A Numerical Study of Performance for Tight Gas and Shale Gas Reservoir Systems
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Abstract
Various analytical, semi-analytical, and empirical models have been proposed to characterize rate and pressure behavior as a function of time in tight gas and shale gas systems featuring a horizontal well with multiple hydraulic fractures. Despite a few analytical models, as well as a small number of published numerical studies there is currently little consensus regarding the large-scale flow behavior over time in such systems, particularly regarding the dominant flow regimes and whether or not reservoir properties or volumes can be estimated from well performance data.

We constructed a fit-for-purpose numerical simulator which accounts for a variety of production features pertinent to these systems — specifically: ultra-tight matrix permeability, hydraulically fractured horizontal wells with induced fractures of various configurations, multiple porosity and permeability fields, and desorption. These features cover the production mechanisms which are currently believed to be most relevant in tight gas and shale gas systems.

We employ the numerical simulator to examine various tight gas and shale gas systems and to identify and illustrate the various flow regimes which progressively occur over time. We perform this study at fine grid discretization on the order of one millimeter to accurately capture flow effects at all time periods. We visualize the flow regimes using specialized plots of rate and pressure functions, as well as maps of pressure and sorption distributions.

We use pressure maps to visualize the various flow regimes and their transitions in tight gas systems. In a typical tight gas system, we illustrate the initial linear flow into the hydraulic fractures (i.e., formation linear flow), transitioning to compound formation linear flow, and eventually transforming into elliptical flow. We explore variations of possible shale gas system models. Based on diffusive flow (with and without desorption), we show that due to the extremely low permeability of shale (a few nanodarcies), the flow behavior is dominated by the extent of and configuration of the fractures.

This work expands our understanding of flow behavior in tight gas and shale gas systems, where such an understanding may ultimately be used to estimate reservoir properties and reserves in these types of reservoirs.
Introduction

The purpose of this work is to quantitatively demonstrate the influence of various reservoir and completion parameters on performance of multiply-fractured horizontal wells in tight gas and shale gas reservoir systems. We seek to provide benchmarks which may guide completion practices and lay the groundwork for future analytical solutions.

Ultra-tight reservoirs present numerous challenges to modeling and understanding. These reservoirs typically require fracture stimulation, which creates complex flow profiles. Additionally, according to Hill and Nelson [2000], between 20 and 85 percent of total storage in shales may be in the form of adsorbed gas, and the majority of this gas may never be produced due to the steepness of the sorption isotherm at lower pressures. Production from desorption follows a nonlinear response to pressure and results in an unintuitive (and difficult-to-model) pressure profile behavior. Closed or open natural fracture networks in ultra-tight reservoirs introduce further complexity through interaction with the induced hydraulic fractures.

Gas desorption from kerogenic media has been studied extensively in coalbed methane reservoirs. Many analytic and semi-analytic models have been developed from the study of gas desorption from coalbed methane reservoirs, including transient responses and multicomponent interactions (see Clarkson and Bustin [1999]). However, the sorptive and transport properties of shale are not necessarily analogous to coal (Schettler and Parmely [1991]). Complex coal-based desorption models provide no additional insight over the commonly used empirical models for single-component surface sorption, the Langmuir isotherm (given by Eq. 1 below and illustrated in Fig. 01) and Freundlich isotherm.

The desorption isotherms as presumed by Langmuir are typified by the $V_L$ term which expresses the total storage at infinite pressure and the pressure at which half of this volume is stored ($p_L$). Further, the Langmuir model assumes instantaneous equilibrium of the sorptive surface and the storage in the pore space — i.e., there is no transient lag between pressure drop and desorption response. Due to the very low permeability of shales, flow through the kerogenic media is extremely slow, so instantaneous equilibrium is a good assumption (see Gao et al. [1994]).

Darcy’s law is valid under the assumptions of continuum flow. In porous media where the average pore throat diameter is on the order of the mean free path of the gas molecules, the continuum assumption does not apply as indicated by Javadpour et al. [2007]. These regimes are characterized by a Knudsen or "microflow" regime in shales. Florence et al. [2007] suggest the possibility of a model where permeability can be adjusted as a function of pressure in the microflow regime, permitting the use of Darcy’s law with a Knudsen-corrected permeability. While this effect may be an important transport consideration, its exploration will be left to future work.

The presence and state of natural fractures varies on a reservoir-by-reservoir (or even well-by-well) basis. In some cases, it is believed that fracture stimulation effectively re-opens an existing, yet dormant or sealed natural fracture network through the idea beyond the assumption of planar hydraulic fractures to include a dual permeability region near the fracture faces to represent a complex-fractured region surrounding the primary hydraulic fracture. The existence of such a complex fracture network has been qualitatively corroborated by real-time microseismic observation of fracture treatments and has come to be referred to as the so-called "stimulated reservoir volume" (SRV) concept. We suggest a "continuum" of possible complex fracture layouts in the near-wellbore reservoir, ranging from the planar fracture case to a dual porosity fractured reservoir case, illustrated in Fig. 02 and Fig. 03.

