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## Foreword

The research presented in this thesis is conducted on behalf of equinor. The work was conducted at EMC's lab located in Forus, Stavanger. Some of the results have been published in a research article.

## Acknowledgement

I would like to thank the European Mud Company for putting their lab and material at my disposal as well as provide excellent counseling and support. I would also like to thank equinor for providing a very interesting and educational thesis. Sverre Bernt Lygren has been of very helpful with his advice and expertise on the subject. A special thanks goes out to Karl Ronny Klungtvedt, one of the most intelligent and interesting person I have met.

## Abstract

Johan Sverdrup is one of the largest and most profitable oil fields ever to be discovered on the Norwegian continental shelf. The extraordinarily high permeability of the intra-Draupne formation is one the main reasons for the excellent reservoir quality but it has also been a source of drilling related challenges.

The aim of this work was to experimentally assess whether the drilling fluid used on Johan Sverdrup could be modified to reduce fluid loss and lost circulation, while also minimizing damage to the formation. To conduct the analysis, it was important to first estimate the pore-sizes in the higher-permeability parts of the intra-Draupne formation. Thereafter, samples of laboratory mixed fluids and field fluids were tested on a range of permeabilities, with and without exposure to wear, to assess the effective sealing ranges of the fluids.

The results show that the reason for lost circulation primarily is related to the formation pore-sizes in parts of the formations being larger than the effective sealing limit of the fluid. A solution was found using cellulose based particles which did not degrade during the exposure to wear and thus maintained effective sealing under all tested conditions. Furthermore, a finer cellulose additive was found to reduce fluid loss and formation damage in the medium to low permeability parts of the reservoir.

The overall findings thus suggest that lost circulation may be prevented and thereby reduce time and cost of drilling and improve the productivity of each well.

# Acronyms

AHR – After hot rolling

BHR – Before hot rolling

ECD – Equivalent circulating density

HTHP – High temperature high pressure

LCM – Lost circulation material

NPT – Non productive time

PAC – Polyanionic cellulose

## List of Contents

## List of Figures

## List of Tables

# 1 Introduction

For over 40 years petroleum has been the most important industry in Norway and has been the largest contributor for the huge economic growth and financing of the Norwegian welfare state. Since production started the industry has contributed approximately 22,000 billion NOK to the GDP, and it currently employs about 200,000 workers **[1]**. Climate change has raised uncertainties regarding the future of Norwegian oil and gas. However, with increasing world energy demand, reliance on hard to abate industries, and slow development of renewable energy, there is little to indicate that production will seize any time soon. Nevertheless, measures to reduce emissions, i.e. $CO_2$ taxes, will lead to increased costs and lower the profitability of industry. **[2]**

After over 50 years of activity, petroleum production is now in a mature phase and the activity will gradually decline over the century. It is estimated that the total recoverable volume on the Norwegian continental (NCS) shelf is approximately 15,767 million standard cubic meter of oil equivalents ($Sm^3$ o.e.). By the end of 2022, 8,274 million have been produced and sold, over 52,3% of the total volume. About 36% of the remaining reserves are in producing reservoirs, while 14% lies in conditional resources in fields and discoveries and 50% in undiscovered resources. Furthermore, most of the resources in producing fields have been extracted, and out of the three largest fields discovered on the NCS, Troll, Statfjord and Ekofisk, the remaining reserves are 37,5%, 2,3%, and 5,8% respectively. Beyond Troll, there are still a few large fields with considerable reserves, the most notable being the Johan Sverdrup field, which is the largest discovery since 1981.

As the largest fields are depleting, a greater proportion of the remaining reserves are in conditional and undiscovered fields. These are less profitable to develop and produce and it will therefore be important to continue to reduce costs and increase recovery from each field. The largest cost driver for an offshore drilling operation is time. DeepSea Atlantic, which is being used to drill on Johan Sverdrup, costs between 6 and 8 mNOK per day [3]. Consequently, implementing technologies that facilitate faster drilling, and reduce the probability of halts and delays in the operation, can have enormous cost benefits. There are numerous ways this can be done

Drilling fluid is a crucial component in most drilling operations. One of the most important functions of the fluid is maintaining wellbore stability and preventing incidents such as kicks, blowout, and collapse of the borehole.

When creating a hole, the pressure exerted by the surrounding formation will naturally seek to fill it. Therefore, it is essential that the mud column provides a hydrostatic pressure that balances the formation pressure. To achieve this, the density of the drilling fluid is continuously adjusted, ensuring that the equivalent circulating density remains between the pore pressure and the fracture pressure [4]. The equivalent circulating density (ECD) represents the effective density of the fluid, considering both the measured density and the frictional pressure drop in the annulus. When the ECD is above the pore pressure, fluid will naturally seep into the porous formation, leading to filtration loss. As drilling fluid is pushed into the formation, particles larger than the pore openings will accumulate on the wellbore wall and create a filter cake. To minimize further fluid loss and avoid a stuck pipe situation, it is desirable that the filter cake is as impermeable and thin as possible.

Accurately calculating the pore pressure and fracture pressure of the formation can be quite difficult due to several factors, making the estimates somewhat uncertain. As a result of this, the ECD may sometimes exceed the fracture pressure, which in turn can result in the creation of fractures and growth of existing fractures. Similarly, when drilling through high permeable zones, the pore pressure may be much lower than the hydrostatic pressure. Both cases can lead to severe fluid loss, and lost circulation, when less drilling fluid is returned to the surface than what is being pumped downhole.

Fluid loss and lost circulation may lead to a range of different problems and can be very costly. When drilling fluid is lost to the formation, it may damage the formation permeability in the process. Fines and additives, such as polymers and solids may migrate with the filtrate into the formation [5]. One ramification of this is that it may eliminate the opportunities for accurate geological surveys and logs. An even greater consequence is when these solids and polymers plug the pores and cause a reduction in permeability. This is problematic because lower permeability may lead to lower productivity and profitability of the field, which is why formation damage is especially undesirable in reservoir formations.

It is difficult to estimate the extent and economic consequences of fluid loss induced formation damage. However, there are also significant costs attributed to the lost fluid volume, as well as Non-Productive Time (NPT) caused by fluid related issues. Grelland [6] conducted a study on lost circulation treatment by numerous companies operating in the North Sea region. He found that of the wells studied which had severe losses, there was an average of 800 $m^3$ lost fluid, which would cost between 1.1 mNOK and 1.9 mNOK [3]. He also found that average NPT was 50 hours, which on DeepSea Atlantic would cost upwards of 16.7 mNOK, while the average Lost Circulation Material (LCM) cost on these wells was 0.3 mNOK only about 1-2% of the total cost related to lost circulation [6].

Due to the many issues and potential costs related to fluid loss and lost circulation, it is important to minimize the risk of occurrence as well as quickly and effectively remedy the situation when required. One way this is done is by regularly verifying the strength of the formation through integrity tests and leak-off test and adjust the operation and fluid accordingly. To reduce filtration loss there are several additives used in water-based drilling fluid, such as long chain Poly Anionic Cellulose (PAC) and Starch. These are effective due to their viscosity properties but have reduced effect when the pore throats exceed 20µm and the differential pressure exceeds 500psi [7]. To effectively seal fractures and larger pore throats, bridging agents or LCM can be used. There are a wide range of different materials available in the market, and some of the most common includes graphite, ground marble, nutshell, cross-linked polymer, and cementitious materials [8].

LCM can be separated into preventive and remedial applications. Preventive treatment includes continuous addition of LCM during circulation, or various wellbore strengthening techniques, which have shown to facilitate higher differential pressure in the well [9]**.** Remedial applications are often executed to stop severe losses by pumping down a high concentrated fluid pill of about 8-15 cubic meters, containing various granular, flaky, or fibrous particles. On Johan Sverdrup such an LCM pill typically contains 120-160 lb/bbl of a mix between calcium carbonate and various graphite, while a concentration of 14 lb/bbl is used for preventive treatment [3]. Alsaba et al. [10] studied the performance of different types of LCM. They fibers gave the best sealing capabilities on slotted discs, and that the seal created by granular materials had lower integrity in comparison. They considered the compressibility, irregularities in the shape and the broad Particle Size Distribution (PSD) of the fibers to be the determining factors.

There are numerous studies regarding what the optimal PSD is for effectively sealing permeable formations and fractures. The Ideal Packing theory proposed by Keauffer 1973 [11] is one method commonly used for creating the bridging agent blend. It suggests that the optimal blend is achieved when the cumulative volume (%) of the particles forms a linear relationship with the square root of the particle diameter. Abrams [12] proposed another rule which aims to minimize particle invasion and thus formation damage. He suggests that the mean particle size should be equal to or slightly greater than 1/3 of the median pore size of the permeable formation. Additionally, the volumetric concentration of bridging particles should be at least 5%, meaning a concentration of at least 50 pound per barrel. Scott et al. [13] suggests that successful bridging requires 10-20 lb/bbl of particles sized equal or slightly larger than the pore opening. They concluded that trying to continually optimize the PSD is not needed for curing lost circulation and it may even be detrimental. Additionally, they found that drill solids in a field mud up to 75-150 µm, depending on shaker screens used, will remain in the fluid and facilitate bridging, which may trivialize addition of fine cellulose and calcium carbonate.

Although there are a wide range of different materials available, Grelland [6] found that 74% of the total LCM used on the NCS were ground marble, graphite, or a combination of these. He concluded that in most cases these were insufficient in curing the losses when not used in combination with other materials. A reason why ground marble may be insufficient in curing lost circulation is due to its brittleness. Scott et al 2012 [14] did an extensive study on degradation of various LCM when subjected to variable shear stress using a Hamilton Beach mixer and a Silverson High-Shear Mixer. They found that all granular LCMs degrade to a certain degree when exposed to shear stress in both field and lab. Ground marble showed the worst performance, almost completely degraded in the range 250-595 µm only retaining 0.5% of the particle, when exposed to heavy shear. The degradation was lower for smaller particles, but it was still significant in the range 44-74 µm. Field results supported the findings, in terms of relative degradation of the particles, but it was overall lessened. It was concluded that ground marble may not be effective as an LCM when larger particle sizes are required. In a study conducted by Klungtvedt et al. [15] mechanical shear was applied during hot-rolling of the drilling fluid. The results show that 99% of the calcium carbonate particles initially above 420 µm were finer than 420 µm after the degradation. For graphite particles and granular cellulose in the same range, the degradation resulted in a reduction of 30% and 5%, respectively, suggesting that the cellulose is highly resistant to shear degradation.

There are several factors to consider when engineering a drilling fluid. It must have the right properties to fulfill all its functionalities, and especially maintain wellbore stability. Every well and field is different, the formation and environment may differ from what is expected, and the downhole conditions may change at any point. It is therefore not possible to design one perfect fluid that would be work in all scenarios. Consequently, mud engineers must continuously monitor, test, and adjust the fluid. This is done both on-site during operations, and in lab for research purposes. There are extensive industry standards related to various tests for drilling fluid such as the ANSI/API 13B-1 [16], which include a detailed procedure on how to conduct fluid loss tests. These are typically done as either an API or HTHP filter press test. For HTHP normal testing conditions are 66 C (150 F) and 3.45 MPa (500 psi). For North Sea applications, reservoir temperatures are often above 90°C, and differential pressures may be in the regions of 1000-3000 psi for depleted reservoirs [13, 17]

The fluid design will often be a trade-off between what is technically possible and what is practically feasible, and even when it is possible to create an optimized fluid in the lab, it may not so easily be implemented in operations.

This research is in part carried out on behalf of Equinor and is centered around current issues on the Johan Sverdrup field. The following section will present a brief description of the field, including relevant technical and economically information, as well as introduce the issues and objectives. Due to confidentiality, some information has been excluded, and parts of the data is based on estimates and approximations.

