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Snøhvit CO_2 storage project: Assessment of CO_2 injection performance through history matching of the injection well pressure over a 32-months period

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Abstract

A performance assessment study of the Snøhvit CO_2 project, where approximately 1.1 million tonnes of CO_2 have been injected into a fault segment of the Snøhvit field was carried out. Since the start of CO_2 injection, the injection well pressure has risen at a rate faster than what is sustainable for a 25-years expected lifetime of the project. An important element of the history matching effort is the incorporation of fluvial facies in the reservoir model to reflect the sedimentary environment in the sandstone Tubåen formation. With the help of 4D seismic analysis, excellent match to both the flowing and shut-in bottom-hole pressure data throughout a 32-months injection period have been obtained. The outcomes of this study suggest that the fluvial depositional environment, together with the fact that the injection well is situated in a fault-segment, have contributed to a significant reduction in the injectivity at F2H.

Keywords: Snøhvit CO_2 storage; fluvial facies modelling; performance assessment; history matching

1. Introduction

Injection of CO_2 into the Tubåen formation, a sandstone saline aquifer lying beneath the producing Snøhvit gas reservoir (Stø formation) at a depth of around 2600-2700 m below sea surface, started in April 2008. By April 2011, approximately 1.1 million tonnes of CO_2, separated from the produced natural

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gas stream, have been injected into a fault segment (F-segment) of the Snøhvit field (Fig. 1). The location of the injection well (7121/4-F-2H, or simply F2H) was chosen based upon preliminary reservoir simulations conducted by Statoil. The target Tubåen formation is made up of 5 sand intervals of varying reservoir qualities: Tubåen 1 (base), Tubåen 2, Tubåen 3, Tubåen 4-1 and Tubåen 4-2. The mid and lower parts of the Tubåen (Tubåen 1 to Tubåen 3) are perforated for CO_2 injection, Fig. 2. A more detailed description of the Snøhvit CO_2 storage project and associated 4D seismic monitoring is given by a sister paper [1] in the GHGT-11 proceedings.

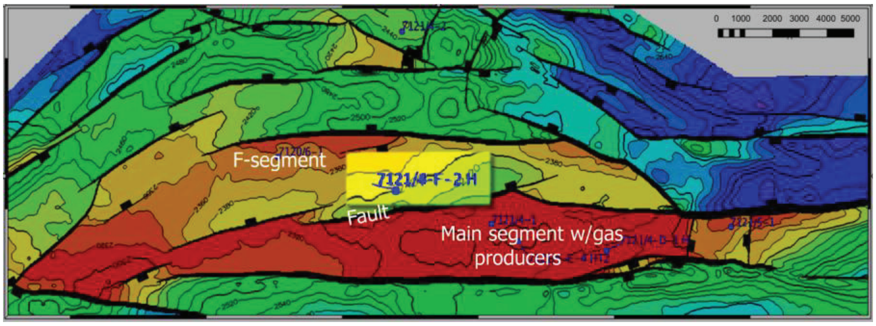


Fig. 1. Geology map and location of 7121/4 F-2 H at Snøhvit (courtesy of Statoil).

