The Analysis of Dynamic Data in Shale Gas Reservoirs – Part 1
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The original version of the "Part 1" document was dated July 2010. It only addresses theoretical considerations and simulations, with no real example. This update is simultaneous to the release of Part 2, where a real data set is used and a workflow is suggested.

1 - Introduction

Shale Gas (or unconventional gas to be a little more generic) is the latest buzzword in town.

For KAPPA, the issue is not whether shale gas is economically viable or not. Operating Companies say yes, and we do not have all the elements to express a qualified opinion. However, if some of the statements are based on reserves calculated from straight line analyses, operating companies may be up to some bad surprises in the years to come.

Well whatever, what we are interested at KAPPA is the analysis, modelling and forecasting of dynamic data, mainly production and pressure, in shale gas reservoirs. We tried to identify the specific problems, the limitations of the current methodology and models, and what can be done to properly address this. In this document we are going to (respectfully) object to what some of our fellow competitors, and their followers, do today. We are also going to be positive and suggest what can be done.

If one looks at the process of producing shale gas, we can see four specifics:
- Permeability is extremely low
- As a result shale gas is generally produced using fractured horizontal wells, though historically there has been flow through single fractures.
- Gas diffusion is somewhat complexified by the desorption of gas from the shale
- Reservoir also exhibits unconsolidation, i.e. the permeability reduces when pressure drops

To address dynamic data (PTA, PA, simulation) a few methods are offered in the industry:
- "Early time" straight line analysis of linear flow
- Sometimes dual straight line analysis of compound linear flow is considered
- Late time material balance calculation on a restricted volume (SRV)
- Analytical models
- Numerical models using pseudopressures (but we will not use these here)
- Numerical models simulating the real gas diffusion (Saphir NL, Topaze NL and Rubis)

Naturally, only the nonlinear numerical model, if properly implemented, will address exactly all our hypotheses. Other methods will carry approximations, and the real question is whether the errors linked to such or such method are acceptable or not for our production forecast.

Pressure Transient Analyses (Saphir) can be seen here and then, the time scale of a build-up, when combined with the value of the diffusivity, lead to a very small volume of investigation.

History matching (Rubis) could be used for multi-well simulation for complex geometries. However interferences between wells are rare, and today we are still fighting to discriminate permeability from fracture length, so we are still far from modelling complex cases.

So, for any practical purpose the tool of choice today is still Production Analysis (Topaze NL).

2 - Methodology used in this document

In Part 1 we use NO real data. The point here is not to draw a straight line on real data, or match an analytical model, or a numerical model, and get results. As we see in Part 2 anything will fit and prove nothing. We get some results, and then what? Even rolling dice or picking random numbers would give us result.

In this document we will list our hypotheses, run the "exact" simulations according to these hypotheses, and then apply different techniques to assess their pros and cons.

This document is structured as follows:
- Presentation of the different techniques and modelling tools: early time (§3) and late time (§4) straight line analyses, analytical models (§5) and numerical models (§6);
- Validation of the reference nonlinear numerical model (§7);
- Simulation and application of the different techniques to a single fracture (§8) and a fractured horizontal well (§9);
- Integration of desorption (§10) and non-consolidation (§11);
- Material balance plot on the SRV with sensitivity to fracture density and spacing (§12);
- *Influence of real data signature was removed and transferred to Part 2;*
- *Conclusions were also removed and transferred to Part 2;*
- List of additional theoretical developments to be done (§13).

We illustrate all this by simulating a reference case that has to be representative of what we are likely to encounter, say, when fracing a horizontal well in Barnett shales. We use the following parameters:

reservoir permeability	1E-2 ; **1E-4 md** ; 1E-6	horizontal well length	4000 ft
reservoir thickness	100 ft	horizontal well position	centered
reservoir porosity	3%	horizontal well radius	0.32 ft
(connate) water saturation	30%	horizontal well skin factor	0
reservoir initial pressure	5000 psia	number of fractures	10
reservoir temperature	200 °F	fractures ½ length	200 ft
gas specific gravity	0.65	fractures conductivity	infinite
percent CO2	0%	fractures penetration	full
percent H2S	0%	fractures position	centered
percent N2	0%	production duration	4 years data 20 years forecast
Adsorbed gas	120 scf/ton	well flowing pressure	500 psia

In most cases an "average" permeability value of 1E-4 md is considered. When needed, this base case is complemented by simulation runs on lower (1E-6 md) and upper (1E-2 md) permeability. This will be sufficient to illustrate the strengths and pitfalls of the various techniques presented here.

3 – Early / intermediate time straight line analysis of linear flow

The early time analysis relies on the assumption that fractured horizontal wells exhibit a linear flow regime at early and intermediate times. This gives us an estimate of $k.X_f^2$ similar to what we do in the analysis of the early time behaviour of a single fracture. The classical relationship defining linear flow between dimensionless times and pressures can be used:
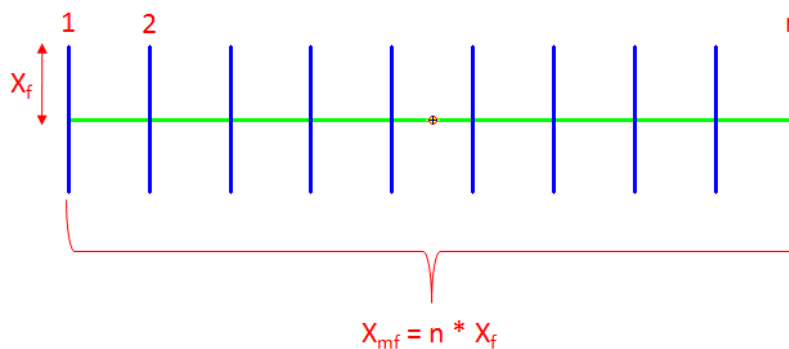
$$p_D = \sqrt{\pi t_{DXf}}$$

With in our case:

$$p_D = \frac{\pi k h T_{SC}}{T q_{SC} p_{SC}}\left[m(p_i) - m(p_{wf})\right]$$

$$t_{DXf} = \frac{kt}{(\phi \mu c_t)_i X_{mf}^2}$$

The quantity "X_{mf}" is the sum of all individual fractures half-lengths:

$$X_{mf} = n * X_f$$

A plot of $\Delta m/q_{sc}$ as a function of $\sqrt{t}$ should exhibit a straight line of slope α with:

$$\alpha = \frac{T p_{SC}}{h X_{mf}\sqrt{k}T_{SC}\sqrt{\pi(\phi \mu c_t)_i}}$$

If we introduce A as the surface contact between the fracture and the matrix ($A = 4.X_{mf}.h$):

$$A\sqrt{k} = \frac{4 p_{SC} T}{T_{SC}\sqrt{\pi(\phi \mu c_t)_i}}\frac{1}{\alpha} \qquad for\ constant\ rate\ production$$

$$A\sqrt{k} = \frac{2\sqrt{\pi} p_{SC} T}{T_{SC}\sqrt{(\phi \mu c_t)_i}}\frac{1}{\alpha} \qquad for\ constant\ pressure\ production$$

The underlying assumption is that the fractured horizontal well intersecting n vertical fractures of ½ length X_f behaves like a unique, large vertical fracture of half-length $n.X_f$. We try to evaluate in which circumstances this assumption is correct, for how long it is correct, and the error we make when "pure" linear flow is no longer visible.

Some authors suggested that a second (compound) linear flow could occur later towards the whole well+fractures group, as illustrated below. Such linear flow should be driven this time by the perimeter of the SRV rather than the sum of individual fracture lengths. If both linear regimes could be detected and quantified, then the uncertainty on the permeability would go.
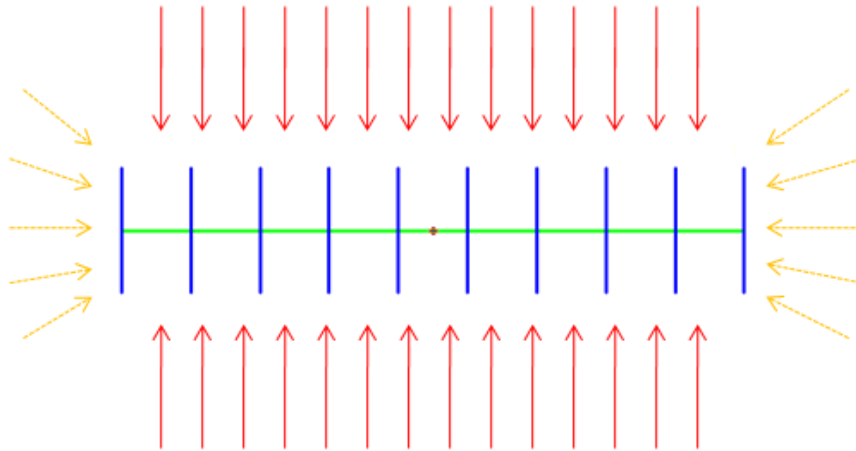
Though possible in theory, we are somewhat sceptical about this. First it is inconsistent with the assumptions that permeability is so low that only the SRV will be seen during the commercial life of the wells. In this respect, finding a second linear flow outside the SRV seems to be a poor excuse for a mismatch of the original straight line. Looking at the physical geometry using an analytical or numerical model seems a better idea. In the unlikely case where such flow exists and can be captured, it will also be present in the analytical and numerical models. We will not devote a specific study on this hypothesis.
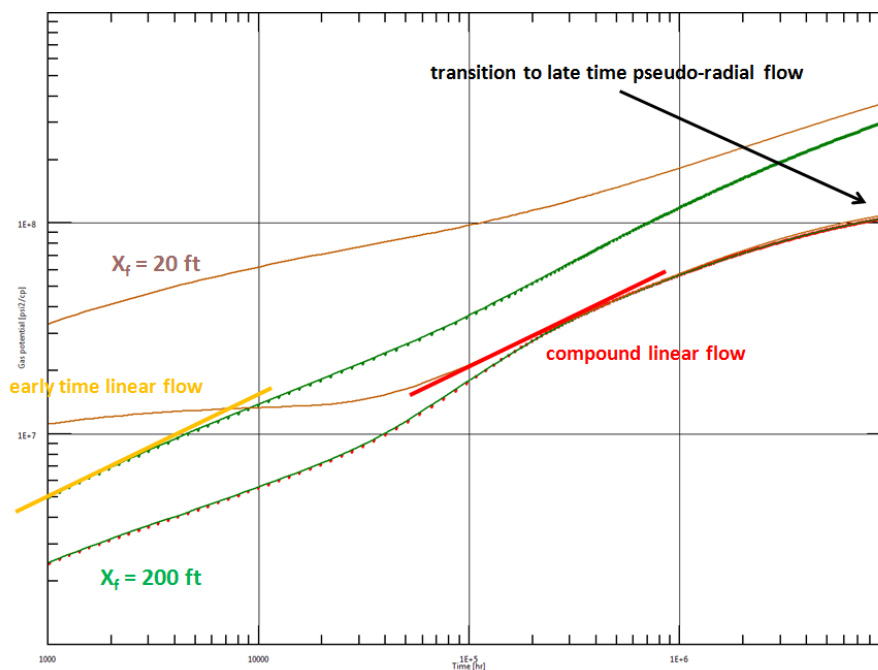
4 – Late time straight line material balance plot

This classical analysis is already implemented in Topaze in the normalized rate cumulative plot; it relies on a material balance calculation. For boundary dominated flow, dimensionless rates and cumulative productions are linked by:

$$q_D = \frac{1}{2\pi} - Q_{DA}$$

A plot of q_D versus Q_{DA} exhibits a straight line when boundary dominated flow is established, and an estimate of the pore volume can be obtained from this slope. Here again the question that we have to address is whether this analysis technique can be applied to the interpretation of shale gas wells – in other words: can we see any actual boundary dominated flow and what is the physical meaning of the parameters derived from this technique?