## 1.1 Case Description: Johan Sverdrup

Johan Sverdrup is the one of the largest oil fields ever to be discovered on the NCS, only exceeded by Statfjord and Ekofisk. The original reserves are estimated to 420.2 $Sm^3$ o.e., were 401,4 million $Sm^3$ is oil, and the rest being mostly gas and some Natural Gas Liquids. For comparison Statfjord and Ekofisk had original oil reserves of 582.85 and 534.73 million $Sm^3$ respectively. In terms of remaining oil reserves, it is currently the largest by far, with 314.6 million $Sm^3$ remaining at the end of 2022, which is close to 30% of the total reserves of all fields, producing and planned for producing. Following Sverdrup is Johan Castberg and Snorre with reserves of 88.97 and 65,76 million $Sm^3$ respectively. [1]

The field was discovered in 2010 and production started from phase one in October 2019. It was originally estimated that the field would be able to produce up to 115,000 $Sm^3$ oil per day, but earlier this year a top capacity of above 120 000 $Sm^3$ was reached. This is approximately 30% of Norwegian oil production and corresponds to 6-7% of Europe's daily oil demand. According to the operator, it also has among lowest $CO_2$ emissions of any oil field, about 80-90% lower than the global average. This makes it less exposed to increased costs due to climate measures, and over the lifespan of the field, it is expected to net the Norwegian state about 900 bnNOK. [18]

The size of the field is about 200 square kilometers and has a water depth of 110-120 meters. It is located in the Utsira high area in the North Sea, about 160km west of Stavanger. The main reservoir is in the Intra-Draupne sandstone formation at 1900m depth. There are also significant resources in the Statfjord Group, but the extraordinary characteristics and issues are mainly related to the former, which will be the area of interest

There are several factors that affect the quality of a reservoir. In an analysis conducted by Olsen et al [19] they concluded that the reservoir quality in the Intra-Draupne formation was excellent, and one of the best to ever be discovered on the NCS. The reasons for this were the high net/gross ratio of 97% and extremely high permeability. The median permeability of the entire formation was estimated to 19 Darcies, and the median for individual wells ranged from 0.5 to 40 Darcies. There were also specific measurements of up 50 Darcies, which was the limitation of the equipment used. Although they were not able to measure above this value, they argue that a significant portion of the reservoir may have permeability in excess of this based on results from drill stem testing.

The analysis of Olsen et al [19] also include grain size distribution within the formation. They suggest that the extraordinary permeabilities is in parts a result of the sediments being composed primarily of coarser particles and relatively low concentration of finer particles and clays. Additionally, they found that the distribution varied significantly across the formation, with the largest observed being a median grain size of -1.2 Φ, or approximately 2.3 mm. The grain size distribution they found is shown Figure 1 and is found on page 123 in Olsen et al [19]

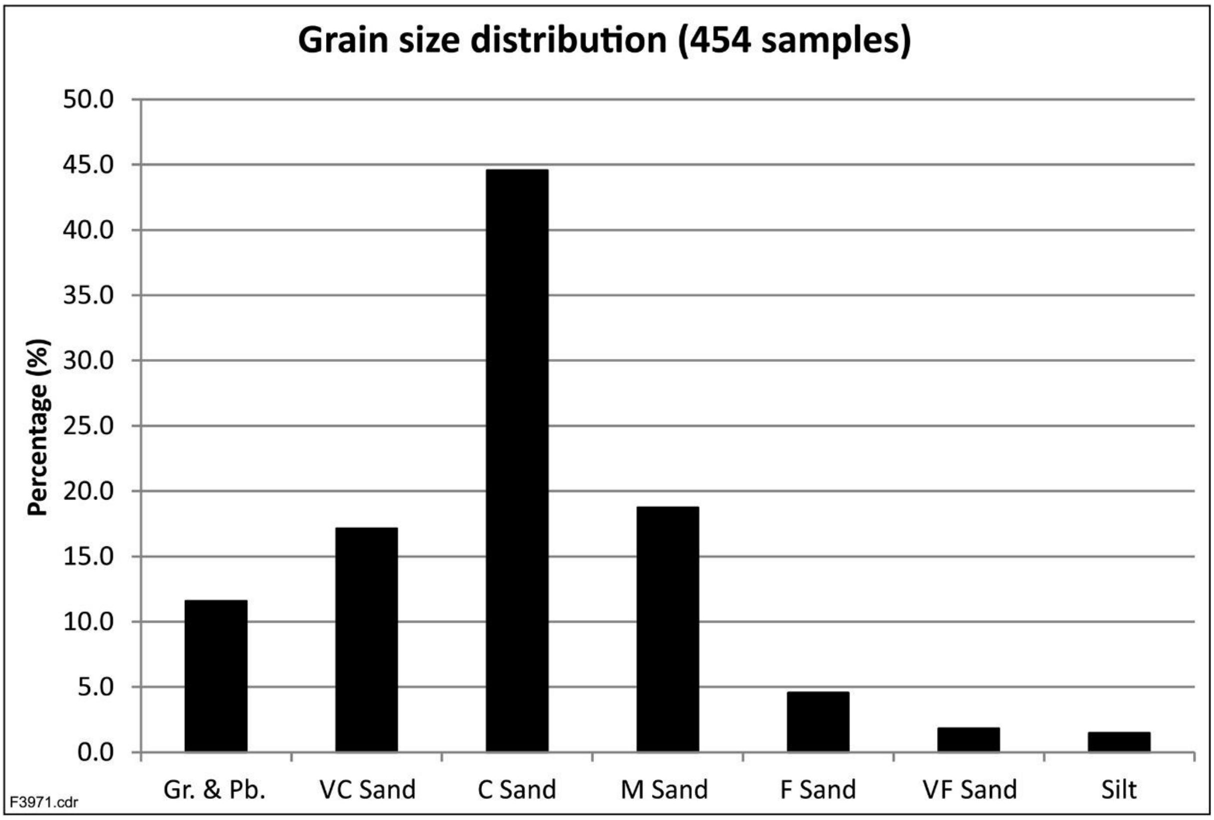



*Figure 1 - Intra-Draupne Formation sandstone porosity vs. permeability crossplot from routine core analysis [19, p. 123]*

**NB: Hentet direkte fra Olsen HUSK REFERANSE + SITERING!**

The reservoir's high permeability, which contribute to its exceptional productivity and profitability, can also present challenges during the drilling process. Equinor has encountered issues on some wells when drilling through the Draupne formation in the form of significantly increased fluid loss [3]. Based on the analysis of the formation characteristics presented above and information from the operator, this is likely due to high-permeable zones within the formation, the pore sizes being underestimated, and the drilling fluids lack of capability to effectively seal the formation. Due to confidentiality, data regarding pore throat size distribution has not been made available, hence an estimation must be made. A conventional method is to use Mercury Injection Capillary Pressure, but due to its complexity and limitations it is outside the scope of this research. A more manageable approach will therefore be applied. As mentioned by Scott et al 2020 [13], tetrahedral uniform particle packing may be used as a simple but conservative approach to determine the required minimum size of a bridging particle. This can also be used to calculate the pore diameters, but it assumes that the particles are homogeneous, meaning all of the same size, which is not usually the case. This is supported in a study conducted by Kaspersen [20] of the reservoir characteristics of Johan Sverdrup, where his findings suggests that the intra-Draupne Sandstone is poorly to moderately sorted. Thus, the results from using tetrahedral uniform particle packing may be overestimations of the actual pore sizes in the formation.

$$d_{max} = 0.155D, \qquad where$$
$$d_{max}\ is\ the\ maximum\ pore\ space\ between\ the\ particles$$
$$D\ is\ the\ particle\ diameter$$

In table 1 different grain types are listed with their associated grain size and calculated pore size using the tetrahedral uniform particle packing equation. The calculations show that between four spherical particles of very coarse sand of 2 mm grain size the maximum diameter of the pore volume between them will be 310 µm. As the largest median grain size was measured to be 2.3mm, using these calculations, this result in the median pore size potentially being as high as 360 µm.

*Table 1- Different grain types with sizes and pore calculations*

| Grain type: | Grain Size (µm) | | Pore Size (µm) | |
|---|---|---|---|---|
| | From | To | From | To |
| Silt | 3,9 | 62,5 | 0,6 | 9,7 |
| VF Sand | 62,5 | 125 | 9,7 | 19,4 |
| F Sans | 125 | 250 | 19,4 | 38,8 |
| M Sand | 250 | 500 | 38,75 | 77,5 |
| C Sand | 500 | 1000 | 77,5 | 155 |
| VC Sand | 1000 | 2000 | 155 | 310 |
| Gr. & Pb. | 2000 | *6000* | 310 | 930 |

As the formation is not perfectly sorted and formation is heterogeneous, a second method is used for comparison. This is centered around using the Kozeny-Carman equation [21] to calculate the average grain size based on permeability, porosity, and sphericity of the particles. The formula is arranged to the following form:

**FORMEL REF**

$$D_p = \frac{180\, k\, (1-\epsilon)^2}{\varphi_s^2 \epsilon^3}, \quad where$$

$$D_p \text{ is the average grain diamer}$$

$$k \text{ is permeability}$$

$$\epsilon \text{ is the porosity}$$

$$\varphi \text{ is the sphericity}$$

The permeability-porosity cross plot presented in Olsen et al [19] on page 109 is shown in Figure 2. As previously mentioned, their equipment was not able to measure above 50 Darcies, which is very evident in the plot below. As it was assumed certain part of the formation could have even higher permeability, a modification of their plot was made to illustrate this, shown in Figure 3**.**

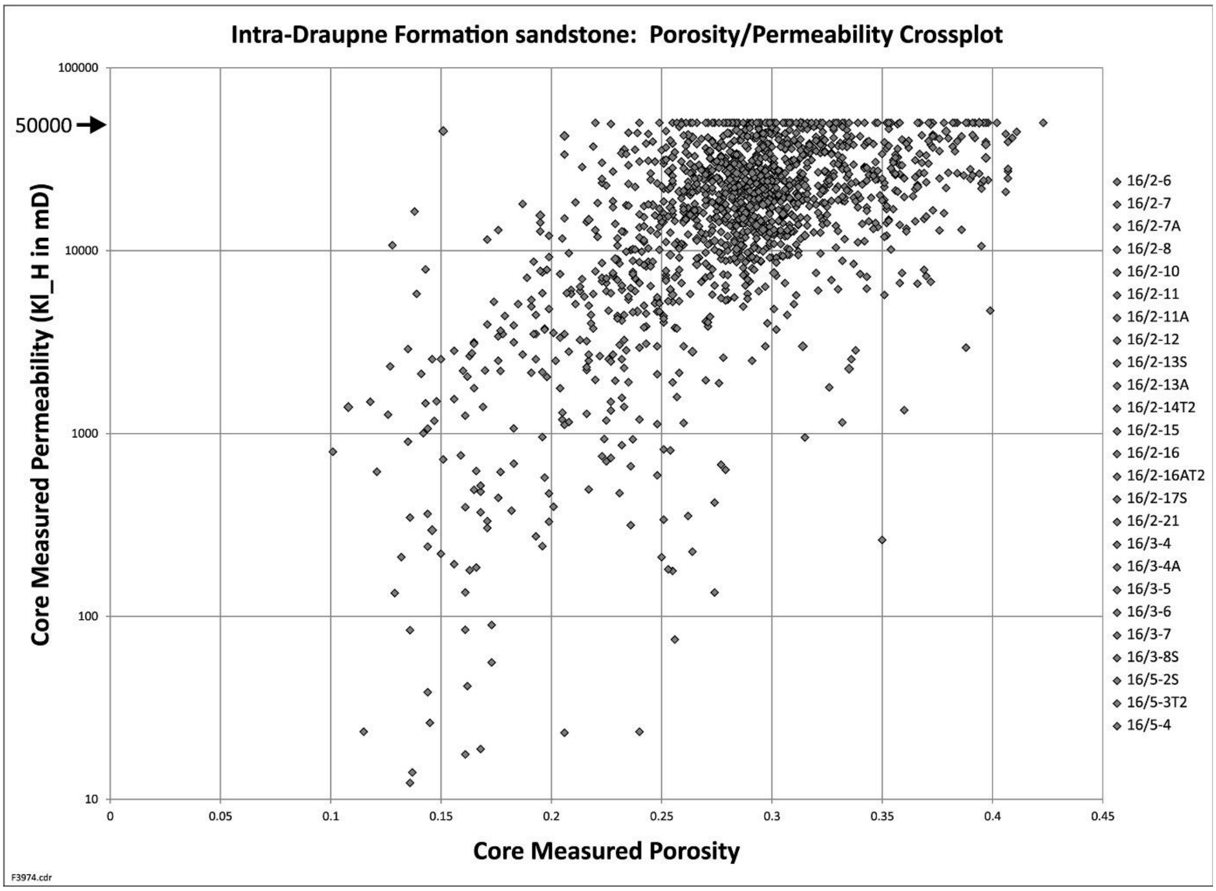



*Figure 2 - Intra-Draupne Formation sandstone porosity vs. permeability crossplot from routine core analysis [19, p. 109]*

