



## New surfactant classes for enhanced oil recovery and their tertiary oil recovery potential

Stefan Iglauer<sup>a</sup>, Yongfu Wu<sup>a</sup>, Patrick Shuler<sup>a</sup>, Yongchun Tang<sup>a,\*</sup>, William A. Goddard III<sup>b</sup>

<sup>a</sup> Division of Chemistry & Chemical Engineering, Power, Energy Environmental Research (PEER) Center, California Institute of Technology, Covina, CA 91722, United States

<sup>b</sup> Division of Chemistry & Chemical Engineering, Materials and Process Simulation Center (MSC), MC 139-74, California Institute of Technology, Pasadena, CA 91106, United States

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### ABSTRACT

We investigate four different types of surfactants for effectiveness in tertiary oil recovery (TOR). The selected surfactant formulations were tested for enhanced oil recovery using coreflood tests on Berea sandstones. In addition to the corefloods, one sandpack surfactant flood was performed. The porous media were conditioned to residual waterflood oil saturation prior to surfactant slug injection. This was followed by polymer drive slug injection, and incremental oil recovery was measured against time.

The tested formulations were selected after an extensive research effort including measuring interfacial tensions (IFT) and adsorption behavior on kaolinite clay. Effective were low 1-naphthol concentrations dissolved in 1-butanol in alkyl polyglycoside surfactant formulations which led to significant additional incremental oil recovery (40% TOR) due to dramatic reductions in IFT. Three other types of surfactants in this study include:

- a di-tridecyl sulfosuccinic acid ester,
- coconut diethanolamide, and
- alkylpropoxy sulfate sodium salts

which led to TOR of 15%, 75% and 35–50%, respectively.

These results indicate that a wide variety of surfactants can meet the technical requirements as enhanced oil recovery (EOR) agents.

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### 1. Introduction

Surfactant flood tertiary oil recovery schemes have been employed for more than 35 years, in particular in the USA in depleted oil reservoirs after waterflooding (Garrett, 1972; US DOE, 1977, 1979; Ferrell et al., 1984, 1988; Cole, 1988a,b; Reppert, 1990; Huh et al., 1990; Maerker and Gale, 1992; Green and Willhite, 1998). Most of these projects were pilot scale, but several commercial scale projects were also executed. Nowadays, because of the high oil price, this technology has experienced increased interest.

We present experimental coreflood tests which prove that surfactant formulations are effective in terms of significantly increasing oil production. The corefloods included four surfactant classes, namely a di-tridecyl sulfosuccinic acid ester, a coconut diethanolamide, alkylpolyglycosides and alkylpropoxy sulfate sodium salts.

We based the selection of the tested surfactant formulations on the extensive experimental and theoretical studies we conducted in the last several years (Wu et al., 2004, 2005; Goddard et al., 2004; Iglauer et al., 2004a,b, 2009; Tang et al., 2006) as well as on results published by other

independent researchers (Shinoda et al., 1961; Cash et al., 1976; Shah and Schechter, 1977; Cayias et al., 1977; Doe et al., 1977, 1978; Braden and Flournoy, 1977; Kahlweit et al., 1991; Balzer, 1991a,b; Strey and Jonströmer, 1992; Kahlweit et al., 1995; Kutschmann et al., 1995; Kahl et al., 1996; Förster et al., 1996; Nickel et al., 1997; Hill et al., 1997; Zana, 1998, 2002; von Rybinski et al., 1998; Green and Willhite, 1998; Hill and Rhode, 1999; Balzer and Lüders, 2000; Kluge et al., 2000; Jayanti et al., 2001; Berger and Lee, 2002; Endo et al., 2002).

During a waterflood (which can produce oil until the residual waterflood oil saturation  $S_{or}$  is reached), the capillary number  $N_{cap}$  (Eq. (1)) is around  $10^{-8}$ – $10^{-7}$  and has to be increased by an order of at least two to three magnitudes (Abrams, 1975; Green and Willhite, 1998) to enable additional oil recovery.

$$N_{cap} = v \cdot \mu / IFT \quad (1)$$

where

$N_{cap}$	capillary number [–]
$v$	Darcy velocity [m/s]
$\mu$	viscosity of injected phase [Pa·s]
IFT	interfacial tension oleic phase–aqueous phase [N/m]

\* Corresponding author.

E-mail address: [tang@peer.caltech.edu](mailto:tang@peer.caltech.edu) (Y. Tang).

