Water Shut-off with Polymer in the Alvheim Field

SIS Global Forum 2019

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Accepted for publication in SPE Production and Operation SPE-195485-PA

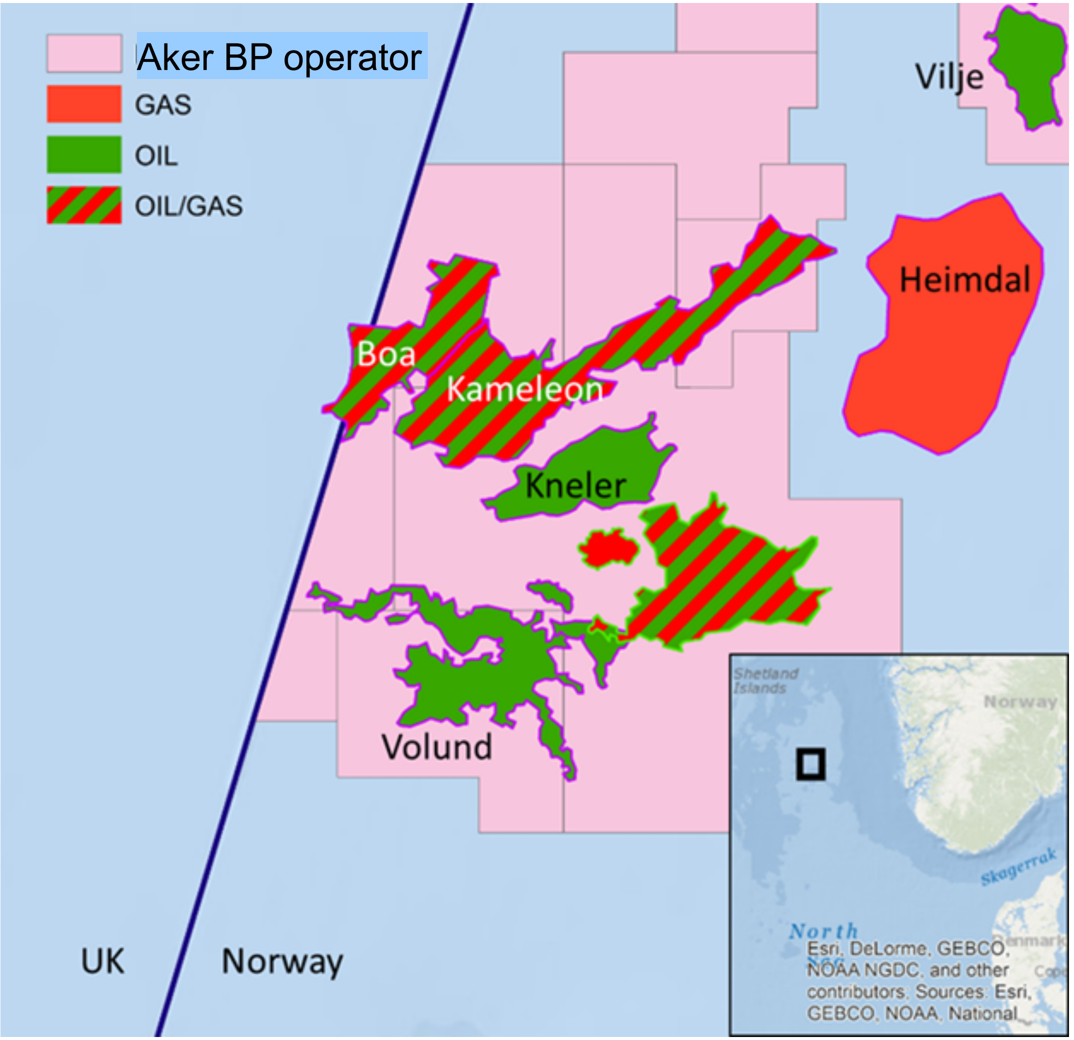
Outline

- Introduction
- Polymer as a water shut-off method: Short overview
- Laboratory core studies
- History matching the polymer water shut-off in the reservoir model
- Conclusions

Introduction – Alvheim Field and Kneler accumulation

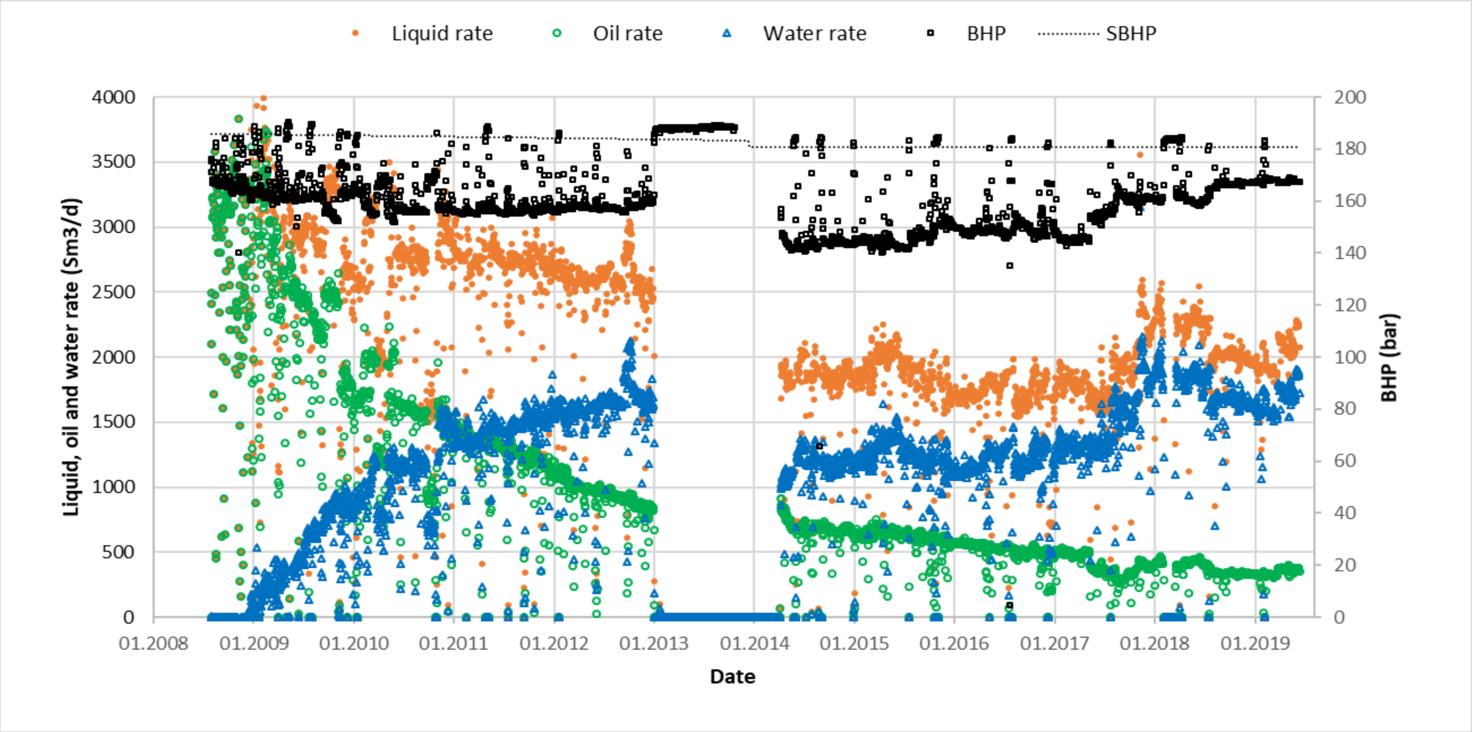
- The Paleocene Alvheim Field extends over three production licenses offshore Norway and a small portion into the UK sector. Within the Norwegian blocks Aker BP is the operator with a 65% ownership while ConocoPhillips and Lundin hold 20% and 15%, respectively.
- The field is composed of several low relief hydrocarbon accumulations within the Heimdal Formation, known as Boa, Kameleon and Kneler.
- The Kneler accumulation is up to 70 m thick and comprises of undersaturated oil detached from the rest of the Alvheim area.
- Production performance has shown that most wells have good pressure support by the aquifer, but also that stratigraphically compartmentalized segments exist.

