Multiwell injectivity for storage of CO$_2$ in aquifers

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Abstract

Geological storage of CO$_2$ in deep saline aquifers has been suggested as a potential methodology for reducing CO$_2$ emissions over short to medium terms. A number of projects are in operation and a larger number are being designed. However, not all aquifers are equally suitable for CO$_2$ storage. Virtually all publications that present the criteria for selection of suitable sites for geological storage of CO$_2$ in aquifers, consider injectivity to be among the top three criteria, with capacity and containment being the other two. Among parameters that affect injectivity, permeability can vary by the largest degree. Unfortunately, selection of storage sites with sufficient permeability that would enable injection of the desired volumes, using only one injection well – such as that achieved in Sleipner – is not always possible. When this is not possible, injectivity needs to be improved for example by increasing the contact area with the formation (e.g. through application of hydraulic fracturing or horizontal wells) and/or employing more than one injector. Recent studies indicate that multiwell injectivity does not increase linearly with the number of injectors. Instead, progressively more number of wells is required to achieve an equal increment in injection rate.

It is well known, that because of the small compressibility of the water, it takes a short time for the pressure pulse from the different injectors to cause significant interference. We use this observation and suggest a well pattern that would minimize such interference effects in an open and homogeneous aquifer. Next, we develop an analytical solution, for the injectivity of multiwell systems as a function of (i) number of wells, (ii) distance between wells, and (iii) injectivity of one well. The analytical solution obtained for single-phase flow is applied to cases of CO$_2$ injection in aquifers. Numerical experimentation over a wide range of parameters demonstrates the applicability of the analytical solution for two-phase flow problems.

This relation is developed for homogeneous aquifers; suggesting that such a relationship may be used for scoping and screening studies early on when data us scarce, and the effect of the number of wells and/or their distance on overall injectivity is being studied. Furthermore, such a relationship allows examining the economic balance between increasing the number of wells or the distance among wells.

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1. Introduction

Among the important factors that determine the suitability of an aquifer for geological storage of CO$_2$ are capacity and injectivity. Capacity and injectivity may be estimated using detailed numerical simulation studies. However, often before such detailed studies a screening study is conducted for selection of favorable formations (Bachu 2003). Over the past few years there have been significant advances in estimation of capacity. Bachu et al.
Injectivity Index per unit of pressure difference between the injection pressure and reservoir pressure, usually referred to as the measure of injectivity of a well. The injectivity is defined as the ratio of injection rate to pressure drop across the wellbore. When the pressure drop is small, this ratio is large, thus the well is injective. The injectivity is high for wells that are laid on parallel rows of equal distance (similar to repeated 5-spot pattern).

2. Question of Injectivity

Let us consider a CO2 storage project that intends to inject a particular amount of CO2 per year. Let us further assume that there are large regional aquifers with high capacity with competent seal ensuring containment. The next question is how many injectors are required to inject the desired volume of CO2, and where should they be placed. Often the rate of injection can be increased by either changing completion techniques (e.g., fracturing, or use of horizontal wells), or by increasing the number of wells. In the following single-well and multiwell injectivity are discussed.

**Single-well injectivity:** The injectivity at or nearby a single well can often be estimated to a reasonable level of accuracy, either using standard flow and shut-in tests (or other well testing techniques), or use of core/log measurements and simple analytical models (Lee et al. 2003). Injectivity of a wellbore is the ratio of injection rate per unit of pressure difference between the injection pressure and reservoir pressure, usually referred to as the Injectivity Index $q/(p_w - p_R)$, where $q$ is injection rate, $p_w$ and $p_R$ are wellbore and reservoir pressure. For a single-well, the change in injection rate as reservoir pressure $p_R$ increases is easily taken into account through the use of well-established well-testing techniques and the corresponding analytical solutions. Such analysis techniques are often used to predict rate of injection with time assuming single-phase flow (e.g., injection of water into an aquifer).

