Simulation using CO_2 for IOR/EOR in the discovery C, Barents Sea, Norway

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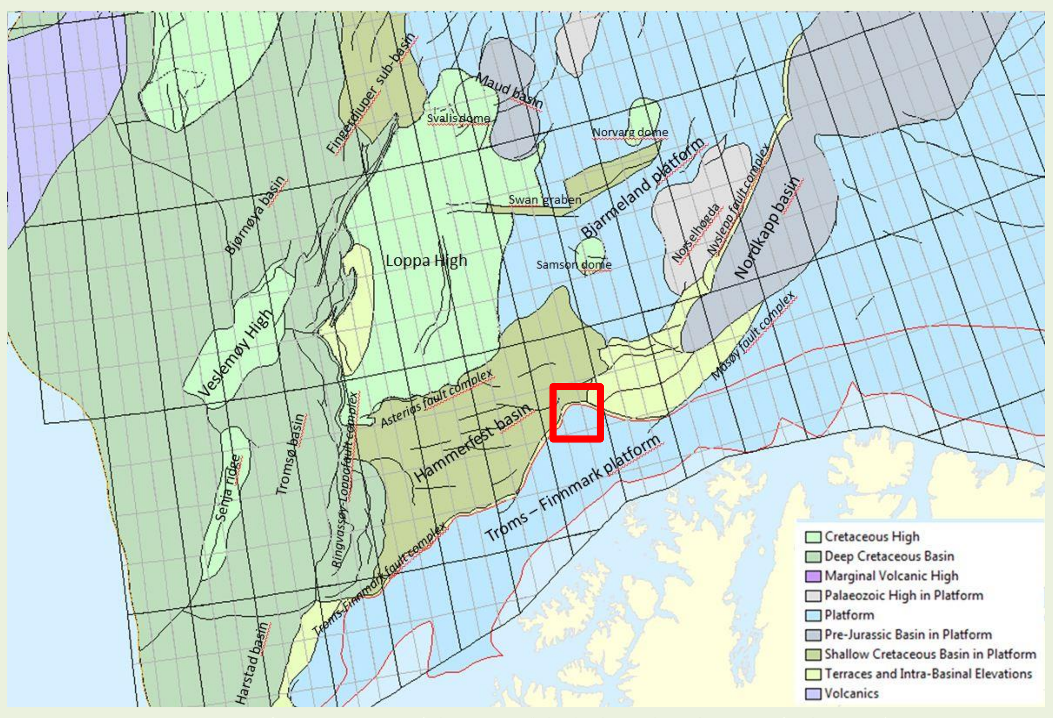
Abstract

Based on a geological-field model, a segment model in the Fr. Formation is built and it is covering an area of nearly 6.0 km2 with a small gas cap on top and an oil layer underneath.
In the C structure model, a segment model was cropped out and simulated with CO2WAG injection. CO2 is used as gas (water-alternating- CO2 gas). The CO2WAG injection method was compared with other recovery methods like gas injection, water injection and WAG injection (gas is hydrocarbon gas).

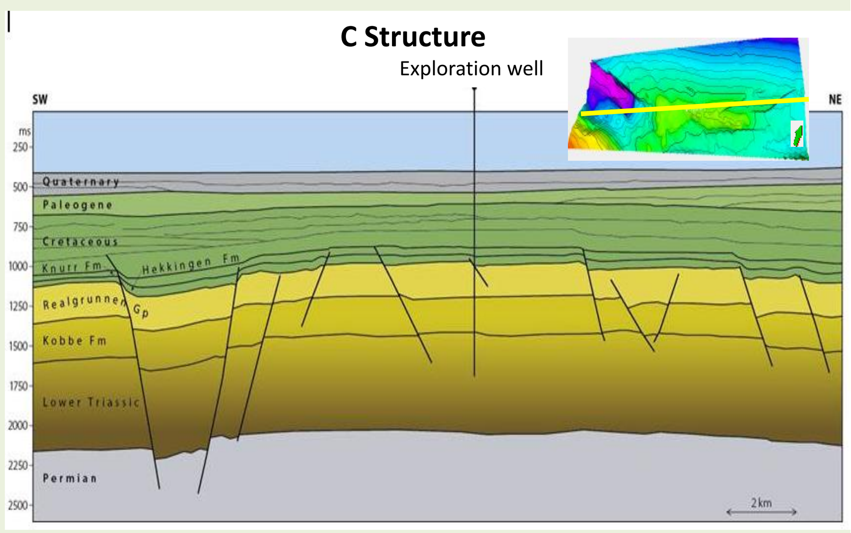
Simulations show promising results on the CO2WAG method in early period compared to the other recovery methods. Lessons from this study show that when a reservoir is near critical temperature, it is very difficult to predict CO2 behavior and oil/gas production volume when CO2 can be in both gas and fluid phase.