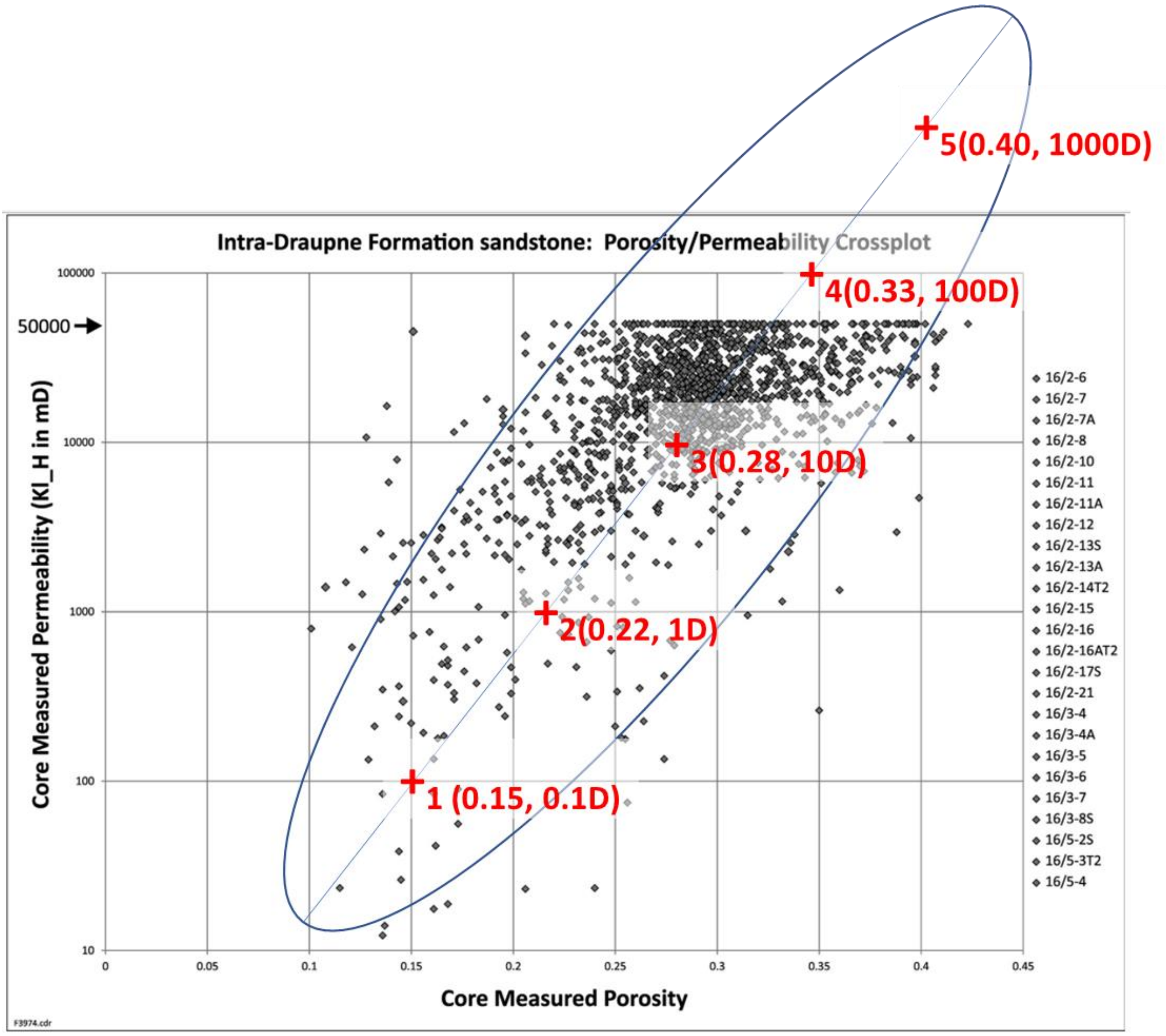



*Figure 3 - Intra-Draupne Formation sandstone porosity vs. permeability crossplot from routine core analysis [19, p. 109] Modified*

The idea of the modified plot is to illustrate that the permeability and porosity could be as high as 1000 Darcies and 40%, respectively. Using the Kozeny-carman and tetrahedral uniform particle packing equations, the grain size and following pore sizes were calculated for different sphericities, shown in Table 2.

*Table 2 – Estimates of grain diameter and pore diameter for different permeabilities, sphericities and porosities*

| Permeability (Darcy) | Sphericity | Porosity | Estimated grain diameter (µm) | Estimated pore diameter (µm) |
|---|---|---|---|---|
| 0,1 | 0,6 | 0,15 | 103 | 16 |
| 1 | 0,6 | 0,22 | 169 | 26 |
| 10 | 0,6 | 0,28 | 344 | 53 |
| 100 | 0,6 | 0,33 | 790 | 122 |
| 1000 | 0,6 | 0,4 | 1677 | 260 |
| | | | | |
| 0,1 | 0,7 | 0,15 | 89 | 14 |
| 1 | 0,7 | 0,22 | 145 | 22 |
| 10 | 0,7 | 0,28 | 295 | 46 |
| 100 | 0,7 | 0,33 | 677 | 105 |
| 1000 | 0,7 | 0,4 | 1437 | 223 |
| | | | | |
| 0,1 | 0,8 | 0,15 | 78 | 12 |
| 1 | 0,8 | 0,22 | 127 | 20 |
| 10 | 0,8 | 0,28 | 258 | 40 |
| 100 | 0,8 | 0,33 | 593 | 92 |
| 1000 | 0,8 | 0,4 | 1258 | 195 |

The calculations using this approach indicate that the largest median pore sizes could be up to 260 µm, which seem more reasonable than the previous indication of 360 µm. However, the 360 µm estimate also assumes particle homogeneity, and is therefore likely exaggerated. Furthermore, it is unlikely that the drillers would experience lost circulation issues if the median pore size was below 100 µm. It is therefore believed that the median pore size in the loss zone is somewhere in the range 120-180 µm, which will be the basis for the following research.

## 1.2 Objective

This study aims to evaluate:

- The current properties and performance of a drilling fluid used on Johan Sverdrup.
- Whether the fluid can be modified to solve the current issues experienced when drilling through the intra-Draupne formation, by effectively sealing high-permeable formations in the range for 120-180 µm, while not causing excessive formation damage.
- Potential economical impact of

# 2 Methodology

In order to evaluate the performance of the drilling fluid various different tests were conducted, including fluid loss test, degradation and sieving analysis, as well as formation damage evaluation through changes in disc mass and permeability measurements.

The formation evaluation and fluid loss tests are centered around ceramic discs with median pore sizes ranging from 10 µm to 250 µm, with most of them concentrated in the 120 µm to 160 µm range in accordance with the estimates for the loss zone Intra-Draupne formation. Figure 4 shows some of the ceramic disks used. Several fluid loss tests are also conducted on 22.5 µm filter paper, although they are outside the area of interest regarding pore size, they can provide good initial indication of a fluid's performance and possible lack of properties.

*Figure 4-OFITE ceramic discs. From left to right: 10µm, 50µm, 120µm and 160µm.*

## 2.1 Mud preparation

In total 46 samples of water-based drilling fluids were used. Table 3 shows the name and a short description of the different additives used in creating the samples.

*Table 3 - Components used in drilling fluid samples.*

| Additive | Description / functionality |
|---|---|
| Barazan - Xanthan Gum | Increase viscosity, adds load-bearing capacity |
| N-dril HT | Modified starch, reduce fluid loss |
| Dextrid - E | Modified starch, reduce fluid loss |
| Auracoat Ultra Fine (AUF) | Cellulose blend with D90 value of 75 µm, for reduced polymer and solids invasion, reduced filter-cake permeability and increased filter-cake strength |
| Auracoat X (AUX) | Cellulose blend sieved (75-250 micron), for sealing of high permeability formations and fractures |
| Auracoat Medium | D 90 value of 150 µm, cellulose blend with D50 value of 75 µm, for reduced polymer and solids invasion, reduced filter-cake permeability and increased filter-cake strength |
| Truecarb 10 & 25 | CaCO3 with a D50 value of 10 µm and 25 µm |
| Baracarb 50 & 150 | $CaCO_3$ with a D50 value of 50 µm and 150 µm |

Ohaus AX1502 was used for weighing all the additive and sieves used in the PSD analysis, shown in Figure 5**.** The mixing of the samples was conducted using a Hamilton Beach mixer, also shown in **FIGRE X.** To simulate the degradation a drilling fluid is exposed during circulation, most of the fluid samples were put into a hot rolling oven for 16 hours at 90°C. A 135 mm long threaded M16 rod with 2 mm pitch was placed into the hot rolling cells to further simulate mechanical wear on the solid particles. The test enables analysis of particle degradation and an accretion test. After hot rolling, the samples were spun with the Hamilton laboratory mixer for at least 5 minutes to counteract potential sag.


*Figure 5- Ohaus ax1502 to the left, and Hamilton beach mixer on the right.*

## 2.2 Fluid loss procedure

Fluid loss tests were conducted using a high-temperature high-pressure (HTHP) filter press. The procedure differs slightly for the tests conducted on filter paper and those on ceramic discs. Each disc was initially placed in the OHAUS MB120 moisture analyzer, which removes all the moisture and records the dry mass of the disc. It was then presoaked in room temperature water under vacuum. This is done to remove as much air as possible from pores and minimize fluid loss uncertainties.

After soaking, the disk was placed inside the HTHP cell, and 150ml of fluid sample was added. The cell was heated for approximately 20 minutes, until reaching 90°C, and a pressure of 6.9 MPa (1000 psi) was applied. The filtrate was collected in a measuring cylinder, and the mass was recorded and logged every 5s using an Ohaus Navigator digital scale**.** After 30s, the measuring cylinder was changed which made it possible to do separate analysis on the initial fluid loss (spurt loss), and the subsequent fluid loss. Test on filter paper were conducted with 3.45 MPa (500 psi), there were no presoaking or recording of initial mass.

### 2.3 Determining PSD

To determine the particle size distribution of all fluids and additives used in this research, sieving analysis was applied. This is done using the American Standard Test Sieve Series (ASTM) on a Haver & Boecker sieve shaker.

Sieves used:

- A.S.T.M #40 – 425 µm
- A.S.T.M #60 – 250 µm
- A.S.T.M #80 – 180 µm
- A.S.T.M #100 – 150 µm
- A.S.T.M #120 – 125 µm
- A.S.T.M #170 – 90 µm
- A.S.T.M #200 – 75 µm
- A.S.T.M #270 – 53 µm
- A.S.T.M #550 – 23 µm

The sieving method was slightly adjusted after sieving the first sample, due to difficulties sieving through both of the finest sieves simultaneously. Henceforth, each sieving analysis was carried out in two turns. First, all the sieves except the #550 were stacked in the order above, and the returning fluid was collected and then sieved again through the A.S.T.M #550 sieve. Each sample was diluted with 10L of 50°C water to facilitate penetration and was sieved for 10 minutes on the first turn, and 5 minutes on the second turn. During this time about 10L of water was added to ensure as many particles as possible is transported to the correct sieve. Finally, each sieve was heated on 90°C until dry, then placed in room temperature for at least 1 hour to cool and regain natural moisture, before being weighed to determine the solid mass.

## 2.4 Formation damage procedure

The methods used in this section have been described been used in similar research, and a more detailed description can be found consulting Klungtvedt et al [22], and therefore the following description will be brief. Due to the difficulties measuring permeabilities for coarser disc, the evaluation of formation damage was primarily done through the measurement of disc mass increase. This can be interpreted as the total content of solid particles, polymers and fibers remaining in the porous formation. As described previously, these can plug the pores resulting in reduced permeability. In order to get an accurate estimate of the increase of the disc mass, the filter cake formed by the fluid during the HTHP test first had to be removed using reverse flow. In short, the ceramic disc is placed, inside an acrylic cylinder with the filter cake facing down. 1.5L of 90°C is added the cylinder before a differential pressure of 67 kPa was applied for pushing the water through the disc, effectively flushing the pores for moveable remains. This was done twice for each disc. In some cases, there were filter cake remains along the peripheral of the disc where it had been resting inside the cylinder. This was carefully removed using a wallpaper knife. Finally, the disc was dried and weighed in dry conditions using the Ohaus MB120. Comparing the initial dry weight with the final dry weight results in the disc mass increase

The retained permeability to air was calculated for ceramic discs with median pore size of 10 µm. This was done by measuring the permeability to air after the initial drying and final drying of the disc. More specifically it was done by placing the disc inside a similar acrylic cylinder as used for filter cake removal, before applying air pressure. The pressure was gradually adjusted, while recording both the pressure and measured flow rate. Applying Darcy's law the initial and final permeability could be measured, and the retained permeability is defined as final permeability divided by initial permeability.

