Stress-Sensitivity in Tight Gas Reservoirs: A Curse or an Opportunity for Carbon Dioxide Sequestration?

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Abstract—Stress-sensitivity adds a dependence on pressure to the permeability of tight gas reservoirs making them more challenging to develop optimally. Numerical simulations are presented showing stress-sensitivity can have a dramatic effect on well productivity. Long horizontal wells are shown to maximize well production. The best strategy to mitigate the permeability reduction which occurs in stress-sensitive reservoirs is found to be CO₂ injection. This creates a new opportunity for CO₂ sequestration and improves well production by over 500% in simulated cases.

Keywords—Tight gas production, carbon dioxide sequestration, reservoir simulation.

I. INTRODUCTION

Tight gas reservoirs are porous sub-surface rock formations containing natural gas in which the rock permeability is below 0.1 md [1]. They are becoming increasingly important in production of natural gas in the USA and in other jurisdictions. Their low permeability leads to low flow rates so their development must be managed well to be economically favourable.

If a reservoir is saturated with single phase gas the [2] states that the pressure distribution in the reservoir (in space and time) is governed by (1):

\[ \nabla^2 m = \frac{\phi \mu c}{k} \frac{\partial m}{\partial t} \]  

where \( m \) is a pseudopressure [Pa/s], \( \phi \) is the reservoir porosity [dimensionless], \( \mu \) is the gas viscosity [Pa-s], \( c_t \) is the total compressibility of the system [1/Pa], \( k \) is permeability [m²] and \( t \) is time [s].

The use of pseudopressure allows the diffusivity equation in (1) to be written in linearised form. Reference [2] defines he pseudo-pressure as (2):

\[ m = 2 \int_{p_0}^{p} \frac{P}{\mu Z} dp \]  

where \( p \) is pressure [Pa], \( p_0 \) is a reference pressure [Pa], and \( Z \) is gas compressibility factor [dimensionless]. If (1) is solved analytically for pseudo-pressure then the reservoir pressure can be obtained by consideration of (2). Equation (1) lends itself to solution via Laplace transforms [3].

Equation (1) assumes that the reservoir porosity and permeability are homogenous in space. It is also assumed in (1) that the reservoir permeability has no dependence on reservoir pressure.

Tight gas reservoirs may however display a “stress-sensitive” behavior in which the reservoir permeability exhibits a dependence on pressure. This limits the geometries and boundary conditions for which (1) can be solved by analytical or semi-analytical means. Reference 4 presents relevant analytical solutions derived with the assistance of the Cole-Hopf transform for a well producing from a 1D reservoir, and for an injection/production well pair defined in bipolar coordinates. This work was developed in the context of geothermal energy production. The solutions presented in [4] were extended in [5] to address problems with a petroleum engineering focus.

There have been several approaches to diagnosing stress-sensitivity from pressure transient data [6, 7, 8]. In tight gas reservoirs these methods are likely to be impractical because they could require production wells to be shut-in (i.e. not producing) for long periods of time which is unattractive economically.

Reference [5] applies production data analysis concepts introduced by [9] to the analysis of routine well pressure and flow rate data in stress-sensitive reservoirs. The examples in [5] show that if the permeability of a stress-sensitive reservoir is inferred from pressure and flow rate data using traditional analysis methods (which assume reservoir permeability is not pressure dependent) the result could significantly overestimate the actual reservoir permeability.

This work explores the effect of stress-sensitive reservoir permeability on long term gas production. The impact of different well types (vertical wells, horizontal wells) and...
permeability anisotropy is considered in order to determine which parameters have the greatest control on the production response of tight stress-sensitive gas reservoirs.

In a stress-sensitive reservoir the rock permeability decreases as gas is withdrawn from the porous structure of the reservoir. This occurs because as the fluid pressure is lowered the rock matrix experiences a greater effective stress due to the overburden layers above it. In order to a decrease in permeability having a detrimental effect on gas production rates it is important to mitigate or management. This work tested various strategies for operating production wells on a cyclic basis to allow pressure drawdowns occurring during production to recover around wells when the wells are temporarily shut-in. During this rest phase the pressure and permeability around the wells increases.

