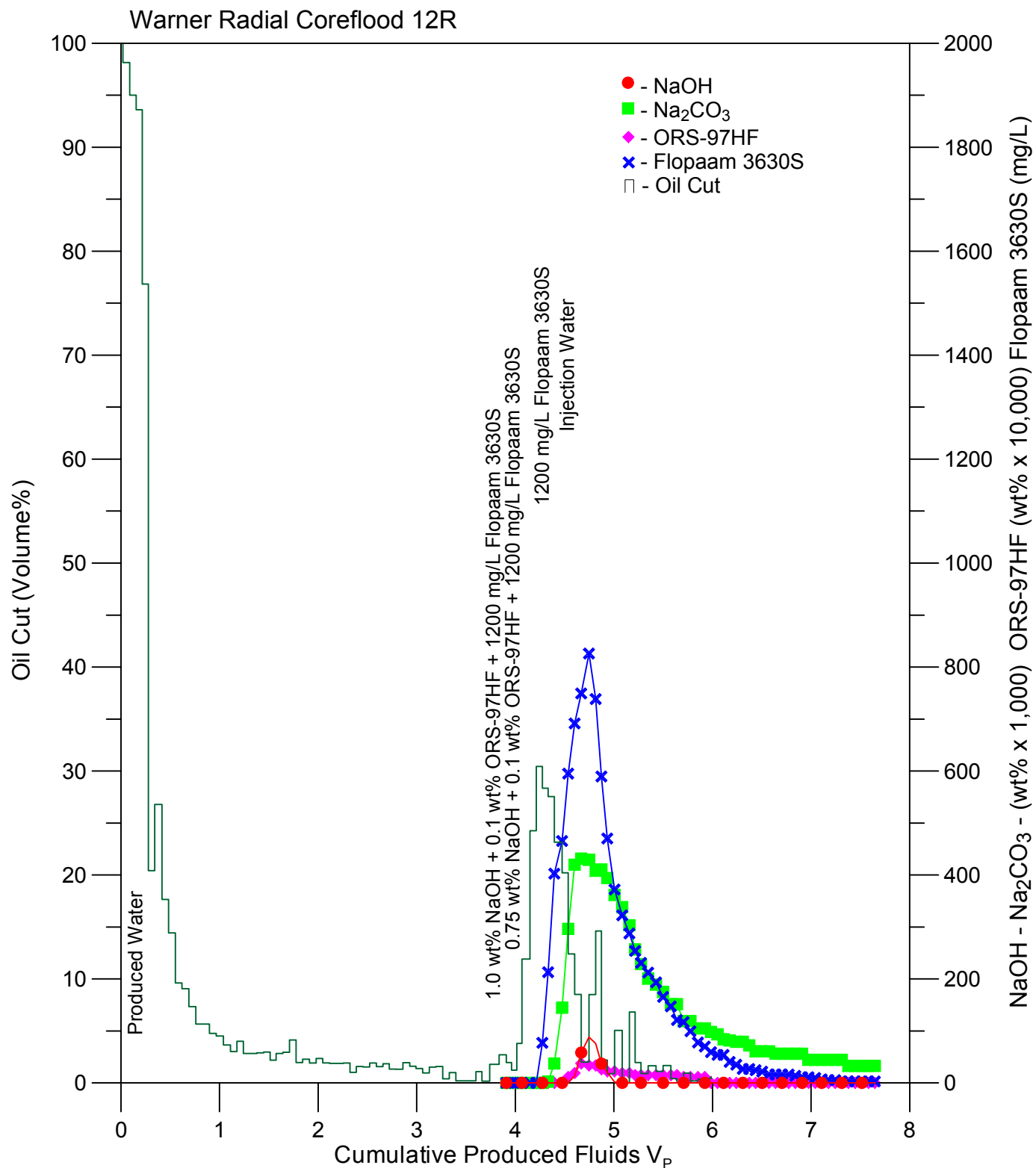
Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids

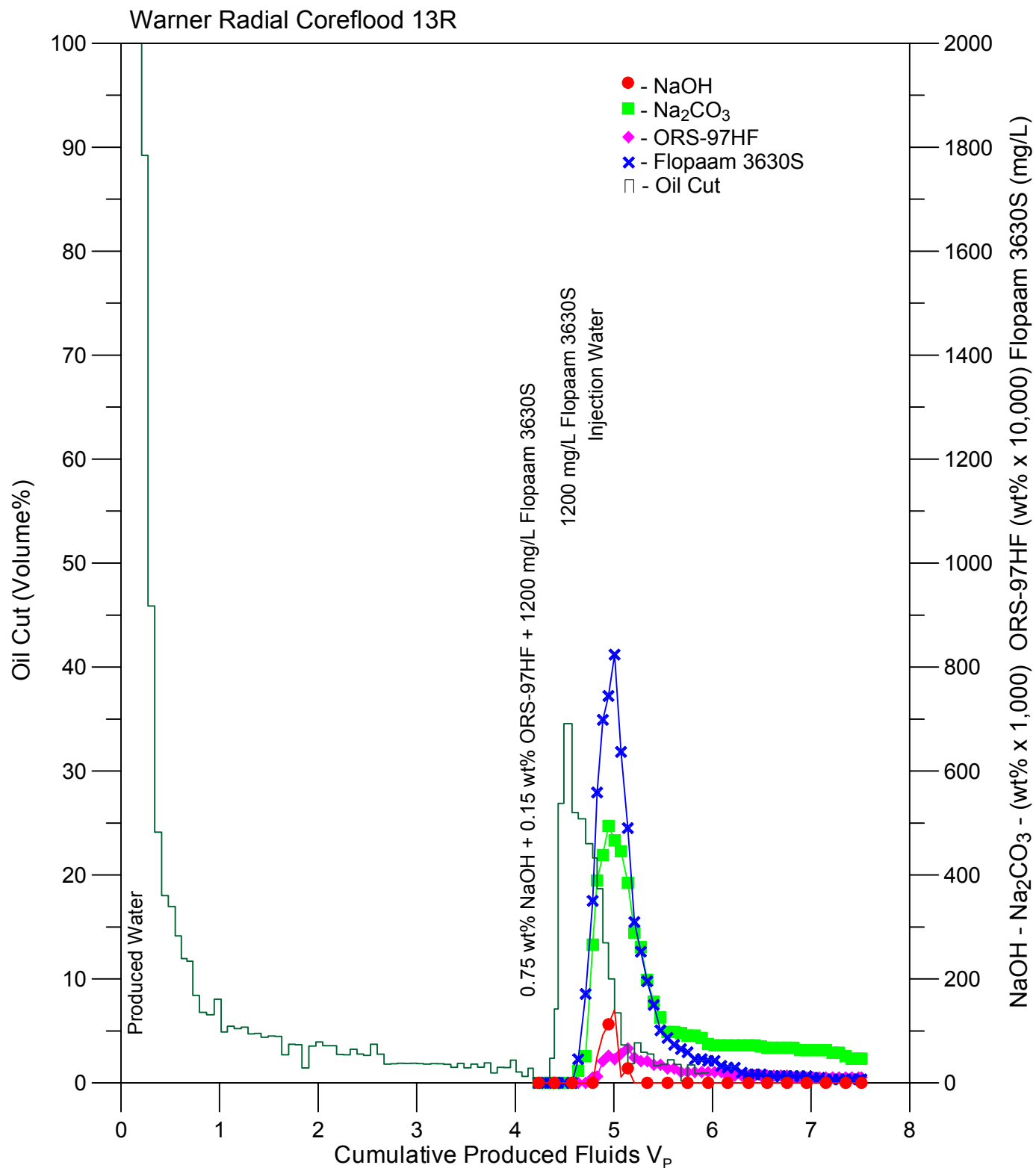
Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids

