The Analysis of Dynamic Data in Shale Gas Reservoirs – Part 2

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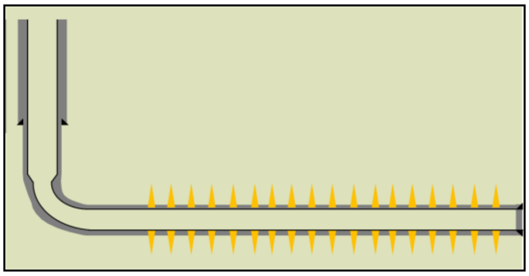
In Part 1 we presented the different hypotheses and analysis techniques currently available for the study of multiple fractures horizontal wells in the environment of shale gas. We simulated a synthetic case using our best numerical model so far, and evaluated the approximations / errors created when using more simplistic methods. We finished by listing other mechanisms that may affect the production of a shale gas reservoir and are not yet integrated in the most advanced KAPPA model. *We have updated Part 1 (originally from July 2010) in order to take into account the release of this Part 2.*

In this document we use the methods presented in Part 1 to analyze real life data. We start with a classical straight line analysis, we refine using an analytical model to finish with our numerical model. In this process we show that simpler methods, though not recommended to perform the final diagnostic and forecast, are an integral part of the workflow.

1 - Case study

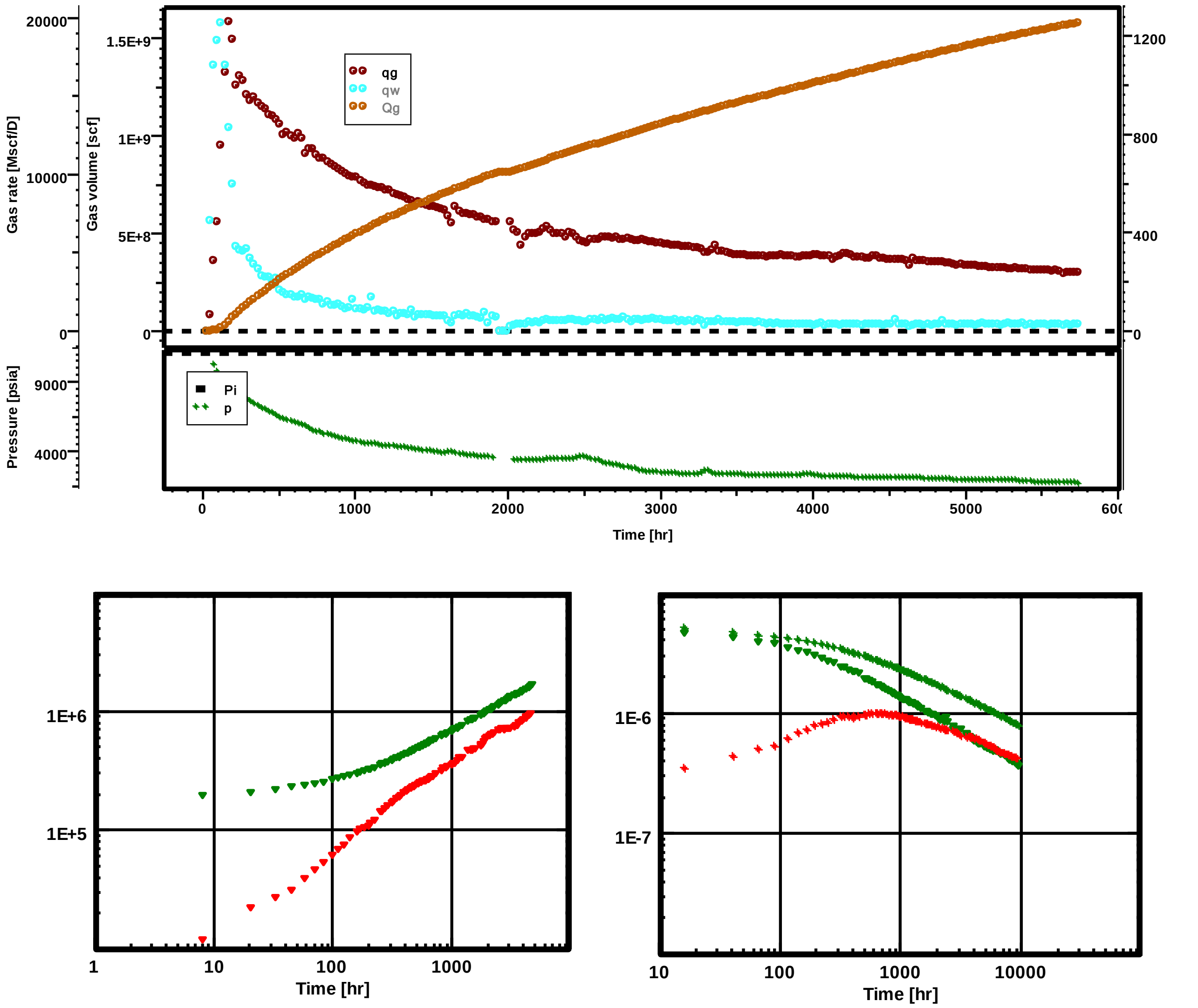
In our case study we have access to eight months of production and pressure data of a multiple fractures horizontal well in a deep shale gas reservoir. The tables, schematic and history plot below show the available production, pressure, reservoir and well information:

Reservoir data	
Initial Reservoir pressure, psia	11005
Reservoir temperature, °F	305
Net pay, ft	100
Porosity, %	7.6
Matrix permeability estimates, mD	5e-5 to 1.5e-4 (9.35e-5)
Water saturation, Swr, %	25
Desorption parameters	
Rock density, g/cc	2.6
Langmuir Volume Vl, scf/ton	70
Langmuir Pressure Pl, psia	750



Well completion schematic

Well data	
Horizontal drain length, ft	3900
Initial estimated number of fractures	40
Fracture half length, ft	220 -360
Completion type	cased hole
Last FBHP, psia	1770



History plot, log-log plot and Blasingame plot

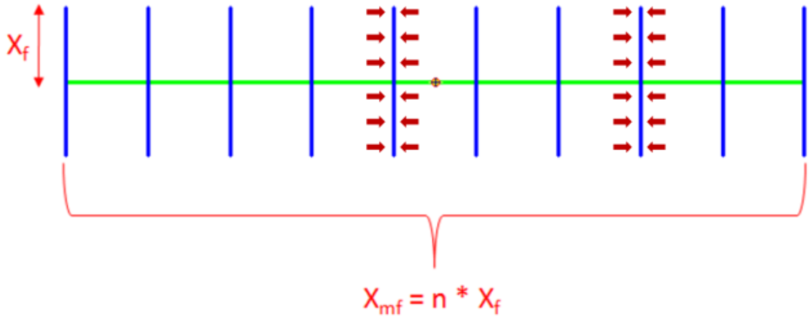
Using different methods we match pressures and rates with the best possible parameters, then we forecast the production and ultimate recovery. To do this we will use and compare the methods developed in Part 1.

We start with the simplest method, then we progressively use more sophisticated models in order to take into account the "real" geometry and the "real" diffusion of the problem. In this workflow we use the result of the previous analysis as a starting point for the next one. We see how using a more complex model affects the results and our production forecast. At a stage we may go back and eliminate sophistications that do not affect the end result.
We assume that gas only flows from the reservoir to the wellbore through the fractures only. Only dry gas flow is considered, although a residual water saturation may be added in the reservoir model. Water flow back was noted during the clean-up and the first hundred hours of production. So we may expect a pseudo-skin from the early time, but this will not impact the description of the general model.