5 – KAPPA's analytical models for fractured horizontal wells

KAPPA has written and published two semi-analytical solutions that can simulate the transient flow behaviour of multi-fractured horizontal wells. The current solutions were developed by Leif Larsen (KAPPA) under the following assumptions:

- The well drain is strictly horizontal, the vertical or slanted section is not perforated;
- the horizontal drain crosses the vertical fractures perpendicularly;
- the distance between the fractures can be variable;
- the reservoir can either be homogeneous or heterogeneous (double-porosity);
- the fracture model can either be infinite conductivity, uniform flux or finite conductivity;
- each fracture can be individually described by its height, its length, skin and conductivity;
- the gas flows into the fractures only, the well drain only or both simultaneously.
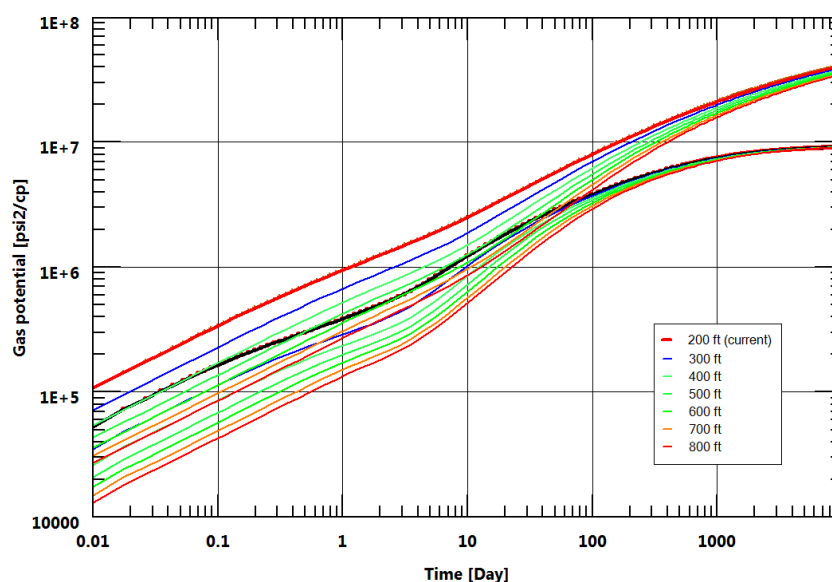
Fractured analytical horizontal well model:
Saphir log-log plot showing the sensitivity to the fractures ½ length

In a typical analysis it is usually an overkill to define each fracture individually (although such a level of detail may be interesting in test designs) – not to mention that it is rather cumbersome. For this reason, we have also released another external model with a simplified interface, where all fractures carry identical properties.

Those solutions are available as external models in both Saphir (PTA) and Topaze (PA); they will be integrated as internal models in Ecrin v4.20 (Q4-2010). Those integrated models will benefit from new additions: fractures will be able to intersect the horizontal drain at any angle and it will be possible to combine the model with variable skin and external boundaries, among other things.

These models are semi-analytical, hence reasonably fast. For the very same reason they suffer from not being able to solve the real gas flow equation – we use the usual pseudo-pressures approach that can take *some* nonlinearities ($\mu.z$ product) into account, but not all ($\mu.c_g$) – not to mention "exotic" effects such as desorption that cannot be handled analytically in a proper manner.

# 6 – KAPPA's numerical models for fractured horizontal wells

When we first heard about the issues on shale gas we immediately filed it in the much-to-complicated tray, and waited. Then we realized we could not get away with it and we asked Dr Raghavan to make a survey and report what we would have to implement in order to properly address what the industry thinks is happening in shale gas reservoirs. One issue was the mechanism of gas desorption from the shale, complemented with some unconsolidation. The other issue was the geometry of the wells which will produce such formations. The very low permeability of these formations required extensive series of fractures from an initial horizontal drain.

In complement of the external analytical models in Saphir / Topaze, we needed a numerical model that would combine the flow geometries with the nonlinearities related to the extremely poor permeability and strong pressure gradients, and additional nonlinearities related to desorption and unconsolidation. This was at least required to check if simpler solutions based on analytical models or straight line analysis worked.

We had already implemented unconsolidation (relation between permeability/porosity and pressure) for some time in Saphir NL and Topaze NL. Desorption was a relatively mild thing to model. The real challenge was with the gridding of a fractured horizontal well, and in Ecrin v4.12 (2009) we ended up with two alternate solutions: a 2D model and a 3D model.

6.1 - The 2D-Model

If the fractures are fully penetrating in the formation, and if we neglect the direct production of the formation gas into the horizontal drain, the problem becomes purely 2-D. The first series of pictures show this model in the 2D-Map option of Saphir / Topaze. Interactively the user can move the well, control the length and direction of the horizontal drain, control the length of the fractures (they are all the same length and are regularly spaced along the horizontal drain). In the dedicated well dialog the user will also control the number of fractures. At the end of any interaction or when a change in the dialog is validated, the grid is automatically calculated and displayed.
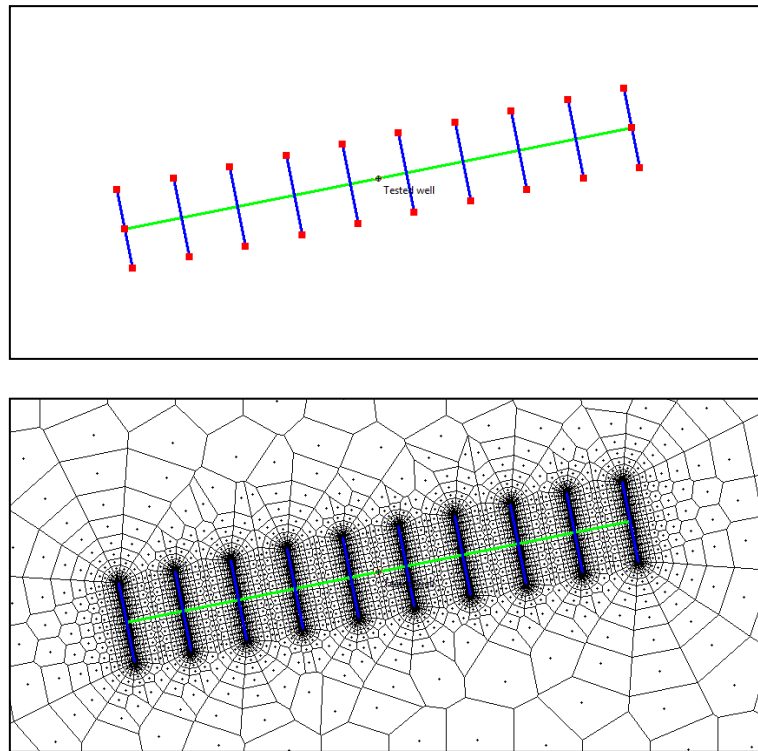
In Saphir NL and Topaze NL the grid geometry of the well may be combined with the different elements affecting the diffusion itself: Gas PVT, desorption, unconsolidation, etc. We will get back to this later.

