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GHGT-12

Towards maximum utilization of CO_2 storage resources

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Abstract

Large scale deployment of CO_2 capture and storage (CCS) has the potential to be an important part of the effort to mitigate climate changes. If large scale CCS is to be realised the storage resources of saline aquifers should be utilised to their full potential by maximising the storage performance of each aquifer. This can not be performed without water production to control and relieve the induced pressure increase from CO_2 injection. Large scale CO_2 injection with a large number of injection wells will hence require a large number of water production wells. For offshore aquifers wells are one of the main cost drivers and pressure control by water production in CO_2 storage operations will increase the number of wells. However, water production will also utilize storage resources better, reduce the area of impact and hence reduce the need for monitoring, give better control on the sub-surface by the increased numbers of observation points and may reduce the future liability of the operator. This study investigates strategies for optimal design of well patterns, inter-well distances, optimal injection rates and average injection period for each well as function of storage characteristics such as areal size, thickness, porosity and safe pressure increase. The main focus is on inverted five spot well patterns in tilted reservoirs and the asymmetry in well positions required due to the tilting. Much of the work is based on simulations reported for similar well patterns in models without tilt in an accompanying paper which will be presented at this conference [1].

Keywords: CO_2 storage, well patterns, tilted aquifers

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1. Introduction

Injection of CO_2 into deep saline aquifers will lead to a pressure increase both in the near-well area and throughout the aquifer. The equilibrium average pressure increase can be calculated if the total compressibility (of fluids + rock + bulk volume), the volume of the aquifer (fluids + rock), and the net fluid volume added are known. The pressure change will, during the injection period, be larger near the wells than far from them. For safe long term storage the pressure at each point in the aquifer must be kept below levels that would cause fracturation of the cap rock or re-activation of faults. By extracting formation water from the aquifer the amount of CO_2 injected for a given pore pressure increase can be significantly increased [2,3,4,5].

Production of water can be implemented from the start as a way to increase long-term CO_2 injectivity or be added to the project sometime after the start as pressure monitoring indicates that the pore pressure is approaching the pressure limit for the formation. The addition of water production wells can also be used to significantly increase the operator's ability to control the migration of the CO_2 plume (by manipulating the injection/extraction rates). Unless the placement and operation of the water production wells are carefully done, however, there is a risk of early breakthrough of CO_2 in the production wells and an associated need for premature cut-back of CO_2 injection.

The present study investigates the effect of tilted and heterogeneous aquifers on such high-level parameters as

- the well distance necessary to achieve simultaneous break through in all production wells,
- the maximum allowable injection rate and
- the overall storage efficiency.

This is done by analyzing the results of a set of simulations on generic tilted and layered models. For tilted models a regular five-spot pattern will not be optimal, since the injected CO_2 will reach the up-dip wells sooner than the down-dip wells. The asymmetry introduced by the tilt may be compensated by a corresponding asymmetry in the well pattern. The change in storage performance and the effect of asymmetric well patterns will be studied in order to arrive at recommendations for optimal well placement. Next, the results from the generic simulations are compared with results from simulations on full field model geometry of a tilted saline aquifer off shore Mid-Norway. The suggested optimal well patterns from the generic model runs are tested to see if the trends for optimised storage capacity are valid also for more realistic full field models.

2. Method

A series of simulations on tilted synthetic models with one injector and two producers is performed. The injector and producer wells are controlled by bottom hole pressure (BHP). The producers are set to produce at hydrostatic pressure (no pumping required) giving production rates dependent on reservoir properties, perforation length and the induced increase in reservoir pressure from the injection well. The injection well injects at a pre-set injection pressure which could be decided based on estimated safe pressure increase in the reservoir. Two different injection pressures have been applied in the synthetic model.

2.1. Models and flow parameters

To investigate the effect of dipping aquifers a set of three synthetic model grids with 2°, 5° and 10° tilt has been constructed. The models represent half the area of a full inverted five-spot well model (see Figure 1) with side lengths L and L/2 (L is here 3000 meters). The average depth of the top layer is 1600 meters varying from 1340 to 1860 meters for the model with 10° dip. The thickness of the models is 60 meters and areal size of the grid blocks is 50 by 50 meters. The model grid has 45 layers with refined layer thickness (0.25 and 0.5 meter) in the top 6 meter and a constant layer thickness of 2 meters in the lower 54 meter. The total number of grid blocks in the model is 81000 (30 by 60 by 45). Initial hydrostatic pressure is assumed and salinity and temperature is kept constant (8 wt% TDS and 49 °C). Viscosity and density of the formation water are based on correlations in [6] and [7]. The density of CO_2 is based on an equation of state for CO_2 developed by Span and Wagner [8] and the viscosity of CO_2 was calculated from a correlation by Fenghour et al. [9]. Solubility of CO_2 in the formation brine is not accounted for in the reported simulations except in the full field example from the Trøndelag platform.

