Foam Pilot Evaluations for the Snorre Field

Part 1: Project Planning and Laboratory Results

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ABSTRACT

The Snorre Field, operated by Saga Petroleum a.s., has been developed based on water flooding as the primary recovery mechanism. The field was put on stream in August 1992. In February 1994 a WAG pilot project involving two injection wells and three production wells was started in the Statfjord Formation of the Snorre Field. Extensive evaluations of the project plans and predictions showed that early gas breakthrough may be a potential problem. As a result of this, the use of foam for gas mobility control, fluid diversion, and blocking to reduce GOR in production wells has been included in the project plans as a means of improving the WAG process. A foam pilot test in a producer is scheduled for 1995. This test will be a first step for scaling laboratory data to field conditions, *i.e.* to investigate the selected surfactant's ability to generate and sustain a stable foam *in-situ*.

This paper presents a summary of laboratory tests and project plans for the foam pilot project. The principal goal for the laboratory work has been to select an efficient surfactant (foamer) to be used in the field test. The laboratory studies have included solubility experiments in the injection temperature-reservoir temperature interval (5-90 ^{0}C), hydrocarbon gas-foam blocking and mobility tests, and surfactant adsorption studies.

A $C_{14/16}$ alpha olefin sulphonate (AOS) has been identified as a suitable candidate for the field test.

INTRODUCTION

The Snorre Field is located in the Northern North Sea in the vicinity of the Statfjord and Gullfaks fields, approximately 150 kilometres off the coast, on the slope of the Norwegian Trench. The field, covering an area of 102 km^2, extends across blocks 34/4 and 34/7 on the oil prolific Tampen Spur. The water depth across the field ranges from 275 meters in south-west to 380 meters in north-east.

The field contains oil in two main reservoirs, the lower Jurassic Statfjord Formation and the Upper Member of the Triassic Lunde Formation (Figure 1). The most likely STOOIP estimate is $520 \cdot 10^6$ Sm^3, with $173 \cdot 10^6$ Sm^3 in the Statfjord reservoir, and $347 \cdot 10^6$ Sm^3 in the Lunde reservoir. In the Snorre Field Development Plan (FDP), approved by the Norwegian Storting in 1988, a two-phased development was outlined. Phase 1 covered development of the mature southern parts of the field (mainly Statfjord Formation), while Phase 2 described a development of the less mature northern area and the Lunde unit L02-L05. The field was put on stream in August 1992.

The Statfjord Formation in the Snorre Field is 120-150 m thick, and is divided by faults into three main westwardly dipping rotated fault blocks (Figure 1), with an average dip angle of 9 degrees. The permeabilities are typically 1-3 D in the Upper Statfjord, and 0.2-1 D in the Lower Statfjord. The Statfjord Formation consists of fluvially deposited

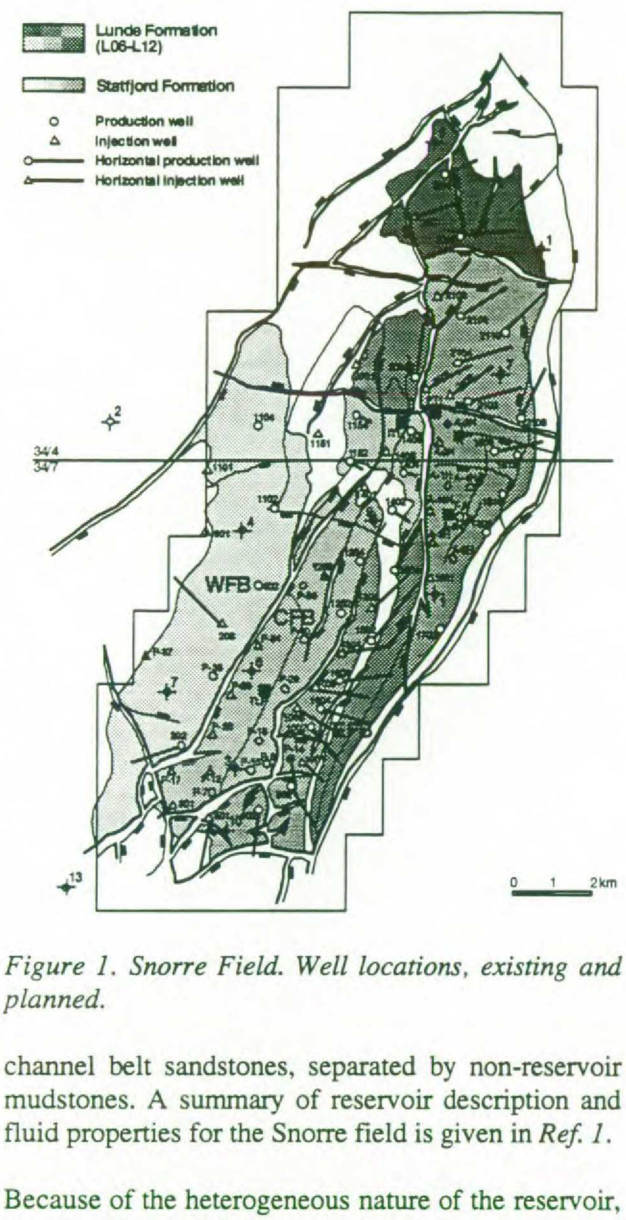

Figure 1. Snorre Field. Well locations, existing and planned.

channel belt sandstones, separated by non-reservoir mudstones. A summary of reservoir description and fluid properties for the Snorre field is given in *Ref. 1*.