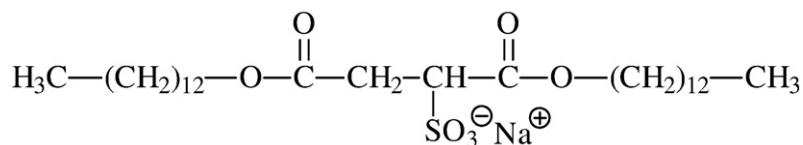


Fig. 1. Chemical structure of di-tridecyl sulfosuccinic acid ester (TR-70).

The approach we take in this work with respect to increase oil production and  $N_{\text{cap}}$  is to significantly decrease the IFT to low or ultra-low levels (i.e. 0.01–0.001 mN/m) with specially formulated surfactant–cosolvent mixtures. We show that significant amounts of incremental oil can be recovered this way.

## 2. Experimental methodology

We screened a large array of surfactants (Goddard et al., 2004). From this basic screening analysis, which included IFT measurements, adsorption measurements and phase behavior studies, we selected the best performing surfactants. Performance in terms of EOR means that the surfactant generates a low IFT and shows low adsorption on the reservoir rock material.

Chronologically, we followed this sequence:

1. Screening of IFT/phase behavior of many surfactant and surfactant–cosolvent formulations.
2. Testing adsorption characteristics of low IFT formulations on clay.
3. Conducting coreflood experiments with the best performing formulations.

As a next fourth future step, pilot-scale field tests are suggested.

### 2.1. Materials

The following four surfactant classes were selected for our subsequent coreflood experimental program.

- A) Di-tridecyl sulfosuccinic acid ester (Aerosol TR-70), supplied by American Cyanamid. The structure is shown in Fig. 1.
- B) Coconut diethanolamide (CW-100), supplied by Pilot Chemical. The structure is shown in Fig. 2.
- C) Alkylpolyglycosides (Agrimul PG2062 and Agrimul PG2069), supplied by Cognis Corporation. Alkyl polyglycosides (APG) are a green chemistry surfactant class manufactured from agricultural raw materials (Hill et al., 1997). They are non-toxic, non-ionic and their phase behavior and IFT values are quasi-independent of temperature and salinity (Shinoda et al., 1961; Kahlweit et al., 1995; Kutschmann et al., 1995; Nickel et al., 1997; Hill et al., 1997; Balzer and Lüders, 2000 and Iglauer et al., 2009). Large quantities of APG are produced commercially, mainly for household, cosmetics and agricultural products. PG2062 and PG2069 are both mixtures of various APG molecules as listed in Tables 1 and 2, their general chemical structure is

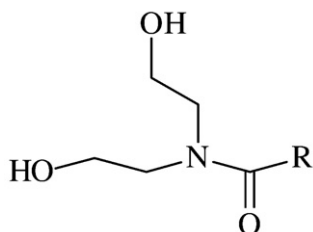


Fig. 2. Coconut diethanolamide (CW-100). R is predominantly a dodecyl ( $-\text{C}_{12}\text{H}_{25}$ ) to tetradecyl ( $-\text{C}_{14}\text{H}_{29}$ ) chain.

presented in Fig. 3.

If formulated with alcohol cosolvents, APG can reach very low IFT values (Iglauer et al., 2009).

Table 2 displays components identified in a  $\text{C}_{12/14}$  APG product by high temperature gas chromatography (reproduced from Waldhoff et al., 1997).

- D) alkylpropoxy sulfate sodium salts (Alfoterra 23 and Alfoterra 38), supplied by Sasol North America Inc. Their structures are shown in Figs. 4 and 5.

Alfoterra 38 is a mixture of four surfactants, the structures of the individual components are displayed in Fig. 4a–d.

The sodium chloride, calcium chloride, n-octane, 1-butanol, 1-naphthol and SPAN20 (all ACS grade) were purchased from Aldrich. SPAN20 has a hydrophilic–lipophilic balance of 8.6 (Wu et al., 2004), its structure is shown in Fig. 6. The de-ionized water was prepared in-house by distilling tap water twice. Alcoflood 1235, a polyacrylamide, was supplied by Ciba Corporation.

### 2.2. Surfactant solid adsorption

During a surfactant coreflood, surfactant can be lost by adsorption onto the porous medium (Green and Willhite, 1998). We studied this phenomenon experimentally to assess the performance of the surfactants in this respect. We used kaolinite clay to simulate the porous medium, which represents the worst case scenario as clays adsorb more due to their larger surface area than bulk rock material. Literature values for surfactant adsorption onto Berea core material range from 0.1 to 1.2 mg/g rock (Gale and Sandvik, 1973; Pursley and Graham, 1975; Healy et al., 1975; Novosad, 1982). Most of the adsorption that occurs in Berea sandstone is due to the few percent of kaolinite clay that is within this sandstone.

We applied following procedure:

Table 1

Chemical structure information for tested commercial APG products (Hill et al., 1997; Garst, 1997; Cognis Corporation, 2004).

