Interface FLUIDICS

CASE STUDY

North Sea Injectivity Challenges

Unlocking the Microfluidic Technology for Formation Damage Control

Challenge

- Lower than expected injectivity during cold seawater injection
- Hot paraffinic oil reservoir
- Reduced injectivity and diminished oil recovery

Solution

- Validate the primary causes of injectivity issues
- Quantify the individual contributions of waxes and scales
- Assess the effectiveness of inhibitors
- Recommendations to optimize operations that Improve the efficiency of the waterflood

Results

- WAT was found to be 35.9 ±0.1C
- Pressure increased by 340% and 11% of the pore volume was covered by precipitates
- Inhibitors improved performance by 22% compared to the control

"the study and its results have significantly raised awareness and highlighted the issue in the license, leading to productive discussions and pushing us towards solutions."

Anders Sundgot Saunes
Senior Reservoir Engineer at Sval

Sval

Challenge

Sval Energi, a exploration and production company that produces oil and gas from the Norwegian Continental Shelf, encountered significant challenges with lower-than-expected injectivity during cold seawater injection into a hot paraffinic oil reservoir. This issue was critical, directly affecting their ability to maintain efficient oil recovery. Wax and scale deposition were identified as possible contributors to formation damage, reduced injectivity, and diminished oil recovery rates. Sval Energi sought to quantify the individual impact of wax and scale on injectivity decline and evaluate the effectiveness of inhibitor treatments in mitigating these issues.

Objective

The project aimed to validate that wax and scale could be causing Sval Energi's injectivity issues during cold seawater injection in one of their reservoirs. By quantifying the individual contributions of wax and scale, the study also sought to assess the effectiveness of inhibitor treatments in mitigating formation damage and enhancing oil recovery. The ultimate objective was to use these insights to optimize operations and improve the efficiency of the waterflooding process.

Methodology

Interface Fluidics employed a novel microfluidic platform with an integrated optical access to replicate the reservoir's porous media properties, enabling direct visualization of wax and scale deposition under simulated reservoir-relevant conditions. The project was conducted in three key phases:

Phase 1: Wax Appearance Temperature and Dynamic Wax Damage Measurement

Phase 2: Water Compatibility Analysis

Phase 3: Waterflood Scenarios

The custom-designed microfluidic reservoir analogue allowed for a detailed investigation of how temperature, fluid incompatibility, and chemical inhibitors influenced the formation and growth of wax and scale deposits.

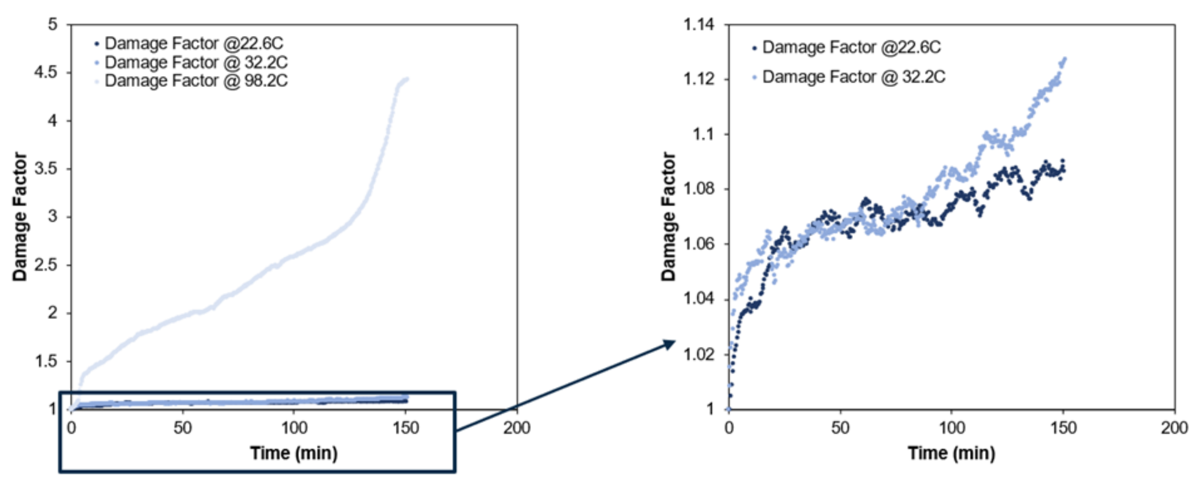
Results

Phase 1: Wax Appearance Temperature and Dynamic Wax Damage Measurement

In this phase, the focus was on determining the wax appearance temperature (WAT) of the crude oil and measuring the dynamic wax damage under various temperature conditions. Utilizing the cross-polar microscopy, the WAT was found to be 35.9 ± 0.1°C. When the temperature dropped below this threshold, wax deposition significantly increased, leading to severe plugging in the porous medium. The microfluidic reservoir analogue allowed for precise measurement of the wax deposition, which was essential in understanding the impact of temperature on wax formation and its subsequent effects on injectivity. The results underscored the importance of maintaining temperatures above WAT to minimize wax-related formation damage and improve injectivity.