Because of the heterogeneous nature of the reservoir, the overall sweep efficiency is relatively poor. For water injection, which is the chosen primary recovery mechanism, estimated recovery efficiencies for the different reservoir zones are in the range of 15 to 60%, with an average of approximately 40%.[1] At an early stage in the development of the Snorre Field it was realized that the potential for enhanced oil recovery (EOR) was considerable.[2] The remaining oil in the Snorre Field is mainly associated with residual oil saturation, poor vertical sweep efficiency, and attic oil accumulations. Based on the current development strategy it is estimated that about $350 \cdot 10^6$ Sm^3 of oil will remain in the Snorre Field at the end of field life. From 1991 to 1994, screening of available EOR methods under Snorre reservoir conditions was carried out to address these challenges. In addition to gas/WAG injection, two methods were identified to have an EOR potential, namely foam and polymer/gel. Estimated potential for these technologies is $20 \cdot 10^6$ Sm^3 extra oil.

The chosen EOR methods require technical and economical qualification through laboratory experiments, reservoir simulation studies and field pilots. Consequently, a qualification plan for EOR has been established with the objective to qualify this type of technology through field pilots. The strategy is to qualify EOR methods and have them available as reservoir management options when they are needed.

In February 1994 a downdip WAG pilot[3] involving two injection wells (P-25 and P-28) and three production wells (P-13, P-18 and P-29) was initiated in the Statfjord Formation in the Central Fault Block (CFB) (*cf.* Figure 1). The WAG pilot was recommended based on promising simulation and laboratory results as well as technical and economical feasibility studies.[1] The increase in recovery efficiency was estimated at 12% of the oil in place, which corresponds to an increased oil recovery of $3.5 \cdot 10^6$ Sm^3 in the pilot area. Furthermore, gas injection helps to alleviate the problems with the limitations on the oil export level from Snorre currently being imposed by gas processing and export constraints. The simulations predicted gas breakthrough to occur after 4-5 months of gas injection. The WAG process so far has shown even earlier gas breakthrough in one producer (P-18) than predicted.[3] This has accelerated the foam activities since foam can be applied both to reduce the gas mobility and to reduce the amount of produced gas by blocking of gas producing layers.

The Statfjord reservoir in the Snorre Field may offer particularly favourable conditions for application of foam. The lack of vertical communication between the Upper and Lower reservoir units reduces the tendency for injectants to bypass a foam plug.[1,4,5] Moreover, the large permeability contrast reduces the volume of foaming agent that enters the Lower Statfjord, thus minimizing the risk for undesirable plugging of this part of the reservoir.

In this paper a summary of the project plans and laboratory work for selection of a surfactant suitable for the field test is given. Another paper[4] summarizes numerical simulations for evaluation of foam-assisted WAG (injector treatment), as well as potential and design of foam treatment in a producer (P-29). In that paper some preliminary cost estimates are also included.

PROJECT PLANNING

The field test is planned for the ongoing WAG pilot area in the Snorre Field. The exact timing of a field test will depend on the gas production development in the involved wells. A large scale field test involving large treated reservoir volumes was considered to cause too high economical risk and be too time consuming with respect to the necessary data recording, for a first step pilot. Therefore, to reduce the risk (cost and time), a producer field test was designed as a first step for scaling laboratory data to reservoir conditions. The purpose of a field test can be summarized in the following terms:

- test ability of foam to reduce GOR
- obtain information regarding foam generation and stability in the Statfjord Formation
- investigate if the foam process operates in accordance with the observation from core flooding experiments
- obtain data to calibrate the numerical foam simulator
- gain experience in handling surfactant on an offshore platform
- gain experience for designing future foam projects

Choice of Well

Five wells in this area are potential candidates for a field test. They are the injectors P-25 and P-28 and the producers P-13, P-18 and P-29. The principal choice is between injector or producer treatments. While an injection well treatment potentially may provide long-term GOR control and improved vertical sweep deep into the reservoir, it will involve the treatment of large volumes with foam, and will imply smeared out response and long response time. (The interwell distance in the Snorre Field is 700-1500 m). It has therefore been decided that a production well should be used for a first step pilot. A producer treatment will give immediate response, and will require smaller surfactant volumes, reducing both economical risk and surfactant handling problems at the platform.

For the three producers in the WAG pilot area, P-13 is at the highest structural position.[4] It has not yet experienced gas breakthrough and is believed to be separated from injector P-25 by a fault line. P-13 is therefore not a primary candidate for a field test.

