# Investigation of Hydraulic Fracture Re-Orientation Effects in Tight Gas Reservoirs

B. Hagemann[*1], J. Wegner[1], L. Ganzer[1]
[1]Clausthal University of Technology
*Corresponding author: Agricolastraße 10, 38678 Clausthal-Zellerfeld, Germany, reseng@tu-clausthal.de

**Abstract:** In tight gas formations where the low matrix permeability prevents successful and economic production rates, hydraulic fracturing is required to produce a well at economic rates. As production from the well and its initial fracture declines, re-fracturing treatments are required to accelerate recovery. The orientation of the following hydraulic fracture depends on the actual stress-state of the formation. Previous investigations demonstrated that the stress alters during depletion and a stress reversal region appears. This behavior causes a different fracture orientation of the re-fracture. COMSOL Multiphysics is used to investigate the re-fracture orientation in a two-dimensional reservoir model. The model represents a fractured vertical well in a reservoir of infinite thickness. Different cases with anisotropic and heterogeneous permeability are set up to determine its significance. The simulation shows that an elliptical shaped stress reversal region appears around the fracture which is influenced by time and reservoir characteristics.

**Keywords:** tight gas, re-fracturing, stress-state, stress altering, re-orientation

## 1. Introduction

Tight gas reservoirs are characterized by very low matrix permeability. The German Society for Petroleum and Coal Science and Technology (DGMK) defined tight gas reservoirs with an average effective permeability for gas below 0.6 mD. Porosities are commonly below 10%. The drainage area of tight gas reservoirs would be very small in absence of fractures. The contribution of hydraulic fractures expands the drainage area to an elliptical shape around the fracture and makes an economic production possible [1]. As production from the well and its initial fracture declines, re-fracturing treatments are required to accelerate recovery. In some cases the second fracture treatment does not re-open the initial fracture but produces an additional fracture which has a different orientation to the first one [1]. This effect is called re-orientation of hydraulic fractures and was confirmed by surface tiltmeter measurements [3].

The re-orientation can be explained by an altered stress distribution in the formation. Elbel and Mack [4] demonstrated that a stress altering can be induced by production from the reservoir. The theory relies on initially small difference between the maximum and minimum horizontal stresses, which is often given in tight gas reservoirs [2].

The creation of a re-oriented fracture is very useful because it is connected to a less depleted region of the reservoir but the occurrence is not yet well understood. A task in reservoir management is the optimum timing of re-fracture treatments to maximize the production.

## 2. Fracture re-orientation concept

The initial fracture treatment creates a fracture which propagates perpendicular to the minimum effective stress into the formation [5]. This behavior is illustrated in Fig.1 where the minimum effective stress is arranged parallel to the y-axis and the initial fracture parallel to the x-axis. During depletion of the reservoir the stress distribution will be altered due to the change in pore pressure. This behavior is based on the Biot's concept wherefore the effective stress has to be taken into account [1]. The effective stress is equal to the total stress minus Biot's coefficient multiplied by pore pressure:

$$\sigma_{eff} = \sigma - \alpha * p \qquad (1)$$

This equation denotes that the stress altering is equal in all directions what would only be valid if the rock is prevented from moving. The consideration of strain affects that the stress reduction is higher in the direction parallel to the initial fracture [6]. Therefore it is possible that the initial small horizontal stress differences can be overcome. A region of stress reversal arises around the fracture which is illustrated by the grey ellipse in Fig.1 [4].