An alternative strategy for mitigating pressure decline in a reservoir is to inject another fluid into the reservoir as natural gas is produced from in it. In this study carbon dioxide is chosen as the injection fluid. At typical reservoir conditions (104 °C, 34.5 MPa or 220°F, 5000 psi) carbon dioxide is a super-critical fluid whose dense, low viscosity nature is attractive for injection. Carbon dioxide was also considered because of the growing interest in geosequestration of carbon dioxide as a method to minimize greenhouse gas emissions. In economies where a “carbon tax” or “carbon price” exists or is introduced it is conceivable that there would be economic incentives to inject carbon dioxide into sub-surface reservoirs if this avoids its release to atmosphere. Injection of carbon dioxide into a producing natural gas reservoir to improve gas recovery is an example of an enhanced gas recovery (EGR) process. These issues involved in EGR were considered in [10] for a wide range of reservoirs types (not including stress-sensitive) reservoirs. While not yet occurring commercially at a large number of sites [10] draws the conclusion that EGR should be a viable process in many situations.

The behavior of stress-sensitive tight gas reservoirs is analyzed numerically in this work. The simulated production profiles are compared to one another by comparing “discounted” total gas production. Discounting is used to give greater weight to gas production occur in the early part of the production period, and less weight to gas production at later times. This is appropriate because this is how revenue from gas production would be considered in an economic analysis of a gas production project.

II. RESERVOIR SIMULATION MODEL

To allow for flexibility in reservoir geometry, well configurations and the nature of permeability variation with pressure, the production response of stress-sensitive reservoirs was modeled using Eclipse [11]. This code is an industry-standard finite-volume simulator that can simulate multi-phase, multi-component flow in heterogeneous porous media. The simulation package also incorporates the ability to handle geomechanical effects such as stress-sensitivity. Note that in the following discussion of the simulation model and its results numerical values are presented in a system of units traditionally used in the petroleum industry with conversions to SI units. Gas production is reported in units of “Mscf” where 1 Mscf is 1,000 standard cubic feet and is equal to 28.2 m³.

A reservoir simulation model was constructed which simulated gas production from a single well in a rectangular reservoir. The parameters that control productivity were assessed via a parametric study with the following parameters:

\[ \phi = 10\% \]
\[ \mu = 0.019 \text{ cp (at initial reservoir pressure)} \]

Base permeability (at initial reservoir pressure), \( k_\text{base} = 0.01 \text{md} \), 0.05md, 0.1md (\( 10^{-17}, 5 \times 10^{-16}, 10^{-16} \text{ m}^2 \))

Permeability anisotropy = none, \( k_x/k_y = 0.1, k_x/k_z = 10 \)

Initial reservoir pressure, \( p_i = 5,000 \text{ psi (34.5 MPa)} \)

Reservoir size = 1,250 x 2,500 ft; 2,500 x 5,000 ft; 5,000 x 10,000 ft (381 x 762m; 762 x 1,524m; 1,524 x 3,048 m)

Reservoir thickness = 50 ft (15m)

Bottomhole pressure = 500 psi (3.45 MPa)

Well types = Vertical (fully completed), short horizontal 1000ft lateral (341 m) in the x-direction, long horizontal 5000ft lateral (1524 m) in the x-direction.

Three stress-sensitivity cases were considered:

- No stress-sensitivity, \( k = k_o \)
- Linear permeability variation, \( k = k_o \cdot \frac{P}{P_i} + k_2 \)
- Exponential permeability variation,
  \[ k = k_o \cdot \exp(\beta (P - P_i)) \]

To assess the role of these parameters a set of 243 reservoir simulation models were constructed which systematically varied these parameters and predicted the resulting gas production. Only key results from those models are reported in this work.