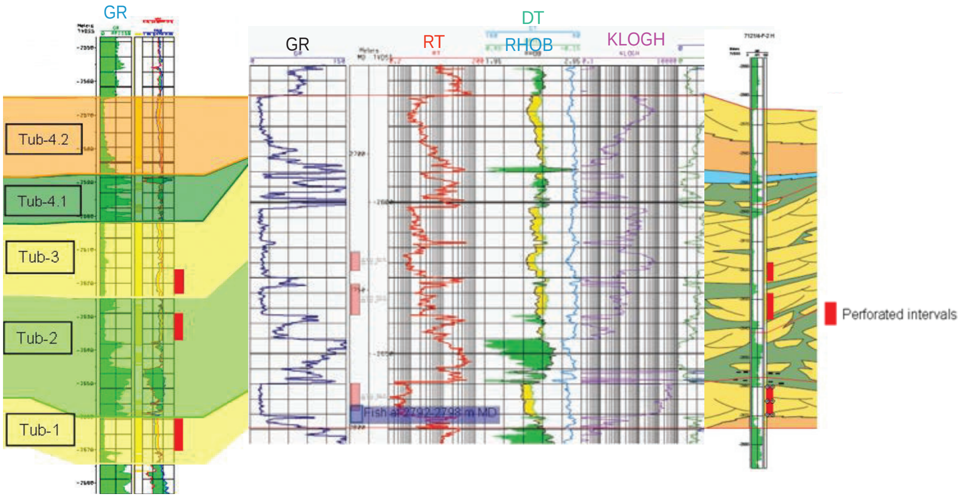


Fig. 2. A schematic of Tubåen formation showing the perforated intervals (courtesy of Statoil).

There are two sets of pressure gauges installed in the injection well, one at the well head (315.5 mTVD) and one at 1777.5 m TVD. During the CO_2 injection operation, short periods of stoppage have taken place regularly, which allows the measurement of well pressure over these shut-in periods, as well as during CO_2 injection. The flowing and shut-in bottomhole pressures (at 2632.5 mTVD) are estimated based upon the pressure gauge readings at these two levels.

Injectivity issue was initially encountered, marked by sharp rise in the injection pressure at the early stages, Fig. 3. This was successfully resolved by downhole MEG wash. Still, the well pressure was rising at a rate faster than what is sustainable for a 25-years expected lifetime of the project. By early August

2009, after the injection of approximately 0.5 million tonnes of CO_2, the shut-in bottomhole pressure (SIBHP) reached 355 bar, an increase of approximately 65 bar over the initial reservoir pressure at 290 bar. A long fall-off in the injection pressure was recorded over the 4.5 months shut-in period that followed (Fig. 3). History matching of the gradual pressure decline, coupled with the more rapid pressure increase during CO_2 injection, has proved to be a challenge. After the resumption of CO_2 injection in January 2010, the pressure rose to 360 bar by May 2010, and further to 368 bar by December 2010.

As part of the CO_2ReMoVe project, Imperial College, in close collaboration with Statoil, has been engaged in short-term performance assessment of CO_2 injection at Snøhvit, focusing mainly on history matching of the injection pressure. Reservoir simulation and history matching has been carried out in two stages: a first attempt in the absence of seismic monitoring data and a more focused effort following the availability of the 4D seismic survey and its interpretation.

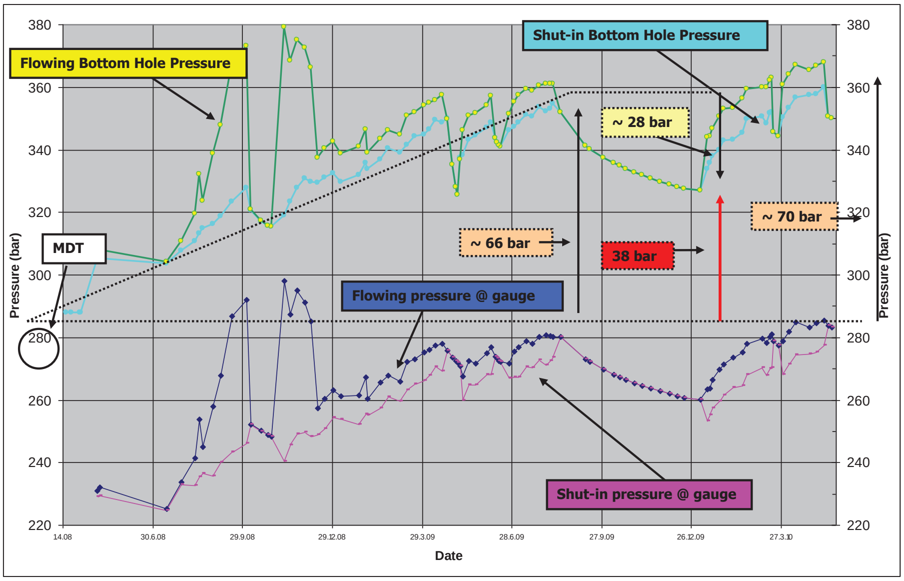


Fig. 3. Development of flowing and shut-in downhole pressures at F2H to May 2010 (courtesy of Statoil).