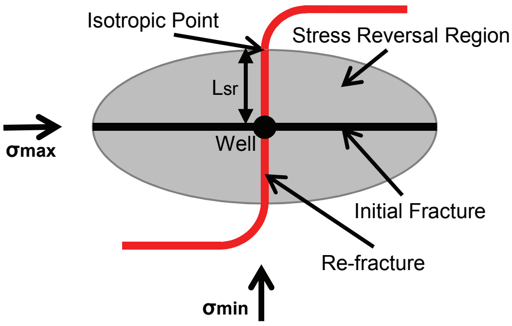


**Figure 1**. Schematic showing orthogonal fracture propagation (Redrawn after [6])

As production continues the area, which is influenced by the induced stress difference, spreads out [4]. The magnitude of induced stress differences at the fracture first increases and later decreases because of the propagation of tension [4]. Therefore the right point in time for the re-fracture treatment has to be identified. A re-fracturing at this point in time produces a fracture which starts to propagate perpendicular to the initial fracture into the formation [4]. At the isotropic stress point (Fig. 1), where the stresses in x- and y-direction are equal, the fracture initiates a turn in direction until it propagates parallel to the initial fracture [4]. An extending region of stress reversal results in an increasing distance of propagation in the perpendicular direction [6]. Therefore investigations have to be done on the included parameters to understand and predict this behavior.

## 3. Theory of poroelasticity

The linear theory of poroelasticity, which is used in this work, was developed by Biot in 1935 and 1941 [7]. Porous media consist of a solid rock framework and a freely moving fluid in the pore space [7]. These two systems are interacting by two mechanisms: An increase of pore pressure results in a distension of the rock and a compression of the rock results in an increasing pore pressure if the fluid cannot exit the rock [7]. An occurrence of these mechanisms is that a further deformation due to compression is possible if the fluid is allowed to diffuse [7]. The theory is derived from two constitutive equations Darcy's law, continuity equation and equilibrium equation. It describes the linear relationship between stress, strain, fluid content increment and fluid pressure.

### 3.1 Governing equations

The first constitutive equation relates to the solid matrix. It describes the behavior between stress and strain [8]:

$$\sigma = C\varepsilon - \alpha pI \qquad (2)$$

Where σ is the total stress, C is the elasticity matrix, ε is the strain, α is the Biot's coefficient, p is the pore pressure and I is the unit matrix. The elasticity matrix C is a function of poroelastic material constants. In this work the Young's modulus E and Poisson's ratio v are used to define the elasticity. These two properties suffice to fully describe the elastic behavior in all directions.

The second constitutive equation is related to the pore fluid and describes the relation of incremental fluid content to volumetric strain and pore pressure [8]:

$$\partial\xi = \alpha\varepsilon_{vol}\frac{\partial p}{M} \qquad (3)$$

Where ζ is the fluid content, $\varepsilon_{vol}$ is the volumetric strain and M is the Biot modulus. The Biot modulus is the inverse of the storage coefficient which is defined as the change in fluid content according to the change in pore pressure [8]:

$$S = \frac{1}{M} = \left(\frac{\partial\xi}{\partial p}\right)_{\varepsilon_{vol}} \qquad (4)$$

Where S is the storage coefficient which can be measured experimentally [8]. For an ideal porous medium, which is defined with no change in porosity, this value can also calculated from the solid and liquid material properties [8].
Additionally the Darcy's law is required to describe the fluid flow. The Darcy's law

describes the flow velocity according to the pore pressure gradient [8]:

$$u = -\frac{k}{\mu}\nabla p \qquad (5)$$

Where u is the Darcy velocity, k is the permeability and $\mu$ is the viscosity. For the modeling of fluid movement the Darcy's law has to be combined with the continuity equation [8]. The continuity equation for flow in poroelastic media is defined as [8]:

$$\rho S\frac{\partial p}{\partial t} + \nabla(\rho u) = Q_m - \rho\alpha\frac{\partial \varepsilon_{vol}}{\partial t} \qquad (6)$$

Where $\rho$ is the fluid density and $Q_m$ is a source of mass. The most right hand side term describes the increasing pore volume according to the change in strain [8].

Finally the equilibrium of loads for the solid matrix has to be integrated. Therefore the Navier's equation is used which is defined for only gravitational forces as [8]:

$$-\nabla\sigma = \rho_{av} g \qquad (7)$$

Where $\rho_{av}$ is the average density of fluid and solid matrix and g is the gravity acceleration. This equation states that the stresses are balanced under gravitational forces at any time.