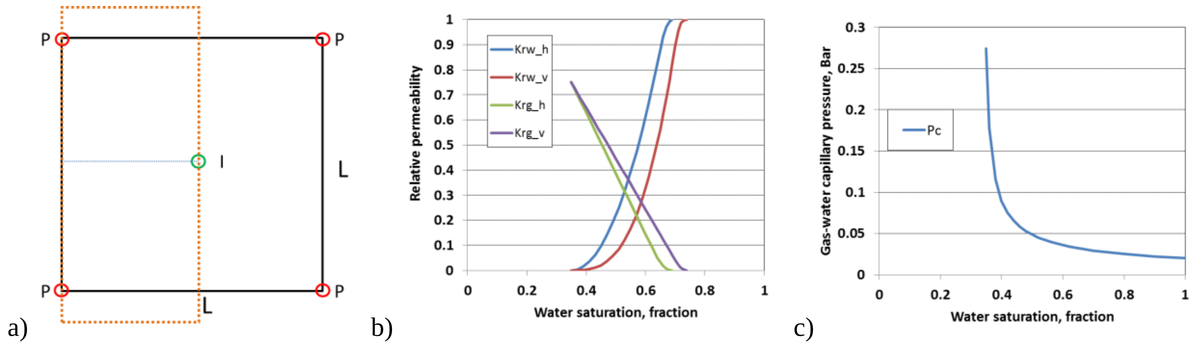

Figure 1 a) Schematic view of an inverted 5-spot well pattern with one injector (I) surrounded by four producers (P). Dotted rectangle indicates model area. b) Pseudo relative permeabilities for CO_2 (Krg) and brine (Krw), horizontal (_h) and vertical (_v). c) Capillary pressure curve for the CO_2-brine system.

Directional relative permeabilities for CO_2 and brine are up-scaled from [10] and the capillary pressure is based on [11], see [1]. The relative permeability and capillary pressure curves used in simulations are shown in Figure 1 b) and c). The residual water saturation is 35 %, the critical gas saturation is 31 % and 26 % (horizontal and vertical) and the capillary entry pressure for CO_2 is 0.02 Bar.

2.2. Simulation setup

The objectives for the simulations are to investigate the effect of tilting, anisotropy, injection pressure and heterogeneity on parameters such as well symmetry (optimal position of injector), CO_2 break through time, injection rate and storage efficiency. It is expected that tilting the model will require a down flank shift in the position of the injector to achieve simultaneous break through of CO_2 in the up- and down-dip production wells and hence maximize the storage efficiency. The production wells are positioned in the outer two corners of the model (see Figure 1a) and are modelled as horizontal wells along the bottom of the formation. The perforation length of the producers is set at 100 meters for all cases. Production from these wells are controlled by a bottom hole pressure (BHP) equal to the hydrostatic pressure. The injection well is vertical, perforated along the whole height of the model and is set to inject at a constant BHP. The perforation length of the producers will affect the injection rate of the injection well but this has not been further investigated in this work. (See Wessel-Berg et al, this conference [1].)

The same variation of parameters is simulated on all three grids (2°, 5° and 10° dip). The horisontal permeability is held constant at 500 mD. Three set of vertical permeabilities (Kv) are simulated; 5 mD, 100 mD and 500 mD. Two injection well BHP's are applied; 195.5 Bar and 231 Bar (at reference depth 1600 meters) and finally two different aquifer heights; 20 and 60 meters is used. The 20 meter high aquifer was only simulated with Kv=100 mD and injection BHP=195.5 Bar. All simulations on the synthetic tilted grids are listed in Table 1.

Table 1 Overview of simulated cases and parameter values for the simulations on tilted grids.

Case	Model dip	Kv permeability	BHP injection	Height of model
#	°	mD	Bar	m
Case1	2	100	195.5	20
Case2	5	100	195.5	20
Case3	10	100	195.5	20

Case4	2	100	195.5	60
Case5	5	100	195.5	60
Case6	10	100	195.5	60
Case7	2	5	195.5	60
Case8	5	5	195.5	60
Case9	10	5	195.5	60
Case10	2	500	195.5	60
Case11	5	500	195.5	60
Case12	10	500	195.5	60
Case13	2	100	231	60
Case14	5	100	231	60
Case15	10	100	231	60

In addition simulations were performed on the 2° dipping model with a high permeability layer either at the top or at the bottom of the model.