2. The preliminary history matching effort

A full-field reservoir model of the Snøhvit and two other nearby (Albatross and Askeladd) gas fields has been developed by Statoil. A sub-model, referred as the limited model, comprising only the Tubåen formation and the overlying Nordmela 2 formation at Snøhvit, has been used for pre-injection simulations. This limited model, which was made available to the research partners in a previous EU project (CASTOR), forms the basis for the reservoir simulations carried out in this study.

In this limited model, the Tubåen formation is represented by a single grid-layer, with thickness ranging from 61.5 to 70.5 m. The model is attributed with a stochastically generated porosity/ permeability distribution. The grid porosity ranges from 0.10 to 0.14, with an average value of 0.125. The grid (isotropic) permeability is in the range 34 mD to 764 mD, averaging at 290 mD. The permeability at the well block is 340 mD. This model has since been updated as more field data became available.

To facilitate the representation of different units in the Tubåen formation, the original single grid-layer was first divided into 12 sub-layers (~ 5 m in thickness), which were then grouped into three zones to represent Tubåen 1, Tubåen 2 and (part of) Tubåen 3 respectively. Thus, the bottom 3 sub-layers (1-3) are now considered to represent Tubåen 1, with the next 7 sub-layers (4-10) making up Tubåen 2 and the top 2 sub-layers (11-12) the bottom part (~10 m) of Tubåen 3. The resulting pore volume of the Snøhvit Main (including F-segment and Main-segment in Fig. 1) in the modified reservoir model is 463.8×10^6 rm^3.

The three zones were assigned with different permeability values (the porosity values remained unchanged): 200 mD for Tubåen 3, 20 mD for Tubåen 2, and 2000 mD for Tubåen 1, based upon the relevant data provided by Statoil. The permeability of Tubåen 3 was subsequently increased from 200 to 340 mD (the well block permeability in the original model) during history matching.

2.1. History matching methodology and results

The injectivity index for the individual injection zone (Tubåen 1 to 3) has been determined by Statoil: 56,000 sm^3/day/bar for Tubåen 2, 105,000 sm^3/day/bar for Tubåen 3, and 750,000 sm^3/day/bar for Tubåen 1, reflecting the permeability contrast between the zones. It is noted that the average overall injectivity index between January 2009 and April 2009 was approximately 133,440 sm^3/day/bar (10 tonnes/hour/bar), which is fairly close to the injectivity index for Tubåen 3.

In view of this analysis, it was hypothesised that only the top perforation (Tubåen 3) was periodically cleared by the MEG wash, with the two lower perforations remained largely blocked. The following history matching strategy was formed based upon this rationale:

- Employing a time-dependent connection transmissibility multiplier to represent the perforation-blocking process pre-October 2008.
- From October 2008 onwards, only the top perforation in Tubaen is reopened, with the two lower perforations remaining blocked.
- Progressively adjusting the size of the model domain to get a best-fit to the flowing BHP.

The CO2STORE option in ECLIPSE 300 was used to simulate the CO_2 injection at Snøhvit Field. A skin factor of 3.3 obtained from the well tests was used for the injector. Several relative permeability curves have been used by Statoil for the Tubåen formation. Fig. 4 shows the generic based relative permeability curves used as the base case for history matching in this study. A total (rock + brine) compressibility of 9.5×10^{-5} bar^{-1} was assumed.