For CO2 injection into aquifers, there is a number of other factors that could affect the injectivity of a well by up to one order of magnitude. Some of these factors improve injectivity while others deteriorate injectivity. They include: (i) stimulation vs. damage, (ii) two-phase flow and the difference between mobility of the injecting fluid and the in-situ fluid with or without salt precipitation (Burton et al., 2008 and Zeidouni et al. 2009) and (iv) stress dependency of permeability.

**Multiwell injectivity:** It is not straightforward to estimate injectivity of a group of wells using the knowledge of single-well injectivity. This is mainly because of interference among wells; injection rate of one well is affected by increase in reservoir pressure $p_R$ caused by injection in other wells. Although interference among wells may be modeled using the principle of superposition (Lee et al. 2003), the calculations are somewhat tedious especially when the location of the injectors are not known a priori.

The small compressibility of the water leads to severe interference effects. Furthermore, the high pressure area created by injection can be orders of magnitude larger than the area covered by the CO2 plume itself. In such cases, increasing the number of wells, does not translate into a proportional increase in the injection rate. Although interference in reservoir engineering is well understood (and for many decades has been used for estimation of reservoir properties away from the injection wells), however, there are few general models that account for it.

In storage operations, Dereniewsky et al. (1982) have given examples from natural gas storage sites, where as a result of pressure interference between wells multiwell deliverability is less than half of the summation of the deliverability of the individual wells (deliverability for producers is the analogous to injectivity for injectors). McCoy (2008) used the solution methodology suggested by Muskat (1937) for steady state flow and developed an analytical solution for wells that are laid on parallel rows of equal distance (similar to repeated 5-spot pattern.
without producers, see Figure 1). The solution was limited to single-phase flow. Zarkisson et al. (2008) used the principle of superposition for steady state flow and applied it to wells placed in a geometry similar to that considered by McCoy (see Figure 1). For two-phase cases he used a numerical simulator and conducted a number of sensitivity studies to show the effect of well-spacing and permeability on multiwell injectivity. Ghaderi et al. (2009) used a numerical simulator and evaluated the number of wells for a desired CO2 injection rate. Transient and two-phase flow effects were incorporated. The authors studied the effect of well-spacing, formation compressibility, permeability and formation thickness. In all cases, progressively more number of wells was required to achieve a fixed improvement in multiwell injectivity. The well-placement geometry was similar to that used by McKoy (2008) and Zarkisson (2008). Gaderi et al. (2009) then evaluated the number of injection wells required for a particular CO2 storage project in Alberta.

In this paper we suggest an alternate geometry for well placement that reduces interference as compared to the repeated rows of wells used by the previous authors. Then we develop an analytical solution for multiwell injectivity, which accounts for the well-spacing, number of wells, and stimulation. It will be shown that this relationship is independent of permeability, formation thickness, and reservoir and injection pressures. The solution is developed for transient flow of a single-phase. We then examine the applicability of this solution for two-phase flow problem of CO2 storage into aquifers.

3. Well Placement

Figure 1 shows the distribution of CO2 (on the left) and pressure (on the right) after 15 years of injection in a corner of a hypothetical carbonate aquifer in Alberta. Wells are spaced in a uniform square-shaped pattern with a well-spacing of 3 km. A number of observations can be made: (i) The CO2 plume has occupied a radius of approximately 1 km sounding the wellbores, with little evidence of interference among them, (ii) the pressure effects are felt at very large distances, (iii) there is significant pressure interference among the wells to a point that the pressure field resembles radial flow from one equivalent well.