Property	Value
Porosity	0.25 (fraction)
Permeability – horizontal (effective)	1 D
Permeability – vertical (effective)	10 mD
Initial (2008) OWC	2112 mTVDMSL
Initial (2008) reservoir pressure @ OWC	203 bars
Reservoir temperature	68 °C
Oil density at surface conditions	837 kg/Sm³
Oil bubble point	135 bars



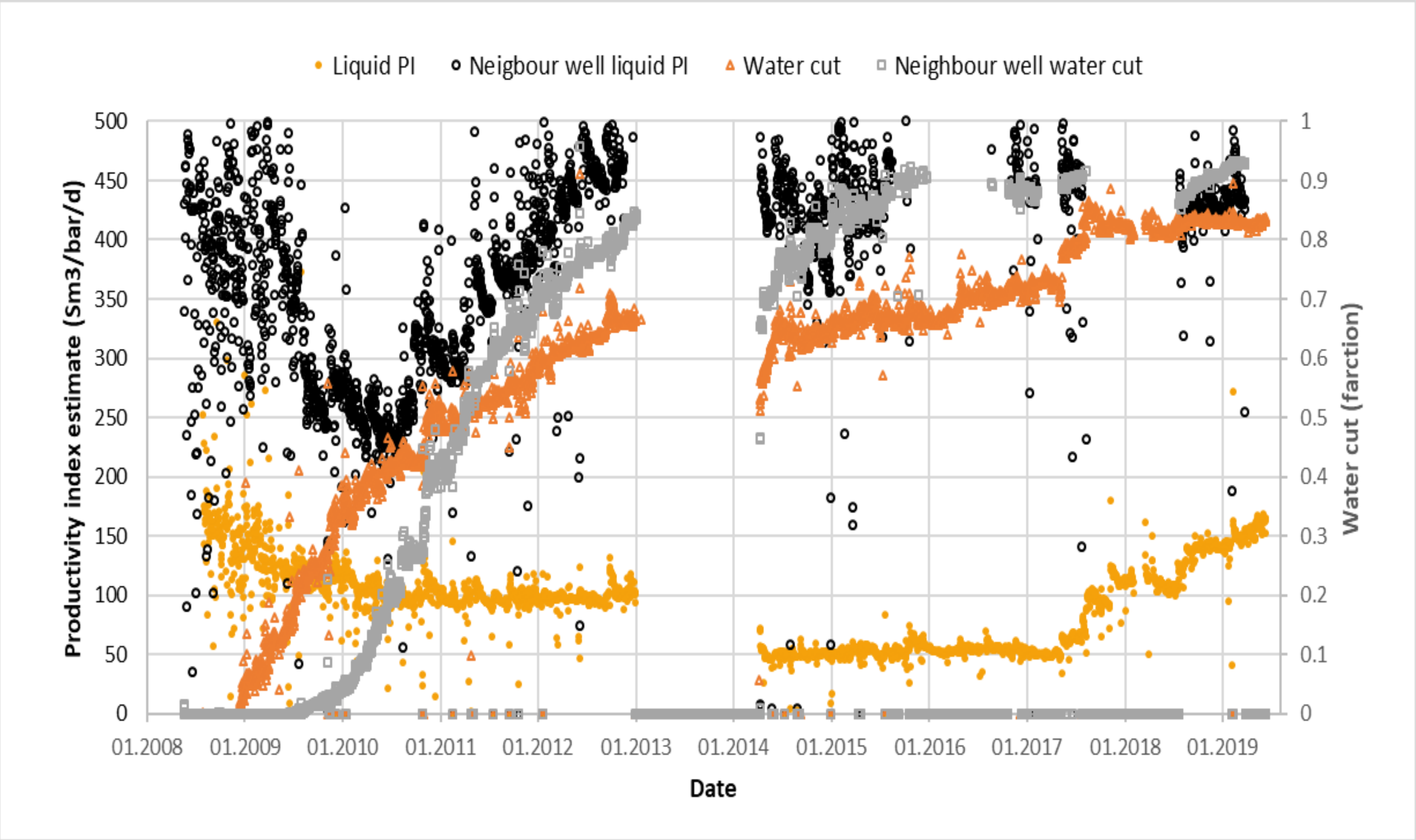
Introduction – polymer injection in two Kneler wells

- In 2013, an intervention campaign was performed to change out the production tubings in two Kneler wells.
- Brine and a polymer were bull headed to remove possible hydrocarbons before the old production tubings were pulled out.
- Normally a starch-based polymer with short life-time is used for this kind of operation to not impair the well productivity.
- Due to availability issues, another polymer, drilling-grade xanthan, was used in the second well.
- The well productivity was reduced in the xanthan-treated well.



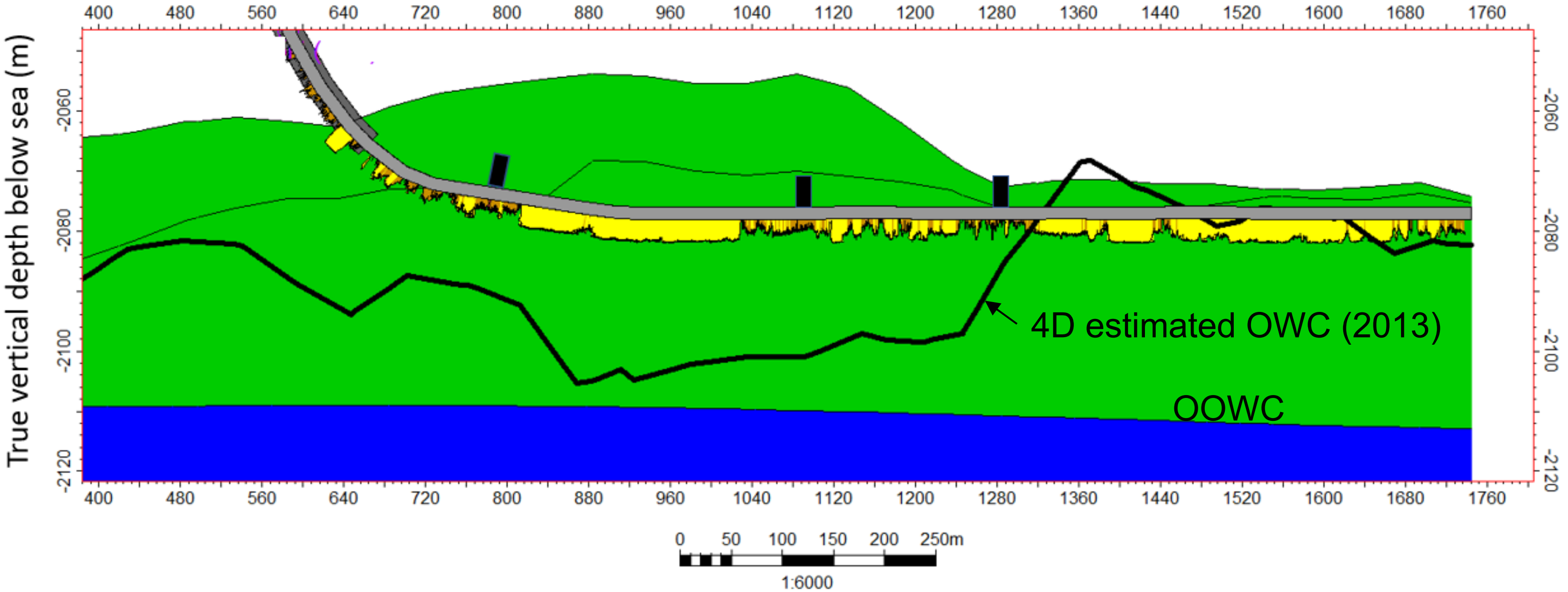
Introduction – polymer injection in two Kneler wells