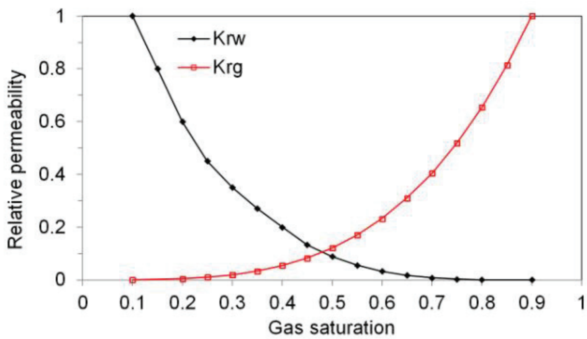


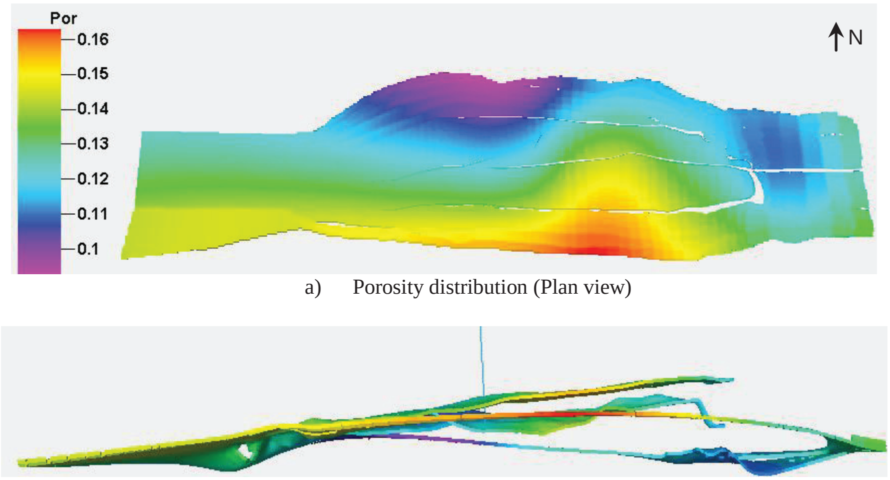
Fig. 4. Generically derived gas-water relative permeability curve used for history matching.

It was found that, in order to match the rising pressure trend in FBHP (up to August 2009), a model domain which is significantly smaller than the F-segment model is required. The history-matched reservoir model has a pore volume of 147 million rm^3, compared to ~220 million rm^3 for the full F-segment, and ~460 million rm^3 for Snøhvit Main.

3. Performance assessment informed by the 4D seismic data

4D seismic data acquisition was carried out between 17th August and 9th September 2009, covering an 8 × 8 km area around F2H. Anomaly is clearly observed at two levels around the injection well, with the largest anomaly being found at the lowermost zone (Tubåen 1), extending about 1 km away from the well [1]. This suggested that the two uppermost perforations had only delivered a minor part of the CO_2 to the formation. This observation has been confirmed by PLT data from a well intervention in 2011, which shows the overwhelming portion (80 - 90 %) of the injected CO_2 is stored in Tubåen 1.

In the light of the 4D seismic data, a decision was made to concentrate the reservoir simulation effort on CO_2 injection into Tubåen 1 only. Accordingly, it was assumed that there was no vertical pressure communication between Tubåen 1 and Tubåen 2. An extended reservoir model (Fig. 5), which includes the Snøhvit Main and flanks to the all four sides and bounded by faults to the South and North (Fig. 1), was chosen for history matching. Note that the F-segment, where the injection wells is located, is delineated by internal faults within the model domain on three sides (North, South and East). The model covers an area of 39 km (E-W) × 10 km (N-S) and has 391 × 104 cells (with dimensions 100m × 100m) in x and y directions respectively (the well is located at cell (204, 43)).



a) Porosity distribution (Plan view)

b) Side view from the South (vertical exaggeration x 10)

Fig. 5. Extended reservoir model domain bounded by faults.

3.1. Facies modelling in Petrel

An important element of the history matching effort is the incorporation of fluvial facies (with decreasing flow capacity: channel sand, levee sand and background floodplain) in the reservoir model to reflect the sedimentary environment in the Tubåen formation. The facies modelling tool in Petrel includes algorithms based on object modelling or stochastic simulation. The object modelling facility allows channels and other features to be built and fitted together. This option seems ideal for the modelling of a fluvial environment where continuous meandering channels can be important for governing flow.