Many models exist for inflow into single vertical fractures. Raghavan et al. [1997] provide a mathematical description of inflow into the late-time compound-linear flow regime. Medeiros et al. [2006] introduced a semi-analytical solution which models the entire range of flow regimes surrounding a multiply-fractured horizontal well system. Medeiros et al. extended the idea beyond the assumption of planar hydraulic fractures to include a dual permeability region near the fracture faces to represent a complex-fractured region surrounding the primary hydraulic fracture. The existence of such a complex fracture network has been qualitatively corroborated by real-time microseismic observation of fracture treatments and has come to be referred to as the so-called "stimulated reservoir volume" (SRV) concept. We suggest a "continuum" of possible complex fracture layouts in the near-wellbore reservoir, ranging from the planar fracture case to a dual porosity fractured reservoir case, illustrated in Fig. 04.

Many efforts have been made to identify and model complex flow features exhibited in tight and ultra-tight shale gas and tight gas reservoirs. Van Kruijsdik and Dullaert [1989] developed an analytical solution which provides an understanding of the flow regimes surrounding horizontal wells with multiple transverse fractures. They developed multiple scenarios to demonstrate that at early time, the dominant flow into such a system is linear, perpendicular to the fracture faces, until such time as the pressure transients of the individual fractures begin to interfere, leading to a compound-linear flow regime, as illustrated in Fig. 02 and Fig. 03.

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These semi-analytical models are robust, but do not account for desorption or a change of permeability as a function of reservoir pressure over time. Desorption can be a significant source of produced gas, and is nonlinear and difficult to include in analytical solutions. Permeability change in shales as a function of reservoir pressure may occur either due to matrix shrinkage or Knudsen flow effects.

Current models for rate-decline prediction and reserves estimation and production forecast from early time data in ultra-tight reservoir systems fail to account for fracture interference, and consequently yield optimistic predictions. The extrapolation of linear flow in Fig. 03 illustrates the nature of this overprediction. A primary goal of this paper is to address this confusion.
Description of Numerical Model

Several distinct gridding schemes were applied in this work. In the first set of simulation models, a fully three-dimensional, finely discretized grid is employed. This grid uses cell dimensions smaller than one millimeter near the fracture face which increase logarithmically in size to a maximum dimension of half a meter. These grids are used to accurately model the near-fracture region at very early times. The layout of this model is illustrated in Fig. 05. The manner in which these repeating well-system elements connect is illustrated in Fig. 06. Several grids of the same general design were created by varying the effective fracture spacing, \( d_f \). For example, in the base case, the distance between the fracture and the no-flow barrier is 5 m (16.40 ft) corresponding to an \( d_f \) of 10 m (32.81 ft), and in the sensitivity cases, \( d_f \) values of 5 m (16.40 ft) and effective \( d_f \) is 20 m (65.62 ft) are used. It is worth mentioning that in all cases, gravity is neglected due to the reasonably thin reservoir intervals concerned.

The third set examines the effects of laterally continuous thin high permeability layers connected to the primary fracture, with and without microfractures in the shale.

The fourth set employs a fully transient highly fractured gridding scheme, utilizing a dual-porosity assumption. The purpose of this grid type is to approximate the "stimulated reservoir volume" (SRV) concept, that there are no true highly conductive planar fractures, instead there is a fractured region surrounding the well.

The fifth set represents both the features of the third and fourth sets, possessing both thin conductive horizontal layers and dual-porosity shale matrix.

The sixth and final grid scheme utilizes less finely discretized gridding and qualitatively demonstrates the large-scale late-time flow behavior of the system. We perform sensitivity analyses on these systems varying Langmuir volume and fracture width.

We treat the fracture as possessing a fixed dimensionless conductivity as described in Eq. 2 in order to compare the conductivity with values obtained using other models. Consequently, we do not examine Forchheimer (inertial) flow, because this would conflict with the finite-conductivity fracture implementation. In this work, we use a range of fracture permeabilities corresponding to a wide range of dimensionless fracture conductivities, defined by Eq. 2:

\[
C_{fD} = \frac{k_f \cdot w}{k_m \cdot x_f}
\]

For example, a fracture with width of 0.1mm, possessing a dimensionless conductivity of 1.05, will possess a \( k_f \) equal to 10.6 md where the matrix permeability is \( 1.0 \times 10^{-4} \) md. The fracture permeabilities (and consequently the fracture conductivities) used in the simulation cases are computed in Table 1 below.

Table 1 — Fracture widths and equivalent dimensionless conductivities used in the simulation runs.

<table>
<thead>
<tr>
<th>Fracture Width (mm)</th>
<th>Fracture Permeability (md)</th>
<th>Reservoir Permeability (md)</th>
<th>Fracture Conductivity (dimless.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>10,555</td>
<td>( 1.0 \times 10^{-4} )</td>
<td>( 1.05 \times 10^{4} )</td>
</tr>
<tr>
<td>0.1</td>
<td>10.6</td>
<td>( 1.0 \times 10^{-4} )</td>
<td>1.05</td>
</tr>
<tr>
<td>0.01</td>
<td>0.0106</td>
<td>( 1.0 \times 10^{-4} )</td>
<td>( 1.05 \times 10^{-4} )</td>
</tr>
<tr>
<td>1</td>
<td>10,555</td>
<td>( 1.0 \times 10^{-5} )</td>
<td>( 1.05 \times 10^{5} )</td>
</tr>
<tr>
<td>0.1</td>
<td>10.6</td>
<td>( 1.0 \times 10^{-5} )</td>
<td>10.5</td>
</tr>
<tr>
<td>0.01</td>
<td>0.0106</td>
<td>( 1.0 \times 10^{-5} )</td>
<td>( 1.05 \times 10^{-3} )</td>
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</tr>
<tr>
<td>0.1</td>
<td>10.6</td>
<td>( 1.0 \times 10^{-3} )</td>
<td>0.105</td>
</tr>
<tr>
<td>0.01</td>
<td>0.0106</td>
<td>( 1.0 \times 10^{-3} )</td>
<td>( 1.05 \times 10^{-5} )</td>
</tr>
</tbody>
</table>