# 3 Results and Discussion

Three water-based fluids were used in this research. Two of these were delivered by the fluid supplier on Johan Sverdrup, and include a field sample and a lab sample of a reservoir drilling fluid used on the field, henceforth labeled JS-Field and JS-Lab. The third fluid, labeled Fluid C, was designed and mixed in the laboratory were all the tests were conducted. The following results are divided into four parts, followed by a summary and short conclusion of the main findings. The first part of the research was conducted to verify the properties and performance of the three fluids, before any modifications were made. Then the effect of degradation is investigated. The third section contains the results from the modified fluids, and the last section include some results on the p

### 3.1.1 Initial analysis of mud used in field

Due to limited information regarding the content of the fluid supplied, a retort analysis of the field and lab sample were conducted, with the main findings summarized in Table 4. The field sample had slightly higher density and solid content, which is reasonable due to remaining fines from drilling, consisting of quartz. This is also supported by the lower solubility to acid of the solids, since quartz is insoluble in hydrochloric acid, while $CaCO_3$ dissolves completely.

*Table 4 – Results from retort and acid solubility of JS-Field and JS-Lab*

| | JS-Field sample | JS-Lab sample |
|---|---|---|
| Density | 1.17 kg/m$^3$ | 1.15 kg/m$^3$ |
| Solid content | 275 kg/m$^3$ | 242 kg/m$^3$ |
| Oil / water ratio | 2.8 / 97.2 | 1.1 / 98.9 |
| Solid solubility to HCl | 78% | Not measured |

Both samples were sieved to determine the PSD, with the results shown in Figure 6**.** Due to the high concentration of particles below 53 µm the figure is split in two, where the left vertical axes represent particles below 53 µm, and the right vertical axes represent the rest of the distribution. Both samples contain mostly fines, and a low number of larger particles. This is as expected, since the field mud has gone through the shakers where the smallest screen removes particles above 75 µm. Regarding the lab sample, this is explained by larger particles not being added until needed. There are some noticeable differences between the samples, looking at particles in the range of 0-53 µm and 53-75 µm. This could be explained using the result from the retort and solubility analysis, where the field sample seem to contain fines from drilling. These are harder and less prone to degradation compared to the $CaCO_3$ which likely makes up most, if not all, of the solid content in the lab sample.

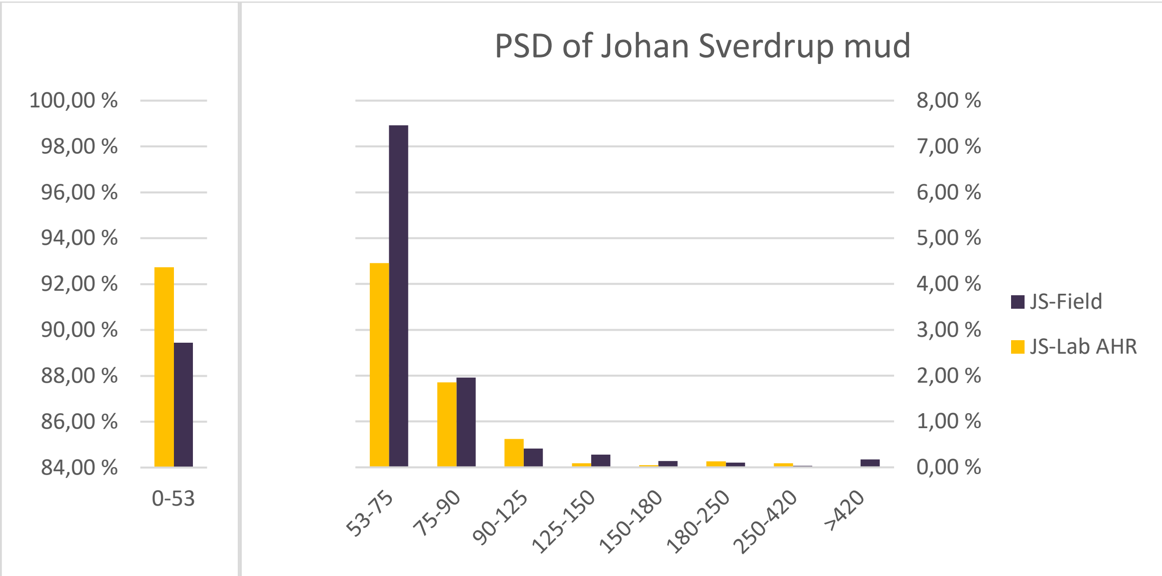



*Figure 6 - PSD of JS-Field and JS-Lab AHR*

To map the performance of the Johan Sverdrup samples, a series of fluid loss tests were conducted on different pore sizes, summarized in Figure 7**.** For these results only the lab mud was hot-rolled, as the field mud had already been exposed to degrading during operation. Neither of the samples had considerable fluid loss on 22.5µ filter paper, but the lab sample seemed to perform significantly better, with under half the amount of spurt loss and about 25% lower fluid loss after 30minutes. The higher fluid loss with the JS-Field fluid may indicate a low concentration of fluid loss polymers. There were some interesting observations of the field mud when comparing the result on the 50µ and 120µ disc. Both the spurt loss and fluid loss were higher for the disc with the smaller pores, but the mass increase of the disc was considerably lower. This could be explained by the larger disc being more porous. Another explanation is that the sealing of the 50µ disc to a larger extent occurs on the surface, due to the size of the particles. Building an external filter cake typically takes longer as the surface to cover is larger then just the pore openings, which is evidenced by the recorded higher spurt loss.

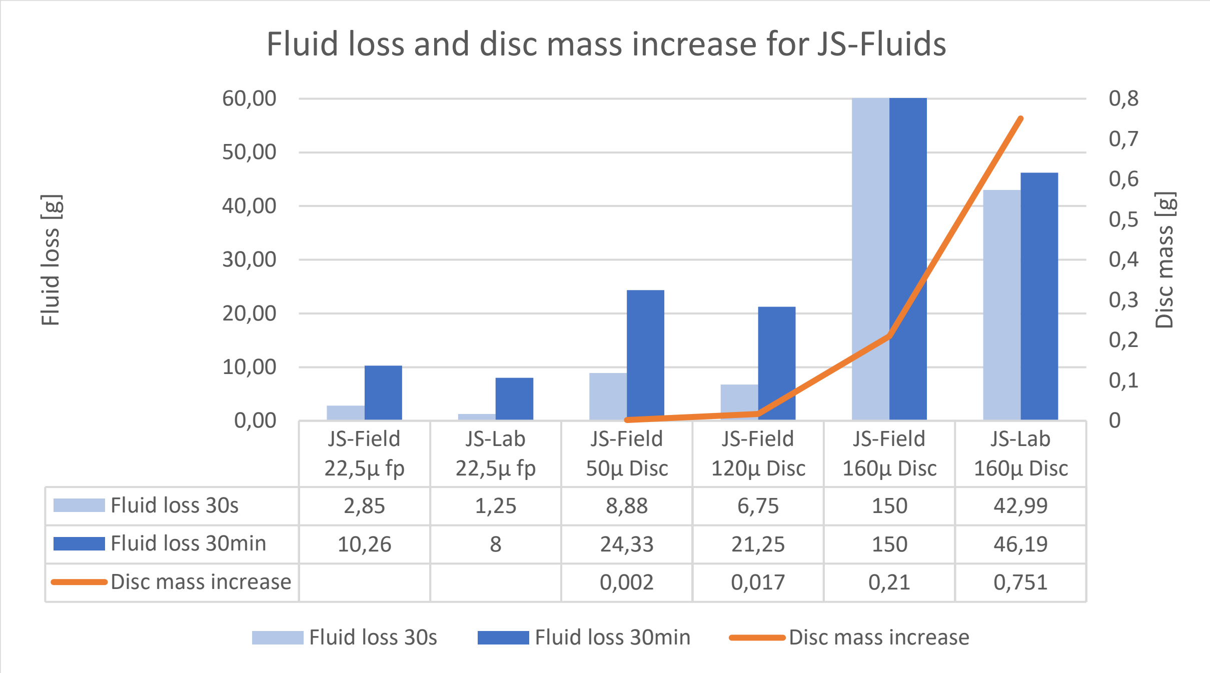



*Figure 7- Fluid loss and disc mass increase for JS-Fluids*

### 3.1.2 Analysis of Fluid C for comparison

Fluid C was designed to test if it was possible to mix a simple drilling fluid using common additives that would be able to seal the problematic formation. The recipe used is shown in Table 5**.**

*Table 5- Content and mixing order of Fluid C*

| Mixing order | Component | Mass [g] |
|---|---|---|
| 1 | Water | 316,7 |
| 2 | Soda ash | 0,02 |
| 3 | Caustic soda | 0,25 |
| 4 | Xanthan gum | 1,75 |
| 5 | Starch N – dril HT | 2 |
| 6 | Starch Dextrid-E | 5 |
| 7 | MgO | 1 |
| 8 | NaCl | 1 |
| 9 | Truecarb 10 | 15 |
| 10 | Truecarb 25 | 15 |
| 11 | Baracarb 50 | 15 |
| 12 | Baracarb 150 | 10 |

Similarly, as with the other two fluids, the PSD was determined and is presented in Figure 8. Compared to both previous samples, Fluid C has a lot higher concentration of coarser particles, and the distribution of particles above 23 µm is quite even, which is consistent with the amount of, and PSD of the added $CaCO_3$.