In the current study, the parameters required for defining layout, section, levee and trends were chosen intuitively based on the shape of the CO_2 plume in the seismic image. Note that the resulting width of channels in the model is also constrained by the grid resolution (100 m × 100 m). An example of the fluvial facies generated by Petrel is shown in Fig. 6.

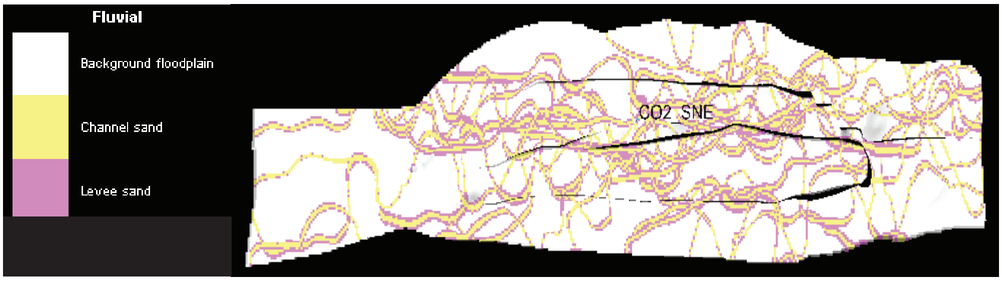


Fig. 6. An example of stochastically generated facies distribution in Tubåen 1.

In populating the reservoir model (Tubåen 1), each cell was assigned with facies-specific flow properties. The base case permeability for the floodplain, levee sand and channel sand was set at 20, 200 mD and 2000 mD respectively, which are within the range of available field data. Two scenarios concerning porosity were considered for history matching: 1) independent of facies; and 2) facies-specific as for permeability. In the latter case the base case porosity for the three facies was 0.103 (the floodplain), 0.166 (levee sand) and 0.195 (channel sand). Due to the lack of space, only the history-matching results for scenario 1 are presented. Excellent results have also been obtained for scenario 2.

3.2. History matching results

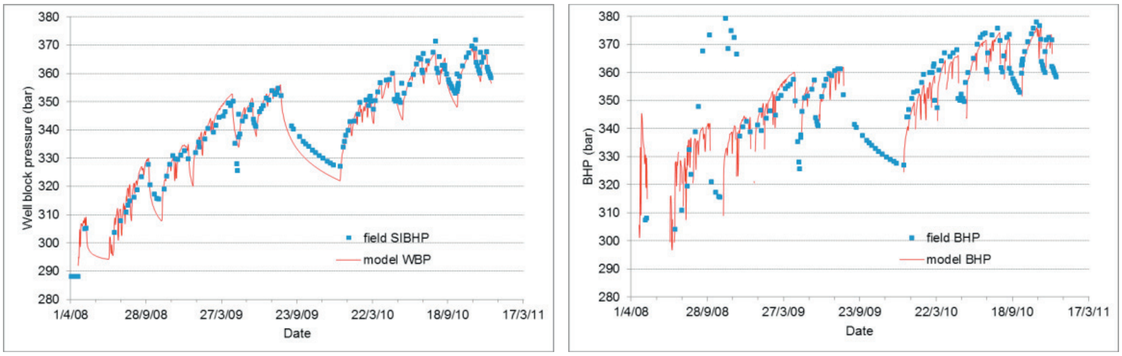
For fluvial reservoirs well injectivity is affected both by the volume fraction of high permeability channels in the formation and their spatial connectivity linked to the injection well. The former is pre-set and can be adjusted through a trial-and-error process, whereas the latter is stochastically generated in Petrel and as such it cannot be fine-tuned between successful simulation runs. History matching thus involves two stages 1) adjusting the volume fraction of the facies together with the tuning of facies-specific permeability/porosity; 2) finding one or more realisation(s) which gives the best fit to the field data (both flowing and shut-in BHP).