The Langmuir isotherm curve models desorption as a function of pressure. The Langmuir parameters are tuned to provide storage in a similar range found in known shale reservoirs. The Langmuir volume parameter (\( V_L \) in Eq. 1) is varied as shown in Table 2 while the Langmuir pressure parameter (\( p_L \) in Eq. 1) is held at initial reservoir pressure for all cases. The real properties of pure methane are computed as a function of pressure at isothermal conditions using the Peng-Robinson equation of state. Water flow is not modeled, as its interaction with the shale is poorly understood and would merely add a confounding influence to the results. Additionally, this would only hinder analytical comparison. The other pertinent simulation case parameters for Set A are presented in Table 2.
Table 2 — Description of the simulation runs and sensitivity analyses varying fracture conductivity.

<table>
<thead>
<tr>
<th>Case</th>
<th>Fracture Spacing (m)</th>
<th>Permeability (nD)</th>
<th>$C_{nD}$</th>
<th>Langmuir Volume (scf/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A1</td>
<td>10</td>
<td>10</td>
<td>$1.05 \times 10^4$</td>
<td>0</td>
</tr>
<tr>
<td>A2</td>
<td>10</td>
<td>10</td>
<td>$1.05 \times 10^4$</td>
<td>200</td>
</tr>
<tr>
<td>A3</td>
<td>10</td>
<td>10</td>
<td>1.05</td>
<td>0</td>
</tr>
<tr>
<td>A4</td>
<td>10</td>
<td>10</td>
<td>1.05</td>
<td>200</td>
</tr>
<tr>
<td>A5</td>
<td>10</td>
<td>10</td>
<td>$1.05 \times 10^{-4}$</td>
<td>0</td>
</tr>
<tr>
<td>A6</td>
<td>10</td>
<td>10</td>
<td>$1.05 \times 10^{-4}$</td>
<td>200</td>
</tr>
</tbody>
</table>

We note that for all the cases in Set A, a matrix permeability of 10 nD was assumed. In all the cases in Set B, presented in Table 3, a matrix permeability of 100 nD is assumed, except for the sensitivity cases where 10 nD and 1000 nD are shown. The full gridding scheme also uses 100 nD permeability.

Table 3 — Description of the simulation runs and sensitivity analyses using highly refined gridding scheme.

<table>
<thead>
<tr>
<th>Case</th>
<th>Fracture Spacing (ft)</th>
<th>Permeability (nD)</th>
<th>Perforations Per Fracture</th>
<th>Drawdown (psi)</th>
<th>Langmuir Volume (scf/ton)</th>
</tr>
</thead>
<tbody>
<tr>
<td>B1</td>
<td>32.8</td>
<td>100</td>
<td>3</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B2</td>
<td><strong>32.8</strong></td>
<td>100</td>
<td><strong>1</strong></td>
<td><strong>1000</strong></td>
<td><strong>100</strong></td>
</tr>
<tr>
<td>B3</td>
<td>32.8</td>
<td>100</td>
<td>5</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B4</td>
<td>32.8</td>
<td>10</td>
<td>1</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B5</td>
<td>32.8</td>
<td>1000</td>
<td>1</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B6</td>
<td>32.8</td>
<td>100</td>
<td>1</td>
<td>1000</td>
<td>0</td>
</tr>
<tr>
<td>B7</td>
<td>32.8</td>
<td>100</td>
<td>1</td>
<td>1000</td>
<td>200</td>
</tr>
<tr>
<td>B8</td>
<td>16.4</td>
<td>100</td>
<td>1</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B9</td>
<td>65.6</td>
<td>100</td>
<td>1</td>
<td>1000</td>
<td>100</td>
</tr>
<tr>
<td>B10</td>
<td>32.8</td>
<td>100</td>
<td>1</td>
<td>1400</td>
<td>100</td>
</tr>
<tr>
<td>B11</td>
<td>32.8</td>
<td>100</td>
<td>1</td>
<td>4500</td>
<td>100</td>
</tr>
<tr>
<td>B12</td>
<td>32.8</td>
<td>100</td>
<td>1</td>
<td>1000</td>
<td>2000</td>
</tr>
</tbody>
</table>

Results and Analysis

We will first discuss the base case results. Then the effects of various completion parameters will be analyzed. Next we will discuss the effects of desorption. Finally we will discuss other parameters related to the reservoir and the porous medium.

All results are presented in dimensionless form. The conventions for dimensionless time and dimensionless rate are

$$t_D = 0.0002637 \frac{k}{\phi \epsilon t \sqrt{\frac{x}{f}}} t$$

and

$$q_D = 141.2 \frac{B \mu}{kh (p_i - p_w)}$$

This convention is adopted to better enable the identification of those variations in performance which are a consequence of fracture interference, which is the focus of this work.