3. Results

One of the main results from the simulations on tilted models is the distance one has to shift the injection well to achieve simultaneous CO_2 break through in the two production wells. The required shift is as expected dependent on the tilt of the model since buoyancy forces will make the injected CO_2 migrate up-dip but it is also dependent on vertical to horizontal permeability ratio and the injection pressure. Figure 2 show an example of CO_2 saturation after 1 year in a) and 2.5 years in b) for the model with 10° tilt. All the synthetic models have no-flow boundary conditions assuming that there is full symmetry with neighbouring well patterns. This is true for a model without tilt but as can be seen in the figure below the upper and lower boundary do not see the same CO_2 saturation. This can lead to an earlier break through for the up-dip wells but our basic assumption is that the error is not very large.

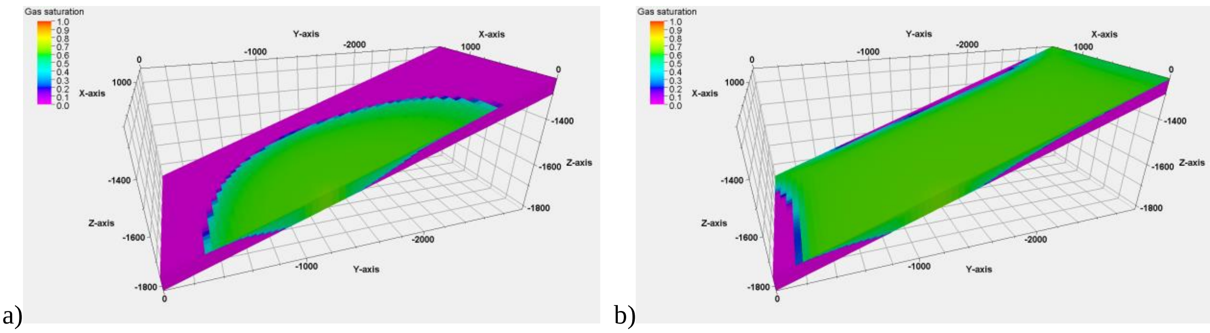

Figure 2 Gas saturation in the 10° tilted model after a) one year injection and b) when the CO_2 breaks through at the production wells (2.5 years). Injection well is shifted 650 meters down-dip, K_v=100 mD and BHP=195.5 bar.

3.1. Well distances and storage efficiency

Introducing a tilt in the models requires a down-flank shift in the position of the injection well to achieve simultaneous CO_2 breakthrough in the up- and down-dip production wells. In all simulated cases an increase in tilt requires an increase in the distance needed to shift the injection well down flank compared to a model without tilt.

Results show that for the model with 2° tilt the injection well needs to be shifted a distance between 6.7 % and 16.7 % of L/2 which corresponds to between 100 and 250 meters in the synthetic model.

Table 2 lists the distance required to shift the injection wells down flank for all the simulated cases. Increasing the tilt while keeping the other controlling parameters unchanged requires a larger shift of the injection well. For the cases with 10° tilt the injection well has to be moved between 23 % and 67 % of the distance to the border of the model. The required distance to shift the injection well for all the simulated cases are plotted in Figure 3 a), b) and c) below.

Table 2 Required distance as percent of L/2 to shift the injection well for the simulated cases. Simulation parameters listed in the three last columns.

Cases 2° dip	Shift % of L/2	Cases 5° dip	Shift % of L/2	Cases 10° dip	Shift % of L/2	Kv, mD	BHP inj Bar	Height m
Case1	6.7	Case2	13.3	Case3	23.3	100	195.5	20
Case4	10	Case5	23.3	Case6	43.3	100	195.5	60
Case7	16.7	Case8	40.0	Case9	66.7	5	195.5	60
Case10	10	Case11	23.3	Case12	40.0	500	195.5	60
Case13	10	Case14	13.3	Case15	23.3	100	231	60