2 - Analytical "straight-line" analyses

2.1 - Square root plot

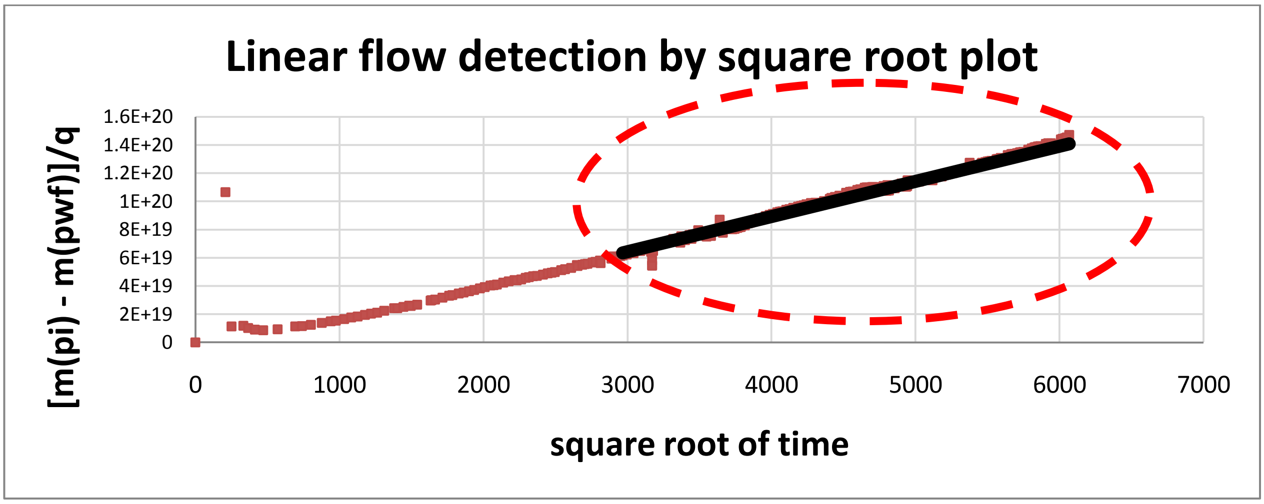
The simplest model assumes a single equivalent fracture with only the "transient" linear flow observed in the data. A single fracture will produce linearly during its transient flow until it transitions towards infinite acting radial flow. For multiple fractures along the horizontal drain we consider a single equivalent fracture. Its half-length would be the sum of the individual, real fractures half lengths.



Equivalent single fracture half length Xmf

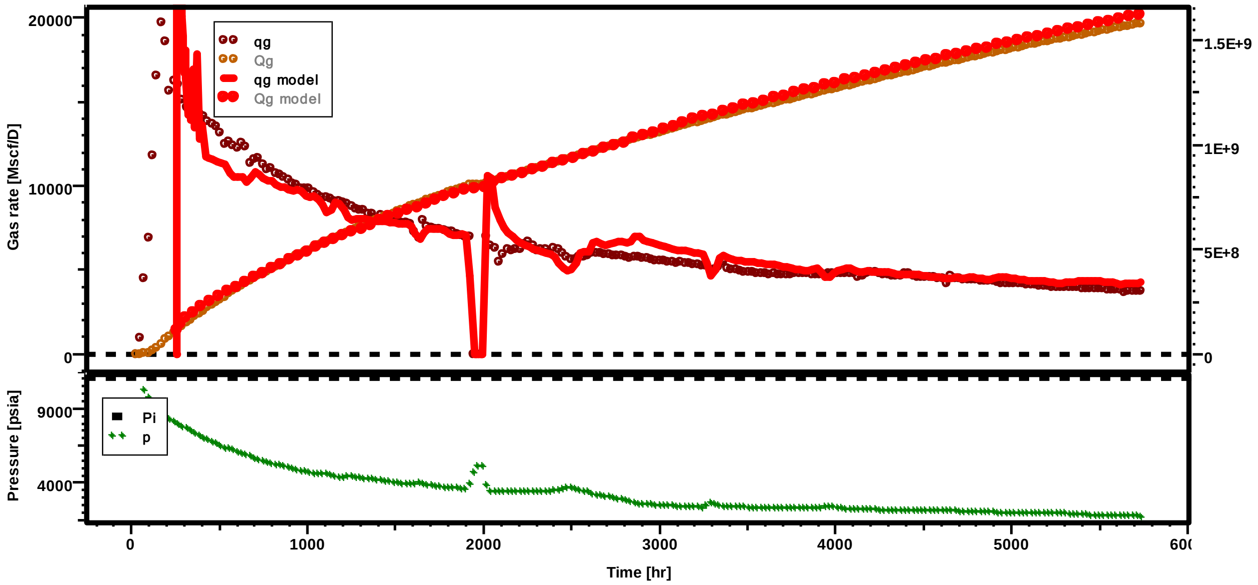
The linear flow towards the equivalent fracture is characterized by a linearity of the pressure response on a square root plot, ∆m(p) vs. $\sqrt{t}$. We fit a straight line and deduce $k * Xmf^2$. If we know k we can then get Xmf, and from our guess of the number of fractures N we can get Xf. Based on the available data we have determined the zone of linear flow and performed a straight line match. We get:

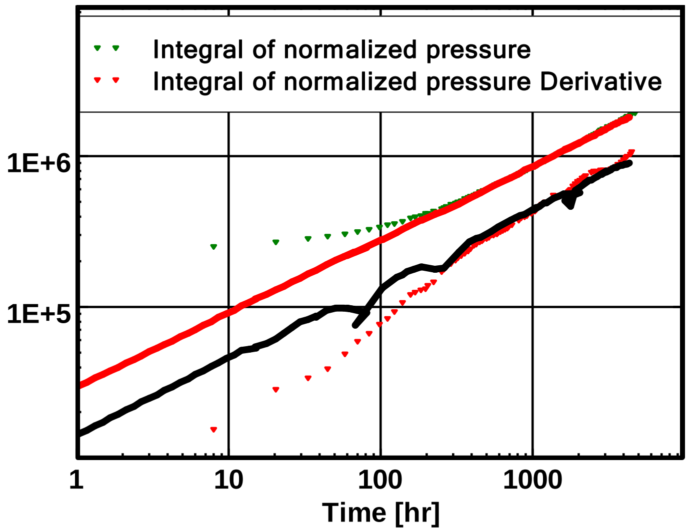
$$k * Xmf^2 = k * N^2 * Xf^2 = 13670\ md.ft^2$$



Square root plot

We have one equation and 3 unknowns: k, N – the number of fractures, and Xf. If we use k = 9.35e-5 md from preliminary studies, we get us an estimate Xmf = 12090 ft. For N = 42 fractures this gets us to Xf = 288 ft. The history and loglog matches are shown below:



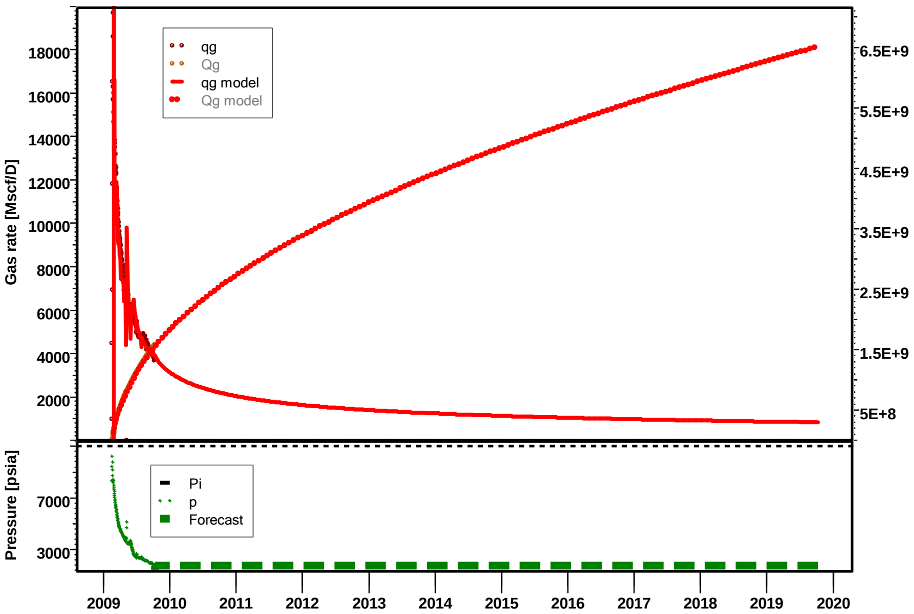


History and Loglog match

Aside from the early time match which is not representative of the system as we have said before, the match in general is reasonable, even using this very simple linear flow geometry.

Well & Wellbore parameters (test)		
Skin	0	
Xf	12090	ft
Reservoir & Boundary parameters		
Pi	11005	psia
k.h	0.00935	md.ft

Using this model let us make a 10-year forecast based on the last flowing well pressure FBHP of 1770 psia. Given the extremely low permeability, the drained area is very close to the fracture itself. Closing off the reservoir would not make any difference.



Forecast using the square root extrapolation

2.2 - Material Balance

In a gas reservoir it could make sense to look at a p/Z plot to assess the reserves. This cannot be done here, because the classical p/Z plot and other related material balance methods are based on the assumption that a pseudo-steady state flow regime is established, which is quite clearly not the case here: there is no indication of late time unit slope on the loglog and Blasingame diagnostic plots.

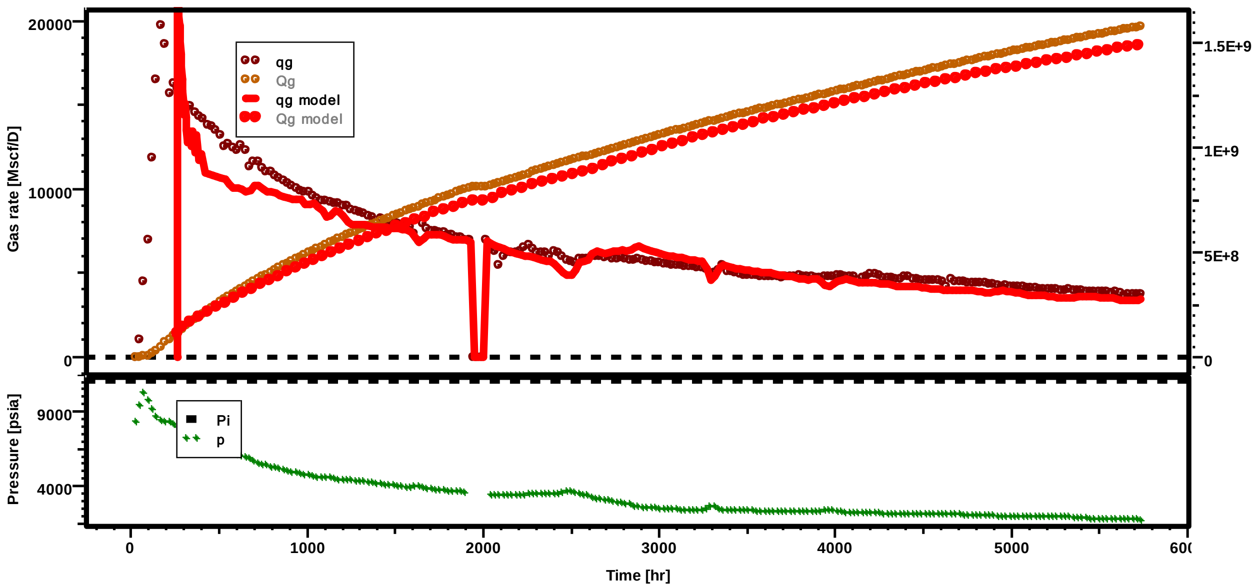
This is to be expected for many shale gas plays, as the extremely low permeability gives such a low mobility to the system that transient flow can last as long as many years. Thus, performing a flowing material balance analysis would be meaningless here.