Gas breakthrough occurred in the Upper Statfjord reservoir in well P-18 late in March 1994.[3] The well has been shut in since because of gas processing and gas export limitations. P-18 is approximately 50 m upstructure from P-29 and would have been a good candidate for a field test.[4] However, at the moment the plan is to set a straddle packer to shut off P-18's Upper Statfjord perforations. Given that this operation works satisfactorily, P-18 is not a primary candidate for a field test.

Producer P-29 has already been affected by the WAG pilot, as indicated by fluctuating GOR with time.[3] Gas breakthrough can be expected in the uppermost reservoir zone in the first half of 1995. The production well P-29 is selected as the prime candidate for a field test for the following reasons:

- gas breakthrough is expected at the top perforation in an isolated sand
- limited amount of surfactant is required, and immediate responce expected
- interpretation of results from the test should be manageable due to the simple reservoir geometry with isolated layers

Foam Injection and Data Acquisition

Gas breakthrough in P-29 is expected to occur in the uppermost sand of the Statfjord Formation. This sand is 2.4 m thick, and is isolated from the zones below by a layer of shale that extends into the reservoir in a distance longer than the foam treatment area. The average permeability is approximately 8 D. The tentative plan is to set a retrievable packer below this uppermost sand so that foam treatment is confined to this layer only. It is planned to inject foam 15-20 m into the formation, and then retrieve the packer, allowing production of oil from the lower zones at reduced gas flow from the uppermost layer. The GOR development will be monitored before (base line) as well as after foam treatment. Moreover, gas and water will be tagged in order to facilitate monitoring of back produced fluids.

Foam injection strategy consists of injecting a small slug of water followed by a slug of gas to clean the near-well region of reservoir oil. This is followed by alternate slugs of surfactant solution and field gas. It is planned to inject the surfactant and gas slugs at a high rate in order to minimise gravity segregation. Following the alternate slugs, an equal volume of foam will be placed by co-injection. This is done for two reasons. Firstly, to test if it is at all possible to inject foam by co-injection. The very high apparent foam viscosity observed in the laboratory (see below) suggest that injectivity reduction may be encountered. Secondly, the co-injection process will serve as a backup in case the alternate slug injection process fails to generate foam due to segregation.

The well tubing-head and bottomhole pressures will be monitored throughout the entire field test with surface read-out pressure gauges. The apparent foam viscosity will be estimated by transient pressure testing.

It is estimated that the application of ~5 tons of surfactant at 1 wt% concentration will make that foam penetrates 15-20 m into the formation, in a radial geometry. The entire test (surfactant and gas injection) will take 1-2 days.

Selection of Foamer

Selecting a surfactant for use in a field test requires careful evaluation of the foaming and other key properties of candidate products. A thorough understanding of the process to be used in the field is necessary. This study comprised two stages of a product selection. A *screening* stage, based on obvious relevant surfactant properties such as solubility, availability at the time of application, environmental acceptability, and experience from foam field projects in the literature, resulted in a list of promising candidate products. (A few products, not available in field scale volume today, was included in the list because of their potential for future pilots). Next, a *qualification* stage evaluated the foam performance of the products that were selected from the screening stage at Snorre reservoir conditions.

LABORATORY RESULTS

Experimental

Solubility Tests

The surfactants were used as received from the manufactures. Deaerated brine, with a composition similar to the injection water at Snorre was added to samples of surfactant, giving surfactant solution concentrations of 1% by weight. The solubility tests were performed in the temperature range of 5-90°C, by heating and cooling the samples after a given scheme.

Core and Fluid Preparation

The foam experiments were performed using three composite cores of rock material from the Statfjord Formation and four Berea sandstone cores. The composite cores were constructed by combining individual core plugs of similar properties from high permeable zones in the Upper Statfjord Formation. The characteristics of the cores are summarised in Table 1. The permeabilities of the Berea cores were in the range of 500 - 900 mD and the core lengths were 50 cm.

Synthetic injection water containing the chlorides of sodium, calcium, magnesium, and potassium at a total salinity of 4 wt% was employed in the experiments. Synthetic Snorre injection gas containing 70 mol% methane was used both for preparative gas flooding and foam experiments. Separator oil and gas samples were recombined to give a reservoir oil with a bubble point of 130 bar.

Some introductory foam coreflood experiments were carried out at 20 bar and 90 °C. At low pressure, a model oil composed of Snorre stock tank oil and hexane was employed. Hexane was added in order to replace the light hydrocarbons that were lost from the reservoir oil when brought to ambient conditions.

Table 1. Characteristics of the composite cores (Statfjord Formation).