The different displays below show the result of the simulation of the test case. The color coding naturally represents the pressure field after four years of production. In the two first figures below we show the model in the X-Y plane, with and without the display of the cells.
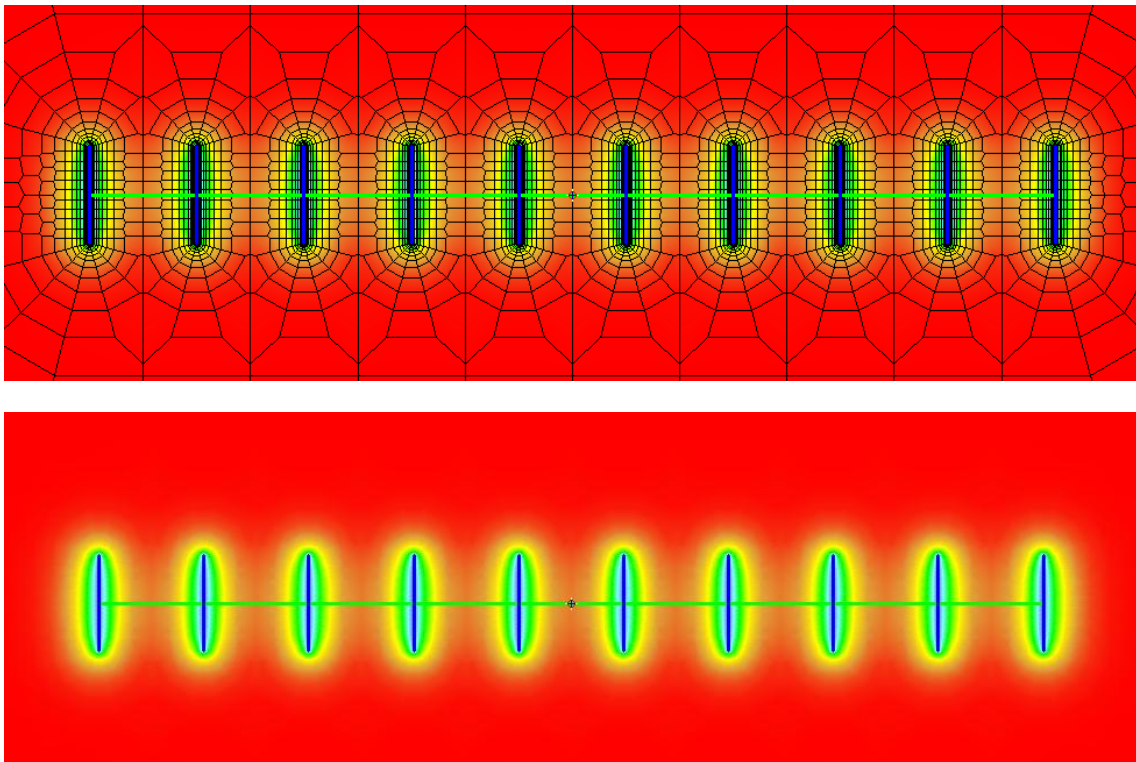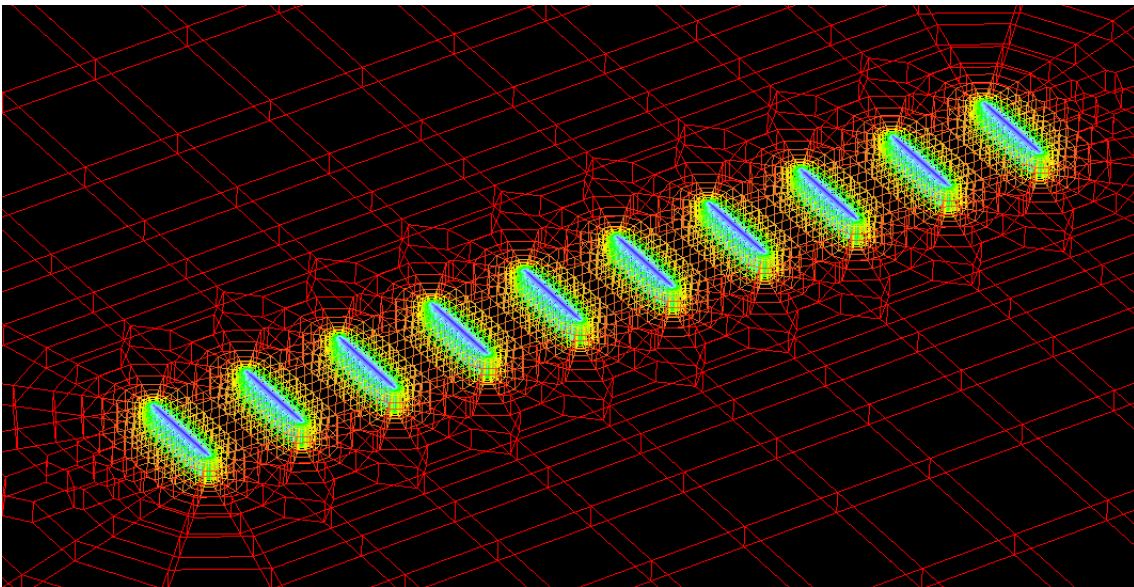
The next figure shows the same simulation, at the same time, in pseudo-2D. The Z axis represent the pressures while the physical reservoir stays as X and Y.
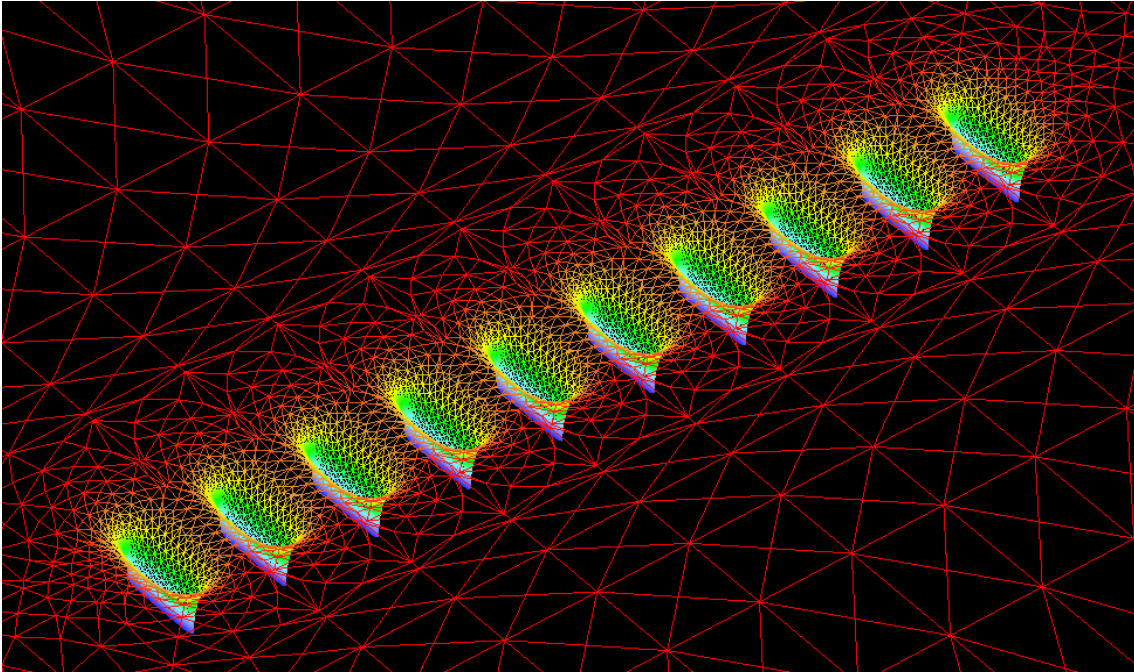
The next figure shows the same case at the same time, but in "true" 3D showing the cell geometries. Because the gridding itself is 2D it is of limited interest but it will help compare with the display of the true 3D model.

6.2 - The 3D model

If we do not want to ignore the direct flow between the formation and the horizontal well, we have to go full 3D. In the 2D-Map, the user interface is the same. The dialog is also the same, but the flow option is set to produce through the fractures and the horizontal drain. The vertical anisotropy and the vertical position of the horizontal drain in the formation then become relevant parameters. When this is done the calculation of the grid takes place. It is substantially longer than the nearly instantaneous calculation of the 2D grids. The display of the cells on the 2D-Map is actually a cross-section of the 3D grid at the vertical level of the horizontal drain.

The figure below is the true 3D display of the gridding of our test case. For the sake of clarity we have zoomed in on only a segment of the well in order to show two consecutive fractures. The colour coding corresponds to the pressure gradient at the end of the four-year production. Though it will be discussed later, the volume affected by the direct production to the horizontal drain is relatively small.
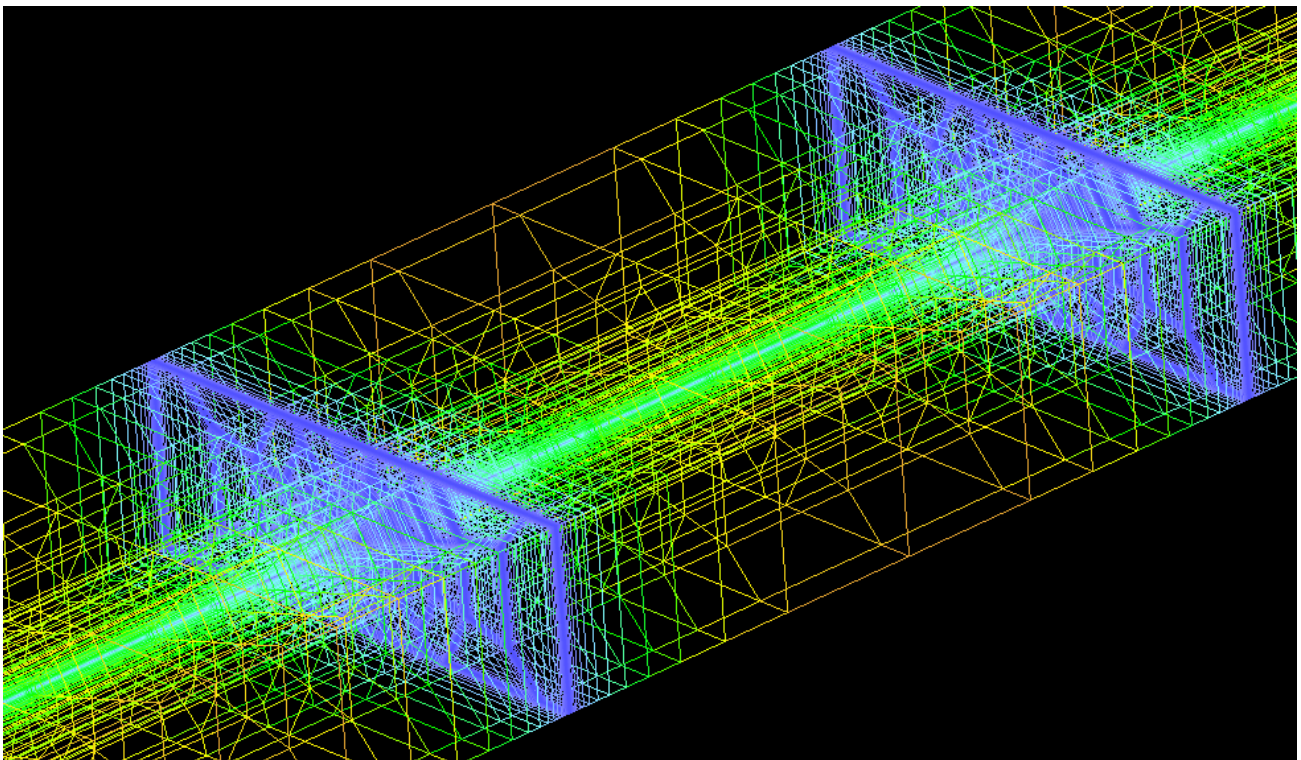
It is relatively uncommon to encounter configurations where the well drain itself is perforated in shale gas. For this reason we will not insist too much on this complex 3D grid geometry in this document, but focus on the 2D geometry – where only the fractures are flowing.

Note that 3D gridding is also required when the fractures do not fully penetrate the formation, although the gridding overhead in that case is less important than what is required in the full well plus fractures gridding case.

7 – Validating the numerical model

The first part of the work below is to validate the numerical model, by comparing the run of linear problems with the equivalent analytical tool. To do this we will cover the different configurations that may be analytically modelled.

Let us first step aside from the multi-fractured complex gridding and consider a simple, single infinite conductivity fracture, with no wellbore storage and infinite behaviour. We just use the slightly compressible fluid assumption, i.e. we also put aside the different nonlinearities we will be dealing a little later with shale gas.