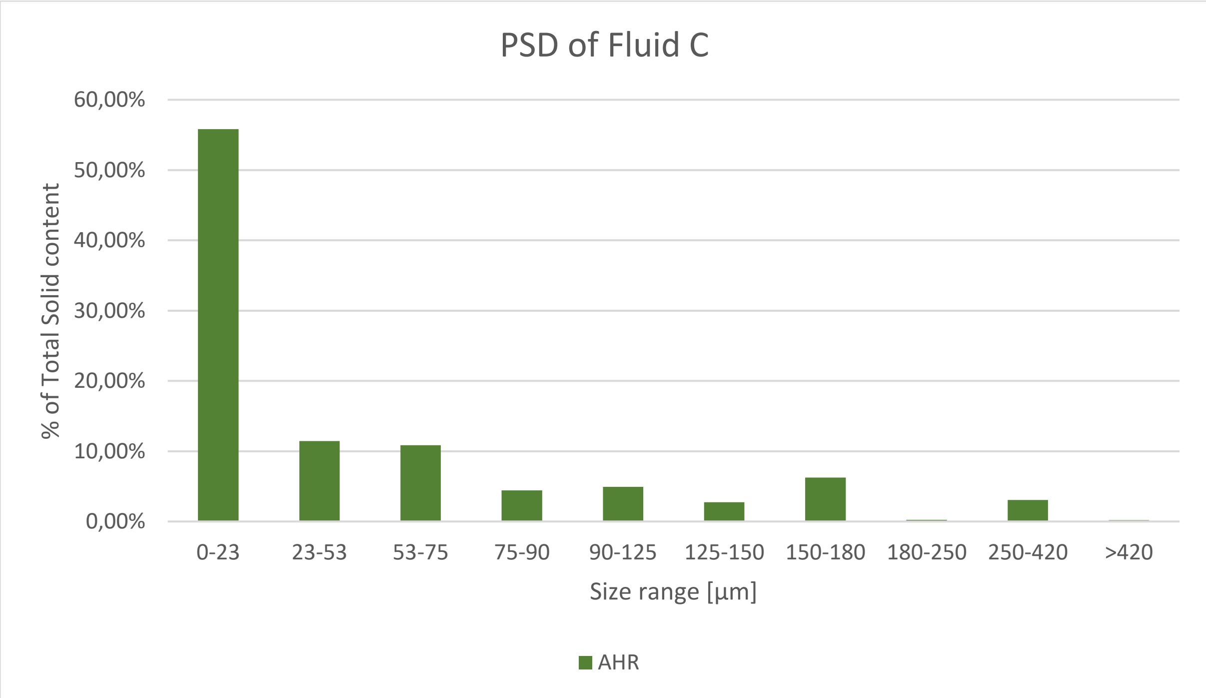
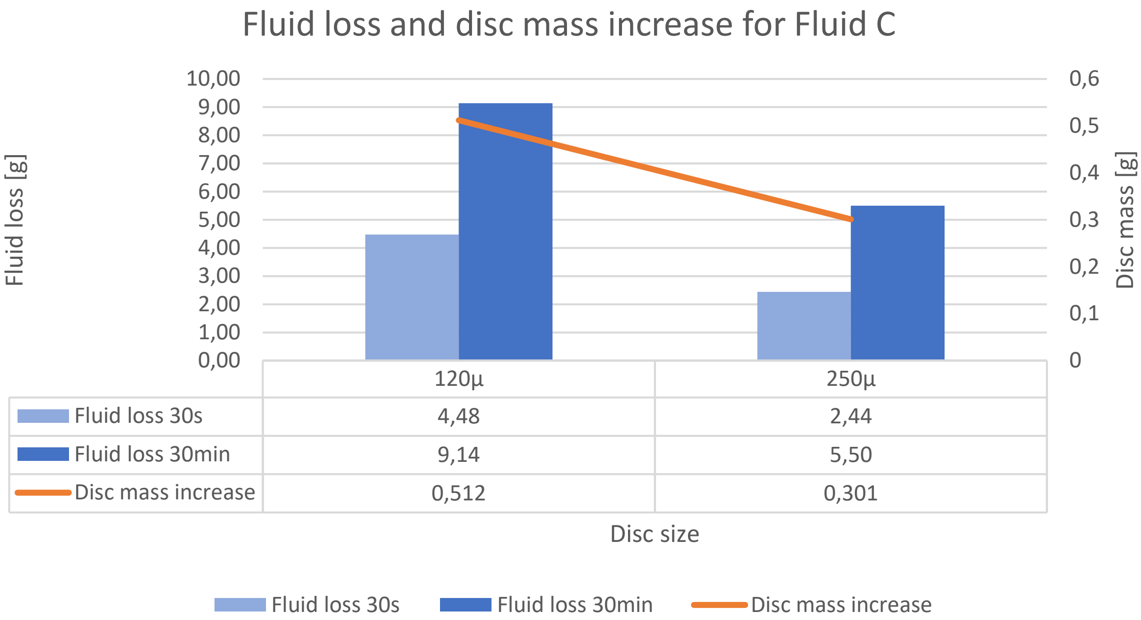



*Figure 8 - PSD of Fluid C*

The results for testing with Fluid C are summarized in Figure 9. This mud managed to seal a 120µ disc with very little fluid loss, considerably lower than the JS-Field sample, which had a total fluid loss of 21.25g. An interesting observation to note is that while the spurt loss is also lower, it makes up a significantly larger proportion of the total loss. In combination with a higher disc mass increase, it may indicate that the sealing takes place internally, through plugging of the pores. Fluid C was also able to seal a 250µ disc with even less fluid lost, but about the same ratio between spurt loss and subsequent loss. It should be noted that the disc mass increase was higher for the 120 µm disc than for the 250 µm disc. This may be due to the particle size distribution of the particles, where e.g. single particles may plug the pores of the 120 µm disc, and thus become more difficult to remove with a reverse flow, where multiple particles were plugging the pores of the 120 µm disc. This may be consistent with Abrams rule [12], which states that the least formation damage is caused when the D50 value of the particles are ≥ 1/3 of the pore size.




| | 120µ | 250µ |
|---|---|---|
| Fluid loss 30s | 4,48 | 2,44 |
| Fluid loss 30min | 9,14 | 5,50 |
| Disc mass increase | 0,512 | 0,301 |

*Figure 9 - Fluid loss and disc mass increase for Fluid C*

## 3.2 Degradation analysis

It is clearly possible to create a fluid in the lab that can manage to seal a permeable formation with a median pore throat opening of 250 µm, which is larger than what was estimated for the intra-Draupne formation. It is obvious that both the samples supplied were lacking bridging agents in their current state, but these are available and used when needed. This raises the question as to why there are still issues related to fluid loss and lost circulation.

This may be explained by the bridging particles agents being degraded during circulation, especially $CaCO_3$. The following sections contain the result for degrading the different fluids and some additives using the technique described previously.

### 3.2.1 Degradation of Fluid C

Figure 10 shows how the particle size distribution of the solids in Fluid C changes as a result of hot-rolling with and without the inclusion of the rod. The results indicate that even normal hot-rolling to some degree degrades the particles, as there were noticeable changes is the lower range sizes. The concentration of the particles increased with about 11 percentage points in the range from 0 to 23 µm and decreased with the same amount in the 23 to 53 µm range. The introduction of the rod had a considerable effect, almost completely removing all the large particles, leaving only 1% of the total particles above 53 µm compared to 33% with standard hot-rolling. This is consistent with the findings of Scott et al 2012 [14].

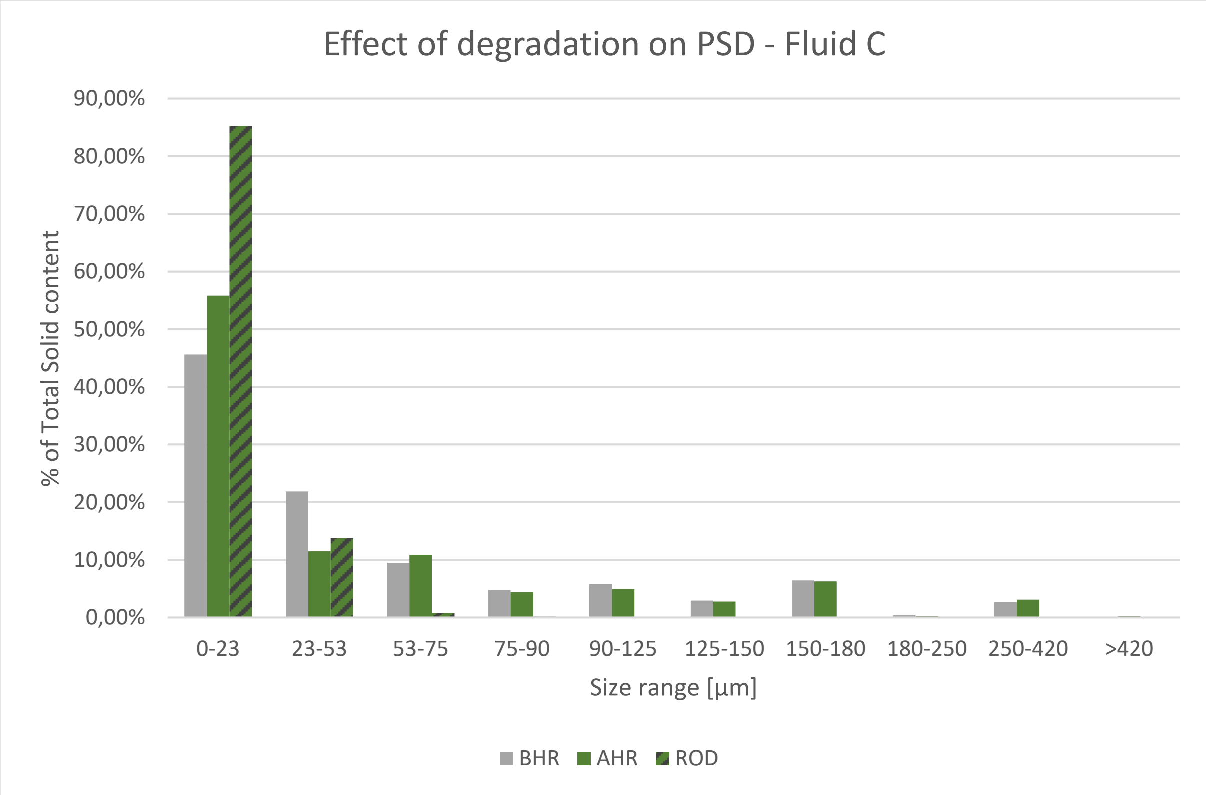



*Figure 10 - Effect of degradation on PSD - Fluid C*

The effect the degradation of the PSD had on the performance of Fluid C is shown in Figure 11. The mud was no longer able to effectively seal a 250 µ disc, and although the disc mass increase is much lower than originally, this is due to the particles being small enough to ass through the pores. This does therefore not translate into reduced formation damage, as the filtrate and containing polymers and fines migrates further into the formation. As for the 120 µ disc, both the fluid loss and disc mass increase was reduced compared to the non-degraded mud.

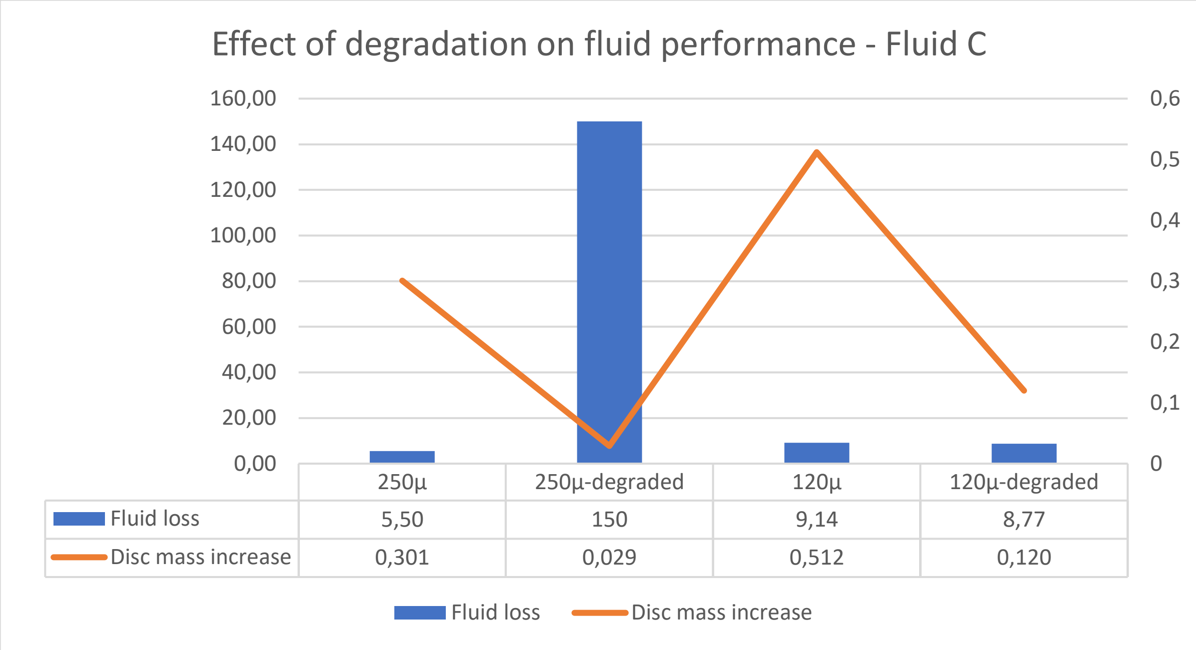



*Figure 11 - Effect of degradation on fluid performance - Fluid C*

### 3.2.2 Degradation of JS Fluid

The ground marble products used in Fluid C is from a different supplier as the one used in the Johan Sverdrup mud and may consequently differ in quality. Therefore, a degradation test was conducted on a mix of the suppliers' products, and the result are very similar. It is important to note that the original PSD differ somewhat from Fluid C, but the same tendencies are observed. Almost all the coarser particles have been degraded removed, and one is left with a mud containing mostly fines as shown in Figure 12.