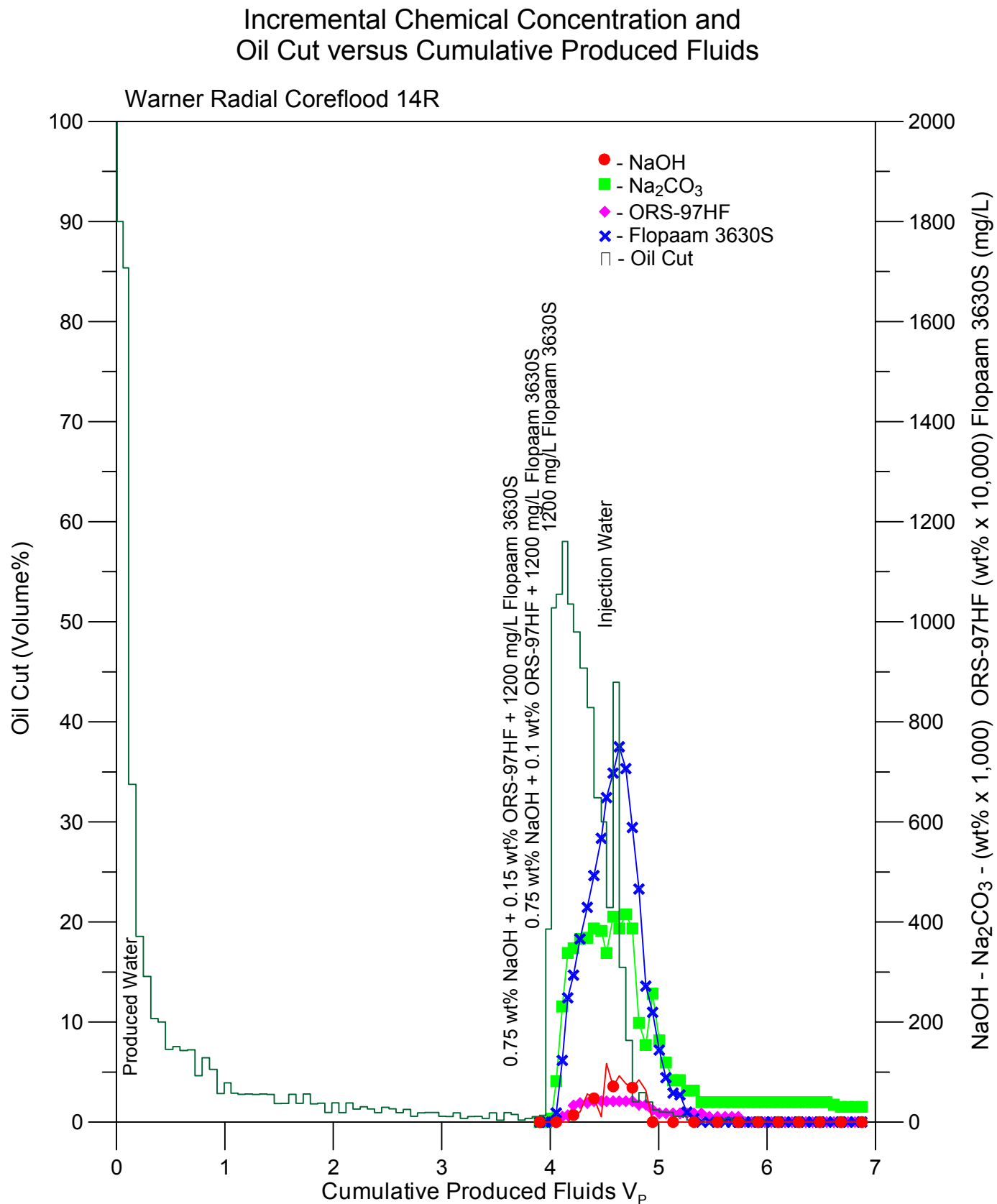




Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids

Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids

Incremental Chemical Concentration and
Oil Cut versus Cumulative Produced Fluids



Appendix A

Phase Behavior Nomenclature

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Phase Behavior Type Descriptions

<u>Phase Type</u>	<u>Phase Type Description</u>
II	Two fluid envelopes exist - a bottom aqueous phase and a top oil phase. No color is visible in the aqueous phase. The crude oil and aqueous phase volumes are equal to the volumes placed in the tube. Either the alkali has generated no visible surfactants or the surfactants have been driven into the crude oil and no crude oil swelling has taken place (Type II+ phase behavior).
II-	Two fluid envelopes exist - a bottom aqueous phase and an oil phase. The bottom aqueous phase is colored indicating the alkali has saponified acids in the crude oil which are now present in the aqueous phase. The crude volume can be swollen due to the interaction with the surfactants (added and in-situ), but this is not a requirement for this designation.
III	Three or more fluid envelopes exist - a bottom aqueous phase, one or more middle emulsion phases, and a top crude oil phase. The aqueous phase can be colored with saponified acids from the crude oil; however, this does not necessarily have to be the case.
II+	Two fluid envelopes exist - a bottom aqueous phase and a top crude oil phase. The bottom aqueous phase is clear because the surfactants (added and in-situ) reside in the crude oil phase. The crude oil phase is swollen due to surfactants carrying water into the crude oil phase.