Product	Agrimul PG 2062	Agrimul PG 2069
Alkyl chain (wt.%;wt.%)	12/14/16 (68:26:6)	9/10/11 (20:40:40)
Average alkyl chain length $k$ (C-atoms)	12.5	10.1
Average $n$ (number of sugar groups)	1.6	1.6
HLB	11.6	13.1
Activity (wt.%)	50	50

Table 2

Components in a  $\text{C}_{12/14}$  APG sample.

Substance	wt.%	Substance	wt.%
C8 furanosides	0.5	C12 $\alpha$ -glucopyranoside	0.4
C8 $\alpha$ -glucopyranoside	8.7	C12 $\beta$ -glucopyranoside	0.2
C8 $\beta$ -glucopyranoside	4.8	Diglycosides	12.2
C10 furanosides	0.5	Triglycosides	7.2
C10 $\alpha$ -glucopyranoside	9.3	Tetraglycosides	5.3
C10 $\beta$ -glucopyranoside	4.5	Pentaglycosides	4.1
C12 furanosides	0.1	Hexaglycosides	2.0

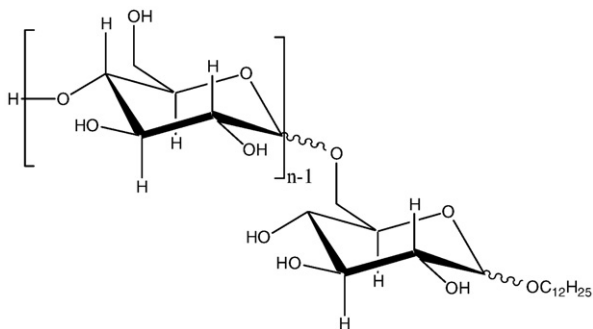


Fig. 3. Molecular structure of Agrimul PG2062 (Hill et al. 1997).

1. Kaolinite clay (more details about this clay can be found in Iglauer et al. (2009)) was heated in an oven at 120 °C for 2 h in order to remove water and any other adsorbed materials.
2. Surfactant solutions were prepared in 2.0 wt.% NaCl brine.
3. Kaolinite clay samples and surfactant solutions were mixed at a 1:20 mass ratio in a test tube and then shaken for 12 h at 25 °C in an electrical shaker. They were then left for equilibration for a minimum of three weeks at ambient conditions.
4. The test tube was next centrifuged to separate the solution and clay.
5. The equilibrium surfactant concentration was analyzed in order to determine the amount of chemical adsorbed.

As expected adsorption levels were significantly higher for kaolinite than for Berea rock material, detailed results are described below.

- A) The adsorption of di-tridecyl sulfosuccinic acid ester onto kaolinite was not measured; however we expect this to be similar to adsorption characteristics of petroleum sulfonates because the chemical structures are similar. Typical petroleum sulfonates would be expected to show 4–13 mg/g surfactant adsorption onto kaolinite (Hanna and Somasundaran, 1979; Barakat et al., 1995; Goddard et al., 2004).
- B) A maximum adsorption of 17 mg/g was observed for the Calamide CW-100 surfactant (Goddard et al., 2004).
- C) APG surfactant adsorption observed is presented in Table 3 (Goddard et al., 2004). Adsorption characteristics for two surfactant–cosolvent systems are included.
- D) Recorded alkylpropoxy sulfate sodium salt adsorption is displayed in Table 4 (Goddard et al., 2004; Wu et al., 2005).

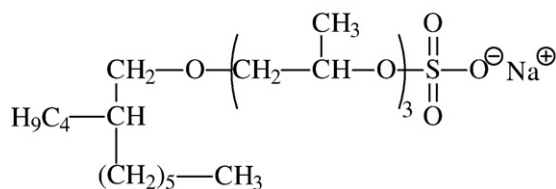


Fig. 5. Alfoterra 23; MW = 446 g/mol.

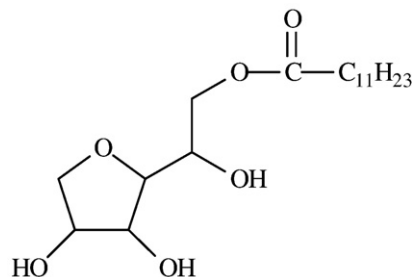


Fig. 6. Molecular structure of SPAN20, a sorbitan ester.

### 2.3. Porous medium

The surfactant floods were performed in a Berea sandstone core which was cut to cylindrical dimensions (25.4 mm diameter, 304.8 mm length) and glued into an aluminium housing with epoxide glue as shown in Fig. 7. The core's brine permeability was then determined to be 300 mD, porosity was 20%.