The coupling of the five basic equations enables the complete description of the poroelastic system. In COMSOL Multiphysics the equations are solved for solid displacement and pore pressure by the use of the finite elements method. All other variables can be solved independently.

## 4. Numerical model

For the investigation of the poroelastic effects a tight gas reservoir model was set up which couples the behavior of fluid flow and geomechanics. For the generation of this model the physics interface "Poroelasticity" was used which couples the "Solid Mechanics" interface with "Darcy's Law". The designed reservoir model is simplified to an ideal case by the following assumptions:

- Isothermal formation
- Constant wellbore flowing pressure
- No flow boundaries
- Single Phase Darcy's law flow behavior
- Infinite Conductivity Fracture
- Uniform initial stress state

The model is implemented in two dimensions which represent a reservoir of infinite thickness. The reservoir has a rectangular shape with a dimension of 1600 m in x-direction and 1200 m in y-direction. The size is selected after the statement of Roussel and Sharma [9]. They determined that the boundaries have no impact to the size of the stress reversal region if the distance from the fracture to the boundaries is at least three times the fracture half-length [9]. The permeability is 0.01 mD and the porosity is 10 % over the total area. The temperature is assumed to be constant with 110 °C. The initial fracture has a half-length of 200 m and is shaped as a straight line in x-direction. The reservoir geometry is illustrated in Fig. 2, where the well has only a symbolic meaning and is not included in the model.

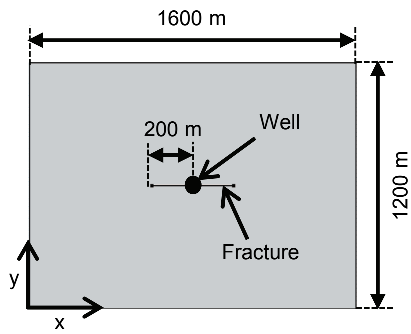


**Figure 2**. Reservoir geometry

The reservoir is saturated by 100 % of natural gas. Consequently the flow is limited to a single phase. The natural gas is defined with a relative density of 0.6. The compressibility factor and gas viscosity are calculated by the Hall-Yarborough and Lee et al. Correlations. These correlations are implemented using the software Matlab and pressure dependent property tables are used to transfer the data. In COMSOL Multiphysics the intermediate values are calculated by a cubic interpolation function. A complete list with all defined parameters for the model can be found in Table 1 in the appendix.

The reservoir will be analyzed in dependence of time within a total time of 100 years.

### 4.1 Initial and boundary conditions

For Darcy's law the initial pressure is defined as 300 bar. The four outer boundaries of the rectangular are defined with "No Flow". The last boundary for Darcy's law is set to the fracture with "Pressure" and a value of 50 bar. This condition is related to a constant bottom hole flowing pressure and a connected infinite conductivity fracture.

For the solid mechanical part of the model the in-situ stress distribution is defined to the outer boundaries of the reservoir by "Boundary Load". Related to the initial fracture distribution the maximum horizontal stress acts in x-direction. Therefore a pressure of 39.5 MPa is applied to the left and right edge of the reservoir. The minimum horizontal stress is set to the top and bottom edge with a value of 38.5 MPa. All stresses act inwards to generate a compressed reservoir condition. To complete the boundary conditions a "Roller" is defined to the fracture. This boundary condition prevents the fracture from movement in y-direction.

## 5. Simulation Results

### 5.1 Pressure Distribution

The first investigation is respected to the fluid pressure in the reservoir. In Fig. 3 the fluid pressure is shown after five years of production with a constant bottom hole flowing pressure.