For the history matching results presented in this section, the relative permeability curves shown in Fig. 4 and a (reduced) total compressibility of 7.5×10^{-5} bar^{-1}, based upon the recent laboratory tests by Statoil, were used. All the faults were assumed to be sealing. Simplification has been made in terms of the components tracked in the reservoir model. Instead of the initial four components, namely CO_2, H_2O, NaCl in the water phase and NaCl in the solid phase, only two components (CO_2 and H_2O) were used. One direct consequence of this simplification is that a higher CO_2 dissolubility in the aqueous phase would be calculated using the keyword CO2STORE in ECLIPSE300.

As well as the more complex fluvial permeability structures, history matching with simple homogeneous permeability distribution has also been conducted and results are presented first. The limitation of this simple approach at Snøhvit is highlighted.

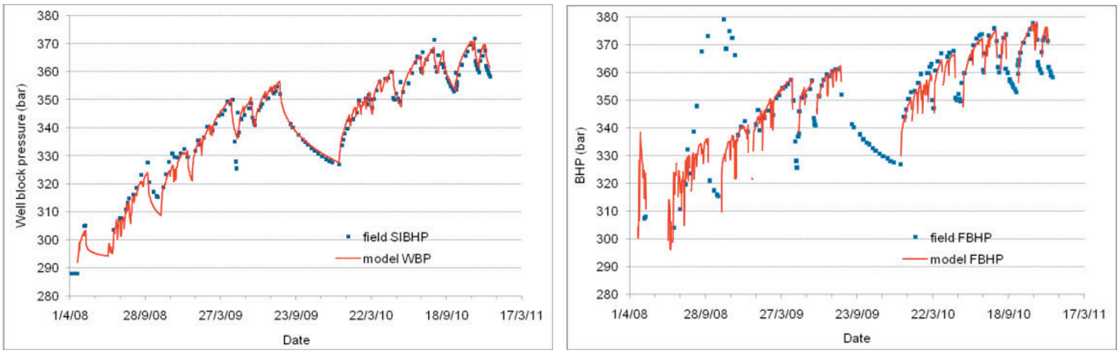
3.2.1. Homogeneous permeability distribution

Although a homogeneous permeability distribution at Tubåen 1 was assumed, the porosity distribution remained unchanged from the limited model (Fig. 5a). This gives rise to a total pore volume of 465.5 million m^3 in Tubåen 1. It was found that a homogeneous permeability of 300 mD in Tubåen 1 gives the closest match between the well block pressure (WBP) and the estimated shut-in BHP (SIBHP), except for the extended shut-in periods (Fig. 7a). Over the same period, a good match to the flowing BHP (FBHP) (excluding the spikes caused by injectivity issues encountered in the early stages, which has since been resolved by MEG wash), was also obtained (Fig. 7b). These results represent a significant improvement over the previous history-matching effort, where the whole Tubåen formation (in the limited model) was pressurized by the injected CO_2. It is also clear that a homogeneous pressure distribution could not accurately represent injection well pressure behaviour during the extended well shut-in period.



a) Shut-in BHP b) Flowing BHP

Fig. 7. Matching injection BHP with a homogeneous permeability distribution (300 mD).



a) Shut-in BHP b) Flowing BHP

Fig. 8. Matching injection BHP with a fluvial permeability distribution (scenario 1).