In case of the PG2069/SPAN 20 formulation 5, a sandpack was used as porous medium. The quartz sand used was 75 wt.% 149–250 μm (60–100 US standard mesh) and 25 wt.% 74–149 μm (100–200 US standard mesh) grain size. The porosity of the sandpack was 29%, the pore volume amounted to 160 mL and the absolute brine permeability was 1 Darcy.

### 2.4. Interfacial tension (IFT)

We analyzed interfacial tensions of a large array of surfactant formulations, including variations in surfactant class, surfactant structure, surfactant concentration, cosolvent type, cosolvent concentration,

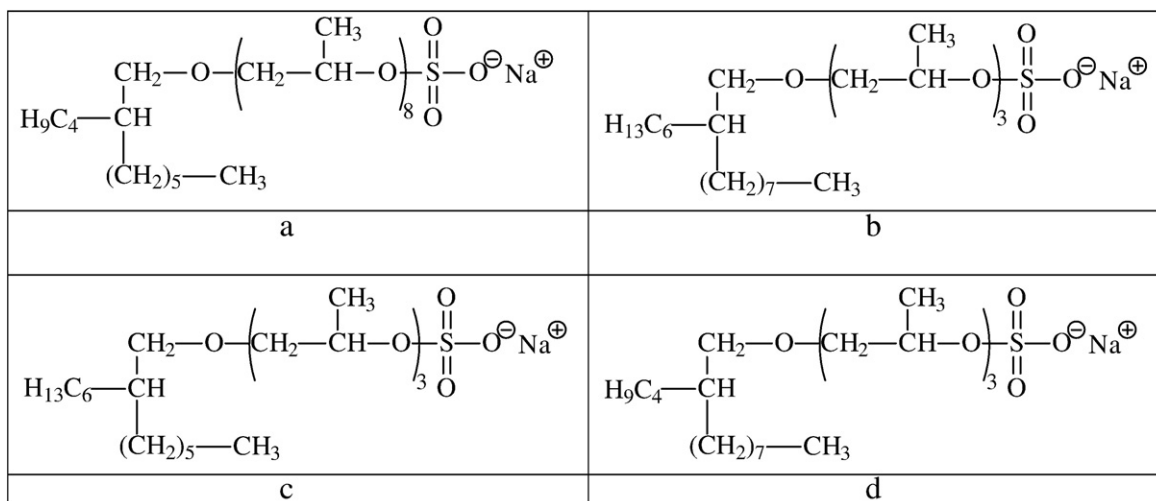


Fig. 4. a. Alfoterra 38 (part 1 = Alfoterra 25); MW = 736 g/mol. b. Alfoterra 38 (part 2); MW = 792 g/mol. c. Alfoterra 38 (part 3); MW = 764 g/mol. d. Alfoterra 38 (part 4); MW = 764 g/mol.

**Table 3**  
Adsorption characteristics of APG formulations.

Surfactant	Surfactant concentration [wt.%]	Cosolvent	Cosolvent concentration [wt.%]	Adsorption onto kaolinite [mg/g]
PG2069	0.5	–	–	negligible
PG2069	0.4	SPAN 20	0.6	121
PG2062	0.5	–	–	61
PG2062	0.4	1-octanol	1.2	46

**Table 4**  
Adsorption characteristics of Alforterra surfactants.

Alforterra	Surfactant concentration [wt.%] <sup>a</sup>	Surfactant concentration [mg/g] <sup>b</sup>	Adsorption onto kaolinite [mg/g] <sup>a</sup>	Adsorption onto kaolinite [mg/g] <sup>b</sup>
Alforterra 23	0.42 [wt.%] <sup>a</sup>	14.5 [mg/g] <sup>b</sup>	0.89 [wt.%] <sup>a</sup>	20.6 [mg/g] <sup>b</sup>
Alforterra 38	0.44 [wt.%] <sup>a</sup>	11.9 [mg/g] <sup>b</sup>	0.89 [wt.%] <sup>a</sup>	20.6 [mg/g] <sup>b</sup>

<sup>a</sup> Surfactant concentration.

<sup>b</sup> Mass of surfactant adsorbed per gram kaolinite.

surfactant–cosolvent mixing ratio, salinity, salt types, temperature and oil types. Details are described elsewhere (Wu et al., 2004; Goddard et al., 2004; Iglauer et al., 2004a,b, 2009; Wu et al., 2005).

Based on the IFT results and the adsorption results, we selected the best performing formulations which we further investigated in terms of their tertiary oil recovery performance.

#### 2.5. Preparation of surfactant–cosolvent formulations

Table 5 lists the tested formulations which all showed good tertiary oil production. All formulations were prepared in 2 wt.% NaCl brine.