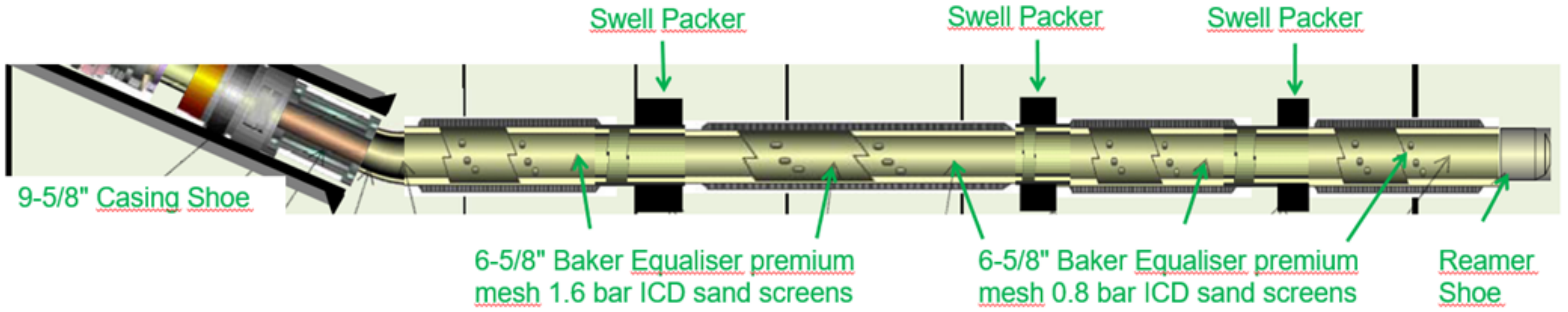
- The first well in the workover campaign, where starch-based polymer was used, showed no reduction in liquid PI
- This “neighbor” well has the same screens, similar ICD settings, and geology as the xanthan treated well. The shut-in time and water-cut before the workover were also similar
- Hence, the reduced liquid PI in the xanthan treated is most likely explained by the xanthan polymer
- Reduced PI period was 3.5 years



Xanthan treated well - details

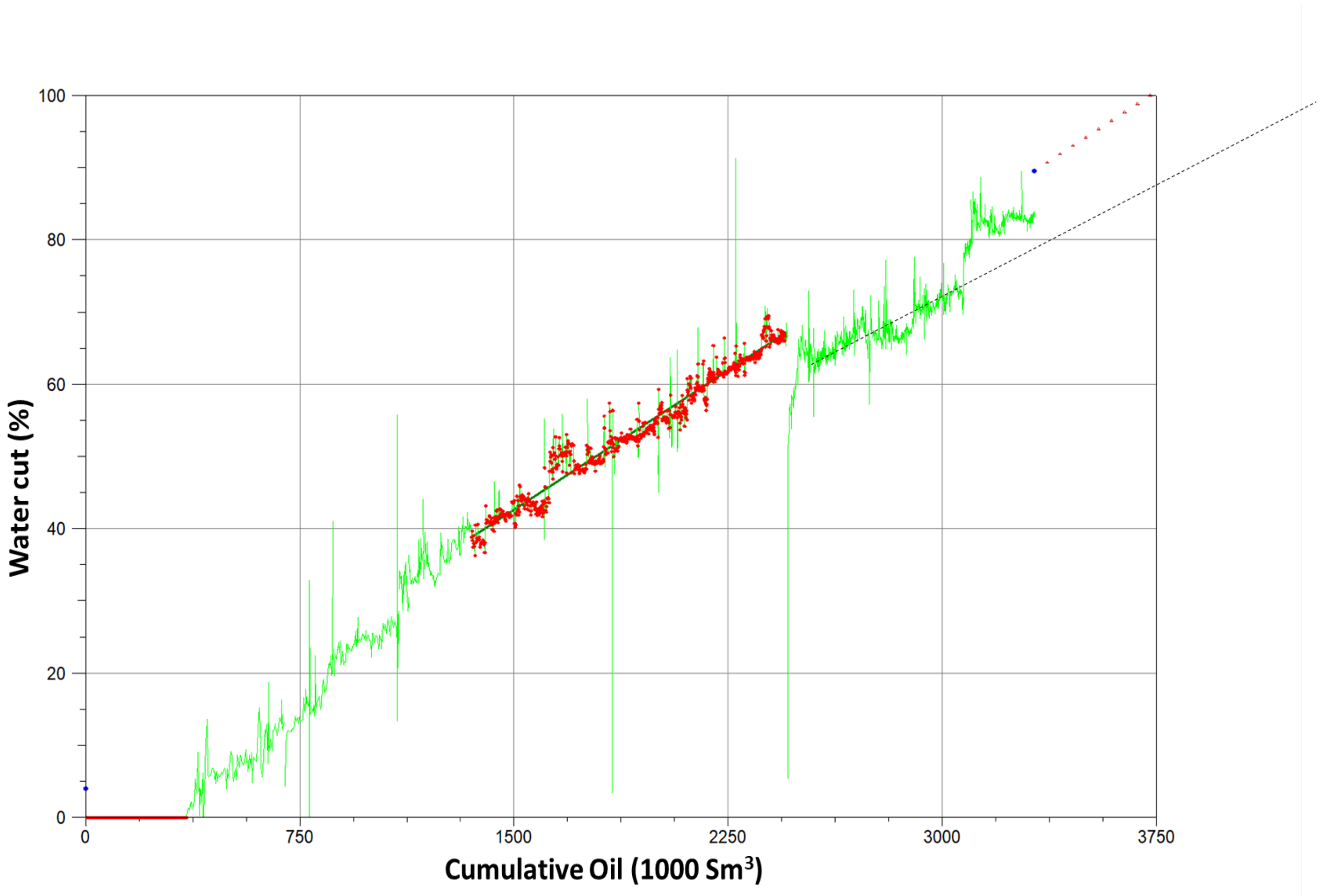
- The PI of this well was low as compared to most Alvheim wells, likely explained by some kind of compartmentalisation
- 4D seismic indicate uneven OWC movement
- The polymer plugging capability is likely proportional to effective flow channel diameter
  - PI reduction most likely explained by formation impairment (not to plugging of ICDs nor screen)





Xanthan treated well – step change in water cut trend

- The water-cut trend showed a step change indicating a possible water shut-off method for Alvheim
- Alvheim move to a future where water will constrain oil production
- Mechanical water shut-off in open hole sand screen is expensive and difficult, hence polymer bull-heading seems like an attractive method
- Possible future EOR method for Alvheim and similar oil fields?