III. PERFORMANCE OF TIGHT GAS RESERVOIRS

In a tight gas reservoir which is not stress-sensitive one of the most critical sensitivities in the reservoir permeability. Fig. 1 demonstrates that by presenting cumulative gas production from a single vertical well in a large reservoir (5,000 x 10,000 ft) with no permeability anisotropy. Reservoir permeabilities of 0.01md, 0.05md and 0.1md are considered. The difference in the simulated production is marked and could have a significant impact on the economic success (or otherwise) of the well – depending on drilling costs and gas prices.

Fig. 2 depicts results from three runs with a stress-sensitive permeability. The cases chosen for Fig 2. are for the same example reservoir as Fig 1. with a base permeability of 0.05md and linear stress-sensitive case (\( k_1 = 0.0432 \text{ md}, k_2 = \)
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0.0067 md) and also an exponential case (\(\beta = 0.004\ psi^{-1}\)). These runs show that stress-sensitivity can cause a drop in production of 50% - the “curse” of stress-sensitivity. It is therefore crucial that the presence of stress-sensitivity is diagnosed early in the life of a well (e.g. using pressure transient testing methods, or rate transient analysis discussed in [6]).

One approach that is used to improve well productivity in traditional tight gas wells is to drill horizontal wells [12] Table 1 demonstrates that this approach can offer significant advantages for both stress-sensitive and non-stress sensitive cases. The models in this table are for the same example reservoir used to generate Fig. 1 and Fig. 2. Note that the cumulative production values in Table 1 are discounted according to:

**Discounted gas production**

\[
G_{\text{discounted}}(\tau) = \sum_{i=1}^{45} G_i (1 + r)^i
\]

Where \(G_i\) is the amount of gas produced in year \(i\) and \(r\) is a discount rate (8%). This calculation would form the basis of an economic “net present value” calculation for an economic appraisal of a well.

### TABLE 1

**HORIZONTAL VERSUS VERTICAL WELL PRODUCTIVITY**

<table>
<thead>
<tr>
<th>Well</th>
<th>Stress sensitivity</th>
<th>Discounted gas production, Mscf/a</th>
</tr>
</thead>
<tbody>
<tr>
<td>1000 ft Horizontal</td>
<td>Exponential</td>
<td>2.24x10^6</td>
</tr>
<tr>
<td>1000 ft Horizontal</td>
<td>Linear</td>
<td>2.78x10^6</td>
</tr>
<tr>
<td>1000 ft Horizontal</td>
<td>None</td>
<td>4.01x10^6</td>
</tr>
<tr>
<td>5000 ft Horizontal</td>
<td>Exponential</td>
<td>5.94x10^6</td>
</tr>
<tr>
<td>5000 ft Horizontal</td>
<td>Linear</td>
<td>7.13x10^6</td>
</tr>
<tr>
<td>5000 ft Horizontal</td>
<td>None</td>
<td>9.85x10^6</td>
</tr>
<tr>
<td>Vertical</td>
<td>Exponential</td>
<td>0.85x10^6</td>
</tr>
<tr>
<td>Vertical</td>
<td>Linear</td>
<td>1.05x10^6</td>
</tr>
<tr>
<td>Vertical</td>
<td>None</td>
<td>1.36x10^6</td>
</tr>
</tbody>
</table>

Table 1 reveals that long (5000 ft) horizontal wells outperform short horizontal wells (1000 ft) by a significant margin – though such wells would cost more to drill. Both styles of horizontal wells are far superior to vertical wells.

The geological formations that host tight gas reservoirs may be also lead to anisotropic permeability distributions, i.e. permeability that differs in different directions due changes in the nature of the rock fabric in those directions. This is most relevant for horizontal wells. The case is used to generate Fig. 2 was reconsidered using an anisotropic permeability model. Simulated gas production was shown to approximately double in cases with both long and short horizontal well laterals, and with and without stress sensitivity, if the horizontal permeability in the direction perpendicular to the horizontal well axis was ten times greater than the permeability in the direction along the well axis. This underlines the importance of optimizing well trajectories if developing tight gas resources.

Horizontal wells performance may also depend on contrast between permeability in the vertical and horizontal directions in a reservoir. When the vertical permeability was reduced by a factor of ten in the case used to generate Fig. 2. The long term performance (in terms of the discounted total gas production) of both short and long horizontal wells was only reduced by approximately 10% in cases with and without stress-sensitivity.