First we take the reference parameters listed in §3, except for the permeability. We will start with a more standard 1 md formation. On the Saphir loglog plot below we see that the numerical and analytical models match very well:
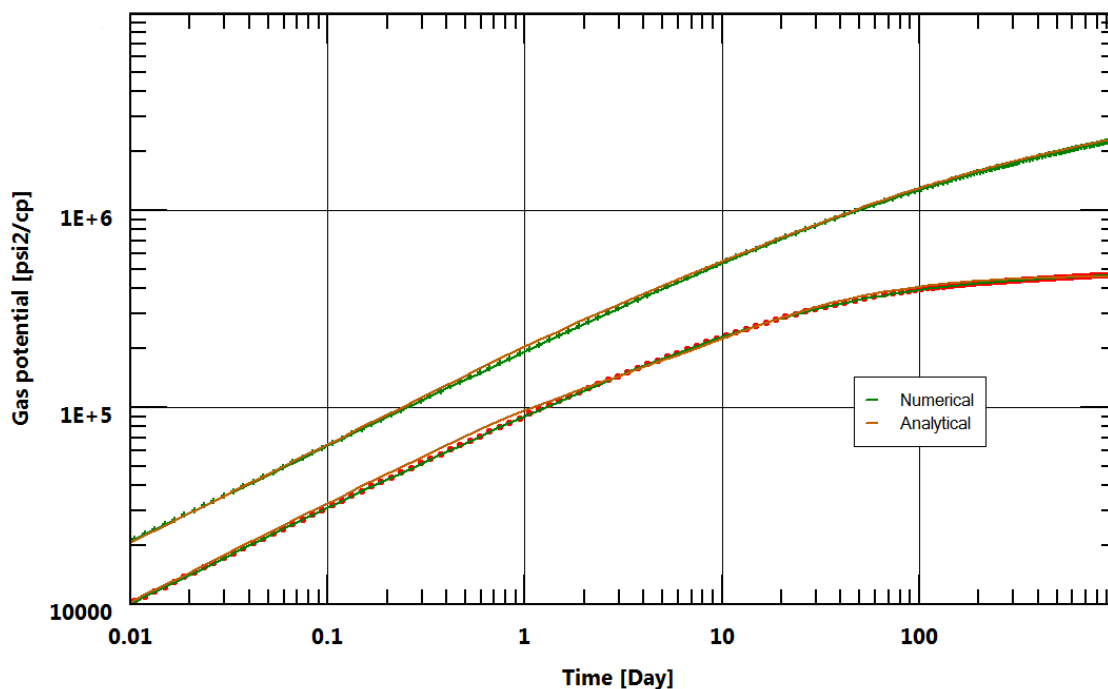

Now if we run the same case with the permeability assigned to shale gas, we see that a first run using the standard gridding of Saphir, which was working perfectly for the 1 md formation shown above, no longer matches the early time response. There is now this infamous early time "double-porosity looking" numerical effect, which has for consequence that numerical and analytical models will only merge after one to ten hours.

In reality this is not that bad, because in shale gas cases one will not seriously expect to see anything on the first ten hours of production or shut-in. However this illustrates the fact that we were a bit optimistic in our initial option to set the grid irrespective of the permeability.

So, for the sake of validation we had to create an additional upscaling (a *downscaling*, in fact) in our numerical model, especially to model early time responses in micro-permeability formations. The result is also shown in the loglog plot below.

In the rest of this document, we will use, when needed, this additional refinement. Before running any complex nonlinear simulation, we run the equivalent linear case and validate it with the corresponding analytical model for the same geometry and permeability value.
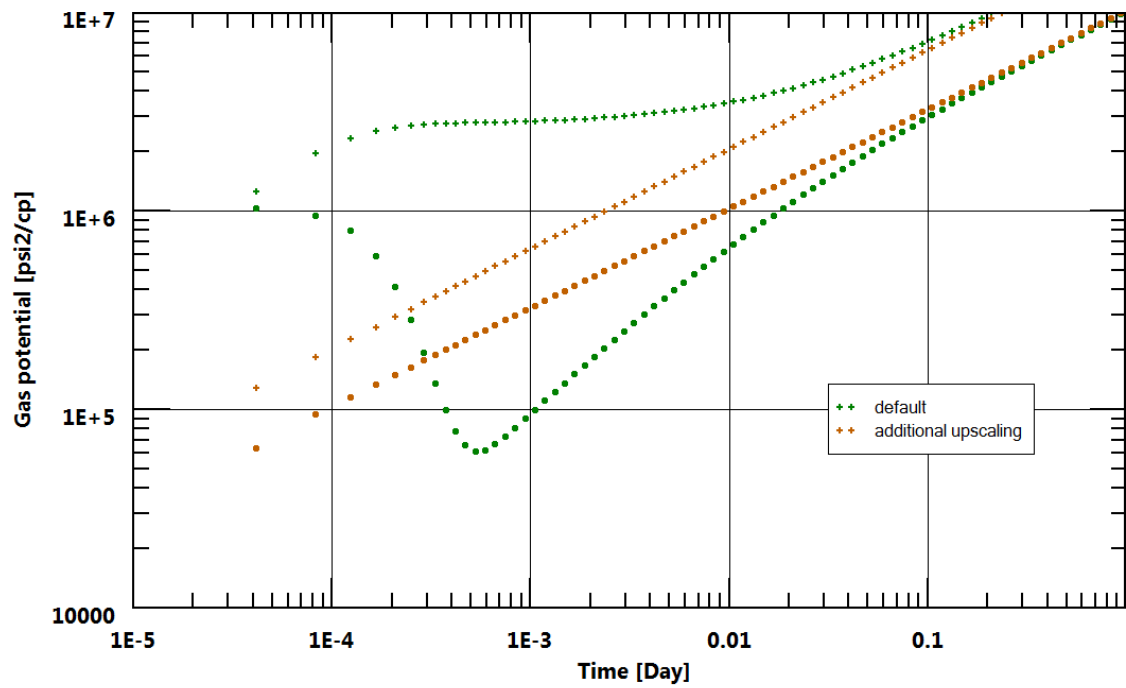
If we now consider the actual multi-fractured well we want to model and again compare with the corresponding analytical model detailed in §5, we get an excellent agreement when only the fractures are flowing – when the numerical model is 2D, as presented in §6.1:
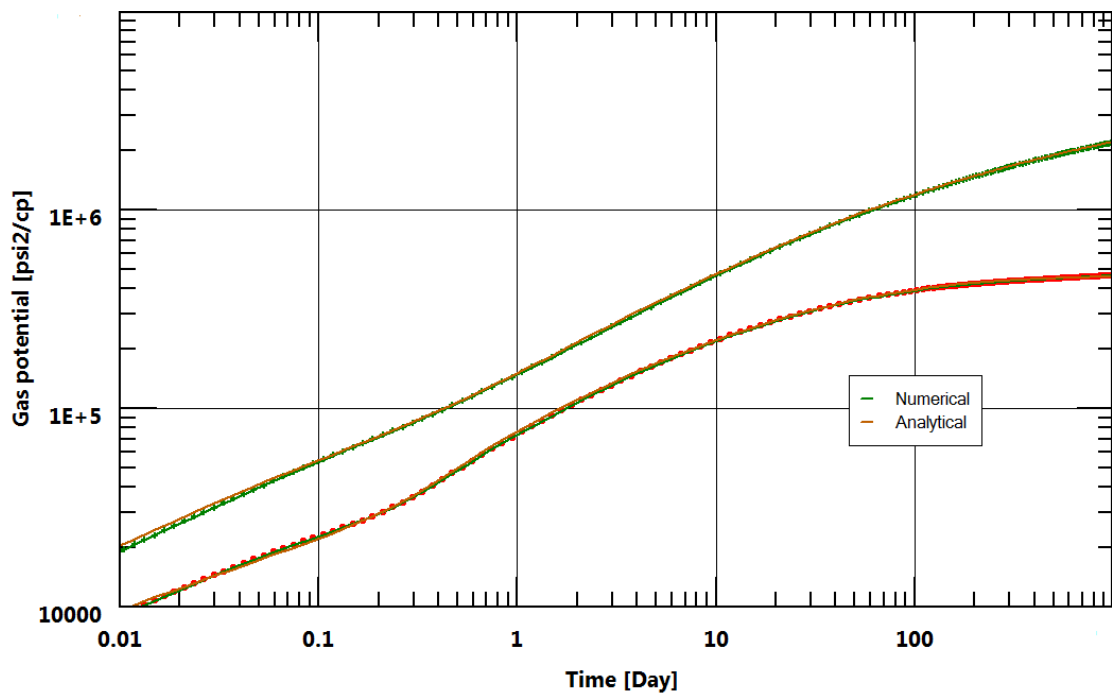
The comparison remains more than acceptable when both well and fractures are gridded (i.e., when the 3D numerical model is built):
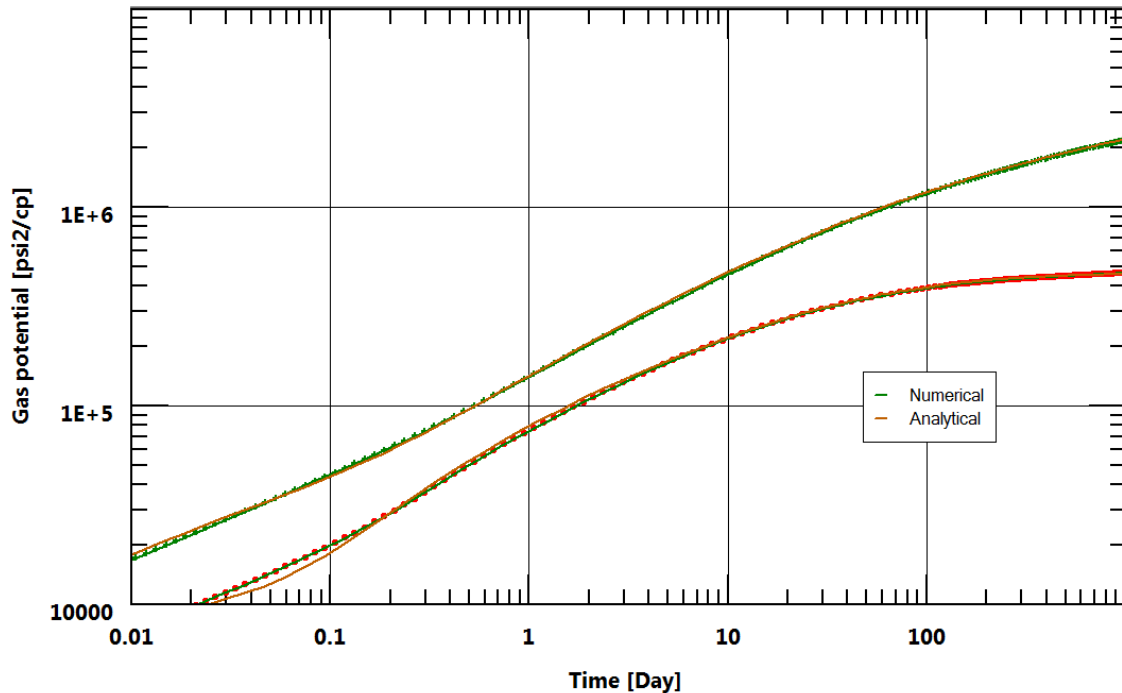
8 – Single fracture and no desorption

We continue with a single fracture case, in order to identify how nonlinearities affect the quality of the different modelling and analysis techniques.

In order to hit two birds with one stone, we will not model one of the individual fractures of our reference case, but a single equivalent infinite conductivity fracture with the total half length of the fractured horizontal well, i.e. X_f =10*200 ft = 2,000 ft. This is the solution currently suggested in the industry to analyse horizontal wells with multiple fractures.