Tructrure map – BCU (Base Cretaceous), location of the hydrocarbon discovery (red-square)

1. Introduction

The C Structure is defined as a half open structure which is located in the northern boundary zone of the Finnmark Platform. The Fr. Formation generally reflect deltaic depositional environment following a widespread Early Norian marine transgression in the Barents Sea region. Hydrocarbons have been proven in the Fr. Formation and the formation is identified as oil bearing. The reservoir sand porosity is about 20-25% and permeability is between 10-100 mD.
In the exploration well, the Fr. Formation occurs at depth between 882 m -1002 m with an approximately thickness of 120 m.



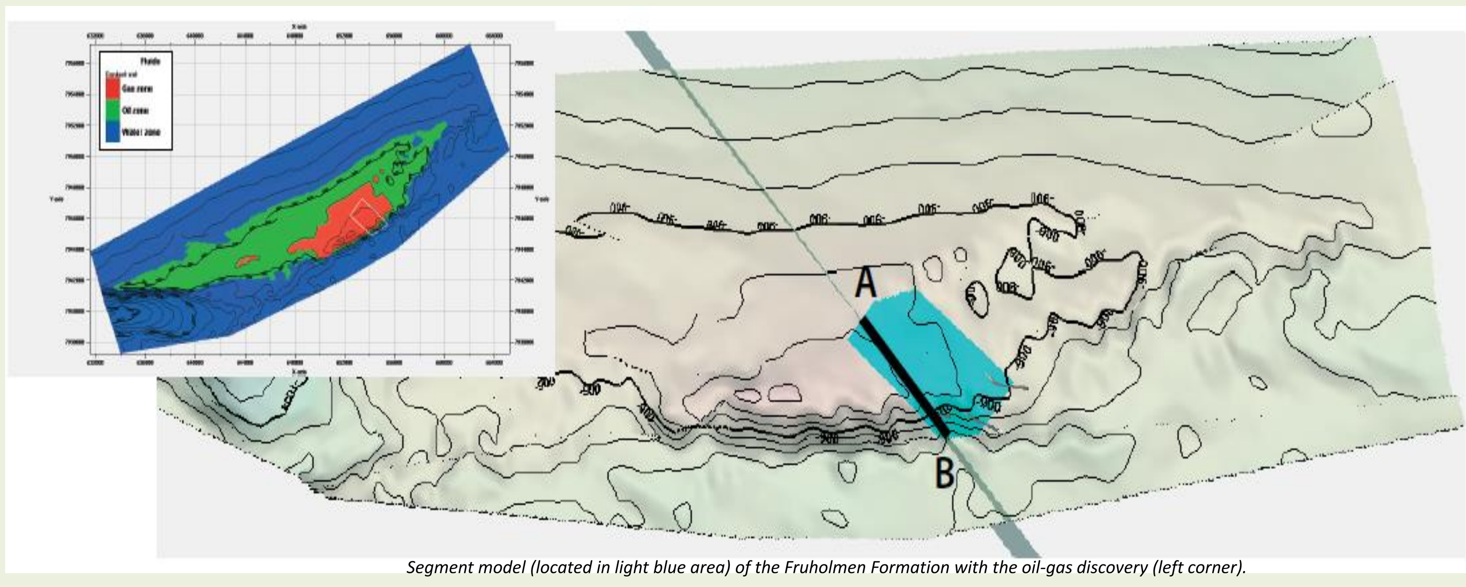
SW-NE profile showing the geometry of aquifers and reservoir (yellow) and sealing formations (green) in the model.