Whilst only results for specific parameter combinations were discussed analysis of full sets of runs studied in the parametric analysis supports the same conclusions, i.e. that - horizontal wells are more productive than vertical wells - permeability is a key control on well performance - exponential stress-sensitivity hampers production more severely than linear stress-sensitivity (cases with the same permeability at 500 psi) - permeability anisotropy can be helpful when producing horizontal wells.

### IV. PRESSURE MANAGEMENT

Fig. 2 and Table 1 both show that stress-sensitivity can have a dramatic impact on the productivity of a well gas in a stress-sensitive gas reservoir. Since such reservoirs lose their permeability as their pressure declines it is crucial to manage reservoir pressure. This work created reservoir simulations of several pressure management strategies to see if resting some wells in a reservoir (i.e. closing them off to production for a period of time) would be beneficial since this would allow the pressure and permeability around those wells to rebound. Any gains in productions however would have to offset by the delay in production which occurs while the wells are closed.

The possible benefits of pressure management were considered by creating a synthetic reservoir with an area of 4000 ft x 4000 ft (1219 m x 1219 m). The base permeability of this reservoir was set to 0.1md. All other reservoir properties were the same as those used in the previous section. Nine wells were evenly distributed in a regular grid pattern through this reservoir.

The first strategy that was tested was a cycling approach in which groups of well were rested for six months while the remaining wells stayed in production. The first version of this approach cycled the wells in lines of three at a time, so one third of the wells were out of production at any one time. The second version of this approach alternated between production from the four wells in the corners of the pattern, and the five remaining wells. A pressure easing strategy was also tested. In this approach instead of immediately starting to produce the well at a bottomhole pressure of 500 psi, the bottomhole pressure was progressively lowered from 4,500 psi to 500 psi in increments of 500 psi every six months.

Table 2 shows that unfortunately none of these approaches could successfully mitigate the effects of stress-sensitivity.
V. PRESSURE MAINTENANCE BY CARBON DIOXIDE SEQUESTRATION

The results obtained in the last section suggest that to mitigate the effects of stress-sensitivity more drastic reservoir management steps must be taken in order to avoid any loss of reservoir pressure, and therefore any consequential loss of reservoir permeability. Pressure maintenance is a commonly used strategy in other types of reservoir, for example injection of water in oil reservoirs to maintain oil flow rates as production proceeds. Injection of other fluids in natural gas reservoirs is less common. If any injected gas travels through the reservoir and reaches the production wells it must be separated from the produced gas stream in order to maintain sales gas specifications. Operators of gas reservoirs have not so far embraced “enhanced gas recovery” widely, though the K-12B project [13] is an example of a commercial EGR project.

The low permeability of tight gas reservoirs means the total volume of CO\(_2\) that could be readily injected into them is low. To inject large volumes of CO\(_2\) very high injection pressures would be required. These pressures would be likely to fracture the reservoir rock. However injection at more modest injection well pressures could maintain reservoir pressure as gas is produced. This injection would have a beneficial “side-effect” of placing CO\(_2\) in a low permeability rock formation. If there are economic incentives to perform such injection then the operation may improve the economics of the natural gas production operation.

The potential benefits of injecting CO\(_2\) into tight gas reservoirs were assessed by constructing a compositional reservoir simulation model that is able to track the mole fractions of CO\(_2\) and natural gas (assumed for these purposes to be pure methane) throughout the reservoir. The phase behavior of the mixture was modeled with the Peng-Robinson equation of state. The reservoir modeled used was the 4000 ft x 4000 ft (1219 m x 1219 m) example used in the pressure management study. The first well configuration tested was a set of nine vertical wells arranged in a grid inside that domain. The four wells on the corners were used to inject CO\(_2\) at a bottomhole pressure of 6,500 psi. The remaining five wells were used to produce gas a bottomhole pressure of 500 psi. Table 3 lists the percentage improvement in the discounted total gas production for this case when compared to base cases with five production wells (and no injection wells), and with nine productions wells (i.e. all wells producing, no injection wells). The table shows that when compared either of the base case well configurations operating four of the wells as CO\(_2\) injectors is very beneficial for overall gas production. The greatest improvements in well productivity occur for the cases when the stress-sensitivity of the reservoir follows an exponential relationship. It is interesting to note that exponential stress-sensitivity produce the most severe decreases in well productivity (compared to linear stress-sensitivity or no stress sensitivity) when gas production without CO\(_2\) injection was being considered.