Type III is considered to have the best probability of recovering additional oil. Type II is considered to have the poorest chance to recover additional oil. Type II- is considered to have the second best chance to recover additional oil because it shows interaction between the aqueous phase and crude oil and saponified acids are observed. Even though Type II+ demonstrates interaction between the crude oil and the aqueous phase, it is considered to have poorer oil recovery potential than Type II-.

Appendix B

Linear Coreflood Procedures

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Warner Linear Coreflood 1L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 00/04-21-007-16W4 to 2.48 cm in diameter by 8.38 cm length. Depth was 3196.5 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 17.5 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C. Calculated injection rate for relative permeability was 17.5 ft/day according to Batycky.¹
8. Inject produced water at 10.3 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 10.3 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 1.00 wt.% NaOH dissolved in softened injection water at 10.3 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 1.00 wt.% NaOH plus 0.10 wt.% EOR 2095 dissolved in softened injection water at 10.3 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 10.3 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

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13. Inject 1.00 wt.% NaOH plus 0.10 wt.% EOR 2095 water plus 1500 mg/L Flopaam 3630S dissolved in softened injection at 10.3 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 2.9 ft/day.
15. Reduce the fluid frontal advance rate to 1.1 ft/day.
16. Inject unsoftened injection water at 10.3 ft/day until the differential pressures are stable. Two to three effluent samples of approximately $2 V_p$ each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Flopaam 3630S.
18. Repeat steps 13 through 16 with 500 mg/L Flopaam 3630S.
19. Inject 1000 mg/L Flopaam 3630S without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened produced water at 10.3 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
22. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,² surfactant,^{3,4} and polymer concentration.⁵

SURTEK

Warner Linear Coreflood 2L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 00/04-21-007-16W4 to 2.48 cm in diameter by 7.67 cm length. Depth was 3200.9 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil, 119 cp, by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 18.1 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 18.1 ft/day at 35°C. Calculate injection rate for relative permeability according to Batycky.^{34, 1}
8. Inject produced water at 10.6 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 10.6 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 2.00 wt% Na_2CO_3 dissolved in softened injection water at 10.6 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 2.00 wt% Na_2CO_3 plus 0.10 wt.% ORS-162HF dissolved in softened injection water at 10.6 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 10.6 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

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13. Inject 2.00 wt% Na_2CO_3 plus 0.10 wt.% ORS-162HF water plus 1500 mg/L Flopaam 3530S dissolved in softened injection at 10.6 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 3.0 ft/day.
15. Reduce the fluid frontal advance rate to 1.1 ft/day.
16. Inject unsoftened injection water at 10.6 ft/day until the differential pressures are stable. Two to three effluent samples of approximately $2 V_p$ each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Flopaam 3530S.
18. Repeat steps 13 through 16 with 500 mg/L Flopaam 3530S.
19. Inject 1000 mg/L Flopaam 3530S without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened injection water at 10.6 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
22. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Linear Coreflood 3L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 02/09-007-16W4 to 2.48 cm in diameter by 8.48 cm length. Depth was 3233.7 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil, 119 cp, by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 20.6 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 20.6 ft/day at 35°C. Calculate injection rate for relative permeability according to Batycky.^{34, 1}
8. Inject produced water at 12.0 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 12.0 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ dissolved in softened injection water at 12.0 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.10 wt.% Petronate EOR 2095 dissolved in softened injection water at 12.0 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 12.0 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

SURTEK

13. Inject 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.10 wt.% Petronate EOR 2095 plus 1500 mg/L Alcoflood 1275A dissolved in softened injection at 12.0 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 3.4 ft/day.
15. Reduce the fluid frontal advance rate to 1.3 ft/day.
16. Inject unsoftened injection water at 12.0 ft/day until the differential pressures are stable. Two to three effluent samples of approximately 2 V_p each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Alcoflood 1275A.
18. Repeat steps 13 through 16 with 500 mg/L Alcoflood 1275A.
19. Inject 1000 mg/L Alcoflood 1275A without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened injection water at 12.0 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
22. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Linear Coreflood 4L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 00/16-20-007-16W4 to 2.48 cm in diameter by 8.42 cm length. Depth was 3226.8 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil, 119 cp, by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 19.1 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 19.1 ft/day at 35°C. Calculate injection rate for relative permeability according to Batycky.^{34, 1}
8. Inject produced water at 11.1 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 11.1 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 0.75 wt% NaOH dissolved in softened injection water at 11.1 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 0.75 wt% NaOH plus 0.10 wt.% ORS-97HF dissolved in softened injection water at 11.1 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 10 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

SURTEK

13. Inject 0.75 wt% NaOH plus 0.10 wt.% ORS-97HF water plus 1500 mg/L Cyantrol 770 dissolved in softened injection at 11.1 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 3.2 ft/day.
15. Reduce the fluid frontal advance rate to 1.2 ft/day.
16. Inject unsoftened injection water at 10 ft/day until the differential pressures are stable. Two to three effluent samples of approximately $2 V_p$ each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Cyantrol 770.
18. Repeat steps 13 through 16 with 500 mg/L Cyantrol 770.
19. Inject 1000 mg/L Cyantrol 770 without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened injection water at 11.1 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
22. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