The surfactants were dissolved in the brine and the mixture was stirred for 2 h. Then the mixtures were equilibrated for at least 24 h. After that the cosolvent was added to the surfactant system, and this formulation was then again stirred for 3 h and equilibrated for at least 24 h. A magnetic stirrer (Corning Hot Plate Stirrer PC-351) was used throughout. After equilibration the formulations were centrifuged at 2000 rpm for 20 min (Jouan CR 412 centrifuge) to remove any excess solid material and only the supernatant was used for coreflooding injection to avoid blocking of the pore network by solid particles. All steps occurred at room temperature and atmospheric pressure.

In case of the 1-naphthol/1-butanol cosolvent, the 1-naphthol was first dissolved in the 1-butanol by adding the solid and stirring for at least 2 h at ambient conditions. Any excess solid was removed by

**Table 5**  
Details of surfactant formulations.

Formulation	Surfactant	Cosolvent I	Cosolvent II	IFT [mN/m] <sup>a</sup>
1	2 wt.% di-tridecyl sulfosuccinic acid ester (Aerosol TR-70)	1 wt.% 2-propanol	–	0.02
2	2 wt.% coconut diethanolamide (Calamide CW-100)	1 wt.% 2-propanol	–	0.002
3	2 wt.% Agrimul PG2062	0.25 wt.% 1-naphthol	1.75 wt.% 1-butanol	0.011
4	0.4 wt.% Agrimul PG2062	1.2 wt.% 1-octanol	–	0.007
5	0.8 wt.% Agrimul PG2069	1.2 wt.% SPAN 20	–	0.003
6	2 wt.% Alforterra 38	–	–	0.0078 <sup>b</sup>
7	0.2 wt.% Alforterra 23	–	–	0.009 <sup>c</sup>

<sup>a</sup> Measured against n-octane in 2 wt.% NaCl brine.

<sup>b</sup> 3 wt.% NaCl brine.

<sup>c</sup> 6 wt.% NaCl brine.

centrifuging the fluid for 20 min at 2000 rpm. 1-naphthol concentrations in the cosolvent were measured via gas chromatography (Hewlett-Packard HP-G 1800A GCD system).

#### 2.6. Optimal salinity

The optimal salinity (1 wt.% NaCl concentration for the Aerosol TR-70 formulation and 4 wt.% NaCl concentration for the Calamide CW-100) was determined via IFT measurements (Goddard et al., 2004). IFT values for APG formulations are quasi-independent of salinities (Iglauer et al., 2009), therefore optimal salinity of APG formulations covers a wide range of salinities (tested for 2–11 wt.% NaCl), including salinities at which we conducted our coreflow experiments. Optimal salinities for Alforterra formulations were 6 wt.% NaCl for Alforterra 23 and 3 wt.% NaCl for Alforterra 38.

#### 2.7. Waterflood

The Berea core was saturated with brine under vacuum and then brought to connate water condition ( $S_{wc} = 40.9\% \pm 2.0\%$ ) in a primary drainage oil flood at  $N_{cap} = 3.36 \cdot 10^{-8}$ . The core was then subjected to a waterflood in a secondary imbibition process at  $N_{cap} = 7.11 \cdot 10^{-8}$ . The residual oil saturation was  $30.2\% \pm 2.0\%$ .

In case of the sandpack flood,  $S_{wc}$  was 28.5% and  $S_{or}$  was 15.0%, the  $N_{cap}$  were identical to those in the corefloods.

#### 2.8. Surfactant flood

The test parameters of the surfactant floods are displayed in Table 6. We selected salinities which are representative of oil reservoirs (Green and Willhite, 1998).

The surfactant and polymer slugs were injected at a flow rate of 0.06 mL/min except for the sandpack (formulation 5), where chemical injection happened at 0.2 mL/min. This is approximately a frontal advance rate of 2 ft/day for both systems.

Note that in experiments 6 and 7 the connate brine salinity was quite high, 10 wt.% NaCl, and the chemical slugs were formulated at a much lower salinity, 1 wt.% NaCl. This was designed to test two aspects, namely that an Alforterra surfactant formulation could recover significant tertiary oil when the in-situ brine has a fairly high salinity, and secondly that the so-called “salinity gradient” approach is a reasonable strategy (Green and Willhite, 1998). That is, the in-situ brine is above the optimal salinity (about 3 wt.% NaCl) for the chemical formulation, and the injected solutions are below this optimum salinity.



Fig. 7. Berea sandstone core preparation.