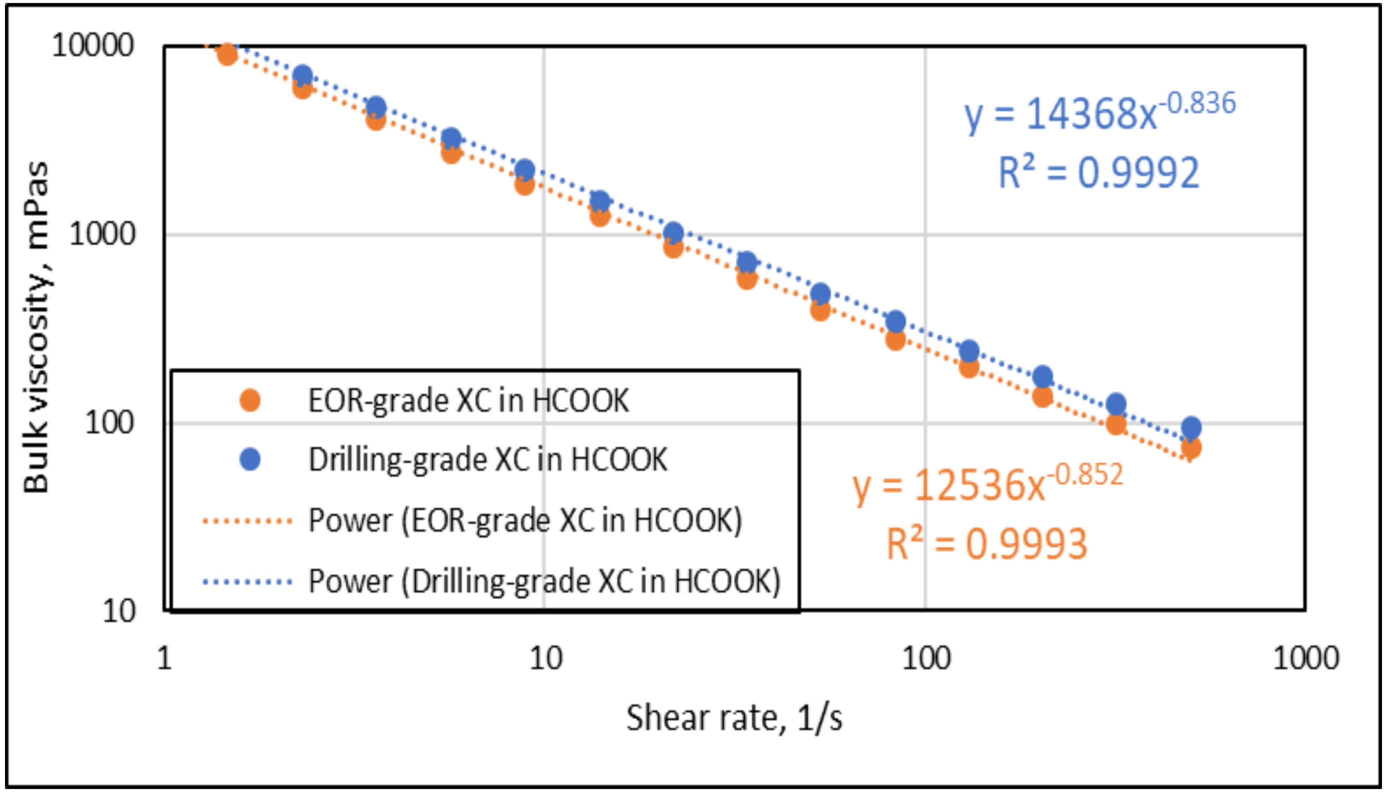


Water shut-off with polymer: Short overview

- Xanthan biopolymer is a polysaccharide produced by a bacteria. The polymer is soluble in brine and is not sensitive to brine salinity
- Not a new method. Goddard et al (1973) reviewed more than 100 wells treated with polymer to reduce water onshore USA, with a high degree (80%) of economic successes
- More recent field applications have mixed results. Challenge is to not reduce oil permeability too much. Reservoir zonation seems key for success
- A general observation reported by Stavland and Nilsson (2001) is that the pore restriction is dominant for the phase in which the fluid is soluble, hence it should be expected that the polymer used in the above well operation reduces the water permeability more than the oil permeability. Disproportionate permeability reduction (DPR)

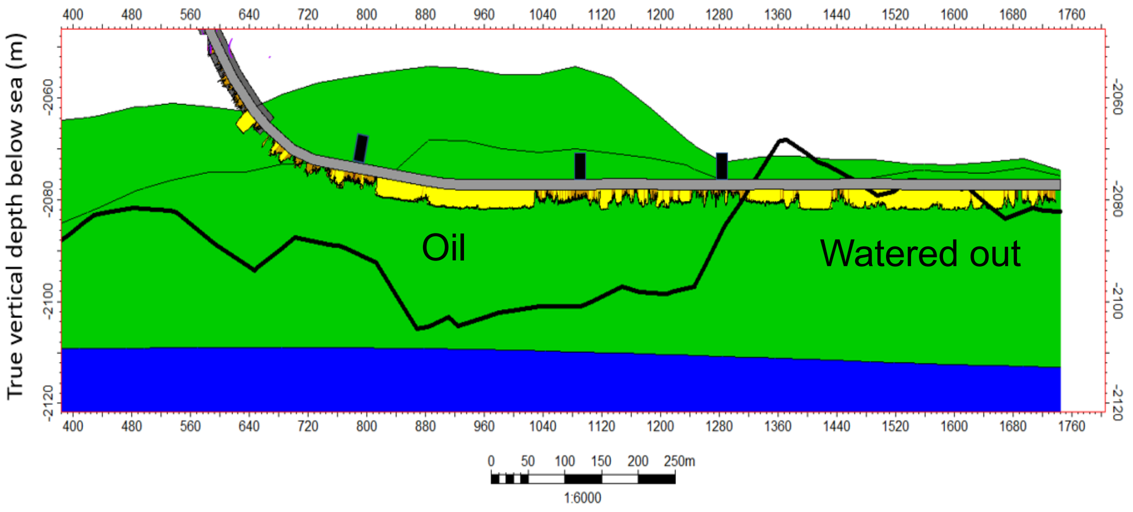
Laboratory core studies

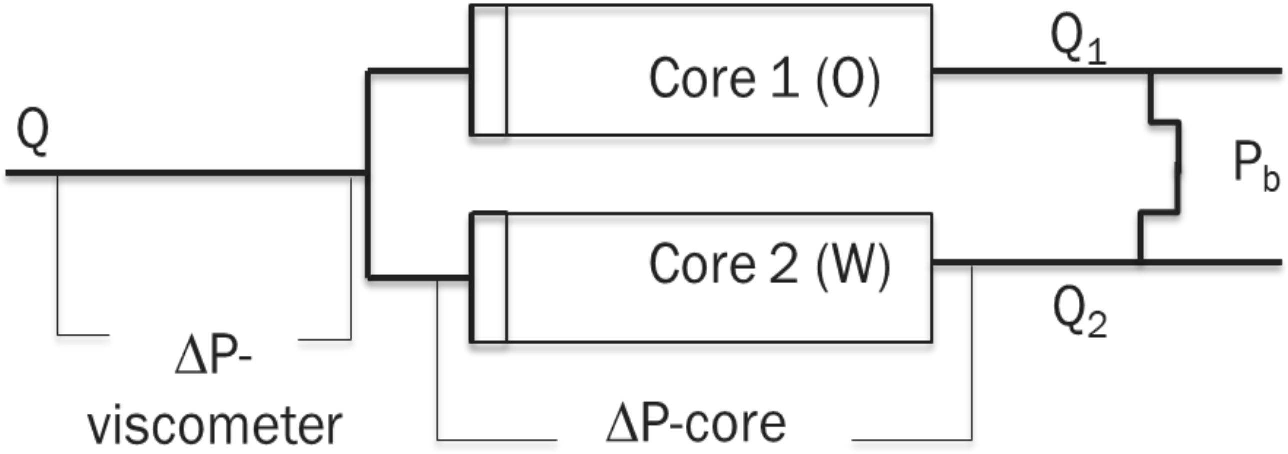
- Drilling-grade xanthan (as used in the well) and an EOR-grade xanthan had similar non-Newtonian viscosity
- Drilling-grade xanthan filterability was low, plugged filters with pore size less than 8 µm
- EOR-grade xanthan had good filterability



Core experiment set-up

- Two cores mounted in parallell to represent a possible 2-layered reservoir
  - Core 1 – Oil at Swi
  - Core 2 – Water at Sorw
- A spacer ring (1 cm) at inlet end was used to allow for realistic external filter cake build-up and the possible back production of this filter cake
- The polymer was first injected into the combined core system
- After a shut-in period of typically 3 days, the cores were back-flooded individually, with oil in the oil core and with brine in the water core