3.2.2. Fluvial permeability distribution (scenario 1)

Here the relative volume of the three facies and the permeability for each facies are the parameters that can be adjusted during history matching. However, the spatial distribution of the high permeability channels (channel sand and levee sand) and their connectivity to the injection well are stochastically generated. Initially the background floodplain was set to take up 60 % of the reservoir volume. This was later reduced to 50 %; with the channel sand and levee sand each occupying 25 %. The level of overall reservoir permeability was adjusted by applying a common multiplier to the base case facies permeability (2000 mD for channel sand, 200 mD for levee sand, and 20 mD for floodplain), so the permeability ratio between the three facies was always maintained. It was decided to match the estimated shut-in BHP data as they are considered to be more accurate than the estimated flowing BHP. An excellent match to the estimated shut-in BHP throughout the 32-months injection period (including the 4.5 month shut-in period) was obtained for at least one realisation (Fig. 8a). However, the simulated flowing BHP, which is computed based on the well-block pressure (WBP) and permeability, was lower than the field data (not shown). This is because the well was now located in the high permeability channel sand. Indeed the application of a well connection multiplier (0.15) resulted in a much closer match (Fig. 8b).

Fig. 9 shows the simulated pressure increase caused by CO_2 injection in Tubåen 1 by 1st September 2009 (the date is chosen to coincide with the 4D seismic survey). The impact of sealing faults surrounding the injection well on the pattern of pressure increase (semi-compartmentalised) throughout the formation is clearly observed. It is further noted that the two-orders of magnitude contrast in the facies permeability (Fig. 10) seems to have a minimum impact on the pressure distribution. Indeed, the pressure distribution is very similar to that obtained from the homogeneous permeability case (not shown).

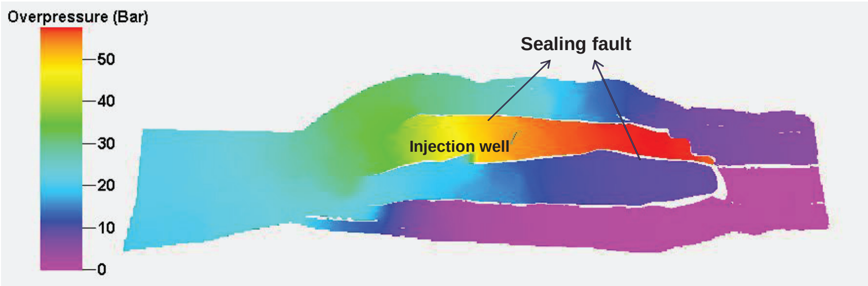


Fig. 9. Simulated pressure increase in Tubåen 1 by 1 September 2009.

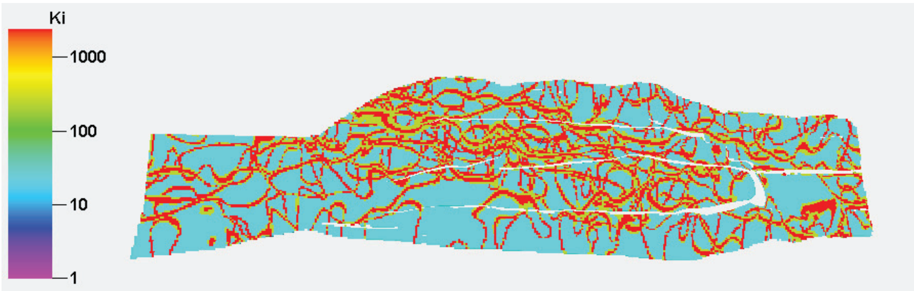


Fig. 10. The facies realisation that gives an excellent match to the shut-in BHP (scenario 1).

4. Discussion and conclusions

The flow characteristics in Tubåen 1 that control pressure response to CO_2 injection (including well shut-in) can be better represented by the modelled fluvial system with three distinctive facies. The impact of the sealing faults surrounding the CO_2 injection well, which effectively lead to the semi-compartmentalisation of the F-segment, on the simulated pressure distribution can be clearly observed. It may be concluded that the fluvial depositional environment, in conjunction with the fact that the injection well is situated in a fault-segment, have contributed to a significant reduction in the injectivity at F2H.

Acknowledgements

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Reference

[1] Eiken O, Gilding D, Hansen H, Hansen O, Nazarian B, Osdal, B, Ringrose P. Snøhvit: The history of injecting and storing 1 Mt CO_2 in the fluvial Tubåen Fm. Proc. GHGT11.