**Table 6**  
Surfactant flood test parameters.

Formulation	Connate brine composition	Surfactant slug volume [PV]	Polymer drive solution composition	Volume of polymer drive solution [PV]
1	1 wt.% NaCl + 10 ppm Ca <sup>2+</sup> <sup>a</sup>	0.25	500 ppm Alcoflood 1235 in 1 wt.% NaCl	0.5
2	1 wt.% NaCl + 10 ppm Ca <sup>2+</sup> <sup>a</sup>	0.25	500 ppm Alcoflood 1235 in 1 wt.% NaCl	0.5
3	2 wt.% NaCl	0.25	350 ppm Alcoflood 1235 in 2 wt.% NaCl <sup>b</sup>	1
4	2 wt.% NaCl	0.25	350 ppm Alcoflood 1235 in 2 wt.% NaCl <sup>b</sup>	1
5	2 wt.% NaCl	0.25	350 ppm Alcoflood 1235 in 2 wt.% NaCl <sup>b</sup>	1
6	10 wt.% NaCl	0.25	350 ppm Alcoflood 1235 in 1 wt.% NaCl	1
7	10 wt.% NaCl	0.8	350 ppm Alcoflood 1235 in 1 wt.% NaCl	1.2

<sup>a</sup> Added as CaCl<sub>2</sub>.

<sup>b</sup> 350 ppm Alcoflood 1235 in 2 wt.% NaCl brine had a viscosity of 1.5 mPa s at 2 rpm, measured with a Brookfield DV-E viscometer. Alcoflood 1235 is a commercial polyacrylamide product commonly used in the petroleum industry.

Incremental oil recoveries were measured against time. All steps occurred at room temperature and ambient pressure.

### 3. Results and discussion

#### 3.1. Tertiary oil recovery for selected coreflood tests

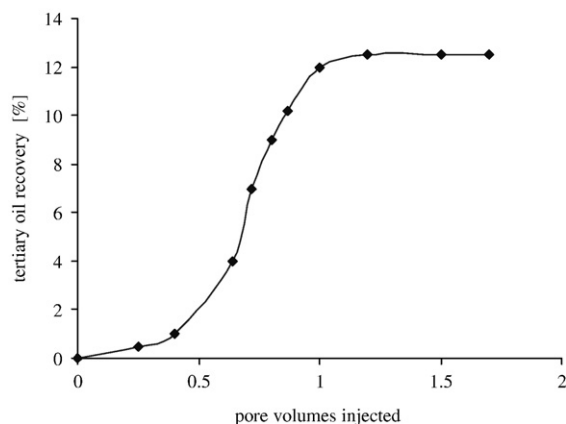
The results of the corefloods are displayed in Figs. 8–14. Several formulations showed a good tertiary oil recovery even at high salinities. Such formulations could be especially attractive as many reservoirs in the USA that might be good candidates for surfactant EOR have a formation brine that has several percent or more concentration of dissolved salts.

Consistent with the measured IFT behavior, the Calamide CW-100 recovered about 75% of the waterflood residual oil, whereas Aerosol TR-70 surfactant only recovered 15% of the trapped oil.

The Calamide CW-100 surfactant also is intriguing in that relatively low IFT was observed for higher salinity conditions (4 wt.% NaCl) in test tube/phase behavior studies. A second coreflood with Calamide CW-100 was performed under identical conditions, except now the connate water salinity was increased to 4 wt.% NaCl. Again, the tertiary recovery was 75–80% of the oil remaining trapped after a complete waterflood.

#### 3.2. Alkylpolyglycoside formulations

Tertiary oil recovery observed for the APG2062/1-naphthol/1-butanol formulation 3 amounted to 40.8%, for the APG2062/1-octanol formulation 4 it was 53.0%. 94% total oil recovery was achieved in the sandpack with the PG2069/SPAN 20 formulation 5.



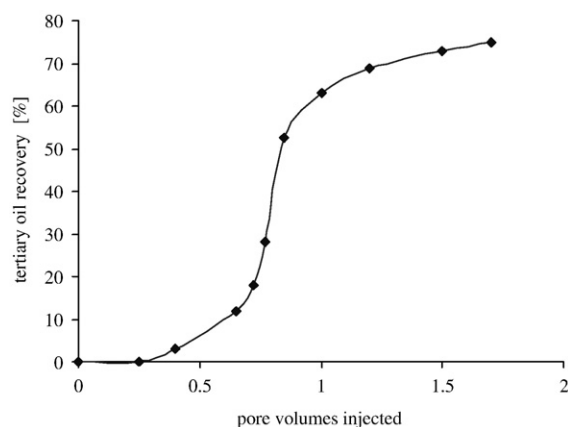
**Fig. 8.** Tertiary oil recovery observed for formulation 1 (di-tridecyl sulfosuccinic acid ester, (Aerosol TR-70)).