The other parameters and the production history follow the reference case description given in §3. We consider the real gas diffusion and we no longer use pseudopressures.

We still ignore desorption for the time being.

We will now compare the "right" simulation with Topaze NL using our reference permeability of 1E-4 md, and we will compare it to the equivalent analytical model using pseudopressures instead of the real gas diffusion. The result is seen in the loglog plot below.

The analytical model does not agree with the Topaze NL run anymore. Thanks to the high pressure gradients and the corresponding changes in the gas compressibility, the numerical model leads to estimates of final cumulative production that are approximately 15% higher than for the analytical solution.

We then run a nonlinear regression on the analytical model to match the numerical case. After regression the match is pretty good, but the estimate of $k.X_f^2$ after the match is 65% higher than the original values.
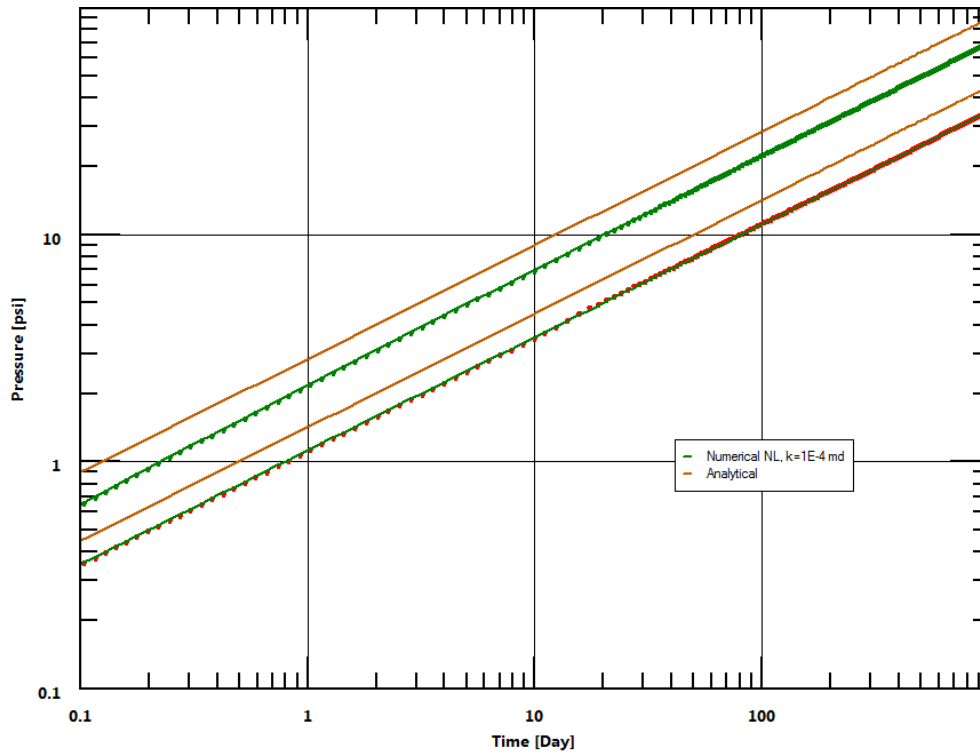
*Analytical model run with the same input parameters as the numerical model
(differences are due to nonlinearities, as explained below)*
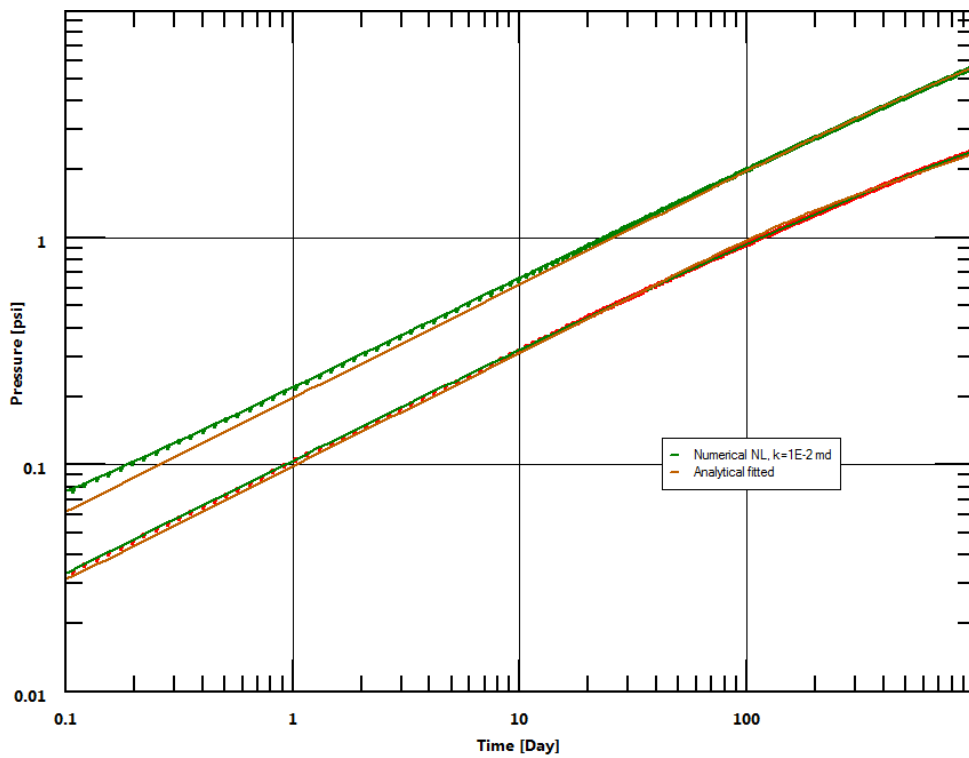
Analytical model match after nonlinear regression on the numerical model

<u>Physical explanation</u>: this very low permeability system creates a high pressure gradient close to the well. Because of the corresponding increase in compressibility, the real performance of the well will be higher than if we use the corresponding analytical model. In order to compensate this higher productivity and match the simulation, the analytical model will require a higher permeability or a higher well productivity.

One may object that the problem comes from the fact that we initialized the PVT parameters at the initial pressure (in other terms, that we used the $\mu.c_g$ product computed at p_i in the analysis), whereas we should have used a much lower pressure – closer to the flowing pressure (500 psia) at least. This is perfectly correct, but the truth is that we do not know which pressure should be used if we want the error to be minimized – and no one does. For instance, the results actually get much worse if we use p_{wf} in the equations...

Naturally, the single fracture geometry, with such a long linear flow, will allow a straight line analysis that is completely consistent (within 1% or less) with the analytical model. So the error found on the analytical model will be exactly the same as for a straight line analysis.

The same process was repeated for higher permeability values, and the results are compared in the table below. As stated just above straight line results and analytical models are consistently wrong in the assessment of $k.X_f^2$.

Permeability	Numerical model	Analytical model and straight line analysis	
	$k.X_f^2$ (md.ft^2)	$k.X_f^2$ (md.ft^2)	Error
1 md	4.0 E+6	4.08 E+6	2 %
1E-2 md	40,000	48,000	20 %
1E-3 md	4,000	5,600	40 %
1E-4 md	400	660	65 %

To be totally honest, we tried to lower even more the permeability (down to 1.E-6 md) and started to encounter serious convergence issues in the numerical model. We expect the error above increase even more for these values of permeability, but at this stage we do not have a suitable benchmark numerical model yet. This is part of the work in progress listed in §17.

Summary: *When dealing with a single fracture in a typical shale gas case, the use of an analytical model or the drawing of a straight line on the early time linear flow will give an order of magnitude of the k.X_f^2 product, but will still be substantially off.*

9 – Fractured horizontal well and no desorption

We now proceed from the single equivalent vertical fracture to our real fractured horizontal well model, carrying on the same parameters described in §3: 10 infinite conductivity fractures with X_f=200 ft each, only the fractures are flowing (flow to the horizontal well drain is not considered), all fractures are fully penetrating.

The comparison between the equivalent single fracture run and the multiple fracture run is shown below for the four first years of production.

Note: we are in Topaze here, the "time" used is the material balance time (cumulative production divided by instantaneous rate). As the rate declines, a production of 4 years will correspond to more than two thousand days on the material balance time scale. Nothing to worry about...
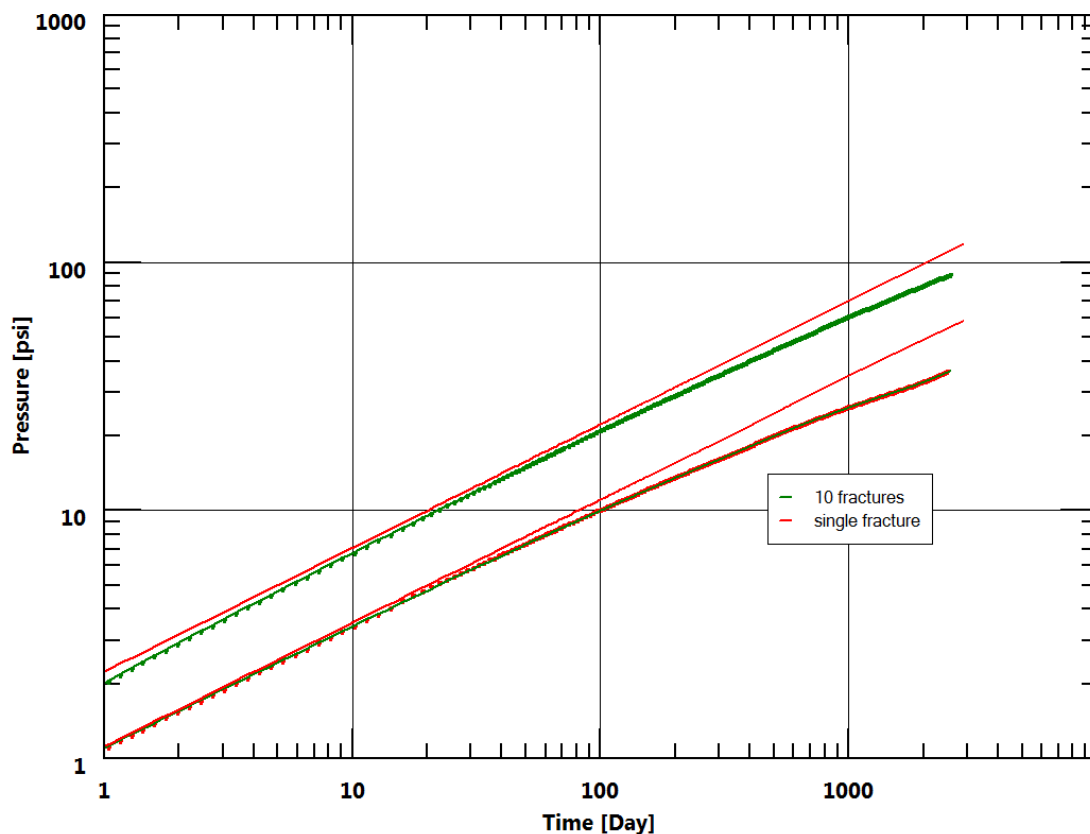

We see that after a couple of months the fractured horizontal well deviates from the single equivalent fracture case. The overall productivity of the fractured horizontal well becomes better.