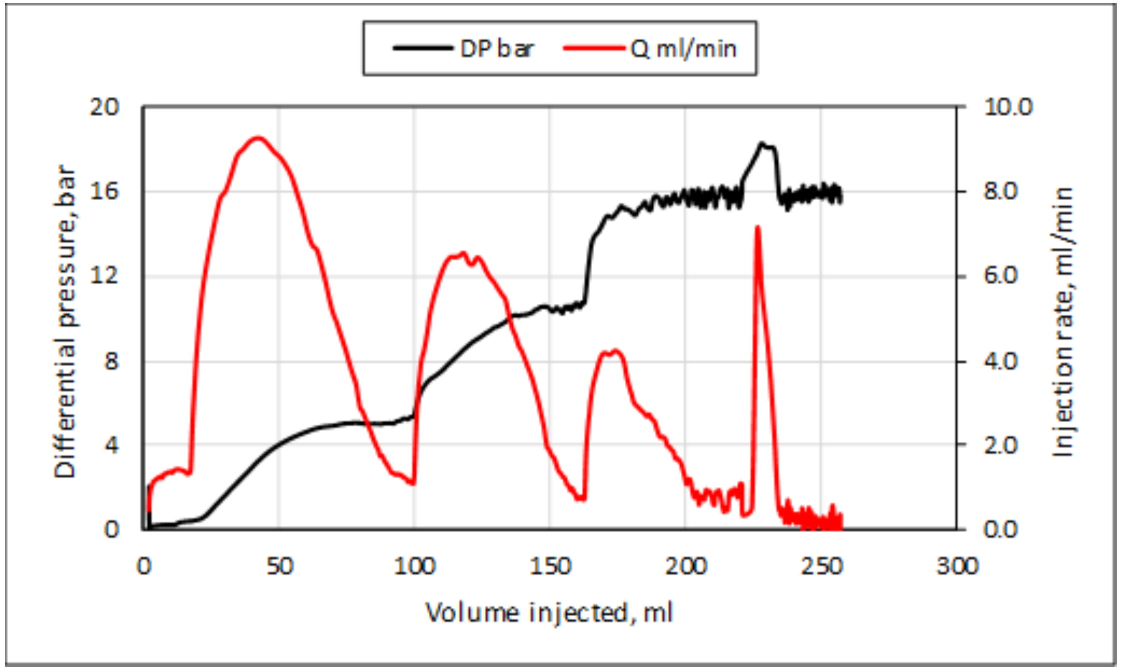
Drilling-grade xanthan into two Bentheimer cores

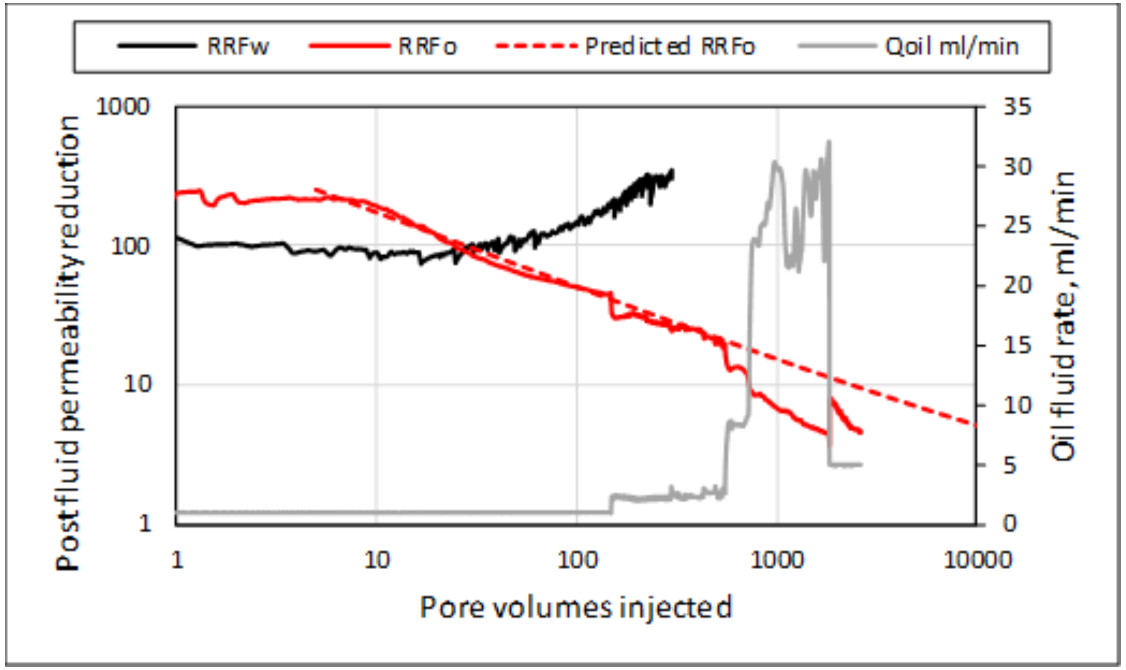
During polymer injection

- Both oil core and water core flushed with polymer
- Large permeability reduction in both cores

During back production

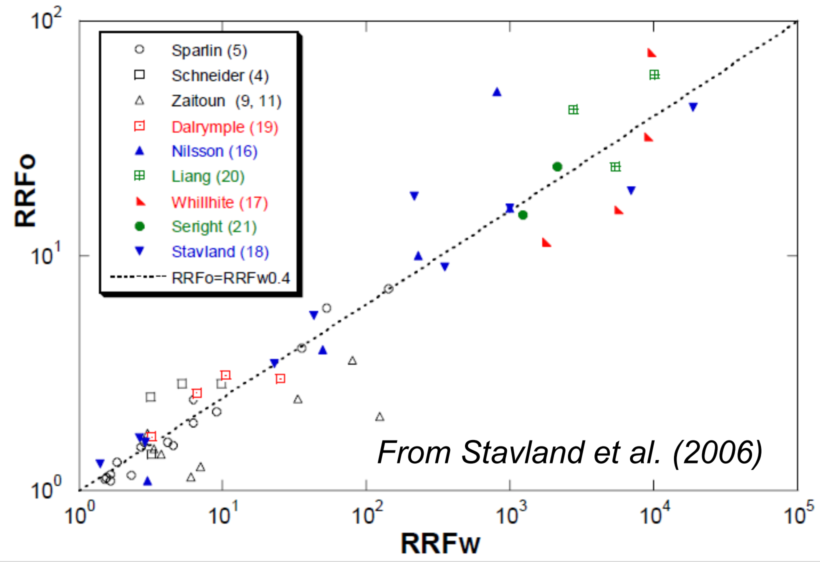
- Brine back-flow does not help to improve permeability
- Oil back-flow help to improve permeability
- End state RRFw = 370; RRFo=4.6
- DPR = 80 and further improving with time

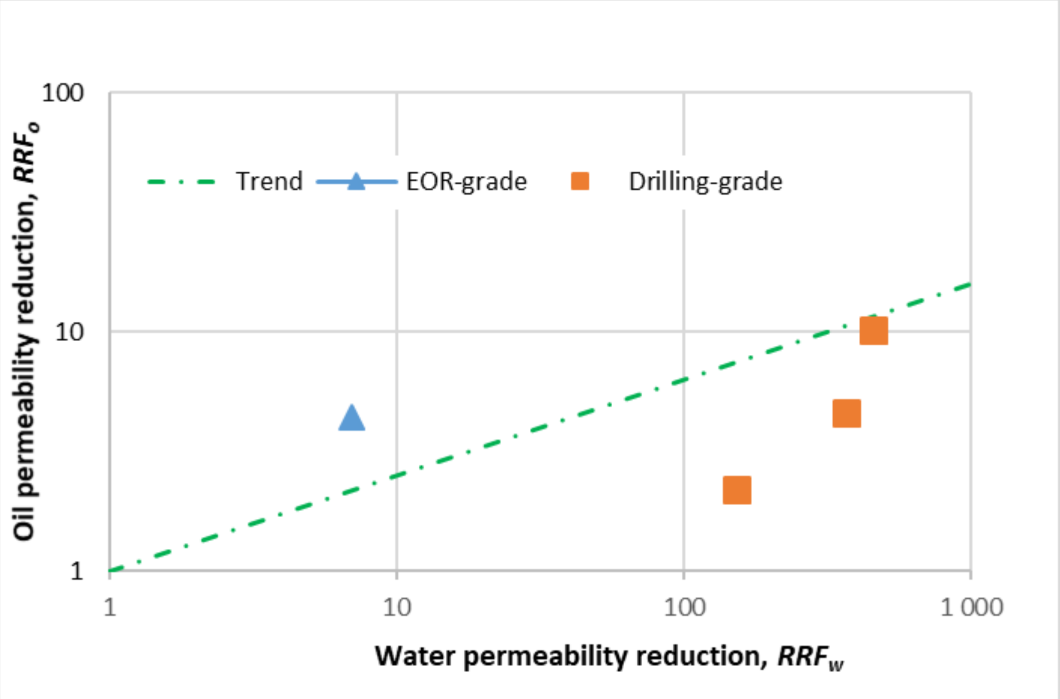




Summary of core results

- Core results with drilling-grade xanthan are better than literature trendline as reported by Stavland et al. (2006)
- RRFo was still improving when experiments were ended
- Cutting the cores in two showed higher permeability reduction at polymer inlet side and that polymer debris at surface (filter cake) can play a role for water shut-off