An important issue in CO\(_2\) injection is the migration of the front of injected CO\(_2\). Since stress-sensitivity lowers the permeability around production wells (since reservoir pressure is lowest in these areas), the production wells become somewhat protected from the advancing CO\(_2\) front. This provides a physical explanation for the observations in Table 3. The cases in Table 3 were run for 10 years. In each case at the conclusion of the simulation small concentrations of CO\(_2\) has reached the production wells (concentrations small enough that they could be readily stripped from the production streams). The amount of CO\(_2\) which is injected in the injections cases is relatively small (under half a million tonnes). However the dramatic improvement in gas production and the additional revenue from carbon credits is quite likely to be sufficient to offset the costs of constructing and operating CO\(_2\) injection facilities. Simulation runs performed with vertical injection wells and horizontal production wells suggest the economics of CO\(_2\) injection with the well configuration is slightly more favourable.

<table>
<thead>
<tr>
<th>TABLE 2</th>
<th>PRESSURE MANAGEMENT – VERTICAL WELLS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>Stress sensitivity</td>
</tr>
<tr>
<td>Base case – no cycling</td>
<td>Exponential</td>
</tr>
<tr>
<td>Base case – no cycling</td>
<td>Linear</td>
</tr>
<tr>
<td>Base case – no cycling</td>
<td>None</td>
</tr>
<tr>
<td>Cycling in lines</td>
<td>Exponential</td>
</tr>
<tr>
<td>Cycling in lines</td>
<td>Linear</td>
</tr>
<tr>
<td>Cycling in lines</td>
<td>None</td>
</tr>
<tr>
<td>Corner/interior wells</td>
<td>Exponential</td>
</tr>
<tr>
<td>Corner/interior wells</td>
<td>Linear</td>
</tr>
<tr>
<td>Corner/interior wells</td>
<td>None</td>
</tr>
<tr>
<td>Pressure easing</td>
<td>Exponential</td>
</tr>
<tr>
<td>Pressure easing</td>
<td>Linear</td>
</tr>
<tr>
<td>Pressure easing</td>
<td>None</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TABLE 3</th>
<th>CO(_2) INJECTION COMPARISON – VERTICAL WELLS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well configuration</td>
<td>Stress sensitivity</td>
</tr>
<tr>
<td>Five producers</td>
<td>Exponential</td>
</tr>
<tr>
<td>Five producers</td>
<td>Linear</td>
</tr>
<tr>
<td>Five producers</td>
<td>None</td>
</tr>
<tr>
<td>Nine producers</td>
<td>Exponential</td>
</tr>
<tr>
<td>Nine producers</td>
<td>Linear</td>
</tr>
<tr>
<td>Nine producers</td>
<td>None</td>
</tr>
</tbody>
</table>
Fig. 1 Comparison of gas production profiles for (non stress sensitive) permeability cases of 0.01md, 0.05md and 0.1md.

Fig. 2 Comparison of gas production profiles for stress-sensitive permeability cases with a base permeability of 0.05md.
VI. CONCLUSION

This work demonstrates that stress-sensitivity in tight gas reservoirs is both a curse and an opportunity. It is a “curse” due the detrimental effects it has on well productivity. This means reservoir management practices should aim to diagnose its presence early in the life of a well if possible. Stress-sensitivity however also poses an opportunity for CO₂ sequestration in tight gas reservoirs since the low permeability zone it causes around production wells shields them from the invading CO₂ front. The pressure maintenance effect of the injected CO₂ boosts well productivity significantly.

REFERENCES