Core	I	II	III
Length [cm]	61.6	52.6	60.1
Average cross section of core [cm^2]	10.8	10.8	10.8
Pore volume [cm^3]	199	163	186
Porosity [%PV]	30.0	28.6	28.6
Permeability [mD]	650	960	1000

Description of Corefloods

The foam experiments were conducted in the following three modes, in the given sequence:

A. Gas injection at constant differential pressure - *gas blocking*
B. Co-injection of surfactant and gas at constant flow rates - *foam injection*
C. Gas injection at constant flow rate-*gas injection*

Mode A: Gas was injected at an imposed (fixed) pressure gradient into a core initially containing gas and residual oil after gas flooding, and surfactant solution. This is described as a blocking experiment. If a gas blocking state was obtained, the experiment was continued for at least 3 days.

Mode B: Surfactant and gas was injected simultaneously at a gas fractional flow (foam quality) of about 80%. Frontal velocites in the range 0.1 to 2.0 m/d were used. Experiments were continued until stable conditions were achieved with respect to the inlet and outlet flow rates and the differential pressure.

Mode C: After foam flooding in *mode B*, the surfactant solution feed was turned off, and the experiment continued with gas injection at the same rates as above until a pseudo-stable differential pressure was obtained.

All core flooding experiments were carried out at 90°C (reservoir temperature). The high pressure tests were made at 300 bar, which is the average operating reservoir pressure for the Snorre Field. The saturation history of the cores mimicked the injection scheme used at Snorre, including water flooding and miscible gas flooding. (The minimum miscible pressure is 283 bar[1]). The high pressure foam experiments were thus carried out at residual oil saturation to gas flooding, S_{org}. The low pressure tests were made at 20 bar.

Rock Characterisation

The Snorre rock was characterised with respect to properties considered important for foam processes. The rock characterisation included studies for determination of mineralogy (thin section analysis, x-ray diffraction, scanning electron microscopy), pore size distribution (Hg injection), specific surface area (Hg injection and N_2 adsorption), surfactant adsorption (extraction of cores used in foam experiments) and wettability (Amott tests).

Loss of Surfactant

Surfactant adsorption was determined for some of the sulphonate-based foamers. Loss of surfactant in the core was obtained as the difference between the amount of surfactant recovered from the core by extraction and that solubilized in the aqueous phase at the end of the foam experiments. Two-phase titration was employed to determine the total amount of surfactant in the extracts, and Karl Fisher analysis of the extracts provided the amount of aqueous phase in the core before extraction. Due to the hydrophilicity of sulphonates it is a reasonable assumption that most of the surfactant was lost by adsorption on the rock, and that only minor amounts partioned into the remaining oil.

Interpretation of Foam Performance Data

When foam is present in a porous medium, the distinction between permeability and viscosity is blurred and the two parameters may even be theoretically inseparable. Therefore, for convenience, the effects of foam may be characterised by lumping all effects into one effective parameter, ***the apparent gas viscosity in the presence of foam***, defined by the one-phase Darcy's law as:

$$\mu_{app} = \frac{kA\Delta p}{q_g L} \tag{1}$$

where k is the absolute permeability of the porous medium, $\Delta p/L$ is the pressure gradient, A is the cross section area to flow, and q_g is the volumetric flow rate of gas.

Another parameter used to compare foam data is the mobility reduction factor (MRF):

$$MRF = \frac{\Delta p(foam)}{\Delta p(water + gas)} = k_{rg}^{no\ foam} \frac{\mu_{app}}{\mu_g} \tag{2}$$

where $k_{rg}^{no\ foam}$ is the relative permeability to gas measured during co-injection of gas and water without surfactant at the same saturation conditions as in the foam experiment.

The apparent viscosity and MRF data are given as averages over periods with stationary pressure drop, constant flow rates, and saturations.

RESULTS AND DISCUSSION

Rock Characterisation

Pore size distribution. Figure 2 shows a comparison of pore size distributions of a 0.6 D Snorre rock, 0.32 D Berea, and 1.5 D Bentheimer sandstones. Relative to Bentheimer, whose narrow pore size distribution is reflected by a step-like cumulative volume curve, the Snorre rock sample is characterised by a smeared-out cumulative volume curve, corresponding to its broad distribution of pore throat radii. The reservoir sample is more like Berea when the pore size distribution at small radii is concerned. The larger pores are more abundant in the Snorre sample, though, corresponding to the higher permeability of this rock. This finding motivated the choice of Berea cores for screening tests. It appears likely that a broad pore size distribution is favourable for foam stability. In a non-homogeneous pore system a fraction of the pores will always have properties suitable for generating and sustaining gas blocking lamellae.