Base Case Results: The base case simulation parameters were chosen to best represent a typical shale gas reservoir and completion. There exist a broad range of shale plays and a variety of workable completion schemes, but these parameters should provide an acceptable starting point of comparison for any given play. We observe in Fig. 07 and Fig. 08 the evolution of formation linear flow starting at early times. As the dimensionless time approaches 1, fracture interference comes into effect, and the transition toward compound linear flow is marked by the approach of the rate integral and rate integral derivative functions. However, we note that these two auxiliary functions never actually merge or cross, because no true reservoir boundary exists.

Effect of Complex Fractures: While in some cases there may exist perfectly linear, planar induced fractures, it is possible that a complex yet narrow region of fractured reservoir is created in a fracture treatment. We model this as the occurrence of
several parallel planar fractures over a small interval of horizontal wellbore. We observe in Fig. 09 that the presence of a more extensive group of planar fractures results in an increase in early time rate, but that the rates merge at the start of transition from formation linear flow to compound linear flow. The rate data for all three cases has clearly merged completely by a dimensionless time of 0.1, which is equivalent to 90 days. In Fig. 09 we are able to see that all the auxiliary functions have the same merging behavior.

We can conclude from this observation that that late time behavior of a hydraulic fracture which is complex or branching will not be any different from the behavior of a single planar hydraulic fracture. However, the extent of complexity of the fractures will strongly affect early time behavior, in the case of these results increasing early time rate by a factor of 4 or more. A practical interpretation of this result is that more intensive fracturing of a narrow volume of rock will enhance early-time rates but will not necessarily prolong the well life.

Effect of Fracture Spacing: We observe the boundary-like effect of fracture interference by comparing runs which vary only in fracture spacing. The data is normalized on a per-fracture basis, and does not reflect the fact that a given horizontal well with tighter fracture spacing will possess a larger number of fractures.

The signature of fracture interference is identified by a substantial drop in flow rate and a corresponding positive slope on the normalized rate-derivative curve. This marks the effective end of linear flow and the beginning of the transition toward compound linear flow, seen very clearly by comparison in Fig. 10. We can also observe that the rate function and rate integral derivative function appear to cross over during the transition to compound linear flow. This effect is clearly illustrated in Fig. 11, where the normalized rate derivative functions for simulated cases of varying fracture density — approaching the limiting case of stimulated reservoir volume gridding. This auxiliary plot can be used to help identify the onset of compound-linear flow. We believe that the onset of compound-linear flow is often mistakenly identified as boundary-dominated flow. No evidence exists to indicate substantial compartmentalization of shale gas or tight gas reservoirs, so wells with declining rate are more likely to be experiencing fracture interference and entering compound-linear flow than to be entering boundary-dominated flow.

In Fig. 03 we present a comparison of two simulations; the first is the case of a finite reservoir (rectangular boundary), while the other case is an effectively infinite reservoir (no boundary effects are observed). In this figure we observe similar trends for the bounded and unbounded reservoir cases, until boundary effects dominate the response. We have imposed a half-slope power-law straight line (representing formation linear flow) — where we note that this trend would (obviously) overestimate future rates after fracture interference begins.

We visually illustrate the typical system responses that could occur during the production of a horizontal well with multiple fractures in Fig. 07 — at early times, only flow from fractures is observed corresponding to formation linear flow, this flow regime is identified by the half-slope. Then fracture interference begins which corresponds to a transitional flow regime. Next, we observe the "compound linear flow regime" and finally the flow regime becomes elliptical. Similarly, Figs. 12-14 (i.e., the pressure profiles) visually depict the flow regimes of linear, compound linear, and beginning elliptic flow. It is important to note that for these runs a matrix permeability of 100 nd was used, and Fig. 12 is reached after 100 days, Fig. 3 is reached after 3300 days or about 10 years, and Fig. 14 requires 9000 days or 30 years, likely longer than the life of a well.

Effect of Fracture Conductivity: The clearest indication of change to the performance behavior is seen in the very early time. The four cases shown in Fig. 15 correspond to different equivalent fracture widths, and directly to different fracture conductivities, ranging from a low value of 5.46×10^{-3} to a high value of 5.46×10^{3}. We see from these figures that the contribution from the fracture is greater at earlier time, and the steepness of decline is less severe in the cases with less fracture conductivity. In middle-time ranges it is observed that the rates of the higher-conductivity stems begin to merge. The higher-conductivity fracture aggressively evacuates the near-fracture region but production soon becomes dominated by the low permeability of the matrix. Rate becomes dominated by fracture surface area rather than fracture conductivity.

We see from Fig. 16 that the pressure depletion near the fracture face is very severe as indicated by the steepness of the pressure profile. With the very low-conductivity, thinner fracture, the wellbore inflow effect is more dominant in the production data signature. In these low-conductivity cases it is difficult to identify a clear half-slope linear flow period. Real wells with ineffective fracture treatments will display more dominant signature horizontal well flow effects and less distinct linear flow effects. No fracture interference effects are observed through this time interval.