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Warner Linear Coreflood 5L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 00/04-21-007-16W4 to 2.46 cm in diameter by 8.33 cm length. Depth was 3199.3 ft. Extract core with hot toluene.
2. Saturate the core with produced water by evaluation and determine core pore volume and porosity.
3. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
4. Inject viscosity adjusted crude oil, 52 cp, at 35°C to initial oil saturation until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}).
5. Age core for one week at 95°F.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C to initial oil saturation until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 17.6 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 17.6 ft/day at 35°C. Calculate injection rate for relative permeability according to Batycky.^{34, 1}
8. Inject produced water at 10.2 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 10.2 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 0.75 wt% NaOH dissolved in softened injection water at 10.2 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 0.75 wt% NaOH plus 0.10 wt.% ORS-97HF dissolved in softened injection water at 10.2 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 10.2 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

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13. Inject 0.75 wt% NaOH plus 0.10 wt.% ORS-97HF water plus 1500 mg/L Alcoflood 1275A dissolved in softened injection at 10.2 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 3.6 ft/day.
15. Reduce the fluid frontal advance rate to 1.1 ft/day.
16. Inject unsoftened injection water at 10.2 ft/day until the differential pressures are stable. Two to three effluent samples of approximately $2 V_p$ each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Alcoflood 1275A.
18. Repeat steps 13 through 16 with 500 mg/L Alcoflood 1275A.
19. Inject 1000 mg/L Alcoflood 1275A without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened injection water at 10.2 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
23. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

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Warner Linear Coreflood 6L Polymer Rheology Linear Procedure

1. Cut a horizontal core from Well 00/16-20-007-16W4 to 2.47 cm in diameter by 8.26 cm length. Depth was 3236.1 ft. Extract core with hot toluene.
2. Saturate the core with produced water by evaluation and determine core pore volume and porosity.
3. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
4. Inject viscosity adjusted crude oil, 52 cp, at 35°C to initial oil saturation until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}).
5. Age core for one week at 95°F.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 18.0 ft/day.
7. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 18.0 ft/day at 35°C. Calculate injection rate for relative permeability according to Batycky.^{34, 1}
8. Inject produced water at 10.5 ft/day fluid frontal advance rate. This step establishes the baseline for resistance factor calculations.
9. Inject unsoftened injection water at 10.5 ft/day fluid frontal advance rate. This step is to determine core sensitivity to softened injection water.
10. Inject 1.00 wt% NaOH dissolved in softened injection water at 10.5 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-blended alkali incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali injection. Effluent samples were saved for alkali retention analysis.
11. Inject 1.00 wt% NaOH plus 0.10 wt.% ORS-97HF dissolved in softened injection water at 10.5 ft/day until no further oil production occurs and the differential pressures are stable. This step determines if a rock-surfactant incompatibility problem exists and estimates the amount of oil which can be mobilized by alkali-surfactant injection. An effluent sample was saved for alkali and surfactant retention analyses.
12. Inject unsoftened injection water at 10.5 ft/day fluid frontal advance rate and evaluate the core for water composition sensitivity. Two to three effluent samples of approximately 1 to 2 core pore volumes each were collected.

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13. Inject 1.00 wt% NaOH plus 0.10 wt.% ORS-97HF water plus 1500 mg/L Flopaam 3630S dissolved in softened injection at 10.5 ft/day. The objective of this step is to reduce the residual oil saturation to a low value so the subsequent polymer rheology evaluation will have a minimal shift in baseline. Polymer injectivity and flow characteristics are also evaluated.
14. Reduce the fluid frontal advance rate to 3.7 ft/day.
15. Reduce the fluid frontal advance rate to 1.1 ft/day.
16. Inject unsoftened injection water at 10.5 ft/day until the differential pressures are stable. Two to three effluent samples of approximately $2 V_p$ each were collected and saved for alkali, surfactant, and polymer analysis.
17. Repeat steps 13 through 16 with 1000 mg/L Flopaam 3630S.
18. Repeat steps 13 through 16 with 500 mg/L Flopaam 3630S.
19. Inject 1000 mg/L Flopaam 3630S without alkali and surfactant dissolved in softened produced water, repeating steps 13 through 16.
20. Inject unsoftened injection water at 10.5 ft/day and determine the effective permeability to water.
21. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
22. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

Appendix C

Linear and Radial Coreflood Equations

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Equations for Linear Corefloods

DARCY'S LAW
$$K = \frac{14.7 \ q \ \mu L}{A \Delta P} \quad (\text{darcys})$$

MOBILITY
$$\frac{K}{\mu} = \frac{14.7 \ q \ L}{A \Delta P} = \lambda \quad (\text{darcys/cp})$$

EFFECTIVE VISCOSITY
(Reciprocal Relative Mobility)
$$\mu_{eff} = \frac{K_f}{\lambda} = \frac{K_f A \Delta P}{14.7 \ q \ L} \quad (\text{cp})$$

RESISTANCE
FACTOR
$$RF = \frac{(\Delta P/q)_i}{(\Delta P/q)_{baseline}} = \frac{(\mu/K)_i}{(\mu/K)_{baseline}} = \lambda_i / \lambda_{baseline}$$

PERMEABILITY
REDUCTION (Residual
Resistance Factor)
$$K_{RED} = \frac{K_i}{K_f}$$

PORE VOLUME
$$PV = \frac{(\text{Sat. Wt.} - \text{Dry Wt.})}{\text{Sat. Fluid Density}} \quad (\text{ml})$$

POROSITY
$$\emptyset = \frac{\text{Pore Volume}}{\text{Bulk Volume}} = \frac{PV}{AL}$$

FRONTAL VELOCITY
$$FV = \frac{2830 \ q}{A \emptyset} \quad (\text{ft/day})$$

where:

- K = permeability (darcys)
- q = volumetric flow rate (ml/sec)
- μ = apparent viscosity (cp)
- L = core length (cm)
- A = cross sectional area (cm²)
- ΔP = pressure drop (psi)
- K_i = initial permeability (darcys)
- K_f = final (flush) permeability (darcys)
- V_p = pore volume (ml)
- ∅ = porosity (fraction)

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Equations for Radial Corefloods

DARCY'S LAW	$K = \frac{2.340 \ q \ \mu \ \ln (r_e/r_w)}{\Delta P \ h}$	(darcys)