The 1-naphthol/1-butanol floods produced significant amounts of additional oil though cosolvent concentrations were low. It is hypothesized, based on the IFT observations (Goddard et al., 2004; Iglauer et al., 2009), that similar results can be achieved with an even more dilute and therefore more economical 1-naphthol/1-butanol system.

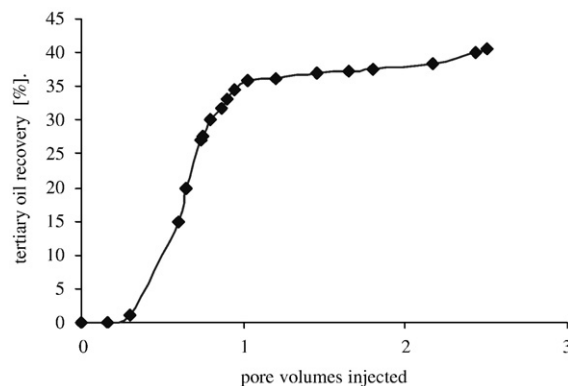
In summary, APG formulations were efficient in terms of recovering additional oil out of cores at waterflood residual oil saturation.

#### 3.3. Alkylpropoxy sulfate sodium salts – Alfoterra surfactants

The tertiary oil recovery for the Alfoterra 38 formulation 6 was found to be above 50%, while the tertiary oil recovery for formulation 7 was 37%. As the mass of Alfoterra 23 surfactant injected was less



**Fig. 9.** Tertiary oil recovery observed for formulation 2 (coconut diethanolamide (Calamide CW-100)).



**Fig. 10.** Tertiary oil recovery observed for the APG2062/1-naphthol/1-butanol formulation 3.

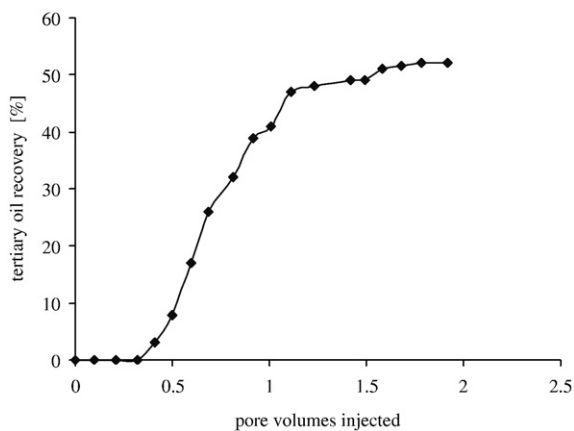


Fig. 11. Tertiary oil recovery observed for the APG2062/1-octanol formulation 4.

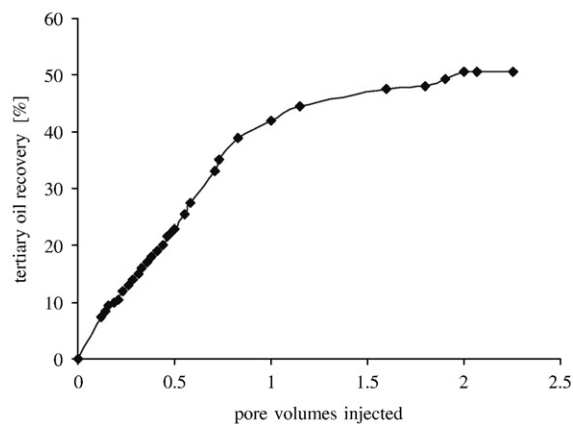


Fig. 13. Tertiary oil recovery observed for the Alforterra 38 formulation 6.

than that used in formulation 6, the chemical efficiency of formulation 7 was also good. Significant residual oil recovery occurred even with the connate brine having a relatively high salinity of 10 wt.% NaCl.

Flaaten et al. (2009) reported significantly higher oil recoveries for alcohol propoxy sulfate surfactant formulations. These are analog surfactants to the Alforterra molecules presented in this work.

There may be several reasons why we achieved lower tertiary oil recoveries as compared to Flaaten et al. (2009). Firstly, and in our opinion most importantly, Flaaten and al. most likely achieved significantly lower interfacial tensions; however, this is a speculation from our side as these numbers were not reported by Flaaten et al. Secondly, it may be that surfactant adsorption in their case was significantly lower leading to significantly lower surfactant loss during flooding. We think this is less likely than the first point, however, this is again speculation as Flaaten et al. did not report this parameter. Thirdly, we injected smaller amounts of surfactant solution (i.e. 0.25 PV instead of 0.3 PV; except for formulation 7 where we injected 0.8 PV) and fourthly, we inject smaller amounts of polymer drive solution (0.5 or 1 PV (or 1.2 PV for formulation 7) instead of 1.7–2.3 PV). Fifthly, permeabilities of the cores used by Flaaten et al. were significantly higher (average 700 mD as compared to 300 mD in our case), and as we demonstrated in our work, higher permeabilities result in higher oil recoveries. All these factors lead to higher tertiary oil recoveries in case of Flaaten et al. (2009) experiments. Overall we think that the difference in IFT and permeability values are the crucial parameters here.