Note that the general observations regarding the effect of complex fractures and the effect of fracture conductivity are similar. A fracture which possesses a higher conductivity or a greater complexity will exhibit a higher initial rate, while ultimately the rate behavior will merge with cases with lower fracture conductivity or fracture complexity. It is doubtful whether the relative effects of fracture complexity and fracture conductivity will be extricable or identifiable in production data without a rigorous inverse analysis (history matching) study.

Effect of Desorption: The next observation concerns the apparent effect of varying desorative contribution. Fig. 17 clearly shows the increase in rate and the lengthening of the rate forward in time that accompanies higher desorative contribution, effectively changing the energy of the system. The first apparent effect is that greater sorptive storage yields higher rates; the second effect is that the pressure profile is steeper as it propagates away from the fracture, as visually depicted in the pressure
map, Fig. 18. Pressure does not correspond linearly to mass storage, since the sorption isotherm is highly nonlinear. As such, we visualize in Fig. 18 the dimensionless mass of gas found at various distance intervals from the hydraulic fracture. The purpose of this figure is twofold – one, to show how slowly the pressure transient moves outward and how thoroughly it depletes a region of gas before advancing, and two, to show how much residual gas remains even after the pressure is drawn down to near wellbore flowing pressure. Further, Fig. 19 lets us examine the steepness and near-fracture localization of the depletion from surface sorption. This emphasizes the steepness of the pressure front due to the ultra-low permeability.

There currently exists no method by which to account for desorption in the nondimensionalization since there is no satisfactory general analytical solution featuring desorption. Since desorption responds to pressure in a nonlinear fashion, and desorption is more properly characterized by at least two parameters (Langmuir volume and Langmuir pressure,) it is not strictly appropriate to scale the results by any constant. However, we obtain interesting results by altering the dimensionless time definition to include an arbitrary variable characterizing sorptive energy.

\[ t_D = \frac{k}{\phi \mu L^2} \left( \frac{1}{\mu (0.00525) V_L} \right) t \]  

The Langmuir volume term is frequently treated as being dimensionless in mathematical developments of desorption. The constant 0.00525 was obtained through a regression fit using all the data of this work. This value of 0.00525 may hold a physical significance (i.e. it may correspond to a unit conversion factor and/or another reservoir parameter) but determination of its specific meaning will be the goal of future work. Using the adjustment in Eq. 5, we show in Fig. 20 that scaling the dimensionless time by a constant factor appears to completely normalize for the effect of desorption at all timeframes. Observing Fig. 18 and comparing it with Fig. 16, it can be verified that desorption delays the effect of fracture interference when we compare the normalized desorption signatures with the true effect of fracture interference caused by varying fracture spacing.

**Effect of Matrix Permeability**: The next observation concerns the apparent effect of varying the matrix permeability. Fig. 21 shows the effect of varying matrix permeability from a very small value of 10nd to a value of 1 md. Matrix permeability appears to affect early time behavior in particular. Convergence of the rate profiles is observed at late times, in particular during compound linear flow.

Again, it is noteworthy that varying permeability appears to strongly affect early time rate data while the rate behavior merges at late times. However, it must be emphasized that permeability is a term in the nondimensionalization of both rate and time. Consequently, this behavior would not appear in rate-time data prior to nondimensionalization. The outstanding result is that nondimensionalization with respect to permeability does not cause the three rate curves to overlie one another. This is due to the complex evolution of the pressure profiles over time through the asymmetric near-wellbore reservoir geometry.

**Effect of Natural Fractures**: The presence and influence of natural fractures in tight gas and shale gas reservoir systems is a matter of debate. Likewise, the role of complex induced fracture networks is not fully understood and its characterization remains a matter of conjecture. We illustrate possible configurations of in situ fracture orientations in Fig. 04. We model the effect of a natural or complex induced fracture network by using a dual porosity model with various shale fracture network permeabilities. As shown in Fig. 22, the presence of conductive natural or induced fractures leads to a higher initial rate but overall a much shorter or nonexistent linear flow period, and faster depletion.

We attempt to capture the possibility that the fracture treatment creates or re-activates a region around the induced planar hydraulic fracture. We model this by treating the region near the induced fracture by a dual porosity model with conductive natural fractures, while the region more distant from the induced fracture is unstimulated shale of 100nd permeability. In Fig. 23 we demonstrate that Case IIIb (corresponding to a near-fracture stimulated region) exhibits flow features from both the base case of a single planar fracture (Case I) and the limiting case, Case IIIa, representing a fully fractured reservoir. In fact, an inflection point in the rate behavior of Case III occurs at the exact point of intersection of Case I and Case IIIa.

**Effect of High-Conductivity Layers**: Core samples of shale gas reservoirs reveal a large degree of stratification and the likely presence of higher-conductivity layers. A possible layout of this system is illustrated in Case Ia and Case IIb in Fig. 04. Fracture stimulation may further fracture already brittle layers, such as microlayers of carbonate sediment. Microseismic monitoring of fracture treatments indicates that microseismic events occur in a ‘cloud’ around the perforations. The distribution and extent of the cloud vary depending on the geology and the stimulation treatment design.