Upscaling the core results to the dynamic model

- The core result (7 cm long cores) suggests that a lot of the permeability reduction happens over the first few centimetres.
- Connection factor for cartesian grid

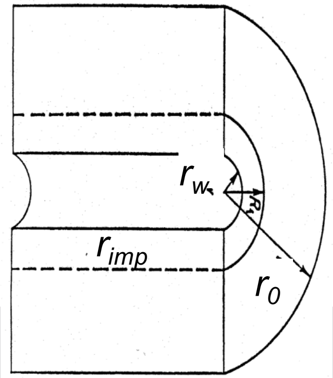
$$T \propto \frac{k}{\ln(r_0 / r_w) + S}$$

- Pressure equivalent radius of the grid block (horizontal well)

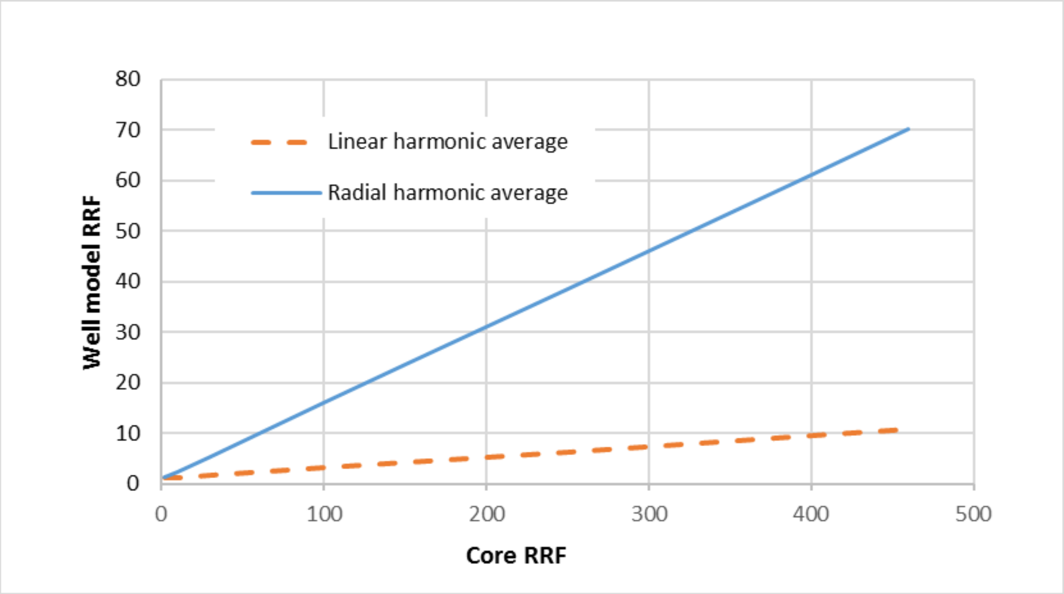
$$r_0 = 0.28 \frac{\left[D_y^2 (\frac{k_z}{k_y})^{1/2} + D_z^2 (\frac{k_y}{k_z})^{1/2} \right]^{1/2}}{(\frac{k_z}{k_y})^{1/4} + (\frac{k_y}{k_z})^{1/4}}$$

- Average permeability of the composite radial system

$$k_{av} = \frac{\ln(r_0 / r_w)}{\frac{\ln(r_o / r_{imp})}{k} + \frac{\ln(r_{imp} / r_w)}{k_{imp}}}$$



- Assume r_{imp} = r_w+0.07m
- Dynamic model grid and properties gives r_0=3.37m
- Well model inflow scale =3.37m, core scale 7 cm



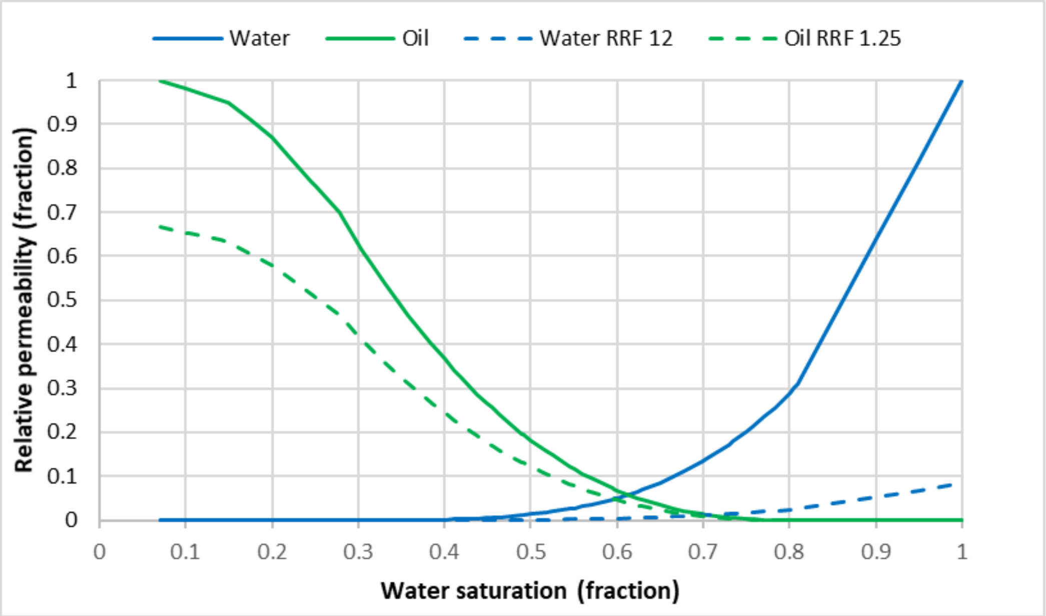
Upscaling the core results to the dynamic model cont.

Practical implementation

- Well model RRF used to scale the relative permeability to water and oil in the inflow model