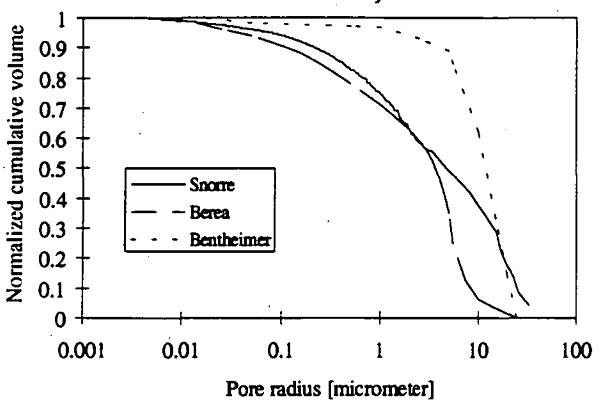

Figure 2. Cumulative pore size distribution

Specific surface area and mineralogy. Hg injection measurements on rock samples from well P-18 suggest values for the specific surface area in the range 0.6 to 1.3 m^2 per gram of rock. The results from N_2 adsorption measurements are in close agreement to the Hg injection data. Values in this range are frequently observed for sandstones. Berea, having a pore structure quite similar to the Snorre rock, displays values of about 0.9 m^2/g. In contrast, Bentheimer outcrop, which consists mainly of quartz sand with little clay, is reported to have a specific surface area of about 0.2 m^2/g. A clay mineral such as kaolinite may alone have a surface area of 15 m^2/g. The mineralogy of samples from well P-18 is characterised by a clay and mica content of about 20% by weight, which would imply specific surface area as high as 3 m^2/g from clays (kaolinite) alone. The lower observed surface area may result from the characteristic for the present Snorre samples, that kaolinite was found in rather coarse crystals which probably do not contribute fully to the surface area.

Adsorption. Adsorption has been measured for three of the surfactants studied in the corefloods (see below). Adsorption data for C_{16}AOS and Chevron Chaser GR1080 on Snorre rock were determined at 0.80 and 0.43 mg surfactant per gram rock, respectively. $C_{14/16}$AOS, which was expected to yield lower adsorption than C_{16}AOS by virtue of the presence of the more soluble C_{14}AOS, surprisingly exhibited adsorption as high as 0.9 mg/g rock. This finding is contradictory to previous observation, and is not understood.

In order to evaluate the significance of the adsorption level obtained for C_{16}AOS and $C_{14/16}$AOS, it is instructive to compare the amount of adsorbed surfactant with that present in the aqueous phase at typical foam flooding conditions. Assuming a surfactant solution saturation of 50% and a surfactant concentration of 1 wt%, the surfactant content in the aqueous phase is 0.8 mg/g Snorre rock. According to the measurements, the amount of surfactant adsorped on the rock would be 0.8-0.9 mg/g. The total surfactant demand for treatment of a given reservoir volume is thus approximately doubled relative to the case with no adsorption (for C_{16}AOS and $C_{14/16}$AOS).

The adsorption data for C_{16}AOS has been duplicated in an oil free Snorre reservoir core at an independent institution (Petroleum Research Institute, Canada).

Solubility Tests

The objective of the solubility study was to investigate the solubility of candidate foamers as a function of temperature in representative injection water for the Snorre Field. For a foam process in a North Sea reservoir, the surfactant will experience a change in temperature from low values in the water injection system up to the high values prevailing in the reservoir. For the Statfjord Formation, the upper temperature limit in the reservoir is 90°C. In the injection system on the platform, the water temperature after the main heat exchanger is normally in the range of 15-23°C. However, in this study the lower temperature limit has been set to 5°C, in order to include conditions met in the tubing at shallow depths in case of an accidental stop during injection.

43 surfactants, belonging to the groups AOSs, secondary alkane sulphonates, ethoxylated tributyl phenolether sulphonates, ethoxyl propoxy sulphonates, and some fluorinated surfactants were tested in seawater at temperatures ranging from 5°C to 90°C. About 20 of these surfactants showed good solubility, giving clear solutions over the whole temperature range. The remaining surfactants showed precipitation or phase separation.

Based on these solubility tests and experience from foam pilot projects reported in the literature, the following surfactants were selected as candidates for further testing (the lower solubility temperature limit is given in parantheses):

- C_{16}AOS, an AOS made by Servo Chemical b.v. (<25°C)
- C_{14}AOS, likewise from Servo (<5°C)
- $C_{14/16}$AOS, likewise from Servo (<10°C)
- Chaser GR1080, a sulfonate blend made by Chevron Chemical (<5°C)
- Hoe B1333, a fluorinated sulfobetain made by Hoechst AG (<5°C)
- Chaser CD1045, a sulfonate blend made by Chevron Chemical (<5°C)

$C_{16}AOS$ was included in spite of the poor solubility at low temperatures, due to previous experience with this surfactant.

Coreflood Experiments

In the present work, the three experimental modes described in the Experimental section were employed in order to characterise foam behaviour. All three injection processes were chosen for this study since it is not obvious which of the processes that give the best representation of the flow conditions in the reservoir.