In Fig. 24 we compare the behavior of reservoirs with high-conductivity layers (Case IIa) against a naturally-fractured or complex-fractured reservoir (Case IIIa) and finally a reservoir possessing both natural fractures and laterally continuous high conductivity layers (Case IVa.) All these results are compared, once again, against the base case (Case Ia) possessing only a single vertical fracture. We observe that late time behavior shows the same character, regardless of the fracture configuration, indicating that at late times, the signature of laterally continuous layers may be indistinguishable from a natural fracture signature. However, at early times, systems possessing natural fractures show a strong fracture-depletion signature which does not occur in the case with laterally continuous layers.
Field Case Model Match: Production data was obtained from a Haynesville Shale gas well. Completion parameters were obtained from the operator, and reservoir parameters were obtained through use of a model fit using a commercial software package. These parameters were used as input for a simulation case. The numerical model is currently only able to perform constant-pressure or constant-rate production, so it was not possible to match the variable bottomhole pressure data. Regardless, a good rate match was obtained, shown in Fig. 25. The auxiliary functions were not matched, as shown in Fig. 26, which should be expected due to the failure to account for variable bottomhole pressure, and additionally due to the nonuniqueness of the model parameter match.

Conclusions

In this work we make an attempt to characterize the influence of various reservoir and completion parameters on performance of multiply-fractured horizontal wells in ultra-low permeability reservoir systems.

1. Contrary to intuition, the effect of desorption can be accounted for by a time scaling constant as a function of the Langmuir storage parameter. The presence of desorption appears to shift fracture interference forward in time.

2. Ultra-low permeability systems with large fractures will possess extremely sharp pressure gradients. The steepness of these gradients will be exacerbated where desorption is present. The onset of fracture interference is gradual and flow regimes in these systems are constantly evolving. The use of coarse gridding schemes will fail to capture the nuance of this evolution and will lead to inaccurate characterization of fracture interference behavior, as well as inaccurate interpretation of production data.

3. While a simple dual porosity model with no planar fractures may appear to match field data, such a model will not correctly capture the effect of fracture interference. Application of dual porosity or "stimulated reservoir volume" schemes requires implicit assumptions of fractured volume. Models employing discrete fractures will capture the transient behavior of fracture interference, which appears to approach boundary-dominated flow, but, unlike the "stimulated reservoir volume" case, never actually reaches boundary-dominated flow.

None of these three features are a true reservoir boundary. Due to the relatively small volumes of investigation of these well systems, it is unlikely that reservoir compartmentalization is the true cause of "boundary-dominated flow" effects as interpreted from rate data.

The features of higher permeability, higher fracture conductivity, higher induced fracture complexity, and more highly fractured reservoir will all lead to a higher initial rate and initial dimensionless rate, yet late time dimensionless rates will merge with lower permeability/conductivity/complexity cases sometime during the compound linear flow period. The effect of desorption, on the other hand, is more apparent at late time than early time, tending to prolong all flow periods and extend production.

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Nomenclature

- \( b \) = fracture half-width, mm
- \( k_f \) = effective fracture permeability, \( m^2 \)
- \( p \) = pressure, Pa
- \( V_L \) = Langmuir volume, scf/ton
- \( p_L \) = Langmuir pressure, Pa
- \( \theta \) = Langmuir storage, scf/ton
- \( q \) = Gas flowrate, MSCF/D
- \( s_f \) = Fracture spacing, m
- \( w_f \) = Fracture width, mm
- \( B \) = Formation volume factor, bbl/stb
- \( \mu \) = Viscosity, cP
- \( k \) = Matrix permeability, md
- \( h \) = Reservoir thickness, ft
- \( p_i \) = Initial reservoir pressure, psia
- \( \phi \) = Porosity, fraction
- \( c_t \) = Total compressibility, 1/psi
- \( x_f \) = Fracture half-length, ft
References


Figure 01 — Langmuir isotherm storage behavior as a function of pressure.

Compound Linear Flow Concept of Van Kruysdijk

Figure 02 — “Compound linear” flow regime of van Kruysdijk” (van Kruysdijk and Dullaert [1989]).
Figure 03 — Horizontal gas well with multiple (transverse) fractures: Illustration of the transient and transition flow regimes.
Figure 04 — Cartoon of potential fracture network layouts, including laterally continuous layers, naturally or complex fractured matrix, or a combination of both.

I. Planar fracture, transverse fracture only.
IIa. Planar fracture, stimulated thin lateral layers.
IIIb. Planar fracture, with stimulated thin lateral layers, partial extent.
IIIa. Planar fracture, with naturally fractured shale.
IVa. Planar fracture, with naturally fractured shale, partial extent.
IVb. Planar fracture, stimulated layers and fractured shale, partial extent.

Figure 05 — Schematic diagram of horizontal well/transverse fracture element.
a. Well system, full schematic. b. Using an argument of symmetry, we may model one quarter of the system.

c. Assuming a pseudo-boundary caused by flow superposition between adjacent fractures, we designate a repetitive element which reduces the problem size significantly.