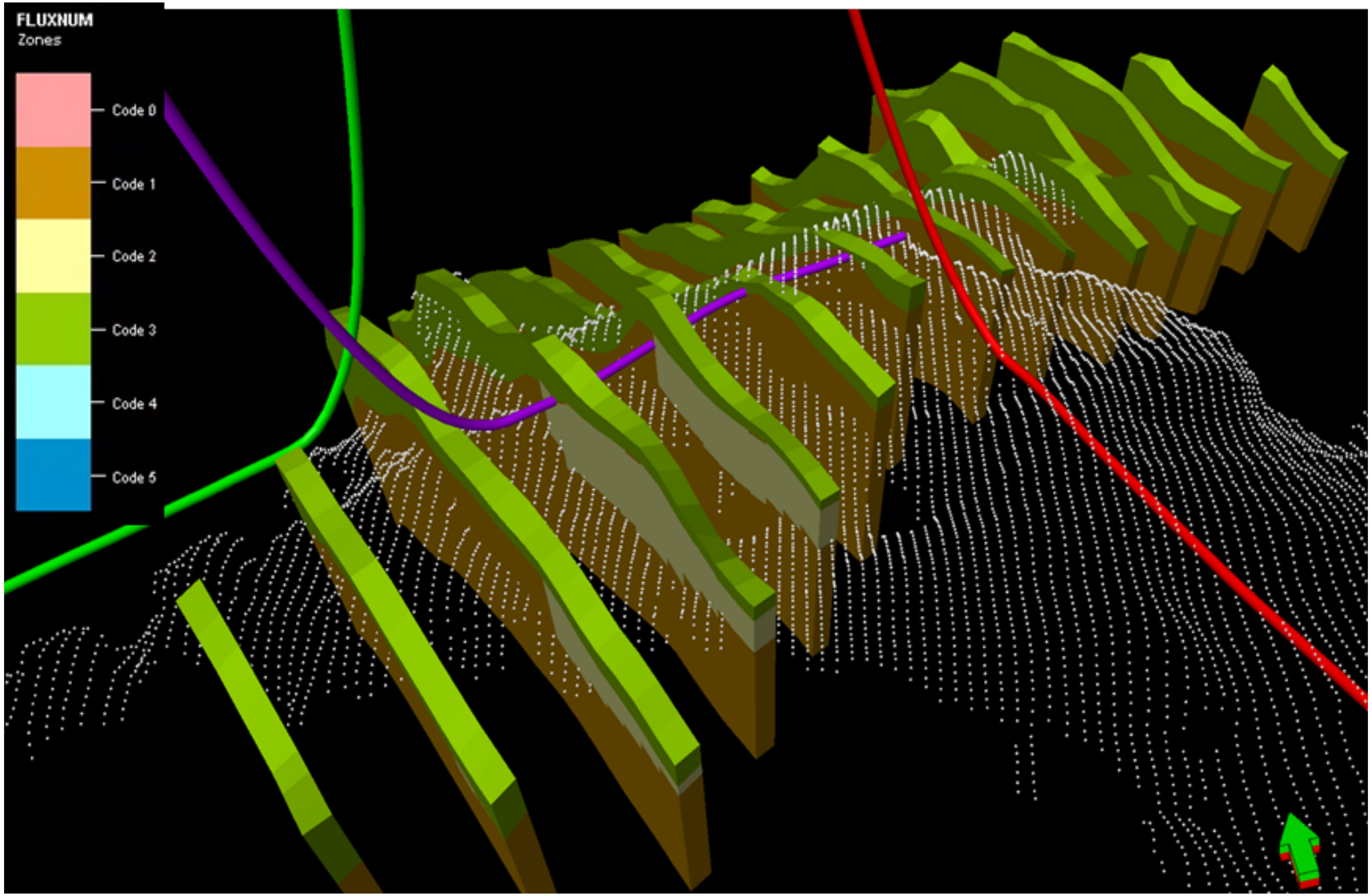
- Scaling used in history matching
  - RRFw well = 12; (RRFw core ~75 +)
  - RRFo well = 1.25; (RRFo core ~2.6 +)

- Practical implementation
  - Import this scaled relative permeability to petrel/Eclipse
  - Change COMPDAT item # 7 at the correct times



History matching the water shut-off in the reservoir model

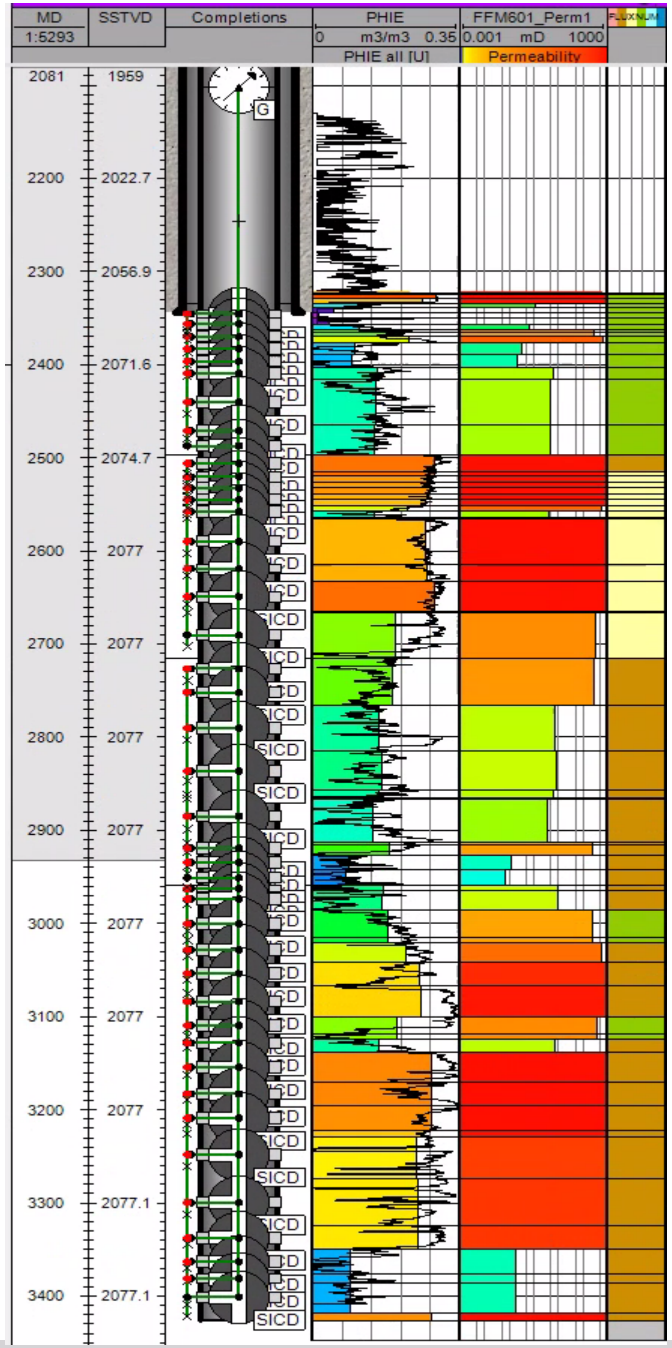
- Sector model from latest full field geomodel, not yet adjusted to 4D seismic data
- Upper zone (KR3) green
- Lower zone (KR2) brown
- White dots is 4D estimated OWC mid 2013
- Made an extra zone (yellow) to try improve match vs 4D seismic data