MOBILITY	$\lambda = \frac{2.340 \ q \ \mu \ \ln (r_e/r_w)}{\Delta P \ h} = \frac{K}{\mu}$	(darcy/cp)

EFFECTIVE VISCOSITY (Reciprocal Relative Mobility)	$\mu_{eff} = \frac{K_f}{\lambda} = \frac{0.427 \ h \ K_f \ \Delta P}{\ln (r_e / r_w) \ Q}$	(cp)

RESISTANCE FACTOR

PERMEABILITY REDUCTION (Residual Resistance Factor)	$RF = \frac{(\Delta P/q)_i}{(\Delta P/q)_{baseline}} = \frac{(K/\mu)_i}{K_{RED} \frac{(K/\mu)_{baseline}}{K_f}} = \lambda_i / \lambda_{baseline}$	
POROSITY	$\emptyset = \frac{pore \ volume}{bulk \ volume - wellbore \ volume}$	

FRONTAL VELOCITY	$(median) \ FV_m = \frac{636.98 \ Q}{r_e \ h \ \emptyset}$	(ft/day)
	$FV_e = FV_m \sqrt{2}$	(ft/day)

where:

- K = permeability (darcys)
- q = volumetric flow rate (ml/sec)
- μ = viscosity (cp)
- r_e = radius of disk (cm)
- r_w = radius of wellbore (cm)
- ΔP = pressure drop (psi)
- K_i = initial permeability (darcys)
- K_f = final (flush) permeability (darcys)
- ∅ = porosity (fraction)

Appendix D

**Resistance Factor Ratio
and
Mobility Ratio Relationships**

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By careful design, the mobility of an injected phase can be made equal to or less than that of the displaced phase to provide a better displacement efficiency. Mobility is defined as:

$$\lambda_i = \frac{k_i}{\mu_i} \quad (1)$$

where: λ_i = ith fluid mobility
 k_i = ith fluid effective permeability
 μ_i = ith fluid viscosity.

Without mobility control, a high mobility fluid will move at a greater velocity than that of the displaced fluid. In this fashion it will create aqueous channels that advance toward the recovery well. These channels will have a high water saturation and will be at the water endpoint of the relative permeability curves. Therefore, they will provide a better conduit for aqueous solution flow. Once channels have been established between an injector and recovery well, these will provide primary flow paths. Displacement of oil near these paths will occur by stripping it from the boundaries of the flow paths. This scenario, referred to as viscous fingering, is not an efficient displacement mechanism.

Much more desirable is the displacement of the oil in front of the displacing phase in a more piston like fashion. This will only occur if the mobility of the fluids are similar. Expressed in another way, the mobility ratio must be 1 or less for efficient displacement. The mobility ratio is defined as the mobility of the displacing phase divided by the mobility of the displaced phase. With the I subscript denoting the injected or displacing phase and the d subscript denoting the displaced phase, the mobility ratio is defined as:

$$MR = \left(\frac{\frac{k_i}{\mu_i}}{\frac{k_d}{\mu_d}} \right) = \frac{k_i \mu_d}{k_d \mu_i} \quad (2)$$

Assuming that the displacement is efficient, the effective permeabilities used in the calculation of mobility ratio are the relative permeability endpoints. This implies piston-like displacement with the mobility of the displaced phase defined by its effective permeability at its highest saturation condition, and the mobility of the displacing phase defined by its effective permeability with the displaced phase at residual saturation.

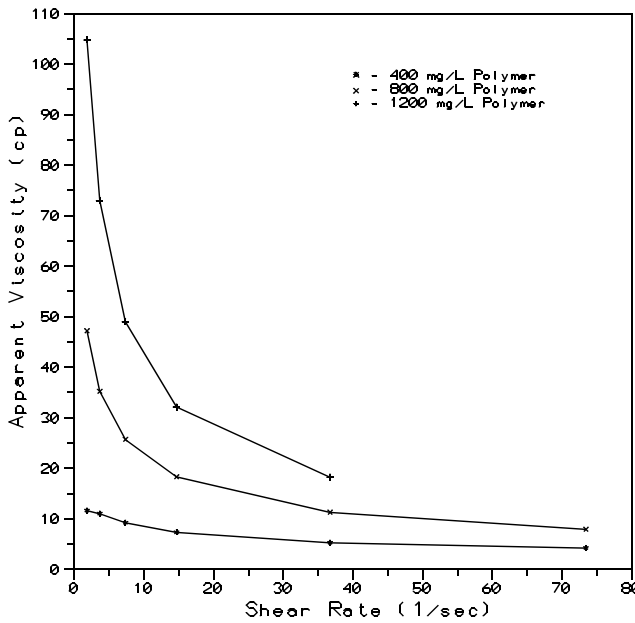
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The difficulty in using polymers for mobility control is due to the viscosity terms. The viscosity of most hydrocarbon solutions is Newtonian in that the shear force is proportional to the local velocity gradient:

$$\tau_{xy} = \mu \frac{dv_x}{dy} \quad (3)$$

where: τ_{xy} = shear force per unit area
 μ = fluid viscosity
 dv_x/dy = shear rate.

Shear rate has no effect upon the viscosity of these solutions. The viscosity is simply a proportionality constant. This is not true with polymer solutions. Solutions of xanthan gum are non-Newtonian. To demonstrate this, the viscosity of a polymer solution was measured at various shear rates at 70°F. The results are shown in Figure 1.



Note that the viscosity increases as the shear rate decrease. This is a rheological property of pseudo-plastics. The behavior can be related by a power law such as that of the Ostwald de Waele model:

$$\tau_{xy} = \left(m \left| \frac{dv_x}{dy} \right|^{n-1} \right) \frac{dv_x}{dy} \quad (4)$$

The equation reduces to equation 3 if $n = 1$ with $m = \mu$. If n is less than 1 the behavior is pseudo-plastic and if n is greater than 1 the rheology is dilatant. The term in parenthesis becomes the proportionality constant relating shear force to shear rate. Then, for a particular solution:

Figure 1
 Polymer Solution Viscosity versus Shear Rate

$$\mu = m \left| \frac{dv_x}{dy} \right|^{n-1} \quad (5)$$

$$\log(\mu) = (n-1) \log \frac{dv_x}{dy} + \log(m)$$

where μ is the apparent viscosity.