Experiments carried out at constant pressure drop characterise the ability of a trapped foam to block gas flow in a given pressure gradient. Such experiments are relevant to simulate foam behaviour in situations where blocking of gas flow does not lead to upstream pressure build-up, but instead to diversion of flow. Flow at constant rate is found near injection wells, and else where geometrical limitations exclude diversion. Gas blocking in such regions leads to pressure build-up, and gas will be forced through the foam. Measurement of foam flow at definite rate and gas fraction may be relevant even if foam may be injected by surfactant-alternating-gas (SAG) injection in the field, since foam flow at a certain foam quality may prevail in transition zones between gas and surfactant solution slugs in the reservoir. Finally, the reason for studying gas injection at constant rate is that this process is characteristic for the SAG injection. In the field, injection of a pre-generated foam may be impractical, and alternate injection of gas and surfactant solution may be called upon in order to reduce pressure build-up during foam injection, or to simplify platform procedures. In conclusion, all three experimental modes provide interesting information.

Results from the core flood experiments are presented in Table 2 and Figures 3-5. Table 2 presents the apparent viscosity as obtained during gas and surfactant co-injection at a gas fraction of 80%, and a total frontal velocity of 0.5 m/d (if otherwise is not given). The table comprises data from both low and high pressure tests. Figures 3-5 summarizes high pressure test results.

The core flooding experimental program was started with a test of the capability of Snorre reservoir rock to generate and sustain an aqueous foam. Experiments were carried out with $C_{16}AOS$ at 20 bar and 90°C, with no oil in the core. The apparent gas viscosity in the presence of foam was measured at 47 cP, which is significantly larger than the pure gas viscosity (0.02 cP). Using the gas relative permeability curve used in the Snorre Field simulation studies (as determined from Snorre rock samples), the gas mobility reduction factor can be deduced at 600. This high MRF value signifies that foam was indeed present in the core.

Table 2. Apparent viscosity measured during foam injection at 0.5 m/d and 80% gas fraction.

Core	Pressure [bar]	Surfactant	S_o [%PV]	μ_{app} [cP]
Snorre I	20	$C_{16}AOS$	0 6 17	- (47[1]) 6 (2[1]) 13 (5[1])
Berea[2]	20	$C_{16}AOS$ GR1080 B1333 CD1045	41 48 37 37	5 70 160 2
Snorre I	300	$C_{16}AOS$ $C_{14}AOS$ $C_{1416}AOS$	7 12 12	970 210 1200[3]
Snorre II	300	GR1080	9	42
Snorre III	300	B1333	16	84

[1] Gas fraction 94 %
[2] Four different cores. Permeabilities were 0.7, 0.9, 0.6, and 0.5 D. Rates employed were 4, 3, 7, and 4 m/d
[3] Total rate 0.27 m/d

At low pressure and 90°C, $C_{16}AOS$ was found to be strongly oil sensitive. The presence of oil induced a reduction in the apparent viscosity by a factor 10 (for comparable gas fractional flow), for oil saturations ranging from 6 to 17 %PV in the Snorre core. The foam behaviour in the presence of oil was essentially duplicated in a Berea core test at significantly higher oil saturation (41 %PV). It should be noted that a model oil was used instead of reservoir oil for these low pressure tests (*cf.* the Experimental section above).

The low pressure tests in Berea cores were dedicated to a first identification of foamers suitable for Snorre conditions. Moreover, if low and high pressure tests for selected surfactants yielded the same ranking of foam performance, low pressure tests could be validated for a large scale search through a number of surfactants, if required. Judging from the data shown in Table 2, the apparent viscosity measured at 0.5 m/d, B1333 was found to be a factor two stronger than GR1080, a factor 30 stronger than $C_{16}AOS$, and two orders of magnitude stronger than CD1045. The results from gas blocking and flooding tests at 20 bar essentially confirmed this ranking. In particular, B1333 performed as an excellent blocking agent, whereas C_{16}AOS barely exhibited any blocking effect.

When the low pressure screening was completed, the initial reservoir condition foam tests with C_{16}AOS had already indicated that coherent results were not obtained at low and high pressure. It was therefore decided to make reservoir condition test of all the most promising candidates from the low pressure experiments. CD1045, which performed poorly at low pressure, and had previously not been used at temperatures as high as in Snorre, was not studied further. Instead, C_{14}AOS was considered in response to the high adsorption level and abundant mobility reduction observed for C_{16}AOS. C_{14}AOS was expected to yield lower mobility reduction and adsorption. Mixture of C_{14}AOS and C_{16}AOS ($C_{14/16}$AOS) was also included, and was expected to provide properties intermediate to that of the pure chain length surfactants.

Results from the high pressure tests are presented in Figures 3-5. The data were obtained in reservoir composite cores containing residual oil after miscible gas flooding, in a test sequence comprising all three modes as described in the Experimental section.