Figure 06 — Schematic diagram of horizontal well/transverse fracture system in a rectangular reservoir (note that the "repetitive element" concept permits placement of evenly-spaced transverse (vertical) fractures).
Figure 07 — Pressure map for a horizontal well with transverse fractures — cross-section "slice" in xy-plane — aerial view.
Figure 08 — Horizontal gas well with multiple (transverse) fractures: Base case parameters and dimensionless rate function results.
Figure 09 — Horizontal gas well with multiple (transverse) fractures: Effect of complex fractures, sensitivity analysis, rates and auxiliary functions.
Figure 10—Horizontal gas well with multiple (transverse) fractures: Effect of fracture spacing, sensitivity analysis, rates and auxiliary functions.
Figure 11 — Effect of various fracture spacings on the normalized rate derivative function (square-root time basis).
Figure 12 — Pressure profile: Aerial view, one-half reservoir, 100nd permeability, 25m fracture spacing, 100 Days.

Figure 13 — Pressure profile: Aerial view, one-half reservoir, 100nd permeability, 25m fracture spacing, 3300 Days.

Figure 14 — Pressure profile: Aerial view, one-half reservoir, 100nd permeability, 25m fracture spacing, 9000 Days.
Figure 15 — Horizontal gas well with multiple (transverse) fractures: Effect of fracture conductivity, sensitivity analysis, rates and auxiliary functions.
Figure 16 — Pressure map showing pressure depletion at 100 days into production, aerial view.

**Pressure Map**

XY-Plane
100 Days
4m above Well-Plane

\[ C_{fd} = 1.05 \]

\[ k_m = 100 \text{ nD} \]

\[ V_L = 100 \text{ scf/ton} \]
Figure 17—Horizontal gas well with multiple (transverse) fractures: Effect of Langmuir storage, sensitivity analysis, rates and auxiliary functions.
Figure 18 — Sorption map showing steepness of sorption gradient at 100 days into production, aerial view.
Figure 19 — Total gas storage at various intervals from the fracture face over time.

Figure 20 — Horizontal gas well with multiple (transverse) fractures: Effect of desorption, redefined dimensionless time parameter normalizing for Langmuir volume.
Figure 21— Horizontal gas well with multiple (transverse) fractures: Effect of matrix permeability, sensitivity analysis, all rates.
Figure 22 — Induced fracture system: Effect of natural fractures with various fracture system permeabilities, sensitivity analysis, rates only.
Figure 23 — Induced fracture system: Effect of discontinuous fracture networks, sensitivity analysis, rates only.
Figure 24 — Induced fracture system: Effect of laterally continuous high conductivity layers and interaction with natural fracture system, sensitivity analysis, rates only.
Figure 25 — Field Example: Horizontal gas well with multiple (transverse) fractures: Model match for horizontal well with 10 transverse fractures, rate only.

Figure 26 — Field Example: Horizontal gas well with multiple (transverse) fractures: Model match for horizontal well with 10 transverse fractures, rate and auxiliary functions.
SPE 124961

A Numerical Study of Tight Gas and Shale Gas Reservoir Systems

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Presentation Outline

● Rationale for this Work

● Orientation/Tight Gas and Shale (TGSG) Gas Reservoir Systems
  ■ TGSG Features
  ■ Fracture Occurrence/Distribution

● Numerical Simulation Model
  ■ Modeling and Gridding
  ■ Base Simulation Case — Description
  ■ Characteristic Flowrate Behavior

● Characteristic Flowrate Behavior Considerations
  ■ Effects of Completion
  ■ Effects of Desorption
  ■ Effects of Medium

● Conclusions and Remaining Issues

This work was supported by RPSEA (Contract No. 07122-23) through the Ultra-Deepwater and Unconventional Natural Gas and Other Petroleum Resources Research and Development Program as authorized by the US Energy Policy Act (EPAct) of 2005.
**Rationale For This Work**

- Horizontal wells with multiple hydraulic fractures in ultra-tight reservoir systems pose numerous challenges to understanding.

- Through *MODELING*, we hope to find a more rigorous method for understanding the production characteristics, estimation of reserves and evaluation of stimulation effectiveness.

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**Compound Linear Flow Concept of van Kruysdijk and Dullaert [1989]**
Orientation: TGSG Reservoir Systems

Current Model (Texas A&M)

- Fractures:
  - Natural fractures.
  - Induced fractures.

- Sorption:
  - Surface adsorption.
  - Langmuir isotherm.

- Issues:
  - Difficult to distinguish characteristic behaviors.

Shale Transport Mechanisms.

Langmuir Isotherm

Langmuir Desorption Isotherm.

Pressure, $p$, (psi)

Langmuir Storage, $V'_L$, (scf/ton)
Orientation: **TGSG Reservoir Systems**

**Future Modeling (Texas A&M)**

- **Nanoscale Flow:**
  - Knudsen diffusion.

- **Permeability Reduction:**
  - Matrix shrinkage.
  - Shale creep?

- **Water:**
  - Imbibition.
  - Damage in fractures.
  - Vaporization/condensation.

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**Effect of Knudsen Flow on Permeability.**
Orientation: **TGSG Reservoir Systems**

I. Planar fracture, transverse fracture only.
IIa. Planar fracture, stimulated thin lateral layers.
IIb. Planar fracture, with stimulated thin lateral layers, partial extent.
IIIa. Planar fracture, with naturally fractured shale.
IIIb. Planar fracture, with naturally fractured shale, partial extent.
IVa. Planar fracture, stimulated layers and fractured shale.
IVb. Planar fracture, stimulated layers and fractured shale, partial extent.
Discussion: van Kruysdijk and Dullaert [1989] Flow Regime Concept:
- Complex pressure profile behavior evolves due to fracture interference.
- Onset of compound linear period marked by rate decline.