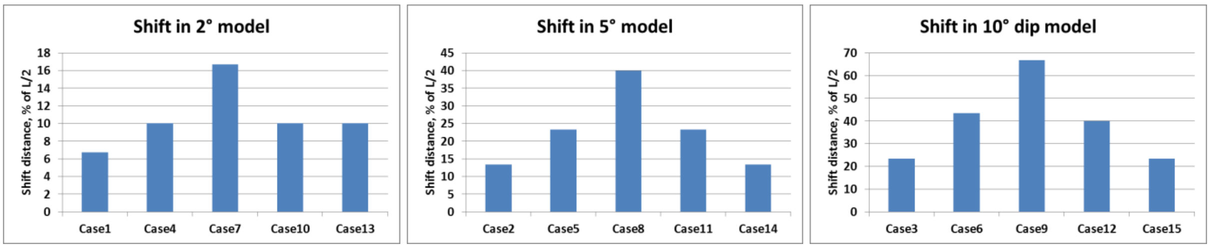

Figure 3 Necessary amount of injection well down-dip shift distance in order to achieve simultaneous breakthrough in the production wells. The distance is given dimensionless as the percent of the side length of a quarter 5-spot model (L/2).

Injection rate, break through time and storage efficiency will vary with the vertical permeability (permeability aspect ratio) and model thickness (reservoir aspect ratio). A thinner reservoir (cases 1–3) or a higher injection pressure (cases 13–15) requires smaller shifts in the well position, probably due to a more viscous dominated flow. A low vertical permeability (low Kv/Kh) normally gives better vertical distribution of the injected CO_2 and longer time before breakthrough in production wells. The resulting slower front velocity and therefore higher influence of gravity could explain why the cases 7–9 need the largest injection well shifts. The increased storage capacity for cases 7–9 caused by the improved sweep is seen in Table 3 below. Here it is also seen that the cases with more viscous dominated flow also scores high on storage capacity.

Table 3 Results from simulation on the synthetic tilted models. The table lists tilt of the model, down flank shift of the injection well, CO_2 break through time, average injection rate and CO_2 storage efficiency as percent of total pore volume.

Case	Dip	Shift	Break through	Injection rate	S_{eff}
	°	% of L/2	days	Mt/y	% of porevol

Case1	2	6.7	1184	0.865	13.1
Case4	2	10.0	1478	1.802	11.2
Case7	2	16.7	5520	0.750	17.6
Case10	2	10.0	1084	2.346	10.7
Case13	2	10.0	888	3.732	13.2
Case2	5	13.3	1184	0.863	13.0
Case5	5	23.3	1478	1.799	11.2
Case8	5	40.0	4831	0.754	15.4
Case11	5	23.3	1084	2.326	10.6
Case14	5	13.3	888	3.716	13.2
Case3	10	23.3	1184	0.863	12.9
Case6	10	43.3	1380	1.854	10.8
Case9	10	66.7	4140	0.758	13.8
Case12	10	40.0	1084	2.295	10.4
Case15	10	23.3	888	3.713	13.1

Figure 4 displays the storage efficiency for the simulated cases and as mentioned above the cases with low Kv/Kh gives the highest storage efficiency in all grid models due to the better vertical sweep of the injected CO_2.

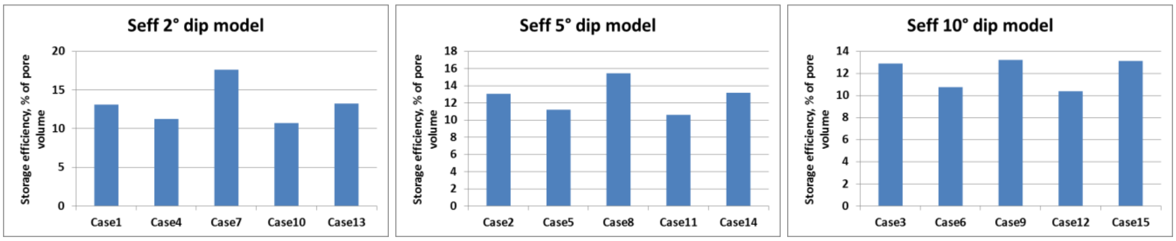

Figure 4 Storage efficiency as percent pore volume occupied by CO_2 for the different simulated cases.

3.2. Layered reservoir storage efficiency

For the grid with 2° tilt and 60 meter thickness a layered geology is modelled by a 20 meter thick high permeable zone (500 mD). Two cases are considered with one having the high permeable zone at the top of the reservoir and the other having the high permeable zone at the bottom. The remaining part of the model (40 m) has a lower permeability. Two cases of low permeability zones are investigated; 50 mD and 5 mD. The vertical to horizontal permeability ratio is set to 0.1. For the cases with high permeable zone in the upper 20 meters most of the injected CO_2 flows through the upper zone and the storage efficiency is low. For the cases where the high permeable zone is at the bottom more of the injected CO_2 enters into the low permeable zone due to buoyancy forces and higher storage efficiency is expected. The storage efficiency in the high permeable zone (20 meter) is high because a higher injection rate can be sustained since the low permeable zone acts as a buffer for the pressure increase.