History matching

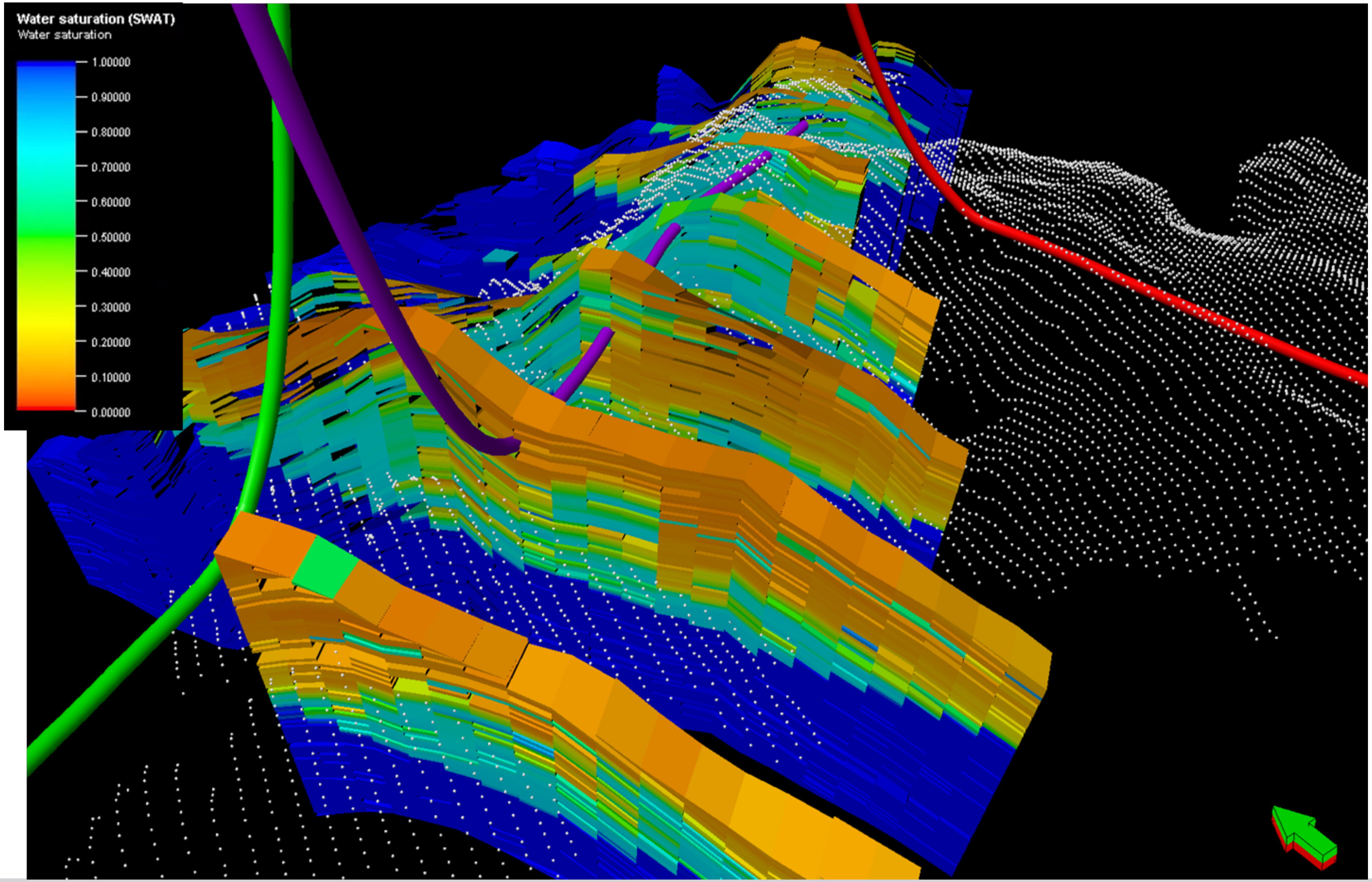
Well modelling

- Horizontal well porosity log data was well represented in this model. Permeability from a permeability-porosity relation based on all Alvheim core data
- Well was modelled with all details of the lower completion, including spiral ICDs and 3 swell packers
- The history-match was sensitive to details of the well segmentation, and the full solution including annulus segments were used in the final history match



History matching result: Oil saturation mid 2013

- Numerical aquifer connected at bottom of sector model
- Difficult to match both well data and 4D seismic data
- Best match was achieved with Kv/Kh=0.1 and TM=1e-4 for the extra zone



History matching

Well data match

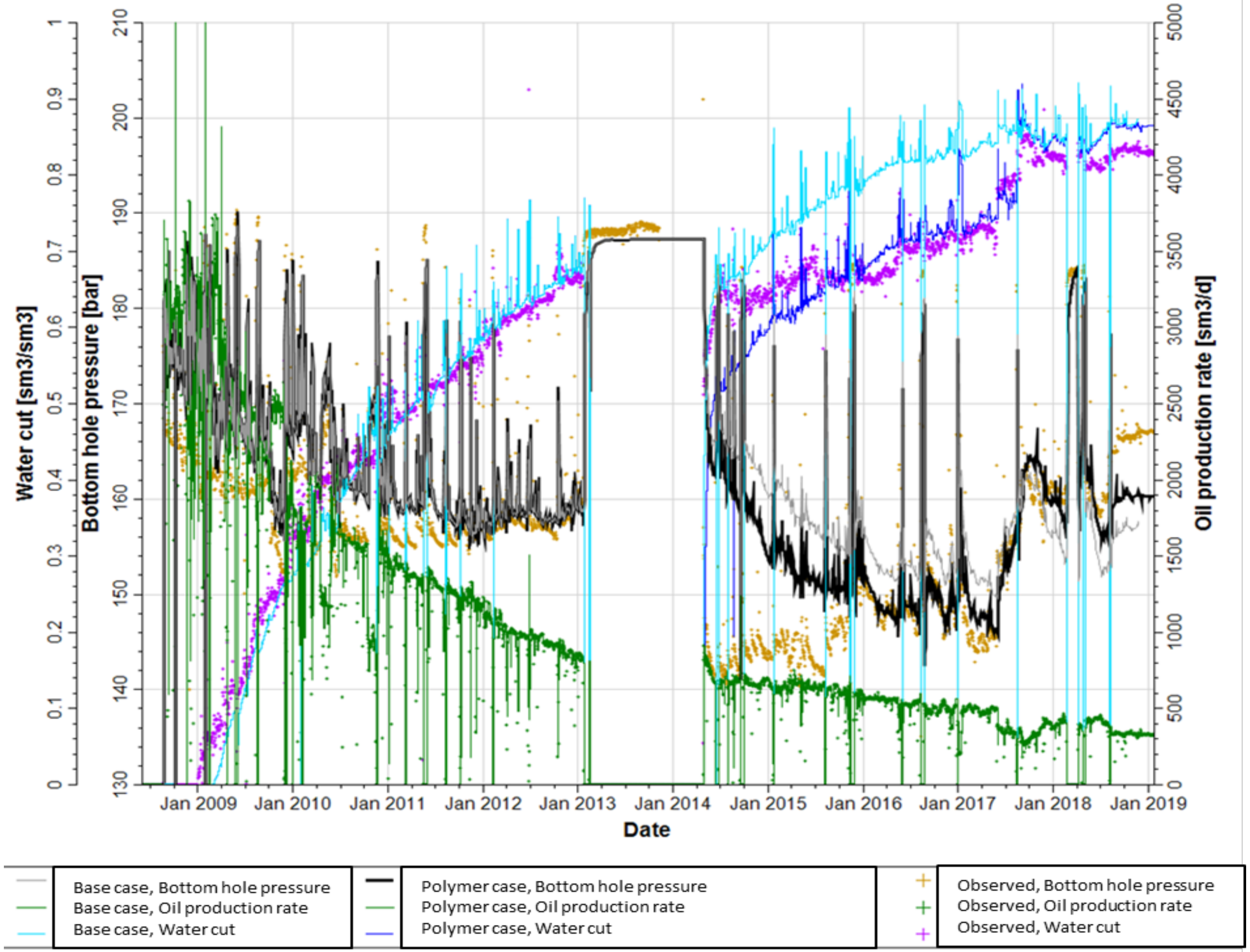
- Auto-match on oil rate

- By introducing the extra segment, the match to 4D seismic, water cut and pressure was improved

- Base case (no polymer)
  - Too high watercut
  - Too high PI

- Polymer case
  - Acceptable match to average water cut and PI throughout the whole history of the well

- Overall, this historymatch aligns well with the laboratory core studies



Conclusions

- The method by bullheading drilling-grade xanthan polymer shows potential as a water shut-off method for wells like in the Alvheim field and seems robust for details like polymer volume, permeability, fluid saturation and history
- The water-shut off in the polymer treated well lasted more than 3 years at reservoir temperature of 70°C and under high drawdown
- The used polymer solution plugged filters with pore size less than 8 µm, but can be injected though sandstone with pore size well below 5 µm
- Back production of treated cores revealed a favorable DPR ratio ~ 45-80 and improving further with time.
- The core result is better than the trend from earlier published results
- A reservoir model gave a satisfactory history match on the polymer effect using permeability reduction well aligned with the laboratory core flood experiments
- Reservoir zonation was needed to get a satisfactory history match of the reservoir model. The Alvheim field has several reservoir zones separated with thin shales, and this reservoir zonation seems key for this EOR method to work
- Reservoir modelling method established to screen this EOR method for candidate wells
- Further research and work to mature a new pilot at Alvheim ongoing

Acknowledgements

The authors would like to thank Aker BP, ConocoPhillips and Lundin for the permission to publish this work

We acknowledge Daniel Strand and Siv Marie Åsen for excellent laboratory work at NORCE

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