Physical explanation: At early time the flow is strictly linear, orthogonal to the fracture planes. However after a while the flow widens beyond the fracture extent and more production starts coming from the tip. This additional production improves the productivity of the system and the pressure / derivative response starts to bend down. When we have a single fracture we have only two fracture tips. When we have ten fractures this makes it 20. Needless to say that the productivity of the fractured horizontal well, at this stage, becomes better than the single equivalent fracture.

Naturally, if we use an analytical model for fractured horizontal well, we will also reproduce this behaviour. For this reason, the error using such model will be limited to the nonlinearity (similar to what we faced in §9).

If we stick to the single fracture analytical model and try to draw a linear flow straight line, we will get an additional error, depending on where we focus to make the match. The error will go up to 120% if we focus on the intermediate times.
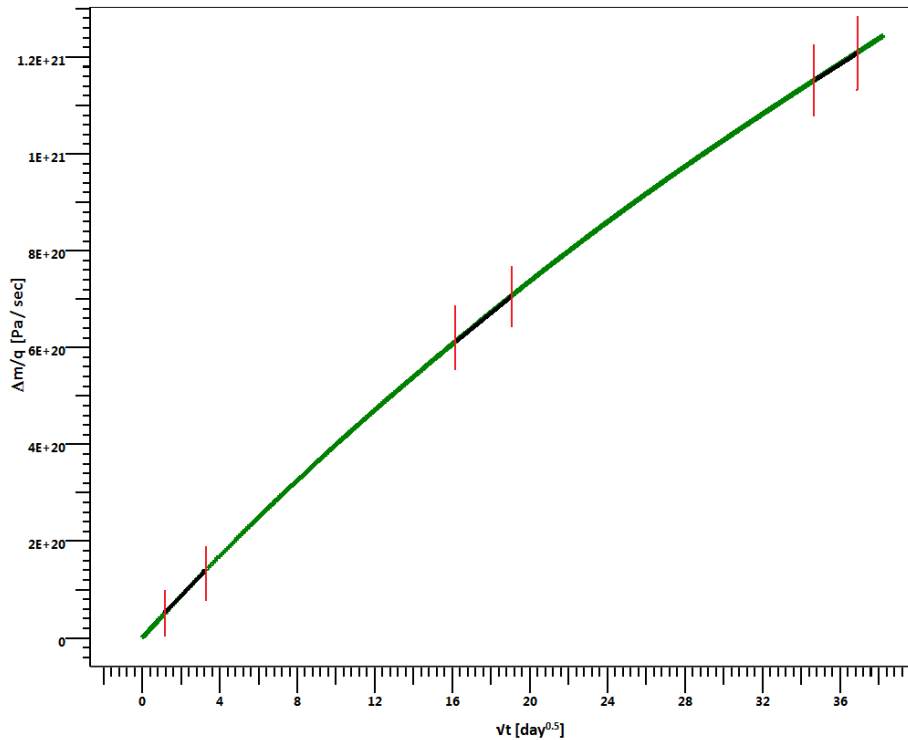

Drawing a straight line of a square root plot

For our reference case, the errors will therefore be the following:

Permeability	Numerical model	Fractured horizontal well analytical model		Single fracture analytical model / Straight line	
	$k.X_f^2$ (md.ft^2)	$k.X_f^2$ (md.ft^2)	Error	$k.X_f^2$ (md.ft^2)	Error
1E-4 md	400	512	28%	540-880	35 - 120%

The divergence of the derivative between the two models is actually a "temporary" one. If we keep the same permeability (1E-4 md) but simulate for a very long time (... 500 years!), we will get the following response: After deviating from the single fracture case, the derivative of our simulation bends back up to return and merge towards the single fracture derivative. At a point both derivatives merge. Note however that this behaviour is particular to the current geometry (and to the comparison with a single fracture of equivalent length), we may not see it with longer fractures, or when more of them are simulated.
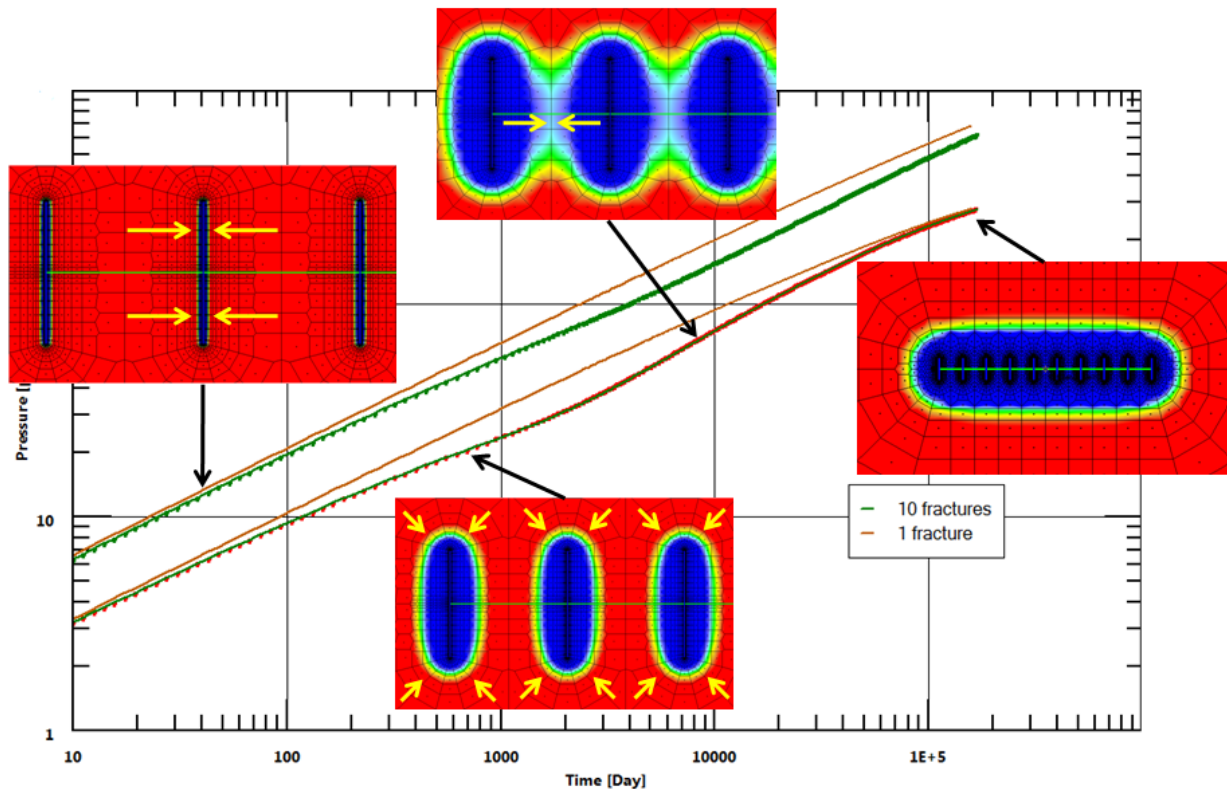
Physical explanation: As we saw above, the higher exposure of the fractured horizontal well, though its 20 tips initially produces a divergence from the single equivalent fracture. This is good news until... the fractures start to interfere with each other. Then the rate of pressure change will progressively return to that of a single fracture for our specific case – but please keep in mind that more complex behaviours are very possible.

Summary: *Modeling analytically or numerically a fractured horizontal well will take into account the improvement of productivity due to the higher exposure to the reservoir. After a transition that may last tens of years, the productivity will reduce again due to the interference with the fracture. Using a single fractured well model, or a straight line analysis will now produce errors of up to 100% or more (fractures length or permeability overestimated).*

10 – Adding desorption

It is relatively straightforward to take into account desorption effects in the numerical NL solution – rather than recalling equations we will just show the comparison of two simulations of the same multi-fractured horizontal well reference solution (§3 with k=1E-4 md) with and without desorption (again, the desorption parameters are listed in §3). Ignoring desorption leads to an over-estimation of the reservoir permeability by 50% in our case.

We can include desorption in the material balance equation (SPE 20730, King, 1993) but our problem in the present case is that we are far from the establishment of boundary dominated flow... In theory a desorption compressibility c_d can be derived that take into account the additional desorbed gas in the diffusivity equation during transient flow (SPE 107705) – in that case the gas compressibility c_g is replaced by $c_g^*=c_g+c_d$ in all equations, with (in oil field units):

$$c_d = \frac{B_g \rho_r V_L p_L}{32.0368 * \phi (p_L + p_{Avg})^2}$$

Where p_{Avg} is the reservoir average pressure. It is then required to introduce a pseudo-time to solve the transient flow equation accounting for gas desorption, pseudo-time that is computed as a function of the average reservoir pressure – hence, with no spatial variability of the parameters. But having recourse to the average reservoir pressure is in contradiction with our need for transient flow correction: in all numerical simulations p_{Avg} is almost constant (and equal to the initial pressure), hence introducing c_g* leads to a negligible correction.