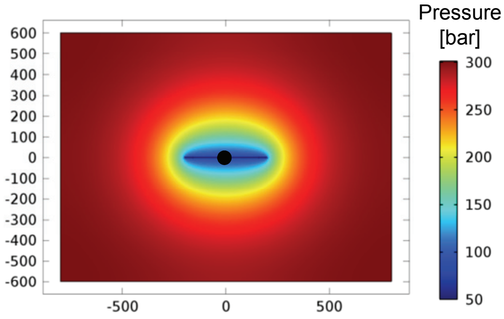


**Figure 3**. Fluid pressure distribution after five years

Brown color represents the initial pressure of 300 bar and dark blue indicates the well pressure. It can be recognized that the drainage area spreads to an elliptical shape around the fracture. At late times also the reservoir boundaries are influenced by the pressure drop. The essential finding from this plot is the behavior of pressure drop in the area above and below the fracture. The pressure drop is much steeper in the y-direction than in the x-direction. This characteristic is responsible for the occurring stress reversal region and will be further investigated later.

### 5.2 Stress Tensor Distribution

In Fig. 4 and Fig. 5 the stress components in x- and y-direction are presented.

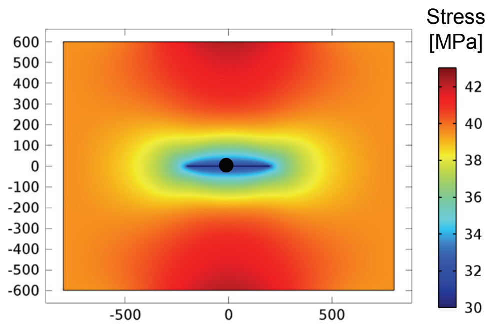


**Figure 4**. Stress tensor in x-direction

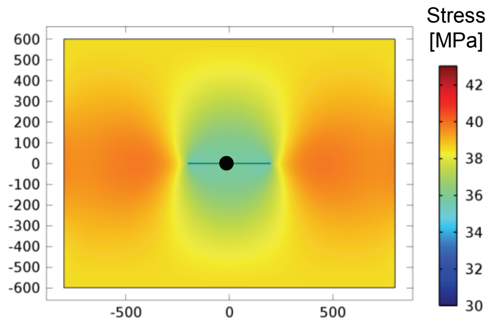


**Figure 5**. Stress tensor in y-direction

Orange color represents the initial stress of 38.5 and 39.5 MPa. Both stress components are significantly lowered in the area near to the fracture what can be indicated by the blue color shades. The reason for this effect is the lowered pore pressure in this region and the stress is directly in conjunction to it by the Biot's concepts. The x-component of the stress tensor decreases more than the y-component in the region above and below the fracture what can be realized by the dark blue color. For this behavior the strain has to be considered. The higher pressure gradient in y-direction results in a higher strain in this direction. Therefore also the stress remains higher in the y-direction. If this effect is stronger than the initial difference of minimum and maximum stress, the maximum stress direction can be changed. A stress reversal occurs in this region.

### 5.3 Maximum principle stress direction

In Fig. 6 the maximum principal stress direction is plotted at the initial situation.

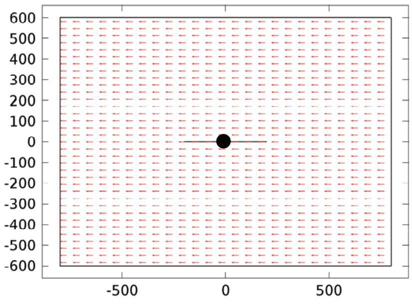


**Figure 6**. Initial maximum principle stress direction

Initially the maximum principal stress is directed parallel to the x-axis because of the uniform definition of in-situ stresses. After five years the principal stress directions have changed due to the poroelastic effects (Fig. 7).