The strong pressure interference among wells suggests that the wells that are surrounded by others do not contribute as much as the ones on the periphery. Therefore it is best to place the wells so that the interference is distributed equally. This can be achieved by placing the wells on the corners of a regular polygon. In Figure 2, this is shown for placement of three and four wells. The solid lines show the no-flow boundaries that form among the wells. In this geometry, each well is assigned a wedge of the reservoir. For \( n \) wells, the wedge angle will be \( \frac{360}{n} \) degrees (shown on Figure 2). The injection capacity of the multiwell system is then equal to \( n \) times that of the individual wells. One can expect that the interference would decrease as the distance from the centre \( R \) increase and would increase as \( n \) increases. In addition, one could expect that the injectivity of the multiwell system could be improved by improving the injectivity of the individual wells, for example by stimulation. However, it is expected that not all of the stimulation applied to the individual wells would be translated to the multi-well system. This is because; stimulation is a near-wellbore enhancement. The pressure distribution in Figure 1, suggest that the combined injectivity is controlled by pressure distributions at large distances. In this work, we propose that the effect of distance from the centre, the number of wells and the stimulation in individual wells can be incorporated.
into an “equivalent” skin factor, such that the multiwell system could be replaced by a single-well with this equivalent skin. This is advantageous, because the skin factor is a dimensionless number. We find that for a unique combination of $R$, $n$ and skin, a unique “equivalent skin” can be estimated. This allows estimation of the rate of the multiwell system, through the definition of skin factor; $S = 2\pi k h \Delta p \gamma / q B \mu$. The effect of permeability, thickness and viscosity can be taken into account through the use of this relation.

Figure 2: Placement of wells on corners of regular polygons for uniform interference among wells.

4. Work scope and methodology

The objective of this work is development of a methodology for estimation of multiwell injectivity for screening purposes. We assume a formation that is homogeneous in all its properties (e.g. permeability, thickness and porosity). For a particular combination of fluid and reservoir properties and injection and reservoir pressure, we use analytical solution developed for single-phase flow for a well-placed in a wedged-shape reservoir and estimate its injectivity leading to single-phase injectivity of the multiwell system. We then estimate the equivalent skin for a well placed in the centre of the same reservoir which would have an injectivity similar to the multiwell system. To determine the relation between the “equivalent skin” and the three parameters of distance to the center ($R$), number of wells ($n$) and skin factor of the individual wells, we vary each of them individually. Once the relation is obtained, we examine its validity against a number of single-phase cases by varying the reservoir parameters and pressure constraints. Finally, the applicability of the relation for the equivalent skin factor for CO$_2$ injection is examined.

The single-phase part of this work is conducted using analytical solutions incorporated in the FAST WellTest software of Fekete, and the two-phase flow studies are conducted using Eclipse of Schlumberger. The solution is developed for open aquifers of infinite extent. In practice, the results are applicable as long as the reservoir is in infinite-acting; reservoir radius is larger than radius of investigation determined from use of water properties.

As we shall see the estimation of multiwell injectivity through use of “equivalent skin” is not exact, particularly for two-phase problems. This suggests that this relation may be used for screening purposes particularly when detailed data is scarce. Once a particular site is selected and characterized, careful studies need to be conducted for selection of the number and location of the injectors. It is expected that design of the injection wells would depend on geometry and heterogeneity (e.g. permeability distribution) of the particular site of interest.

5. Results

Initially, we consider 24 cases, where three parameters of $n$, $R$ and $S$ are varied. In 12 cases $n=2$ and in the other 12 cases $n=4$. Distance from the center is allowed to take three values of 100, 2000 and 4000 m, and the wellbore skin is allowed to vary between $S = -4$, -2, and +4. Other properties were kept unchanged corresponding to a
hydrostatically pressured reservoir at a depth of 2000 m, with permeability, porosity and thickness of 100 mD, 20%, and 20 m. Injection pressure in this work is assumed to be 90% of the estimated fracture pressure, which itself was obtained by multiplying depth by 17 kPa/m as a measure of fracture gradient. Formation and water compressibility were taken to be 5 and $4.2 \times 10^{-7}$ 1/kPa, and water viscosity was taken as 0.46 cp.