Numerical Simulation Model: Concept

a. Formation linear flow.  
b. Compound linear flow.  
c. Pseudo-elliptical flow.
Numerical Simulation Model: Concept

Horizontal Gas Well with Multiple (Transverse) Fractures
van Kruysdijk and Dullaert [1989] Flow Regime Concept
(Infinite-Acting Case)

Legend:
- (q_p) Rate Function Data
- Fracture Drainage
- Formation Linear Flow
- "Compound" Linear Flow
- Pseudo-elliptical Flow

Gas Flowrate Functions, Mscf/d

Production Time, t, days
Numerical Simulation Model: *Modeling*

- Discussion: Linear (Planar) Fracture — Full System
  - The well system layout represents the full flow system.
  - Radial flow into the horizontal well is correctly modeled.
Numerical Simulation Model: **Modeling**

- **Discussion: Linear (Planar) Fracture — Section View**
  - Well/reservoir system is divided along planes of symmetry.
  - Flow physics is retained, but number of grid blocks is reduced.
**Numerical Simulation Model: Modeling**

- **Discussion: Linear (Planar) Fracture — Repetitive Element**
  - Repetitive element used to represent flow of individual fractures.
  - Fracture interference modeled by a no-flow boundary.
Numerical Simulation Model: Gridding

- Single fracture element:
  - Repetitive element simulated using extremely fine grids.
  - 500,000 – 1,000,000 grids (5m x 5m x 50m system).
  - Accounts for wellbore, fracture interference.

a. Schematic of fracture-well system.

b. Repetitive element of system.

c,d. Pressure map results, z-direction slices in time.
Discussion: Numerical Simulation "Base Case"

- A horizontal well with a single planar fracture (repetitive element).
- This case is the basis of the sensitivity analyses carried out in this work.
Base Simulation Case: *Pressure Maps*

- **Pressure Maps:**
  - Linear flow at early time.
  - Fractures dominate flow at early time.
  - Fracture interference is caused by fracture spacing effects.
  - Pressure gradient is very steep near the fractures.
Discussion: Effects of Complex Fractures

- Rate and auxiliary functions merge at large times.
- Functions merge during transition from formation linear flow.
**Flowrate Behavior: Effects of Completion**

Discussion: Effects of Fracture Spacing

- Rate and auxiliary functions merge during compound linear flow.
- Smaller fracture spacing causes earlier fracture interference effect.
Flowrate Behavior: *Effects of Completion*

Discussion: Effects of Fracture Conductivity

- Horizontal well signature is apparent in low-conductivity case.
**Discussion: Effects of Desorption — Langmuir Volume**

- Sorption impacts rate more significantly at late times.
- Sorption appears to prolong flow periods/delays fracture interference.
**Flowrate Behavior: Effects of Desorption**

- **Nonlinear Depletion:**
  - Sorption surfaces near fracture are significantly more depleted.
  - Pressure/Density/Sorptive Storage is not intuitively related.

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**SPE 124961 — Horizontal Gas Well**

Numerical Simulation Results: Effect of Langmuir Volume ($V_L$)

**Characteristic Rate Behavior**

- Dimensionless Rate Function ($q_D$)
- Dimensionless Time ($t_D$)

Flowrates with Various Langmuir Volumes.

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**Dimensionless Desorption Map**

**Dimensionless Density Map**

- **XY-Plane**
  - 100 Days
  - 4m above Well
  - $C_{eq} = 1.05$
  - $k_m = 100$ nD
  - $V_L = 100$ scf/ton
Flowrate Behavior: **Effects of Medium**

**Discussion: Effect of Matrix Permeability**
- Matrix permeability affects the early time rate behavior in particular.
- Convergence of rate profiles are observed at late times.
Flowrate Behavior: *Effects of Medium*

Discussion: Effect of Natural Fractures
- Presence of natural fractures increases rate and hastens depletion.
- Early time fracture drainage flow period is evident with high permeability.
Flowrate Behavior: Effects of Medium

Discussion: Effect of Hydraulic Fractures and Horizontal Layers

- Natural fractures cause early time fracture depletion signature.
- Conductive lateral layers increase rate and hasten depletion.
Flowrate Behavior: Effects of Medium

Discussion: Effect of Partial Natural Fracture Enhancement

- Grid type IIIb exhibits flow character of both regions (coincidence?).
Conclusions and Remaining Issues:

**Conclusions:**

- For TGSG reservoir systems, many factors affect performance.
- Numerical modeling must be robust and tied to *flow physics*.
- Desorption effects originate near fractures.
- The well completion controls early time behavior.
- Complex fractures (any type) substantially enhance early rates.

Flowrates with Various Langmuir Volumes.

Dimensionless Desorption Map

Dimensionless Density Map

**Conclusions and Remaining Issues**
Conclusions and Remaining Issues:

**Issues for Well Performance in TGSG Systems:**

- Correct assessment of the fracture distribution must be made to ensure proper flow regime identification and forecasting.
- Desorption is highly nonlinear, but it defies direct assessment.
- Assessment of fracture conductivity is non-unique.
- Well completion issues are critical — particularly well clean-up.
SPE 124961

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END OF PRESENTATION

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