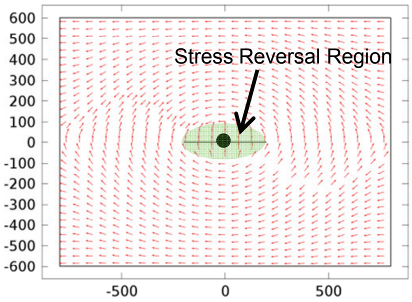


**Figure 7**. Maximum principal stress direction after five years

The stress lines bypass the region around the fracture where a stress reversal occurs. In this region, which is marked by the green ellipse, the direction of maximum principal stress is rotated by 90°. After five years the fracture would first propagate perpendicular to the initial fracture until it reaches the isotropic point. At this point the fracture starts to turn until it propagates parallel to the initial fracture.

### 5.4 Analysis of time dependence and permeability

For the investigation of time dependent behavior the distance from the well to the isotropic point was determined at several points in time. This distance is called Lsr (comparing to Fig. 1). In the following chart the investigations are done for three different permeabilities: 0.1 mD, 0.01 mD (base case) and 0.001 mD (Fig. 8).

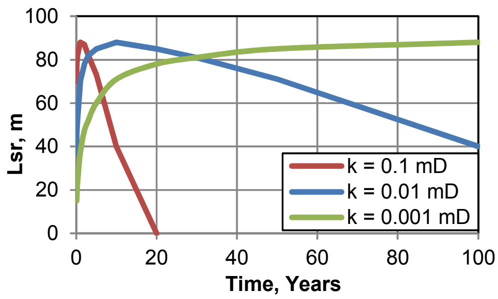


**Figure 8**. Analysis of time dependence and permeability

For the base case with a permeability of 0.01 mD the distance to the isotropic point increases at the beginning very fast. A value of about 90 % of the maximum is already attained after two years. In the next years the distance increases slowly up to the maximum value of 88 m after ten years. The decline in the last 90 years is almost linear.

The observation of the study with a ten times greater permeability shows a similar behavior with a different timing. The maximum distance has the same value like in the previous case but is already achieved after two years. The decrease of the distance processes much faster and after 20 years the stress reversal region disappears.

The third study has a ten times smaller permeability and the distance to the isotropic point increases much slower. The maximum value is not achieved before 100 years of production.

In respect to the stress reversal region the ideal times for a re-fracture treatment can be determined from the diagram. For the three analyzed cases the ideal times are after 2, 10 and 100 years.

The explanation for this behavior is the pressure gradient in the reservoir. This pressure gradient has to exceed a specific value for the origination of a stress reversal region. In reservoirs with a high permeability the pressure gradient spreads faster and therefore the stress reversal region also extends faster. The late time shrinkage of the stress reversal region has the same reason. When the pressure gradient further spreads, its value decreases in the vicinity of the fracture. The pressure gradient declines below the specific value and the stress reversal region shrinks.

### 5.5 Analysis of anisotropic permeability

The influence of anisotropic permeability in the reservoir is analyzed by the same procedure. Two cases with anisotropic permeability are simulated within a time range of 100 years and compared to the base case. The first case has ten times greater permeability in x-direction and the second case has a ten times greater permeability in y-direction. The anisotropic permeability affects at first the shape of drainage area. The drainage area is stretched in the direction of higher permeability. In Fig. 9 the distances to the isotropic point are plotted versus time.

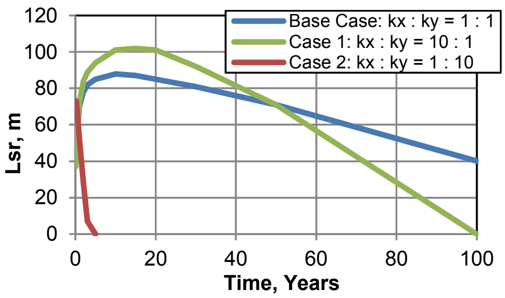


**Figure 9**. Analysis of anisotropic permeability

The green line represents an increased permeability in x-direction. The curve developing is steeper than the base case at the beginning and a maximum distance of 102 m is achieved after 15 years. Therefore the maximum distance is increased and shifted in time compared to the base case.