So, desorption does have a significant impact in the early time determination of the flow parameters; we know how to take desorption into account in the numerical non-linear solution, we know how to include it in the material balance calculations when boundary dominated flow occurs, but we do not know how to incorporate it in both early time straight line analysis and transient flow analytical modelling...
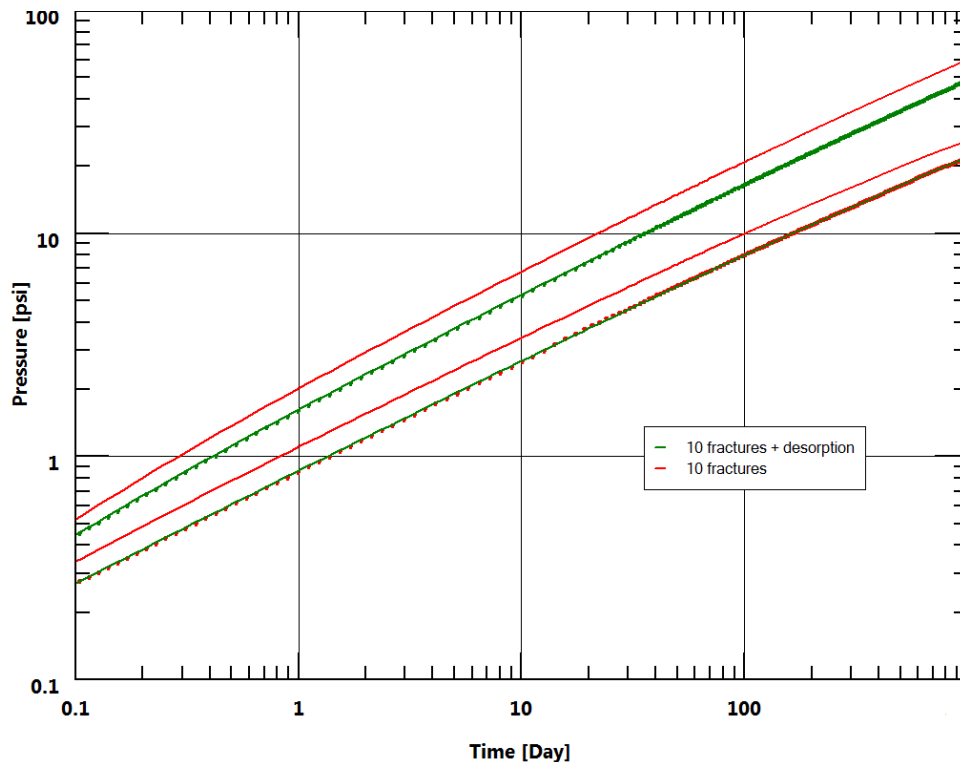
Reference case with and without desorption

The correction of the classical analysis using a "z*" or "c_g*" does not address the nonlinearity of the problem but makes a global correction of the material balance of the same magnitude. What remain, however, are the errors linked to the nonlinearity and geometry issues detailed in §9 and §10.

Before to conclude, we must concede that the effect is so spectacular here because p_{wf} is low (500 psia) and constant right from the start of production. This situation is unlikely to be encountered in practical situations where flowing pressure is lowered step by step until a reasonable plateau is reached. Besides, adsorption parameters may significantly vary from one shale to another. Desorption will always play a role, but it may not be as important as shown on the above loglog plot.

Summary: *Desorption cannot be neglected in the analysis, even at early times. It can be handled numerically and by classical methods once pseudo-steady state flow has been reached, but there is no practical way to incorporate it in transient analytical solutions for the time being.*
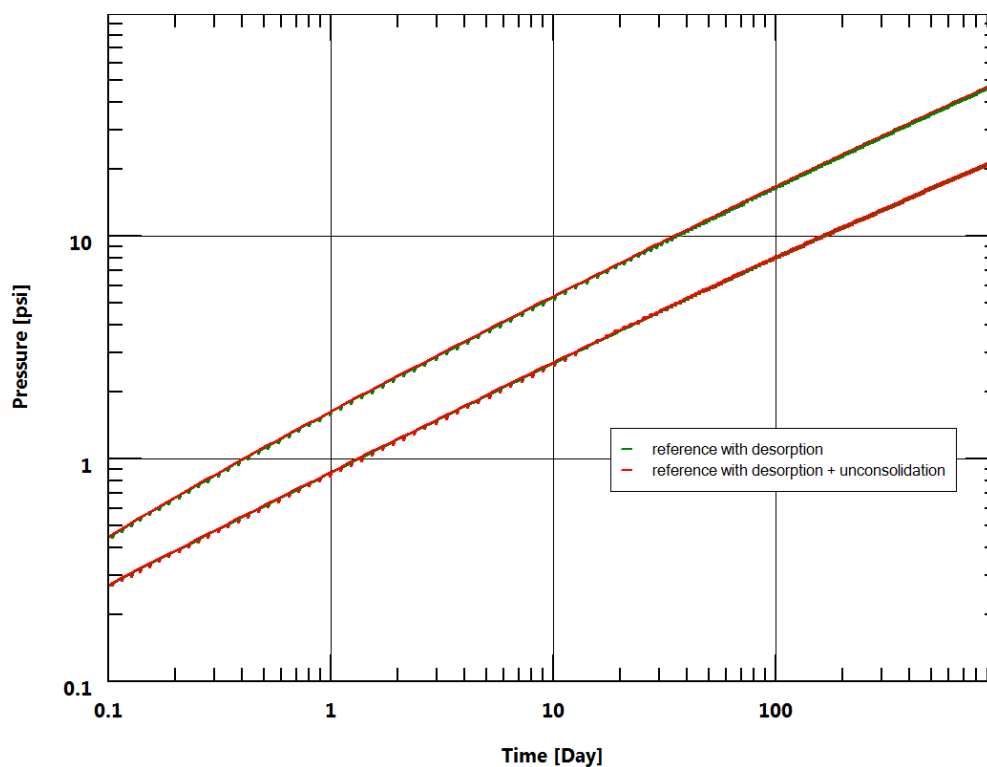
11 – Adding unconsolidation

Here again unconsolidation is an effect that can be introduced in a relatively simple manner in the full non-linear numerical model through the definition of k(p) and ϕ(p) laws, whereas it just cannot be handled properly in analytical models nor in straight-line analysis, to our knowledge. Let us start from the reference multi-fractured well model with desorption (§3, with k=1E-4 md) and add unconsolidation to it, with the following relationships:

$$\phi = \phi_0 e^{c_r(p-p_0)}$$

$$k = k_0 e^{3c_r(p-p_0)}$$

In the above, c_r is the rock compressibility (taken to be 3E-6 psia[-1] here), and p_0 is the reference pressure (taken to be p_i = 5000 psia). The equations above are simple models that are typically applied to CBM reservoirs – so we have no reason to use them here, except that they seem to be widely used by the industry for shale gas. Nevertheless, the pure qualitative analysis leads to the conclusion that ... unconsolidation as we define it has no influence on the reference case simulation:


We would need to increase the rock compressibility to unrealistic values to see any influence at all. In the simple model we have used the fractures are not affected by unconsolidation (their conductivity is infinite, anyway), only the matrix permeability / porosity can change; furthermore those parameters do not vary by more than 10% during the simulation... In other words, our current model may not be well adapted to this shale rock + hydraulic fractures geometry, and we need to modify it - incorporate variability on fracture conductivity, for instance - before to go further...

Summary: _At this stage we have the unconsolidation in the model but it does not seem to have a noticeable effect. We may be using incorrect parameters and this remains to be checked._

## 12 – Long time response and material balance plot

In all simulations we have assumed so far that the reservoir is infinite acting – boundaries have been pushed far away in all numerical runs so that they could not interfere with the pressure response.

Let us now consider a new case with desorption included and k=1E-4 md, with a highly fractured horizontal well (100 fractures) sitting in the middle of a 5'000 square – the reason why we need such a high number of fractures will become clear in a few lines:
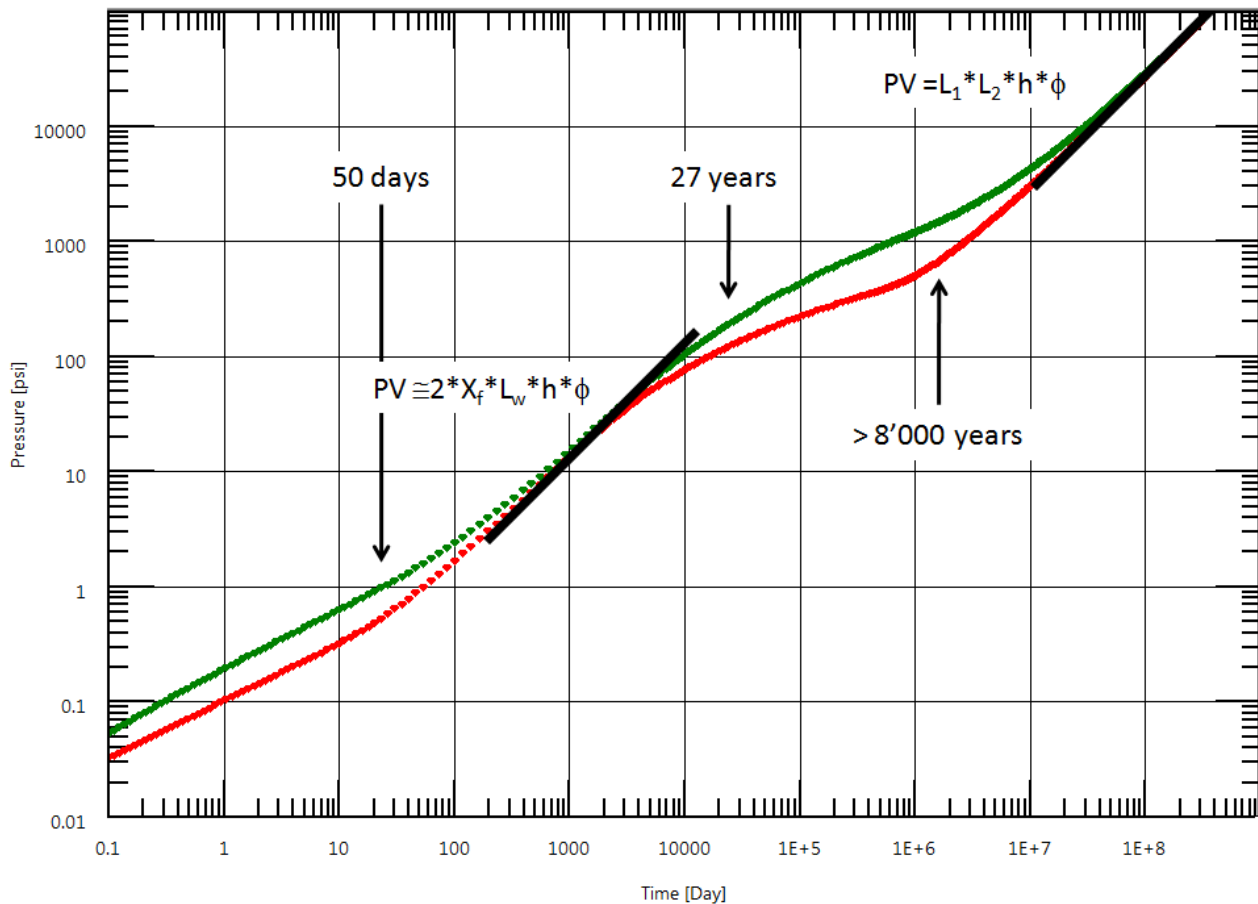

In the above, we let the simulation run until final pseudo-steady state flow could finally be clearly visible, and it took a while: 100'000 years, with the final unit slope starting after 8'000 years. So forget about using the material balance plot to estimate actual shale gas reserves: you will never see actual PSS in your lifetime (neither will your grand-grand-children). Note that this result is not affected by the number of fractures, and that you still need plenty of time (80 years to see PSS) if permeability is highered up to 0.01 md.