The log-log plot of viscosity versus shear rate for a pseudo-plastic should be a straight line with a slope of $n-1$. This can be seen in Figure 2. Note that the slopes of the three curves are nearly the same, which indicates that for a particular polymer-aqueous system, the pseudo-plastic

behavior is independent of concentration. m , which is analogous to the apparent viscosity, μ , of a Newtonian fluid can be calculated from the y-intercept.

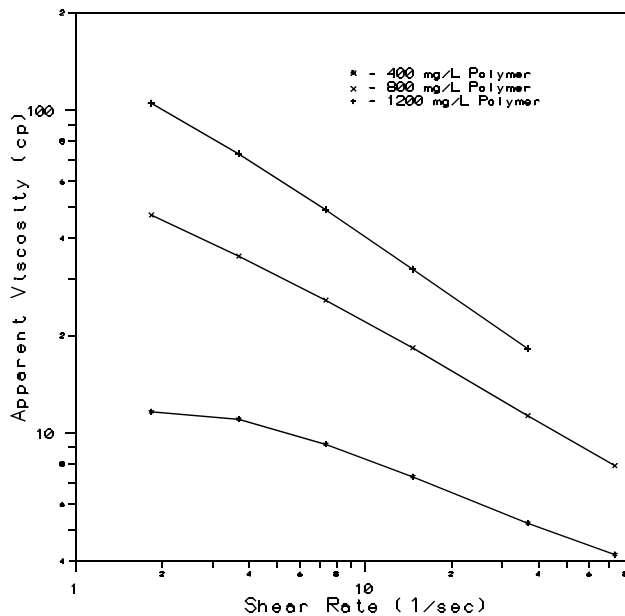


Figure 2

Polymer Solution Viscosity versus Shear Rate

porous flow as was demonstrated by Vogel and Pusch⁹ using a network theory rather than the power law model. Polymers also demonstrate shear thickening characteristics of dilatant material at high flowrates. This is due to deformation of the molecular configuration under high shear stress. Molecules that were generally spherical will become elongated. However, the strongest criticism of the use of power law models to predict the viscosity of the fluid is not due to the nature of the fluid, but to the nature of the porous media. Because fluids will move through constrictions connecting pore spaces, the velocity and therefore the shear will change on a pore to pore scale. On a larger scale, the effects of heterogeneity become significant.

A more reasonable approach might be to measure the mobility of the polymer solution in the porous media. The advantage of this approach is that one can also determine the concentration of polymer solution required for mobility control in the same experiment that the mobility ratio for water displacing oil is measured, as will be demonstrated. This is possible through the use of resistance factor ratios.

The mobility ratio then becomes a function of the rate of shear for a polymer solution displacing an oil. If one knew the rheological properties of a polymer and the shear rate, the mobility ratio could be determined. Several people have derived expressions to correlate shear rate in porous media. Savins⁶, Gogarty⁷ and Jennings et al.⁸ all derived equations relating the shear rate to the fluid velocity and the porous media permeability and porosity. The use of these equations to calculate viscosity becomes difficult because of several factors. One is that polymer solutions often exhibit different rheological characteristics at different flowrates. Note that in Figure 2, the low concentration polymer begins to curve at low shear rate. This is a common phenomena which can be modeled for

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Resistance factor is an experimentally measured quantity that gives the relative degree of force required to move a liquid through a porous media. The definition of resistance factor is:

$$RF = \frac{\left(\frac{\Delta P}{q} \right)_{\text{injected fluid}}}{\left(\frac{\Delta P}{q} \right)_{\text{baseline fluid}}} \quad (6)$$

$$\text{or } RF = \frac{\lambda_{\text{injected fluid}}}{\lambda_{\text{baseline fluid}}}$$

where: ΔP = measured pressure drop across a sample
 q = flowrate
 λ = mobility

The injected fluid can be oil, water, gas, chemical solution etc. The baseline fluid is generally the waterflood water or produced water. The baseline pressure and flowrate are taken during steady state conditions, when no saturation changes are occurring and generally represent the values measured to calculate the effective permeability to water at a residual oil saturation.

Resistance factors are very useful because they can relate many different quantities. The resistance factor is equivalent to an injectivity factor. Thus, for a resistance factor of 3 for instance, the injectivity loss will be 3. Either the injection pressure must be increased by a factor of three to maintain the injection rate compared with the baseline fluid or the injection rate will be reduced to one third. Resistance factors (RF) can also be related to the mobility ratio.

If the numerator and denominator of the right hand side of the RF equation 6 are multiplied by A/L, RF becomes:

$$RF_{\text{injected fluid}} = \frac{(A\Delta P/qL)_{\text{injected fluid}}}{(A\Delta P/qL)_{\text{baseline fluid}}} \quad (7)$$

If both sides of the equation are multiplied by $\mu_{\text{baseline fluid}}/\mu_{\text{injected fluid}}$ the equation becomes:

$$RF_{\text{injected fluid}} \frac{\mu_{\text{baseline fluid}}}{\mu_{\text{injected fluid}}} = \frac{(A\Delta P/qL)_{\text{injected fluid}}}{(A\Delta P/qL)_{\text{baseline fluid}}} \frac{\mu_{\text{baseline fluid}}}{\mu_{\text{injected fluid}}} \quad (8)$$

$$= \frac{K_{\text{baseline fluid}}}{K_{\text{injected fluid}}}$$

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We can use equation 8 to solve for the Darcy viscosity of the flowing fluid. Re-arranging equation 8 yields:

$$\mu_{Darcy} = \frac{RF_{injected\ fluid} \mu_{baseline\ fluid}}{\left(\frac{K_{baseline\ fluid}}{K_{injected\ fluid}} \right)} \quad (9)$$

From equation 8, RF_{water} and RF_{oil} can be written as:

$$RF_{water} = \frac{K_{baseline\ fluid}}{K_{water}} \times \frac{\mu_{water}}{\mu_{baseline\ fluid}} \quad (10)$$

$$RF_{oil} = \frac{K_{baseline\ fluid}}{K_{oil}} \times \frac{\mu_{oil}}{\mu_{baseline\ fluid}} \quad (11)$$

If the baseline fluid is water, then $RF_{water} = 1.0$.