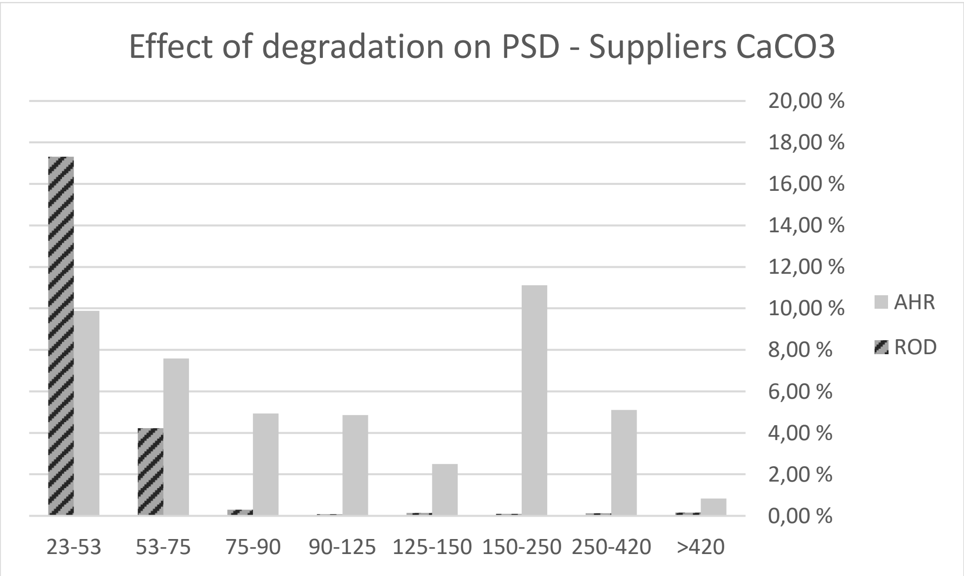



*Figure 12 - Effect of degradation on PSD of suppliers CaCO3*

The changes to the PSD of the JS-lab sample due to degradation is shown in Figure 13. After hot-rolling with rod, over 99.5% of the particles were smaller than 53 µm compared to the 92.7% after regular hot-rolling, which is consistent with the other degradation results. If the method used was completely accurate in predicting the degradation a fluid experiences during operation, one could expect the PSD of the degraded lab sample to be similar to that of the Field sample. They are indeed similar in that there are mostly fines in both, but the field sample contains about 10 percentage point more of particles coarser than 53 µm. However, as previously established, the field mud contains 22% non-soluble solids that are less prone to degradation.

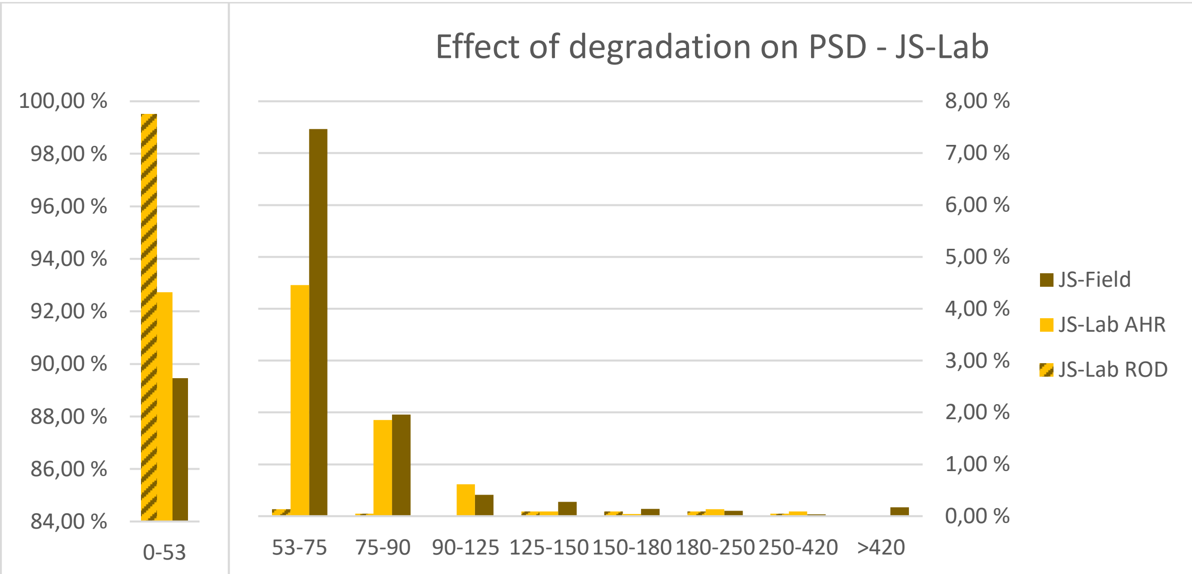



*Figure 13 - Effect of degradation on PSD - JS-Lab*

Figure 14 shows the same result as presented on the previous page, but also include the degradation of the fluid with the addition of 5 ppb AUX, is approximately 5.6 weight % of the solids. The degradation seemed to be lessened with this modification, as there were significantly more coarser particles remaining. The additive does contain coarser particles than what was in the fluid originally, but when comparing it to the tests done on Fluid C and the $CaCO_3$ from the supplier, there are significant differences. This suggests that AUX itself is considerably less prone to degradation, or that the addition help reduce overall degradation.

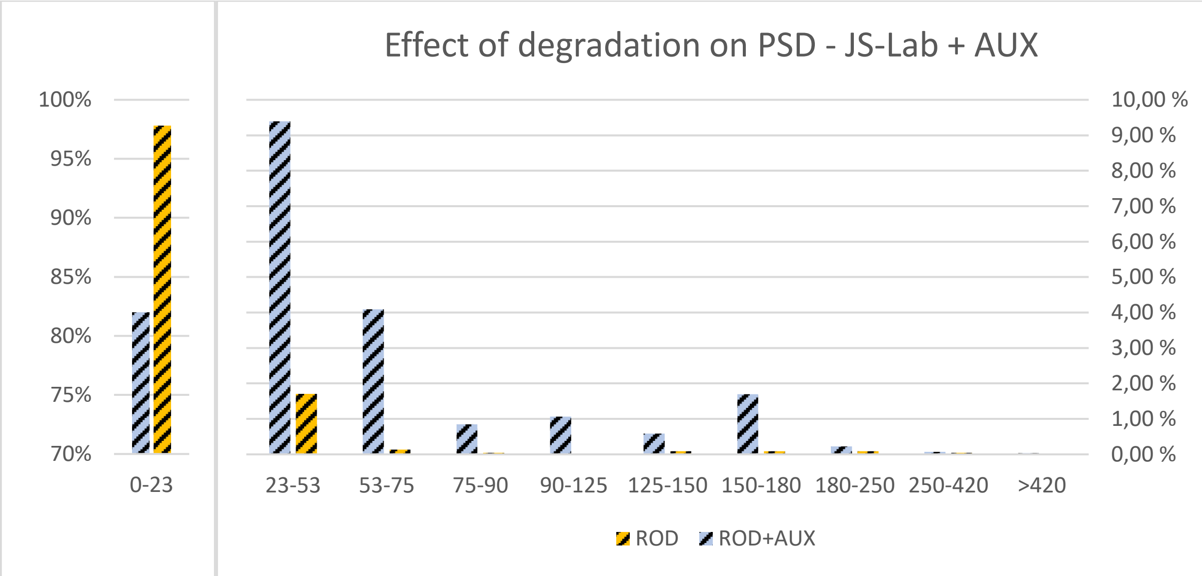



*Figure 14 - Effect of degradation on PSD - JS-Lab + AUX*

Results from the fluid loss test conducted using the degraded JS-lab mud, as well as the previous result for comparison is shown in Figures 15 and 16. There are no considerable differences for 22.5 µm filter paper. The lab mud seems to perform slightly worse after degradation but does still show lower fluid loss than the field sample. With the addition of AUX, fluid loss is slightly higher, and further marginally increased after degradation.

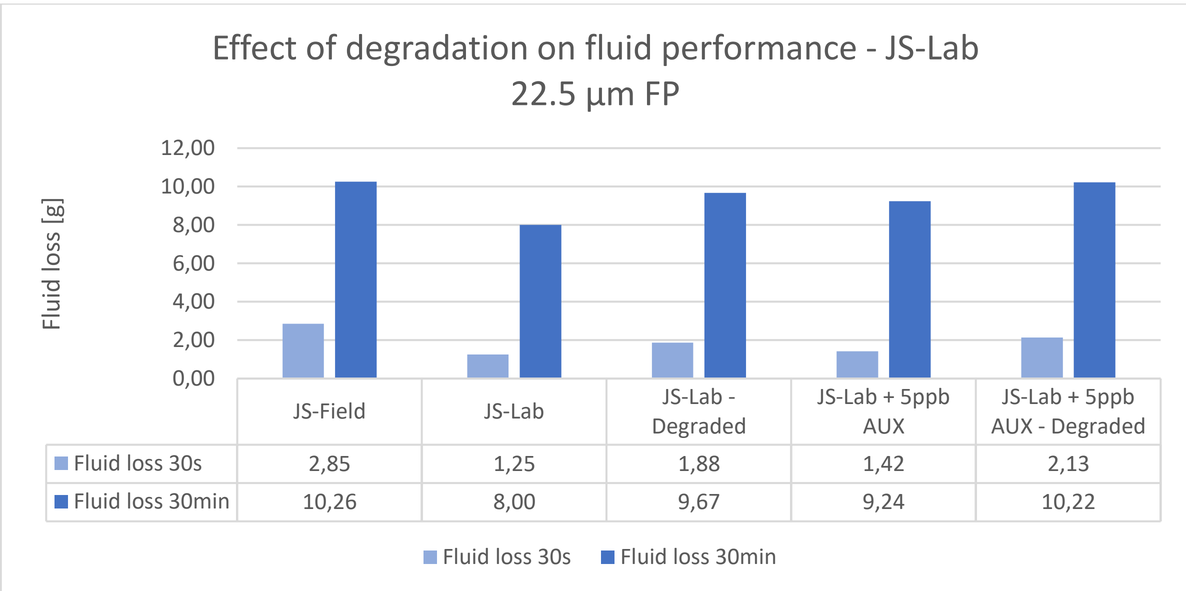



*Figure 15 - Effect of degradation on fluid performance - JS-Lab 22,5 µm FP*

Looking at the results from the tests on 160µ disc, the degraded fluid was no longer able to create an effective seal, resulting in a total loss. The disc mass increase was considerably lower, compared to both the field sample and original lab sample. This is reasonable due to the lack of larger particles that could get stuck inside the pores.

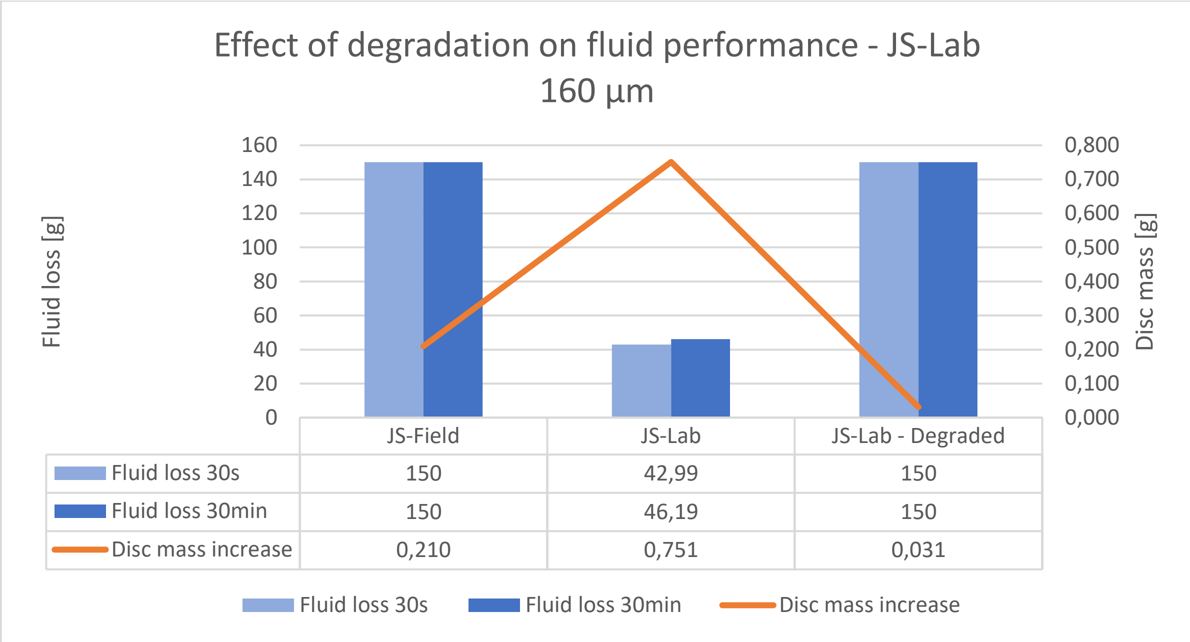



*Figure 16 - Effect of degradation on fluid performance - JS-Lab 160 µm*

It is difficult to measure and simulate the exact degradation a fluid is exposed to during circulation in a well, and the method used here may differ from reality. However, the results are consistent with previous research and partly explain some of the reasons for the issues related through drilling in the Draupne formation.