Figure 3 shows the temporal evolution of gas interstitial velocity through the cores as obtained during the blocking experiments at a pressure drop of nominally 0.5 bar over the cores. Experiments were carried out on three different composite reservoir cores, having different permeabilities (Table 1). Since different cores were used for different surfactants, the figure presents gas velocities normalized by the absolute permeability of each core, in order to extract foamer performance from data that are also influenced by core properties. Effective blocking of gas by foam is recognized in such a plot as a low gas velocity for a long period of time until foam breakdown, which is signified by a sudden increase in gas velocity. C_{14}AOS is seen to provide no such blocking effect. The gas velocity increased rapidly immediately after experiment startup, and continued increasing through the enitre experiment. Likewise did GR1080 not perform well. The gas rate increased steadily throughout the experiment, reaching experimental limitations after 7 hours. Neither did B1333 reach a blocking state with a low and constant gas velocity. This surfactant yielded a lower gas velocity than C_{14}AOS and GR1080, however, and provided thus a more stable foam than these surfactans. Only the C_{16}AOS and $C_{14/16}$AOS foams displayed a blocking state in these experiments. C_{16}AOS was shortly exposed to a pressure drop of 4 bar at about 30 hours experimental time (arrow a). After an intermediate break, the experiment was continued at a pressure drop of 0.5 bar at arrow b. The foam was found to return to nearly the same state as before exposure to high pressure drop, and provided a low gas velocity for nearly two more days. The experiment was interrupted while still in the blocking state. For $C_{14/16}$AOS, gas blocking was observed for more than 110 hours. Then the pressure drop was increased to 2.5 bar (arrow c) and 10 bar (arrow d), in order to accelerate foam breakdown.

The results from the foam flooding experiments are shown in Figure 4. These data were obtained during co-injection of gas and surfactant solution at a gas fractional flow of 80 %. The effects of different core permeabilities are taken into account in the concept of apparent gas viscosity (See Eq. 1). For the AOSs, the apparent viscosities are found to decrease with gas velocity, i.e., the foam is shear thinning. This behaviour is often found for foams in porous media. B1333 displays both shear thinning and shear thickening, dependent on velocity regime, while GR1080 exhibits no rate dependence. GR1080 was found to yield the weakest foam of the tested surfactants. B1333 and C_{14}AOS produced likewise only weak foams. C_{16}AOS and $C_{14/16}$AOS yielded the strongest foams observed in this test. While the strongest foams in the foam flooding tests were the same as in the blocking tests, there appears to be no correlation between blocking and foam flooding performance for the weakest foams.

In the foam flooding tests for the C_{16}AOS, estimated mobility reduction factors (cf. Eq. 2) range from 2400 to 7400, depending on gas velocity, indeed a significant effect of foam on the gas mobility. $C_{14/16}$AOS exhibited mobility reduction factors of about 7000.

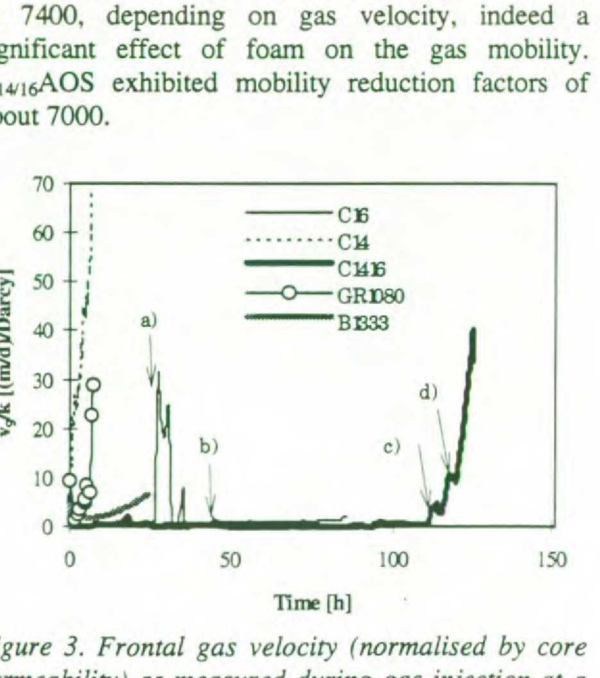

Figure 3. Frontal gas velocity (normalised by core permeability) as measured during gas injection at a constant pressure drop of nominally 0.5 bar, at Snorre reservoir conditions.

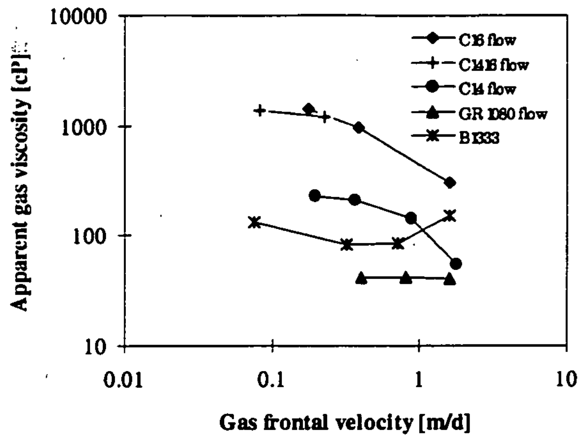

Figure 4. Comparison of apparent viscosity from foam flooding tests at Snorre reservoir conditions.