Table 4 Storage efficiency (percent of total pore volume occupied by CO_2) for the layered geology cases

Cases	High perm zone position	Low perm zone, mD	S_{eff} %

Case16	Upper	50	4.6
Case17	Lower	50	15.6
Case18	Lower	5	6.1

Table 4 lists the storage efficiency for the layered geology cases. As can be seen the storage capacity decreases compared to homogeneous cases since most of the injected CO_2 goes directly towards the producer in the high permeable zone. The highest storage efficiency was achieved for case 17 (15.6) because a large part of the injected CO_2 migrated vertically from the high permeable zone to the above low permeable (50 mD) zone (see Figure 5).

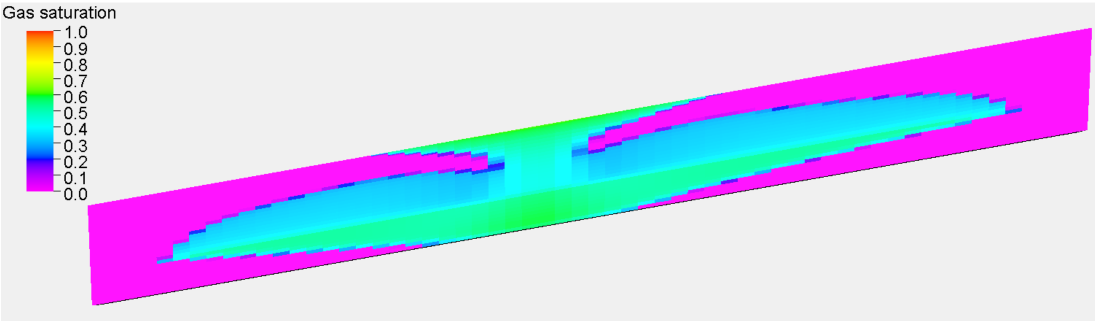

Figure 5 Cross section view of CO_2 saturation in the case with high permeability zone at the bottom and with a 50 mD low permeable zone above.

3.3. Full field simulations

Simulations are performed on a part of the Garn Formation in the Trøndelag Platform with 24 injection wells and 36 production wells to compare the results from the synthetic models with a real aquifer geometry. The region selected in the Trøndelag platform is quite shallow (1250 to 450 meters TVDSS) with an average tilt of 5°. To avoid having a shallow reservoir where the density of CO_2 is changing rapidly an artificial downward shift in depth by 500 meters is performed by increasing the initial reservoir pressure by 50 Bar. The Garn Formation is assumed to have a constant thickness of 127 meters. Reservoir properties are made to be in the same range as for the synthetic models with a homogenous case; porosity and permeability equal to 30 % and 500 mD and a heterogeneous case; with depth dependent porosity and permeability. In the heterogeneous case the porosity varies between 30 and 41 % and permeability varies between 547 and 921 mD. Both cases have a vertical to horizontal permeability ratio of 0.1. In addition a stochastically varying net to gross (NTG between 0.75 and 1.0) is applied to the heterogeneous case. The inverted five spot well pattern has distance between neighbouring production wells equal to 4 km (L=4000 m). The size of the reservoir model is approximately 40 by 15 kilometers with a constant temperature equal to 45 degrees and salinity equal to 3 wt% TDS. The wells are vertical and perforated along the full height of the reservoir (127 m). Grid resolution of the model is 200 by 200 meters laterally and the layer thickness is 11.7 meters except in the upper ten meters where layers are progressively refined down to 1 meter layer thickness. Wells are controlled by BHP, the injection wells are set to inject at 30 Bar above initial pressure and the production wells are as before set to produce at initial pressure. The shift of the injection wells down-dip is the same for all the wells regardless of local topology of the reservoir top or heterogeneity variation for the heterogeneous model. All wells are shifted 600 meters down-dip (30 % of L/2) based on the results from the synthetic models (Kv/Kh=0.1, just below Case 5).