You will notice that data seem to bend towards pseudo-steady state flow much earlier in the production history of this 100 fractures case: after about 50 days of production a "close to-" unit slope is visible on the Topaze loglog plot, that remains for quite a long time (more than 20 years here). In fact if we inject these data in the material balance plot we recover a rough estimate of the pore volume encapsulated by the fractures (or Stimulated Reservoir Volume, SRV): 5191 Mscf, to be compared with $2.X_f.h.L_w.\phi = 4765$ Mscf, where h is the reservoir thickness and L_w the well length.
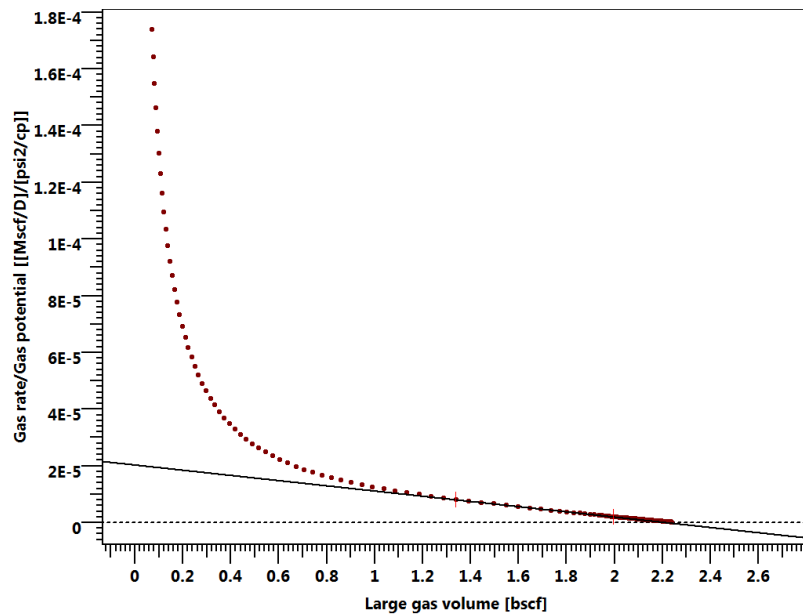
So why did we use 100 fractures in this simulation? Because we need to pile up many fractures in order to see the SRV fake pseudo-steady-state flow, as shown below where the closed reservoir case is re-run with less and less fractures:
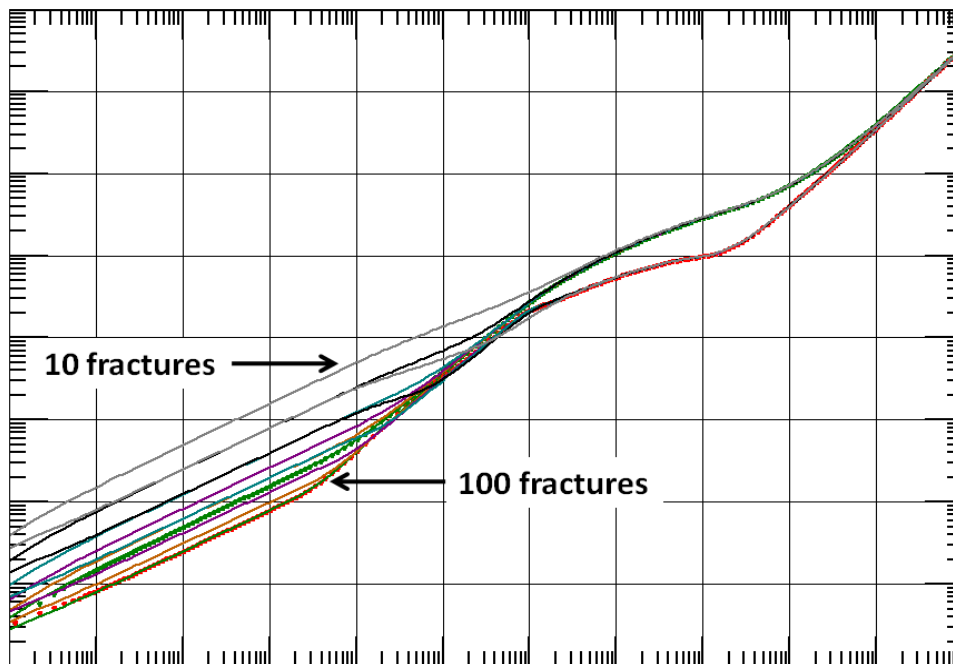
As already explained in §4, the key parameter controlling the appearance of the SRV close-to unit slope is actually not the number of fractures but the ratio between the fractures spacing and their ½ lengths: if the spacing is significantly bigger than X_f you will never see the transition zone unit slope. In all other cases the time at which the SRV will show up is a direct function of the number of fractures (rather, fracture spacing / X_f): we need about 50 days when 100 fractures are simulated, 83 days when the number of fractures is lowered to 50, more than 2 years for 25 fractures.

Summary: *In the best cases the material balance plot will provide a reservoir size corresponding to an inflated version of the volume between the fractures. But you should not expect this method to be systematically meaningful, and the result it provides can be seen as secondary.*

13 – What we do not take (yet) into account

The numerical NL model is the best reference as it is the only one taking both geometry and nonlinearities into account. However even this model is an over-simplification of the actual physics behind shale gas production from fractured horizontal wells. In this section, we have selected a few of the key physical processes that we believe to be missing – and that we may develop in a coming consortium...

Complex fracture networks

Today, we only consider regular, planar hydraulic fracture systems, as described in section 6. Although our fractured horizontal well options account for interferences between fractures, and honor 3D effects around the wellbore or fractures, the considered geometry remains very simple compared to the high complexity of actual flow paths. In general, fracture jobs create a hydraulic (primary) fracture system similar to our model, but also activate a pre-existing natural (secondary) fracture network. The secondary network's stimulation level and its connection to the primary system have a decisive influence on the well productivity, and need to be properly addressed.

With our current model, one would account for the secondary network by artificially increasing the length and/or conductivity of the hydraulic fractures. This classically leads to a reservoir model with (1) a low-permeability matrix and (2) a system of high conductivity parallel fractures accounting for both the primary and secondary networks interactions.

Another possible approach could consist in artificially increasing the permeability of the matrix in the vicinity of the well, in order to account for an effective matrix plus secondary network medium. This seems less relevant - especially at early time - if the secondary network is conductive. Moreover, this requires the use of a composite zone around the fractured horizontal well, with model input parameters relatively hard to interpret. Note that it is also possible to assign double-porosity to the reservoir, in order to simulate the interaction between the matrix and a more permeable fissure system. This, however, remains an approximate, non-practical model. In particular, this double-porosity behavior must also be restricted to the vicinity of the fractured horizontal well.

It is far from certain that a coupled primary-secondary fracture network behaves as a single effective, primary-like system. Hence, a major improvement would be the ability to grid and simulate the secondary network, using either an orthogonal, regular pattern (orthogonal to the primary network), or a more complex, random systems. With this option, we would be able to understand and quantify the impact of the interactions between the primary and secondary fracture networks.

Naturally this improved geometry brings more complexity to the problem definition, and although we will not address such issues here it calls for advanced data integration – the best we can think of is microseismics – and further modifications in the analysis workflow.

Improved stress dependence models

As described in section 11, we account for stress-dependence through our "unconsolidation" model, i.e. we can input tables describing the dependence of permeability and porosity to pressure. It is worth noticing that this dependency is numerically handled using a fully implicit scheme, in other words the model is unconditionally stable and does not suffer from time-step restrictions when using this option.

The main restriction in the current version is that this pressure dependence only impacts the matrix, while the main influence may be due to the stress-dependence of the secondary (unpropped) fracture systems. As a consequence, an extension of the use of unconsolidation to fractures is required.

A threshold model for the unpropped fracture system may also be developed, where the network becomes conductive only when the local pressure gradient becomes high enough. In this case, we would use a new permeability (conductivity) function ruled by the pressure gradient.

Ultimately, we may have to couple our reservoir model with geomechanics, in order to simulate advanced phenomena related to stress changes, such as solid stress-strain relations.

Complex processes

The quantity of gas locally adsorbed (or desorbed) during a time step is classically simulated using an adsorption isotherm, which is a function of pressure only. So far, we have limited ourselves to the Langmuir isotherm. Although this is by far the most widely used model in our industry, many other isotherms are available and could be implemented. Thermal effects could also be investigated, which would require the extension of the current description of adsorbed gas quantities to a more general function of pressure and temperature.

The transport of gas molecules from the microporous organic matter to the production well is an extremely complex process, involving many scales of porosity. At each scale, a different physical process occurs: molecular diffusion in the organic matter, desorption from micropore walls, Knudsen diffusion in the micropores, Darcy flow in macropores, Forchheimer flow in the hydraulic fractures…

Our model currently uses Fick's law to simulate gas diffusion inside the matrix, and Darcy's law to simulate free gas flow in the macropores. In micropores, however, the mean path of gas molecules is not negligible compared to the average throat size. Free gas hence flows under slip regime (gas slippage), usually simulated as an increase of the effective permeability at low pressure. This can be simulated using the Klinkenberg model (which reduces to a pressure-dependent permeability model) or any generalization to model Knudsen diffusion. It is interesting to notice that this approach nicely lumps advection and Knudsen diffusion in a single equation with dependence on pressure gradient only (i.e. similar to Darcy's law in essence), while Fick's law induces dependence on the concentration gradient. Note also that this additional permeability dependence to pressure is an effective way to account for molecular effects, and is not related to the stress-dependence previously described. Both effects can, however, be simultaneously simulated.

Multiphase flow

All the above is considering single phase gas flow, but the creation of fractured horizontal wells requires the injection of massive amounts of water, and quite evidently we must question ourselves about the necessity to take multiphase flow (with at least gas and water) into account in the numerical formulation. In the shale gas context, relative permeability curves and capillary pressure curves can be very different in the matrix and in the fractures. Our model allows one set of curves only, and should be extended. This may be of particular importance to correctly simulate the clean-up phase, and account for potentially large volumes of pumped water trapped in the fracture network. Water loss can be due to combined effects such as gravity and very strong capillary forces, as shale can initially be in a sub-irreducible water saturation state. Ultimately, this may lead to a strong well productivity reduction, as it reduces the contact surface available for flow. Particular attention should hence be paid to the simulation of two-phase flow in this context.

Too many unknowns and too little data

As we will see in Part 2, when you look at real life data over a relatively short period of time (one or a few years), very little occurs because of the very low speed of the diffusion. As a consequence it is pretty trivial to match the observed response with a simple straight line.

There is no problem with this, except that we cannot use such technique to accurately predict the longer term production. The matches with the analytical and numerical models were not better nor worse. However the resulting parameters and the forecast were indeed very different.

We suspect that all additional effects we are describing above will help if we want to be realistic in our prediction and assess when and how the production will behave in the long term. However these represent a large number of unknown parameters if the observed data we have are reduced to a single apparent linear flow. Therefore the challenge will not only to implement these mechanisms, but also to find a way to assess the related parameters.