Figure 3-left shows the equivalent skin for the two-well system. Corresponding results for the four-wells system is shown to the right. Also shown are straight lines with slopes of $(1/2-1)=-0.5$ (on the left) and $(1/4-1)=-0.75$ (on the right). Both figures are semi-log, indicating a logarithmic relationship between equivalent skin and the distance of the wells from the center. This is consistent with the logarithmic pressure profile in radial flow. From these two observations, one can suggest a relationship for the equivalent skin in the form of

$$S_{eq} = a - \left(1 - \frac{1}{n}\right) \ln(R)$$

(1)

where, the intercept $a$ is affected by skin. The results in Figure 3 indicate that when skin of the individual wells is improved from 4 to -4, the improvement in equivalent skin is by 4 and 2 units, for the 2 and 4 well scenarios, respectively. This observation is of importance in economic optimization of multiwell injection systems, as only a fraction $(1/n)$ of the skin of the individual wells is translated into the equivalent skin. Additional cases were studied to investigate effect of wellbore radius, which may be combined with skin as an equivalent wellbore radius. The results of these studies can be summarized in Equation (2).

$$S_{eq} = S + \ln \left(\frac{r_w e^{-\frac{1}{n}}}{R} \right)^{\frac{1}{2} - \frac{1}{n}} - 0.715n^{-0.581} \quad n > 1$$

(2)

6. Validation for single-phase

Equation (2) was obtained for a particular reservoir and pressure constraints. In this section, we allow 8 parameters of reservoir depth, permeability, thickness, porosity, formation compressibility, skin, number of wells, and distance to the centre to vary. Initial pressure and injection pressure are also varied through their relationship with depth, as explained previously. Table 1a, gives the range of parameters, where the number of wells was allowed to vary up to 9, and the distance to the center was allowed to increase up to 9 km. We then conducted a two-level experimental design and in addition to the base case we obtained 12 cases with varying combination of these parameters. In all cases water viscosity and compressibility were kept unchanged. Table 1b gives the characteristics of the cases studied, where the base case is reaped in rows 1 and 3.
In each case, cumulative injection volume was calculated for 10, 30 and 50 years of injection, in two different ways. First the injection volume was calculated using \( n \) wells. Then the injection volume was estimated using a single-well with the equivalent skin. The comparison between the results at 10 and 50 years is shown in Figure 4 (left and right respectively). The cumulative injection among the different cases varies by three orders of magnitude. However in all cases, data fall on 45 degrees indicating that a single-well with equivalent skin is a good representation of the multiwell case.

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<th>Table 1a: Range of Parameters</th>
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<td></td>
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7. Validation for two-phase flow

To examine the validity of Equation (2) for two-phase cases, a number of simulation studies were conducted using the Eclipse simulator of Schlumberger. The reservoir and operating conditions are the same as those shown in Table 1. The PVT properties of the CO\(_2\) and relative permeability functions were incorporated. Figure 5 shows the viscosity and formation volume factor of the CO\(_2\) over the temperature and pressure range of interest.
Once again cumulative injection volume was calculated for 10, 30 and 50 years of injection, in two different ways: using \( n \) wells and using a single-well with the equivalent skin. In a number of cases, the use of equivalent skin as determined from Equation (2) would lead to Peaceman wellbore radii that are larger than the grid-blocks used. In these cases, the permeability in the grid block around the well were improved using Hawkin’s relation to mimic the near wellbore improvement. The comparison between the results at 10 and 50 years is shown in Figure 6. Once again, despite 4 orders of magnitude variation in the injected volume among the different cases, a reasonable agreement is observed between the multi-well cases and the single-well.

8. Conclusions

- A particular geometry for well-placement was suggested so that interference is balanced equally among all wells.
- An analytical relation was obtained for an equivalent skin that allowed representation of multiwell system with a single well with equivalent skin. This relationship takes into account the number of wells and their distance from each other. It is shown that the relationship is valid regardless of the permeability, formation thickness, and injection and reservoir pressure.
- This relation may be used for estimation of multiwell injectivity, facilitating screening of different formations for desired injectivity.
9. Acknowledgements

Karel Zaoral of Fekete suggested the pattern for well-placement used in this paper. Dr. Ramon Bentsen of University of Calgary suggested equations that may be used for prediction of pressure distribution under two-phase flow conditions. The contribution of both of these individuals is gratefully acknowledged.

10. Reference