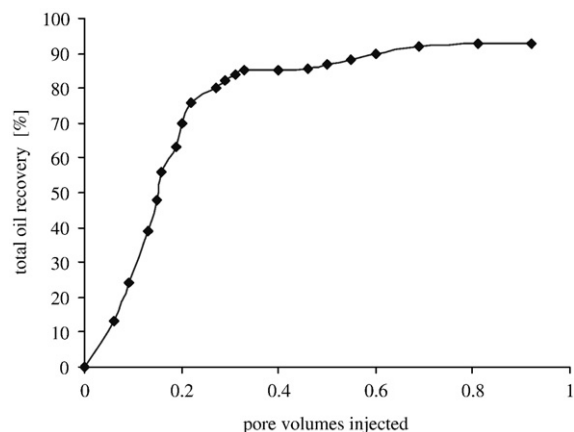


Fig. 12. Total recovery observed for the PG2069/SPAN 20 formulation 5.

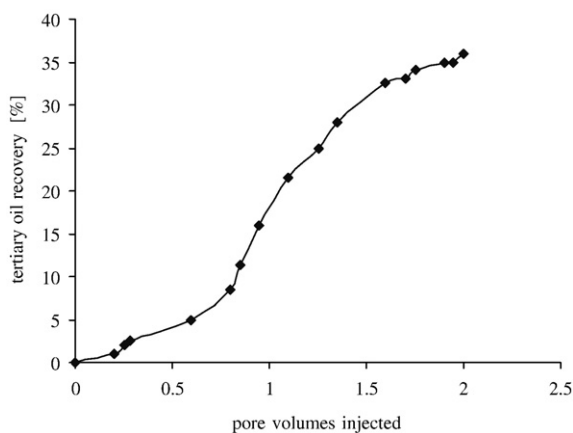


Fig. 14. Tertiary oil recovery observed for the Alforterra 23 formulation 7.

#### 4. Conclusions

Key findings from this study include:

1. A di-tridecyl sulfosuccinic acid ester showed only low (15%) TOR.
2. A coconut diethanolamide formulation produced a high TOR (75%).
3. APG showed a good TOR from 40 to 55%, and a high TOR in a sandpack flood.
4. Alkylpropoxy sulfate sodium salts were also effective in terms of TOR (from 35 to 50% additional oil was produced).
5. Coconut diethanolamide and alkylpropoxy sulfate sodium salts were efficient even at high brine salinities (4–10 wt.% NaCl).
6. The solid adsorption of the APG surfactants was dependent on the APG alkyl chain length. A larger chain length led to more adsorption. A retention of 40–60 mg/g kaolinite was observed for PG2062, while a negligible retention for PG2069 was recorded.
7. The retention of the sorbitan ester SPAN 20/PG2069 formulation was relatively high with 80–120 mg/g kaolinite.
8. Calamide CW-100 had a low adsorption with 17 mg/g on kaolinite.
9. Alforterra 23 and 38 had medium adsorption values with 11.9–42.5 mg/g on kaolinite, depending on surfactant concentration.
10. All surfactant formulations were successful in terms of producing significant amounts of additional incremental oil (after water-flooding). Tertiary oil recoveries observed were in the range 15–75% for consolidated sandstone cores. 94% oil recovery of IOIP were recorded in a sandpack flood.

These results indicate that a wide variety of surfactants can meet the technical requirements as enhanced oil recovery (EOR) agents.

## Nomenclature

APG	alkyl polyglycoside
IFT	interfacial tension [mN/m]
TOR	tertiary oil recovery
EOR	enhanced oil recovery
NaCl	sodium chloride
Ca <sup>2+</sup>	divalent calcium cation
IOIP	initial oil in place
PG2062	Agrimul PG2062 – commercial APG product
PG2069	Agrimul PG2069 – commercial APG product
SPAN20	sorbitan ester
wt.%	weight %
S <sub>or</sub>	residual oil saturation [%]
N <sub>cap</sub>	capillary number [–]
v	Darcy velocity [m/s]
μ	viscosity of injected phase [Pa·s]
PV	pore volume
S <sub>o</sub>	oil saturation [%]
rpm	revolutions per minute
Alfoterra	Alkylpropoxy sulfate sodium salt

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