Substituting the water and oil resistance factor relationships in the equations for water and oil mobility yields:

$$\lambda_{water} = \frac{K_{baseline\ fluid} \mu_{water}}{RF_{water} \mu_{baseline\ fluid} \mu_{water}} = \frac{K_{baseline\ fluid}}{RF_{water} \mu_{baseline\ fluid}} \quad (12)$$

$$\lambda_{oil} = \frac{K_{baseline\ fluid} \mu_{oil}}{RF_{oil} \mu_{baseline\ fluid} \mu_{oil}} = \frac{K_{baseline\ fluid}}{RF_{oil} \mu_{baseline\ fluid}} \quad (13)$$

The mobility ratio for water displacing oil is:

$$MR = \frac{\lambda_{water}}{\lambda_{oil}} \quad (14)$$

$$MR = \frac{\left(\frac{K_{baseline\ fluid}}{RF_{water} \mu_{baseline\ fluid}} \right)}{\left(\frac{K_{baseline\ fluid}}{RF_{oil} \mu_{baseline\ fluid}} \right)} \quad (15)$$

$$MR = \frac{RF_{oil}}{RF_{water}} \quad (16)$$

Assuming the baseline fluid is water so that $RF_{water} = 1.0$, then:

$$MR = RF_{oil} \quad (17)$$

Therefore, if the baseline resistance factor is for water, RF_{oil} gives the mobility ratio. All the resistance factors in a coreflood can be used to estimate the mobility ratio at any time relative to oil. $RF_{time\ x}$ is divided into RF_{oil} and this is the mobility ratio of the injected fluid at time x.

The relationship for resistance factors can be used to determine what concentration of polymer is needed to provide a unit mobility ratio at any fluid advance rate. Recall from equation 9 that the Darcy viscosity of the polymer solution is directly related to the resistance factor and further from equation 5, that for a pseudo plastic the relationship should be exponential with shear rate. The shear rate is a function of the fluid advance rate. Thus a plot similar to that of figure 2 should show a relationship between resistance factor and frontal advance rate for different polymer concentrations. This is shown in figure 3.

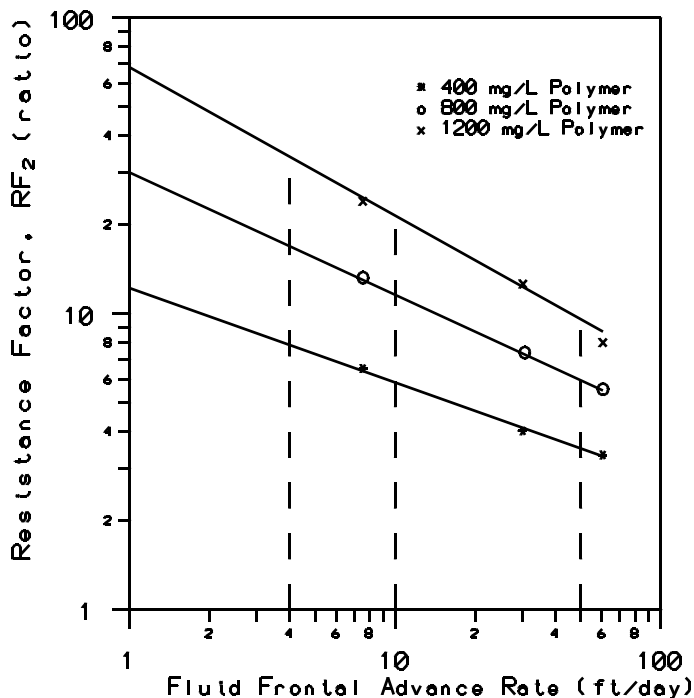


Figure 3 shows the same type of rheologic response observed for the viscosity versus shear rate in figure 2. Using this resistance factor data compiled from a coreflood one can determine the concentration of polymer required to efficiently displace oil. The values at the points of intersection of the solid lines and dashed lines (of constant advance rate) were used to create figure 4 to determine what polymer concentration is required to provide a unit mobility ratio, (which is equal to the resistance factor for the oil) at any advance rate.

Figure 3
Resistance Factor Ratio versus
Fluid Frontal Advance Rate at
Various Polymer Concentrations

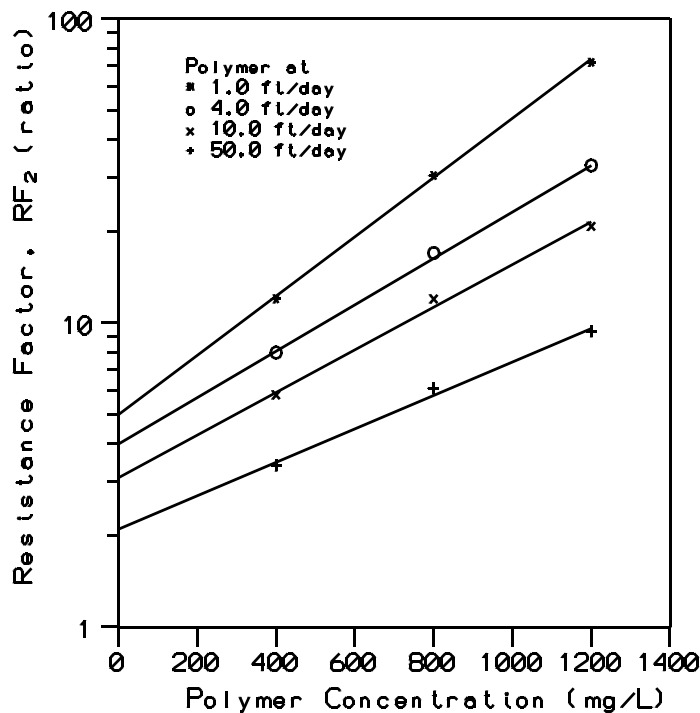


Figure 4
Resistance Factor Ratio versus
Polymer Concentration at
Various Fluid Advance Rates

factor at any advance rate and a horizontal line drawn to intersect the average frontal advance rate of interest. A vertical line from this intersection provides the polymer concentration. A second method is to measure the amount of polymer retained by the porous media and add this amount to the volume of liquid injected. There will be some instances that the mobility ratio is lower than the residual resistance factor. The residual resistance factor is equivalent to a permeability reduction factor. Thus a residual resistance factor in itself will improve the mobility ratio for water displacing an oil by decreasing the effective permeability to water.