In the segment model, there are three wells, two production wells and one injection well.
The same injection rate of water, gas or CO2 (in the reservoir condition) was injected into the reservoir with 3 month-cycle Gas and Water alternative. In the gas injection scenario, the injection well was placed in order to inject gas in the gas cap.

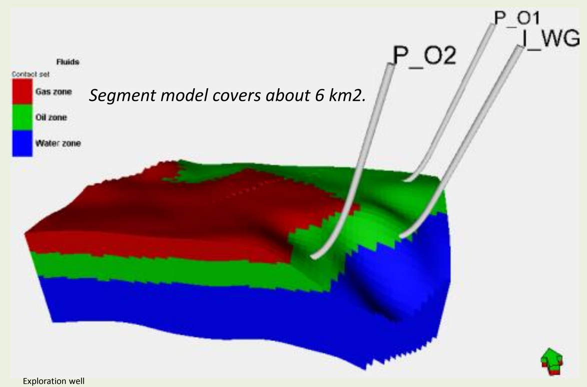
2. The reservoir simulation model

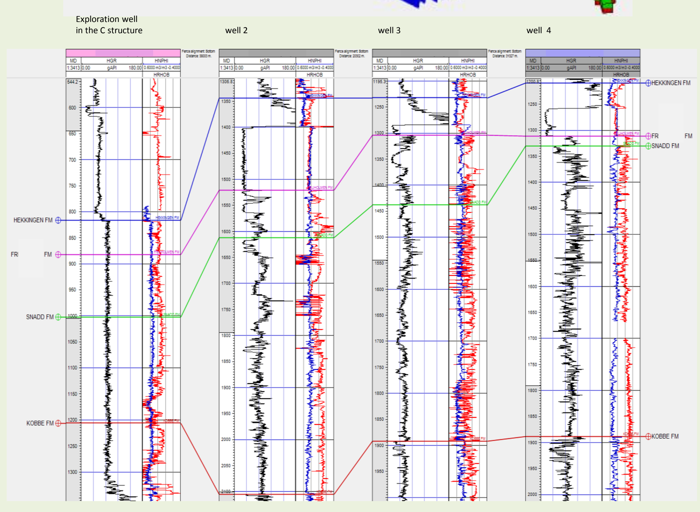
Different oil and gas recovery methods have been used for this model. The same injection rate of water, gas or CO2 in the reservoir condition is injected into the reservoir. In the model, there are three wells, two production wells and one injection well. In the gas injection scenario, the injection well was placed in order to inject gas in the gas cap.

In the C structure model, a segment model was cropped out and simulated with CO2WAG injection. CO2 is used as gas (water-alternating- CO2 gas). The CO2 WAG injection method was compared with other recovery methods like gas injection, water injection and WAG injection (gas is hydrocarbon gas).

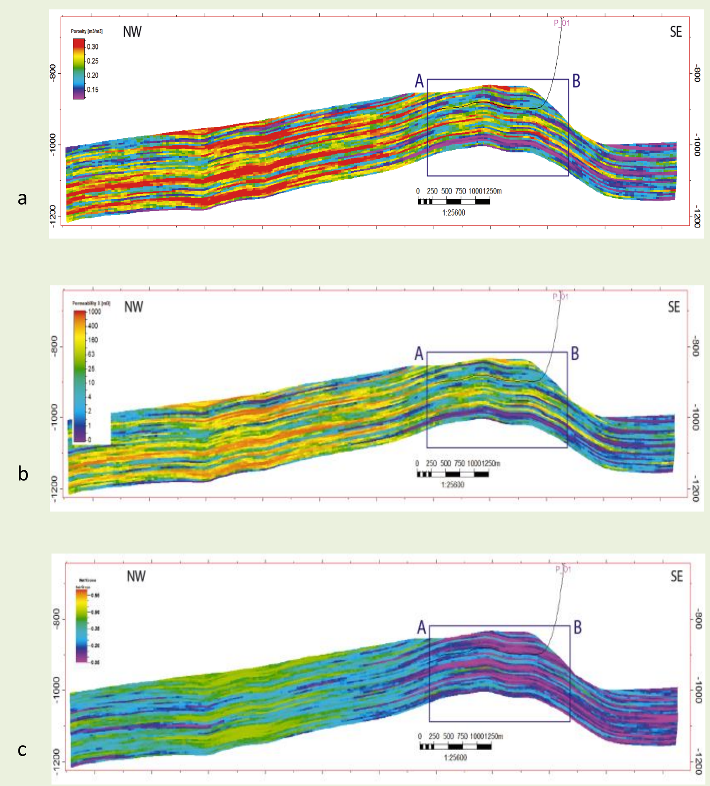


Segment model (located in light blue area) of the Fruholmen Formation with the oil-gas discovery (left corner).