Phase 2: Water Compatibility Analysis

This phase of the study evaluated the impact of water compatibility on injectivity and oil recovery. The analysis focused on the interaction between injected seawater and formation water at various temperature conditions, particularly the differences between near-wellbore and reservoir temperatures. The microfluidic experiments demonstrated that scale deposition was more pronounced at the higher reservoir temperature (98.2°C), where the injection pressure increased by 340% and 11% of the pore volume was covered by precipitates. In contrast, at lower near-wellbore temperatures, scale deposition was less severe, with only minimal pressure increases. The study also highlighted that the scale inhibitor had a modest effect on injectivity, improving it by 22% compared to the control.



$$Damage\ Factor = \frac{Injection\ Pressure\ (Seawater)}{Injection\ Pressure\ (Reservoir\ Water)}\ @\ Constant\ Flow\ Rate$$

Figure 1

The incompatibility between formation water and injection water leads to scale deposition within the porous spaces, which is most pronounced at higher temperatures. These temperatures are indicative of the reservoir's conditions, resulting in greater formation damage deeper within the reservoir, rather than in the near-wellbore region.

Phase 3: Waterflood Scenarios

The third phase of the study explored various waterflood scenarios to assess the effects of temperature and chemical inhibitors on injectivity and oil recovery. The waterflood experiments were conducted at different temperatures: above WAT (51.4°C), near WAT (35.3°C), and below WAT (21.2°C). The results indicated that waterflooding above the WAT resulted in the highest recovery factor (57.9%) and the lowest residual oil saturation (21%), highlighting the importance of temperature in enhancing oil recovery. Additionally, the use of chemical inhibitors showed significant benefits: the wax inhibitor improved oil recovery by 42% and injectivity by 45%, while the combined use of wax and scale inhibitors yielded the best results, with a 52% increase in oil recovery and a 63% improvement in injectivity.

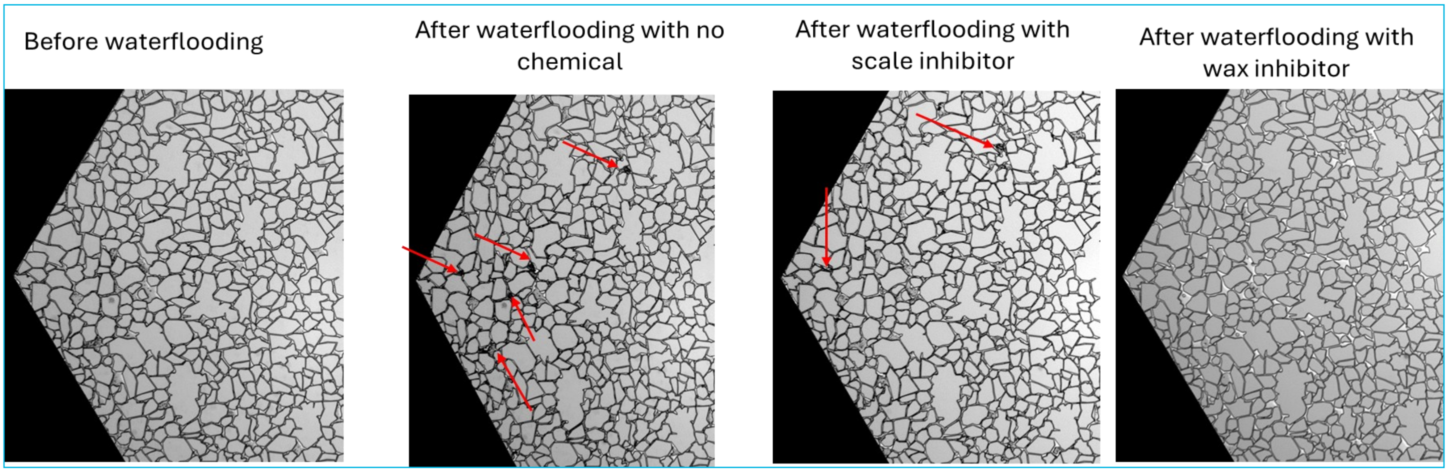


Figure 2

The formation of black clusters is linked to the presence of wax and scale. The use of a scale inhibitor reduces their occurrence, and they are almost entirely eliminated with the application of a wax inhibitor, even in the absence of a scale inhibitor.