$CaCO_3$ is very brittle and prone to heavy degradation when subjected to shear stress, resulting in rapid loss of the original particle size distribution. The largest particles are most exposed, and one may an end up with accumulation of a lot of fines. These are not easily removed from the drilling fluid and may cause further problems and formation damage. With the addition of AUX, the degradation seemed to be reduced. Subsequently, $CaCO_3$ may not be suitable as the sole bridging agent but should rather be used in combination with other materials.

### 3.3 Adjusting the Johan Sverdrup Fluids

As the previous result indicate, the JS-Field may have little fluid loss polymers, and as a result Dextrid-E was added before hot-rolling the sample. The addition showed no improvement, and there were several attempts to improve the JS-Field with various additives that in other research consistently has shown to reduce fluid loss. A sample that was hot-rolled without any polymer additives, ended up being completely watery. It is common that some polymers are degraded during hot-rolling, but not to this extent. This reinforced the idea behind lack of polymers in the fluid, and also that the sample may be overdue. Therefore, the results presented in this section will regard adjustments made to the JS-Lab, which is also the most relevant to modify, as it is how the mud will be initially when starting drilling.

### 3.3.2 Adjusting the Johan Sverdrup Fluids

Different cellulose-based materials with various concentrations and combinations were added to the JS-lab. For all the tests in this section the fluid samples were hot-rolled with rod to ensure that the fluid quality would remain intact even after heavy degradation. In Figure 17 a summary the results are shown for the fluid tests using 22.5 µm filter paper. The addition of AUF gave significant improvements, which is as expected. For the samples containing AUX and AM, the fluid loss was about the same as originally, maybe slightly higher, but these are mainly larger particles compared to the pore size of the filter paper. With the addition of both AUX and AUF, there were improvements compared to JS-Lab, but slightly worse than with only AUF. It is interesting to note that when increasing the concentration of AUX with the same concentration of AUF, the fluid loss is improved.

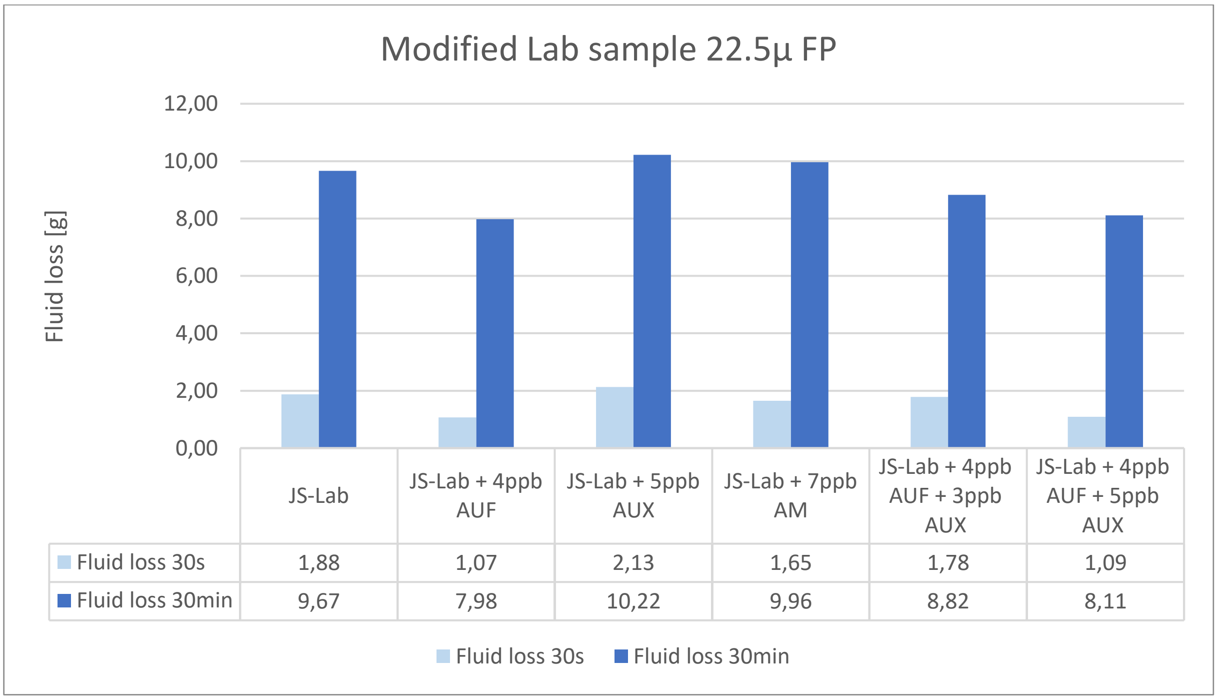



*Figure 17 - Fluid loss for various modified JS-Lab 22.5 µm FP*

The results for JS-lab in combination with AM on coarser discs are shown in Figure 18. It manages to seal the 120 µm disc with very little fluid loss and disc mass increase. It was however not able to seal the 160 µm, as it resulted in total loss and the largest formation damage of all the tests conducted. As the D90 of the AM is 150 µm, this is consistent with previous findings [15], which states that when the cellulose particles are ≲3/2 the pore size, the polymer and solid invasion is limited.

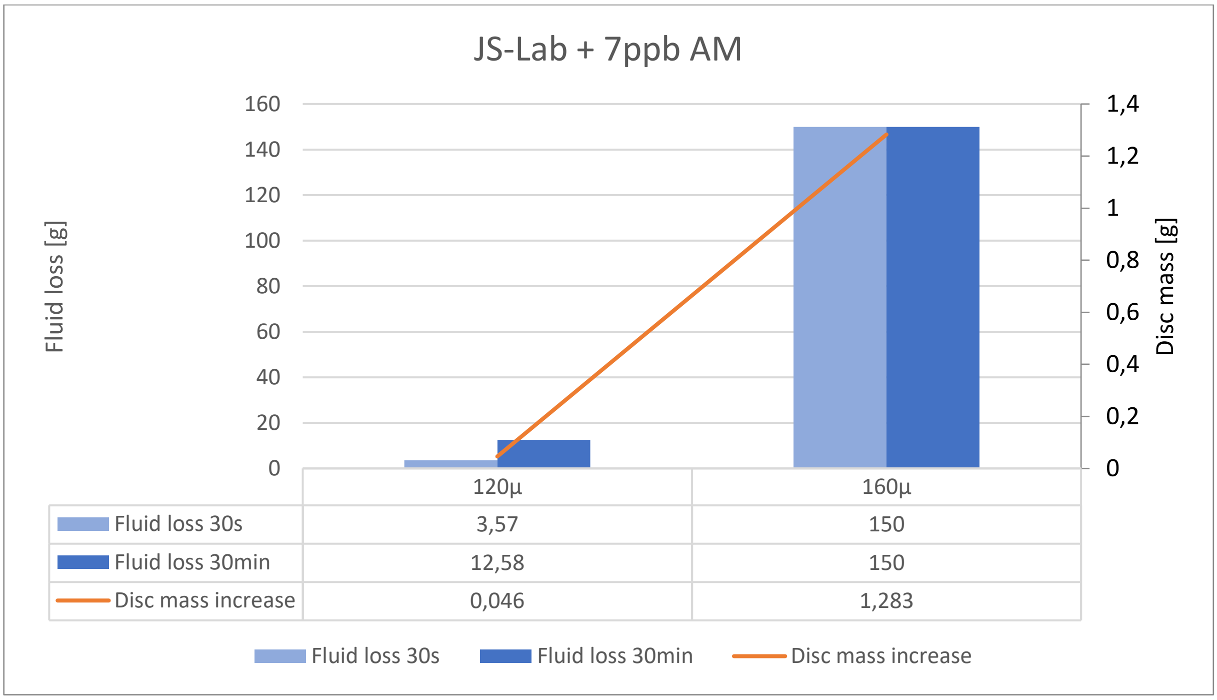
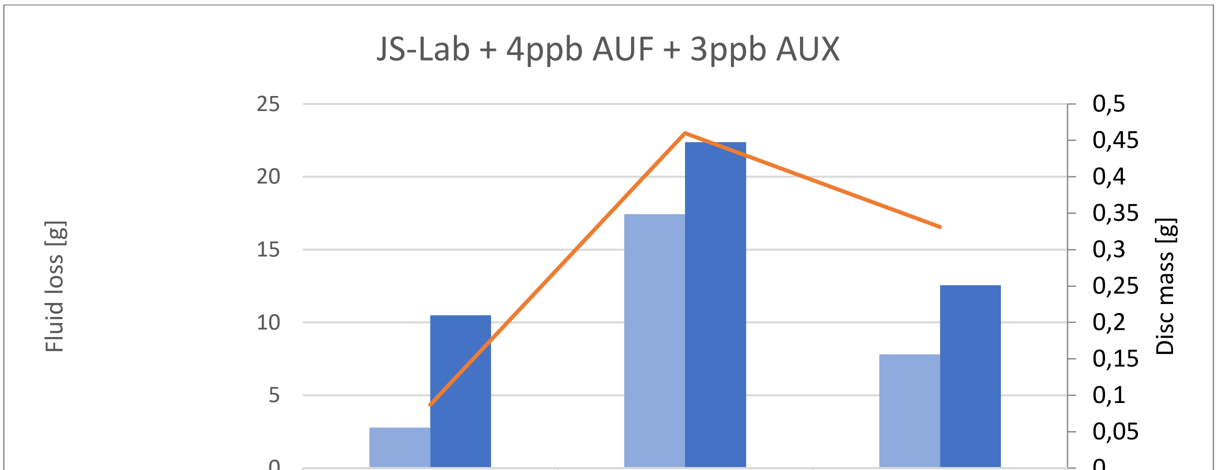



*Figure 18 - Fluid loss and disc mass of JS-Lab + 7ppb AM*

The JS-Lab samples containing 4ppb AUF and 3ppb AUX are shown in **FIGURES X.** This fluid composition successfully sealed all the discs in the relevant range with low fluid loss and limited solids invasion. The measured higher disc mass increase on the 160 µm disc than the 180 µm disc is consistent with the findings when testing Fluid C on 120 µm and 250 µm discs.




| | 120µ | 160µ | 180µ |
|---|---|---|---|
| Fluid loss 30s | 2,78 | 17,44 | 7,81 |
| Fluid loss 30min | 10,49 | 22,38 | 12,55 |
| Disc mass increase | 0,087 | 0,46 | 0,331 |

*Figure 19 - Fluid loss and disc mass of JS-Lab + 4ppb AUF + 3ppb AUX*

When increasing the concentration of AUX to 5ppb, the fluid loss is further reduced on the 160 µm disc and the fluid also successfully sealed the 250 µm disc, although with a relatively high fluid loss. This shows that the additive AUX has the ability to seal pore sizes in the 120-250 µm range effectively, and most likely higher product concentrations may be used to lower fluid loss to formations with pore throat sizes of 250 µm. It should also be noted that the disc mass increase was reduced significantly for the 160 µm disc, with the increased concentration of AUX, thus evidencing that less particles were invading into the disc and that the sealing was primarily by the external filter-cake.