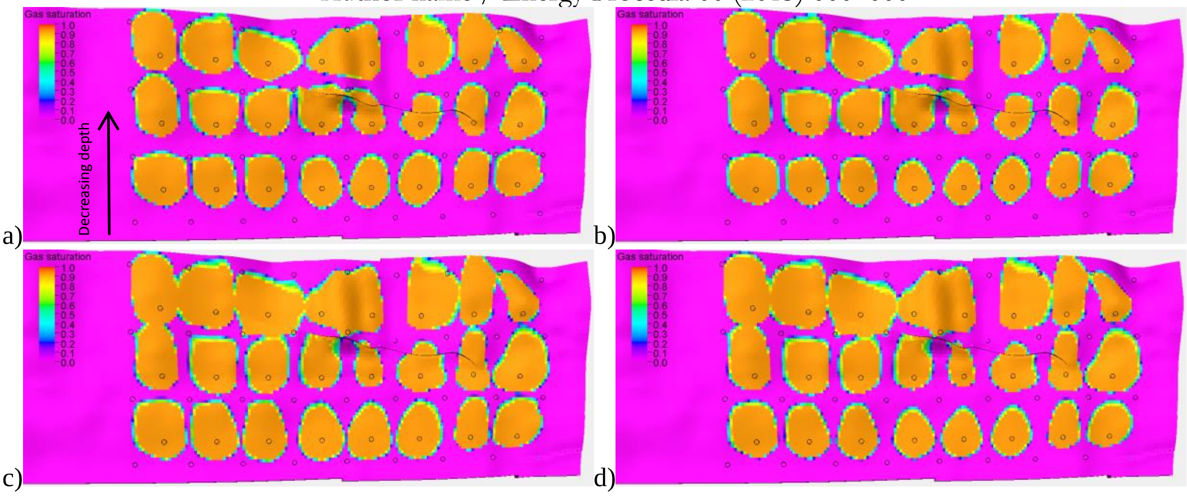

Figure 6 CO_2 saturation after break through in one of the production wells for the field model with average dip 5°. a) homogeneous case without a shift of the injection wells, b) heterogeneous case without shift in wells, c) homogeneous case with a 600 meter shift in injection wells and d) homogeneous case with a 600 meter shift in injection wells.

Figure 6 shows CO_2 saturation in the full field model for the homogeneous case a) and c) and the heterogeneous case b) and d) and only small differences can be seen between the homogeneous and heterogeneous models. Shifting the wells down-dip enables injection of 19 and 20 % more CO_2 compared to the cases with a symmetric well pattern. As can be seen from the figure a more optimal placement of each injection well especially in the lower part of the model can be performed but this has not been attempted here. The simulations were stopped when one well experienced CO_2 break through and the option to shut off offending wells could increase the volume of injected CO_2 further.

Table 5 list the full field model results in terms of injection masses and injection time. Observe that the heterogeneous case has better performance when it comes to injection rate and this is mainly due to slightly better reservoir properties resulting in higher injectivity and productivity for the wells.

Table 5 Full field model simulations results with total injected CO_2, injection time and the average yearly injection rate for the operation.

Heterogeneous yes/no	Well shift m	Injected CO_2 Mt	Injection time years	Yearly rate Mt/y
no	0	308.08	5.7	54.3
no	600	367.22	6.8	54.3
yes	0	324.86	4.0	80.2
yes	600	392.87	4.9	80.7

The increased cost associated with the water production wells has not been discussed here but it is noted that there can also be a reduction in the cost associated with other parts of the CO_2 storage operation, since fewer storage formations need to be explored and evaluated for safe, long term storage. A proper analysis requires that a value is set on the additional storage resources made available through water production.

4. Conclusions

Simulations on tilted models have shown that a shift in position of the injector is required to account for the tilt of the model. The resulting asymmetry in well pattern will depend on the size of the tilt, anisotropy and injection rate.

Low vertical permeability (high anisotropy) increases the storage efficiency of the operation and also leads to the largest asymmetry in well patterns. Storage efficiency on the synthetic models is in the range of 10 to 18 % with the use of inverted five spot well patterns. For a layered geology with a high permeable thief zone this reduces to between 4 and 6 percent, but for a favorable mobility relation with a high permeable zone below a zone with moderately lower permeability can give storage efficiency up to 15 %.

Simulations on full field models show that a shift in the symmetry for the well pattern based on the synthetic modelling give up to 20 % extra injection volume without optimising well placement with regard to local heterogeneity and topology.

Increasing storage capacity by water production and going towards maximum use of storage resources has an associated cost due to the increased number of required wells. However, water production will also utilize storage resources better, reduce the area of impact and hence reduce the need for monitoring, give better control on the sub-surface by the increased numbers of observation points and may reduce the future liability of the operator.

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