Conclusion

Overall, pore-scale visual observations revealed the formation of complex clusters composed of a mixture of wax and scale. Interestingly, the appearance of these clusters was found to be more dependent on wax presence than scale, as evidenced by the greater efficacy of wax inhibitors in reducing their formation and consequent reservoir impairments. The microfluidic tests and optical assessment confirmed that the lower injectivity could be due to the presence of wax and scale. It also allowed for the quantification of the individual damage caused by each and the evaluation of the effectiveness of wax and scale prevention products in reducing formation damage and improving oil recovery.

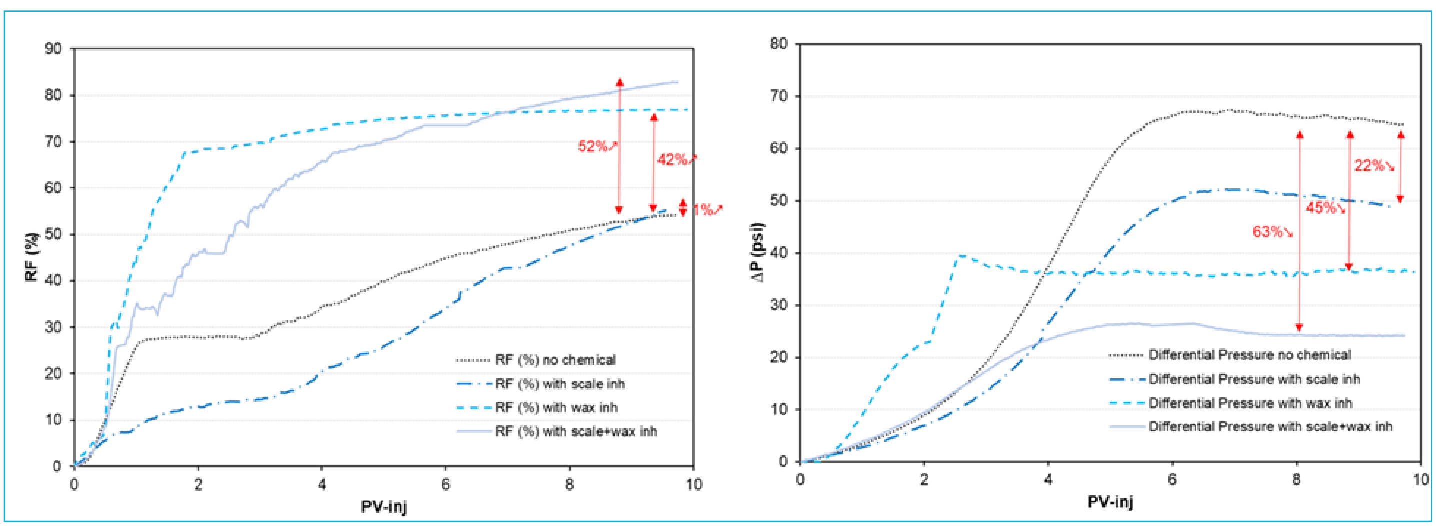


Figure 3

Recovery factors and associated pressure differential were measured during injection processes with and without chemicals, revealing that the wax inhibitor significantly impacted both.

Valuable insights were provided into the complex interactions between wax and scale during cold seawater injection. Our results showed:

- A 45% improvement in injectivity and a 42% increase in oil recovery with the use of wax inhibitors.
- A respectable 22% improvement in injectivity with scale inhibitors.
- The combined use of wax and scale inhibitors yielded the highest improvements, with a 63% increase in injectivity and a 52% increase in oil recovery.

By utilizing Interface Fluidics' microfluidic platform, the project delivered detailed insights into the individual and combined effects of wax and scale deposition on injectivity and oil recovery. These findings highlighted some of the factors that could contribute to formation damage and offered actionable strategies for mitigating these challenges, pushing Sval towards solutions with more efficient and sustainable reservoir management for Sval Energi.

SapphireLab

SapphireLab is Interface Fluidics' cutting-edge microfluidics system that is revolutionizing fluid analysis n the energy sector. It delivers faster, sharper insights into fluid behavior under extreme pressures and temperatures, with the speed and precision that traditional methods can't match. With integrated hardware and software, SapphireLab supports you from start to finish, making it easy to run microfluidic tests with minimal setup and smaller samples. Best of all, its interchangeable microfluidic chips allow for a wide range of tests, offering unmatched versatility.

SapphireLab Pro	
Component	**Description**
Maximum system pressure capacity	890 bar (12,900 psi)
Maximum system temperature	Room temperature to 200°C (390°F)[2]
Pumps	4x high precision with 10 ml syringe pumps
Pressure sensors	6x quartz pressure sensors
Microscope	Upright epifluorescence microscope
Camera	CMOS 7 MP sensor, extended dynamic range
Light source	Cooled LED light source with adjustable output
Software	SapphireLab Control, SapphireLab Analysis
Sample Cylinders	4x 50 ml cylinders with integrated valves and mixing ring

References and Citations

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Additional Resources