Some observations about figure 4 are in order. One would expect the resistance factor of a 0.0 concentration polymer solution to be 1.0 and that all the lines shown would converge at $RF_2 = 1.0$. The reason that they do not is because of polymer adsorption and entrapment. Instead they intersect at some value of residual resistance factor. Note from figure 4 that at higher flowrates the residual resistance factor is reduced as the mechanical energy is provided to desorb and dislodge trapped polymer.

As polymer will inevitably be lost to adsorption and entrapment, one must adjust the concentration of polymer required for a unit mobility ratio to account for polymer loss. This can be done in one of two ways. The resistance factor of the oil can be added to the residual resistance

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Appendix E

Radial Coreflood Procedures

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Warner Radial Coreflood 1R

1. Cut a radial core from Well 00/04-21-007-16W4 to 8.76 cm in diameter by 5.11 cm in height. Depth was 3196.3 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 0.75 wt% NaOH plus 0.1 wt% ORS-164HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,¹⁰ surfactant,^{11,12} and polymer concentration.¹³

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Warner Radial Coreflood 2R

1. Cut a radial core from Well 00/04-21-007-16W4 to 8.79 cm in diameter by 5.12 cm in height. Depth was 3196.7 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.1 wt% Petronate EOR 2095 plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 3R

1. Cut a radial core from Well 02/09-20-007-16W4 to 8.84 cm in diameter by 5.11 cm in height. Depth was 3246.4 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan AS-1216 plus 1,500 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,500 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 4R

1. Cut a radial core from Well 02/09-20-007-16W4 to 8.83 cm in diameter by 5.10 cm in height. Depth was 3246.7 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 2.00 wt% Na_2CO_3 plus 0.1 wt% ORS-162HF plus 1,500 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,500 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 5R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.87 cm in diameter by 5.11 cm in height. Depth was 3232.5 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 0.75 wt% NaOH plus 0.1 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 6R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.87 cm in diameter by 5.11 cm in height. Depth was 3233.6 ft. Extract core with hot toluene.
2. Saturate the core with dead crude oil by evacuation and then injection.
3. Take core out of core holder, weigh, and determine core pore volume and porosity.
4. Inject produced water to determine the effective permeability to produced water (k_{wro}) at 35°C.
5. Take core out of core holder and place in dead crude oil. Age core at ambient temperature until the fluid-fluid work is complete. A minimum of 6 weeks.
6. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
7. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
8. Inject 0.3 Vp of 0.625 wt% NaOH plus 0.50 wt% Na_2CO_3 plus 0.1 wt% ORS-162HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.
12. Saturate the core with produced water and determine the pore volume and porosity.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 7R

1. Cut a radial core from Well 00/04-21-007-16W4 to 8.73 cm in diameter by 5.12 cm in height. Depth was 3199.8 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.75 wt% NaOH plus 0.1 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 8R

1. Cut a radial core from Well 00/04-21-007-16W4 to 8.80 cm in diameter by 5.12 cm in height. Depth was 3200.8 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.50 wt% NaOH plus 0.25 wt% Na₂CO₃ plus 0.05 wt% Petrostep B-100 plus 0.05 wt% Stepantan AS-1216 plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 9R

1. Cut a radial core from Well 00/04-21-007-16W4 to 8.78 cm in diameter by 5.11 cm in height. Depth was 3215.6 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.625 wt% NaOH plus 0.10 wt% ORS-97HF plus 1,200 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Alcoflood 1275A at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 10R

1. Cut a radial core from Well 02/09-20-007-16W4 to 8.86 cm in diameter by 5.11 cm in height. Depth was 3234.9 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.625 wt% NaOH plus 0.1 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 11R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.84 cm in diameter by 5.11 cm in height. Depth was 3220.7 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.75 wt% NaOH plus 0.15 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 12R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.82 cm in diameter by 5.11 cm in height. Depth was 3220.9 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.05 Vp of 1.00 wt% NaOH plus 0.1 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.25 Vp of 0.75 wt% NaOH plus 0.1 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 13R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.86 cm in diameter by 5.14 cm in height. Depth was 3246.9 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.3 Vp of 0.75 wt% NaOH plus 0.15 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
10. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

SURTEK

Warner Radial Coreflood 14R

1. Cut a radial core from Well 00/16-20-007-16W4 to 8.83 cm in diameter by 5.11 cm in height. Depth was 3237.8 ft. Extract core with hot toluene.
2. Extract core with hot toluene to remove oil.
3. Saturate with produced water by evacuation. Determine core pore volume and porosity.
4. Inject produced water to determine the absolute permeability to produced water (k_{wro}) at 35°C.
5. Inject viscosity adjusted crude oil, 52 cp, at 35°C until no water is being produced from the core. Determine the effective permeability to crude oil at residual water (k_{orw}) at three fluid frontal advance rates, the last and lowest being 0.5 ft/day.
6. Inject 4 to 5 pore volumes of produced water at 0.5 ft/day to determine the effective permeability to produced water (k_{wro}) at 35°C.
7. Inject 0.15 Vp of 0.75 wt% NaOH plus 0.15 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
8. Inject 0.15 Vp of 0.75 wt% NaOH plus 0.10 wt% ORS-97HF plus 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
9. Inject 0.3 Vp of 1,200 mg/L Flopaam 3630S at 0.5 ft/day fluid frontal advance rate.
10. Inject unsoftened injection water at 0.5 ft/day fluid frontal advance rate, approximately 2 to 3 core pore volumes are injected.
11. Extract core with hot toluene in a Soxhlet extractor to determine final oil saturation.

Coreflood temperature is 35°C. Effluent samples collected with each rate change and with each change in injected fluid were analyzed for alkali,^{2, 10} surfactant,^{3, 11, 4, 12} and polymer concentration.^{5, 13}

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