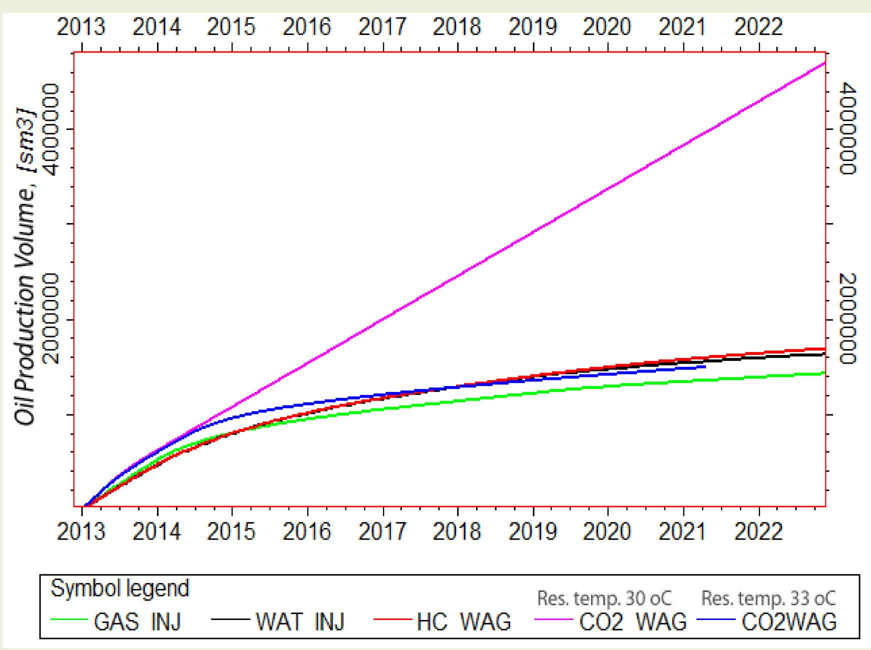
Log correlation panel with gamma ray, neutron and density logs.



Fruholmen Formation (Realgrunnen Subgroup) cross-section is showing porosity (a), permeability (b) and net/gross (c) distribution in the segment model terminated in the black box.

3. Results

Simulations show promising results on the CO_2 WAG method in early period in both CO_2WAG-30°C and CO_2WAG -33°C cases compared to the other recovery methods, but it shows less cumulative oil volume in long-term in the case CO_2WAG -33°C and very optimistic in the case 30 °C. The explanation for that is in The discussion part.



Total Oil production from the segment model. CO2WAG at critical condition (33°C, 102 Bars) Eclipse consider CO_2 as gas, but at 30°C, 102 Bars condition, CO_2 is in fluid phase. Eclipse considers CO2 as oil and total oil production includes CO_2 in liquid phase.

4. Discussion

The different of CO2WAG cases are reservoir temperature, ping color CO2WAG with temperature is 30oC and it is lower Than the critical temperature. CO2 was In fluid phase and consider as one component of oil. That means the total oil production volume consists of real oil and CO2 liquid phase. That can be seen in the result of the other case with the temperature 33oC that is higher than critical temperature. And therefor CO2 could be gas phase and that is not included in the oil production profile.
Lessons from this study show that when a reservoir is near critical temperature, it is very difficult to predict CO2 behavior and oil/gas production volume when CO2 can be in both gas and liquid phase. More simulation research should be done to get optimizing oil production volume and the effectiveness of the mixing of CO_2 and gas when we have the mixing available.

5. Summary

CO_2 injection is effective for increasing oil recovery, probably in short period about 5 years after injection in this model.
The oil production volume results could be very high in the cases with reservoir temperature lower than critical temperature of CO_2. this is due to CO_2 is reproduced and included in total oil production volume.

6. Acknowledgements

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7. References

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