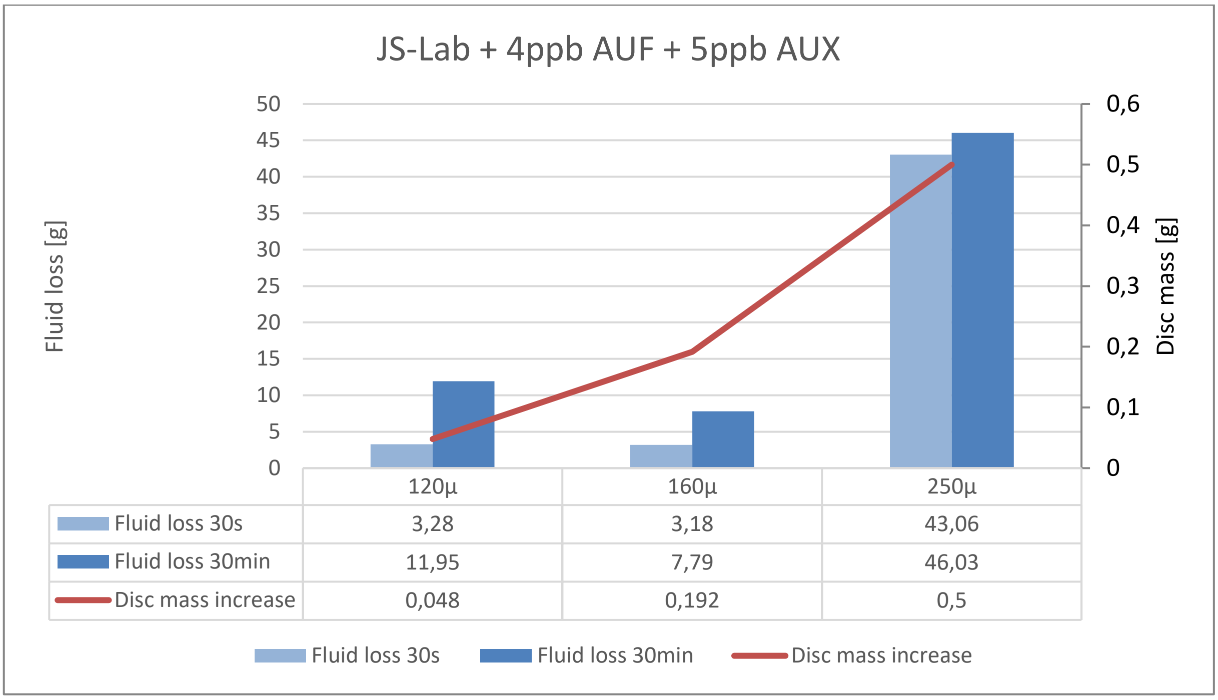



*Figure 20Fluid loss and disc mass of JS-Lab + 4ppb AUF + 5ppb AUX*

### 3.4 Permeability effects due to polymer and solids invasion

Figures 21 and 22 show the result from the tests done with various fluids on the 10 µm disc. It is evident that the base fluid has the highest fluid loss and disc mass increase compared to either of the modified samples. The retained permeability is also significantly worse, of about 69% for the modified sample, but approximately 90% for all the samples containing cellulose. The results indicate that the addition of either AM or AUF reduce the invasion of polymers and solids. This is consistent with the findings of Klungtvedt and Saasen [15].

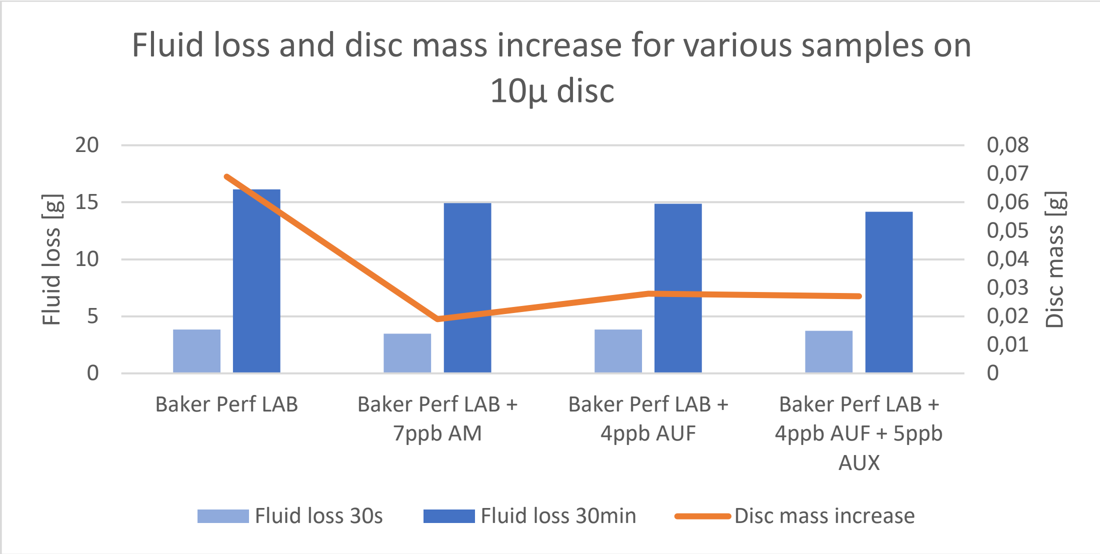



*Figure 21 - Fluid loss and disc mass for various samples on 10 µm disc*

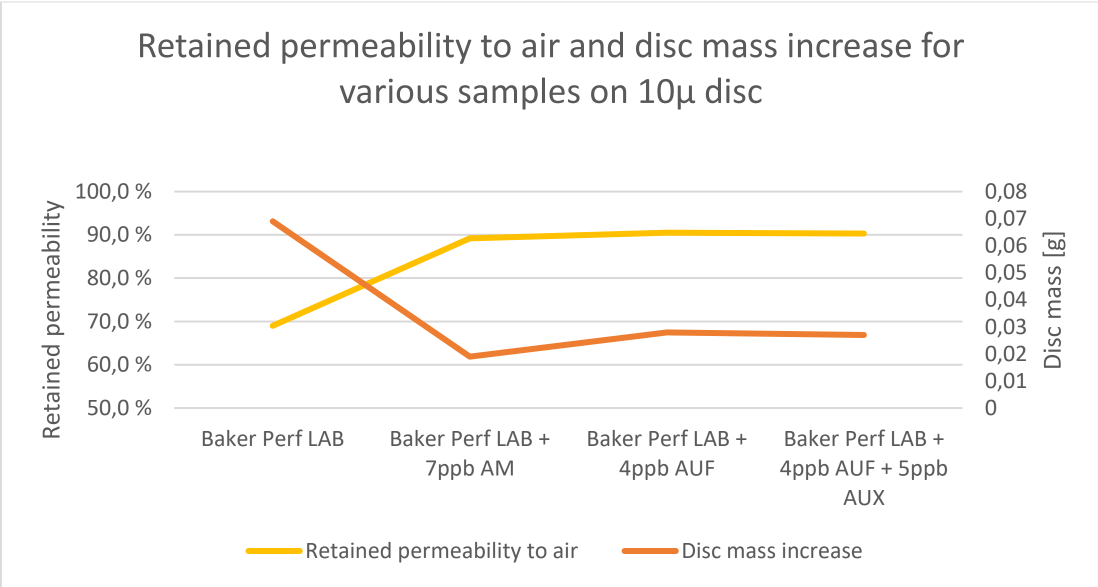



*Figure 22 - Retained permeability and disc mass for various samples on 10 µm disc*

### 3.5 Overview and economical considerations

The fluid loss with all the different JS-Lab fluids for the entire median pore size range is shown in Figure 23. The best solution is using a combination of AUF and AUX to create a low permeable seal towards most formations, and thus reduce fluid loss and potential formation damage.

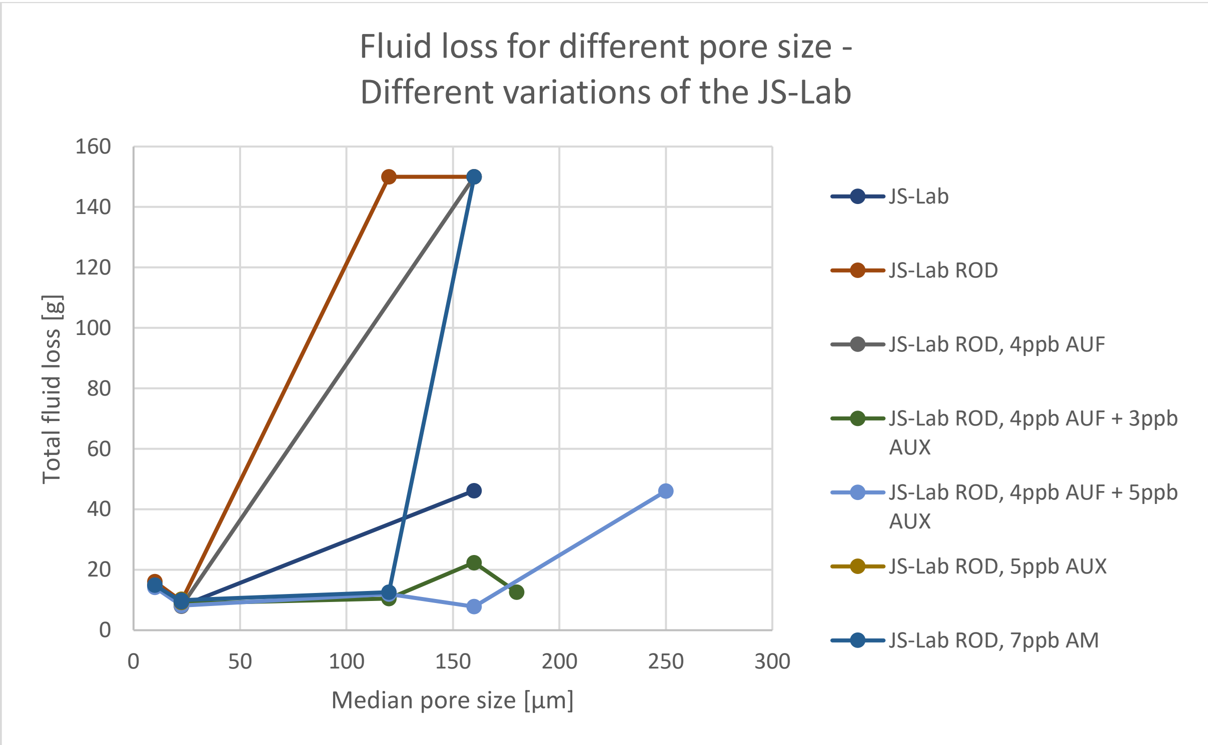



*Figure 23 - Comparison of different variations of JS-Lab effect on fluid loss for variying pore sizes*

A previously discussed, it is difficult to measure the related consequence of formation damage caused by fluid loss. The cost of the LCM product are very cheap, with the AUX and AUF being estimated to about the same costs as the LCM already being used, which has been shown to be miniscule in comparison to the cost of non-productive time and lost fluid volume.

# 4 Conclusion

The main finding is that the fluid used on the Johan Sverdrup field successfully modified to be able to effectively seal the high-permeable zones very severe losses occurred, without causing additional formation damage.

- Significant degradation of $CaCO_3$ particles under shear stress, which makes $CaCO_3$ alone not suitable/sufficient for creating an effective seal in formations where the pore-size is ≥ 120µm
- Tests indicate that permeable formation damage is caused by fluids with $CaCO_3$ as the only bridging agent
- Addition of cellulose particles:
    - Reduced formation damage and fluid loss with AUF, which is sized for API #170-200 screens.
    - Enhanced sealing ability with AUX for 120-250µm pore throat formations, which is sized such that it is able to remove the finer screen sto keep the additive in circulation
    - No significant change in particle size distribution after degradation tests
- Introduction of the tested cellulose particles indicates that replenishment of CaCO3 during drilling will be substantially reduced.

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## Appendix A – Costs approximations related to Johan Sverdrup

The following costs are approximations given by equinor.

**Rig costs:**

Johan Sverdrup Drilling Platform – about 2 mNOK per day

DeepSea Atlantic – 6-8 mNOK per day

**Fluid costs:**

*Table A1-Fluid costs for two fluids used on the Johan Sverdrup Field*

| | Density, sg | Per meter drilled, NOK | Per $m^3$ lost fluid, NOK (Beyond $25m^3$) |
|---|---|---|---|
| Fluid 1 | 1.16-1.20 | 1850 | 1375 |
| Fluid 2 | 1.21-1.25 | 3140 | 2305 |

**Lost circulation materials:**

There are currently two types of LCM used on the field, ground marble and graphite.

$CaCO_3$ – 3-5 NOK/kg

Graphite (G-Seal, SteelSeal, LC lube) 30-40 NOK/kg

A typical LCM pill used for curing lost circulation is about 8-15 cubic meters ($m^3$) and contain 350-450 $kg/m^3$ of LCM. When drilling with LCM actively in the system the desired concentration is 40 $kg/m^3$