Finally, Figure 5 displays the apparent viscosities calculated for the gas flooding experiments carried out after the foam flooding. While apparent viscosities greatly in excess of the gas viscosity signifies the action of foam also in these tests, it should be noted that mobility reduction is significantly lower during gas injection than in the foam injection tests. This demonstrates the possibilty of using gas injection to alleviate problems of injectivity loss potentially encountered during foam injection in the field. The conclusion that C_{16}AOS and $C_{14/16}$AOS perform significantly better than the other surfactants is valid also with reference to the gas flooding data.

The data for C_{16}AOS have been essentially duplicated in parallell Snorre reservoir condition foam tests, carried out in another Snorre composite reservoir core at an independent institution (Petroleum Research Institute, Canada).

The presented foam data provide an interesting comparison between results obtained at low and high pressure. Table 2 shows that C_{16}AOS was found to perform significantly better in flooding tests at high pressure than at low pressure, at comparable oil saturations. The observed apparent viscosity increased by more than two orders of magnitude when the pressure changed from 20 to 300 bar. For B1333 and GR1080, the opposite effect of pressure was found. Also for the blocking tests, high and low pressure test results deviate considerably. While C_{16}AOS was found to be poor as a blocking agent at low pressure, effective gas blocking was observed at the reservoir pressure. B1333 exhibited the opposite pressure behaviour, as the stable gas blocking properties observed at low pressure was changed to only a weak blocking effect only at reservoir pressure. *I.e.*, that the ranking observed at low pressure was not preserved in any experimental

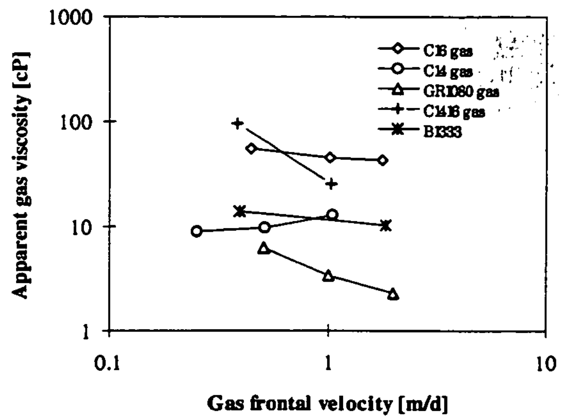

Figure 5. Comparison of apparent viscosity from gas flooding tests at Snorre reservoir conditions.

mode when the pressure was increased to reservoir pressure. Apparently, system pressure is a critical parameter even for surfactant screening.

Choice of Surfactant

The choice of surfactant to be employed in the pilot depends on the surfactant characteristics available in the emsemble of chemicals studied, held against possible pilot designs. Since the first pilot will be a producer treatment, it is obvious that a foam as strong as possible is desired for effective and prolonged GOR reduction. Oil sensitivity is central for a producer treatment, but the present experiments provide no data for varying oil saturation, and conclusions have to be drawn from data recorded at S_{org}. Surfactant adsorption is not critical, however, since only a small reservoir volume will be treated, and chemical cost is minor in the project. Solubility at injection conditions is a major issue for any pilot design, and has been given considerable attention in the present study.

The maximum foam strength requirement suggests that either C_{16}AOS or $C_{14/16}$AOS, which exhibit similar foam performance, is chosen for use at Snorre conditions. Of these two, $C_{14/16}$AOS has the superior solubility, and can be used at typical injection conditions. The use of C_{16}AOS will involve the risk of surfactant precipitation during injection.

Like the other AOSs, $C_{14/16}$AOS is available in large quanta at a relatively low price (~2 USD/kg). This surfactant appear to fulfill (more or less) the criteria set to the pilot chemical, and is thus chosen for the planned foam pilot at Snorre.

CONCLUSIONS

1. Based on the screening studies, $C_{14/16}$AOS seems to be a good candidate as foamer in the Snorre Field. It satisfies the requirements set to solubility, foam properties, availability, and cost.

2. $C_{14/16}$AOS provided strong gas blocking at a pressure gradient of 1 bar/m, at Snorre reservoir conditions. Gas mobility reduction factors of up to 7000 were observed during foam flooding at 80 % gas fractional flow. For pure gas injection, mobility reduction was lowered by a factor of 10.

3. System pressure is a critical parameter for surfactant screening. Surfactants that show good foam performance at low pressure, do not necessary have the same foam properties at high pressure.

4. More experimental work is in progress in order to aquire data for tuning the foam option of a numerical reservoir simulator. This comprises studies of the influence of oil saturation, surfactant concentration, and gas fractional flow on the foam stability.

5. A foam pilot is presently being designed for the production well P-29 in the Statfjord Formation of the Snorre Field. A production well treatment has been chosen for this first test in order to reduce treatment size and pilot response time. The amount of injected surfactant can be minimized, reducing operational difficulties, cost and risk. Finally, it is assumed that the interpretation of a production well treatment will be simpler for a producer than an injector treatment for the conditions prevailing at the Snorre Field.

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