The red line represents an increased permeability in y-direction. The maximum value is already achieved after 2.5 months. Compared to the base case this value is smaller with a value of 73 m. The subsequent decline is very fast and the stress reversal region almost disappears after two years.

In respect to the stress reversal region the best times for re-fracture treatments would be after 2.5 months and 15 years.

The study indicates that a re-fracture treatment is very efficient for cases with greater permeability parallel to the initial fracture. A greater permeability perpendicular to the initial fracture degrades the re-fracture treatment.

### 5.6 Analysis of heterogeneous permeability

For this investigation the reservoir model is extended to heterogeneous permeability. Therefore the reservoir is divided into a grid with 50 x 50 blocks. For the generation of the heterogeneity the software Matlab is used. By the use of a geostatistical function the permeability in x- and y-direction is calculated for each grid block. The generated permeability matrices vary between 0.005 mD and 0.017 mD with an average of 0.01 mD. In COMSOL Multiphysics the data is imported and assigned to the mesh by an interpolation function.

For a detailed examination the distances to the isotropic point are again taken into account. In this case the distances are expected to differ in +y and –y-direction because of the heterogeneity. Therefore both distances were determined and compared to the homogeneous base case (Fig. 10).

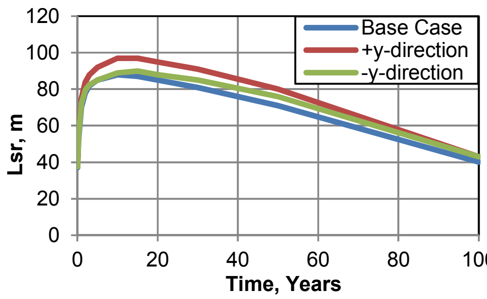


**Figure 10**. Analysis of heterogeneous permeability

The red line represents the distance in the +y-direction and the green line the distance in –y-direction. Both lines progress similar to the base case and therefore no strong influence of heterogeneities is noticed. The variation is within 10 % for both directions.

## 6. Conclusions

- The physics interface "Poroelasticity" in COMSOL Multiphysics enables the coupled simulation of fluid flow and geomechanics.
- The simulation shows that an elliptically shaped stress reversal region arises, if the difference between minimum and maximum stress is small. The reservoir characteristics influence the size and time frame of this process.
- Based on the simplified model the optimum time for re-fracturing treatment can be predicted. Therefore the maximum extension of stress reversal region can be taken into account.
- The dimension of the stress reversal region initially extends fast and after reaching its maximum it shrinks slowly.
- The actual value of the permeability influences the time but not the maximum dimension of the development of the stress reversal region. The time frame of stress reversal increases with decreasing permeability.
- Permeability heterogeneity has only small influence on the appearance of the stress reversal region.
- Permeability anisotropy has strong influence both, on the maximum dimension and the time development of the stress reversal region. A greater permeability parallel to the initial fracture enhances the efficiency of the re-fracture treatment.

## 7. References

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## 8. Appendix

**Table 1:** Base Case Model Parameters

| Parameter | Value | Unit |
|---|---|---|
| Reservoir Length | 1600 | m |
| Reservoir Width | 1200 | m |
| Fracture Half Length | 200 | m |
| Permeability | 0.01 | mD |
| Porosity | 0.1 | - |
| Reservoir Rock Density | 2500 | $kg/m^3$ |
| Young's Modulus | 2.75*105 | bar |
| Poisson's Ratio | 0.25 | - |
| Biot's Coefficient | 0.7 | - |
| Gas Relative Density | 0.6 | - |
| Temperature | 110 | °C |
| Gas Compressibility Factor | From Hall-Yarborough Correlation | - |
| Gas Viscosity | From Lee et. al Correlation | Pa*s |
| Reservoir Pressure | 300 | bar |
| Bottom Hole Flowing Pressure | 50 | bar |
| Maximum Horizontal Stress | 39.5 | MPa |
| Minimum Horizontal Stress | 38.5 | MPa |