3 - Advanced analytical model: multiple fractures horizontal well (MFHW)

In Part 1, we have described KAPPA's analytical multiple fractures horizontal well model. This model has the advantage over the equivalent single fracture model to account for the real geometry of the system. The main difference is that it takes into account the interferences between the different fractures.

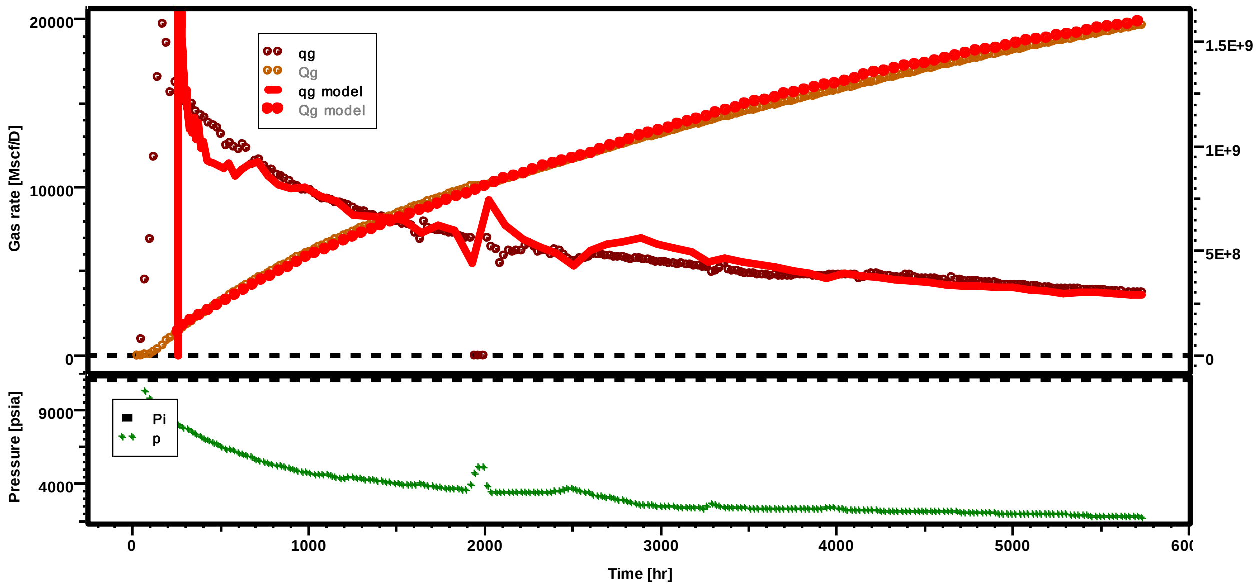
3.1 - Matching with the analytical model

From the square root plot, we have defined k.N².Xf². Assuming a value of k and N we got a value for Xf. We can now use these values to make a first run of the analytical model. The "match" is shown below.

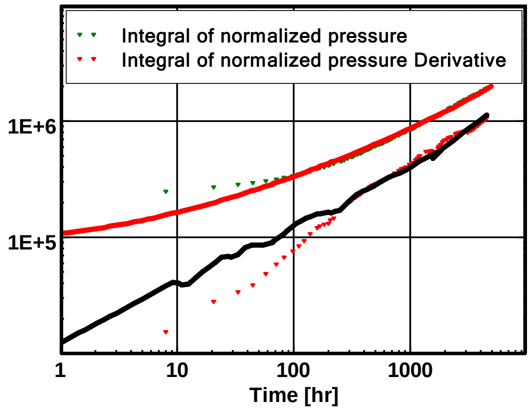


History match using the analytical model with the straight line result.

After refining, we obtained the following match using the parameters shown below. We can see on the loglog plot that the derivative of the model follows a slight deviation from the half slope at late time, indicative of the start of some interference between the fractures.



History match with the analytical model after nonlinear regression

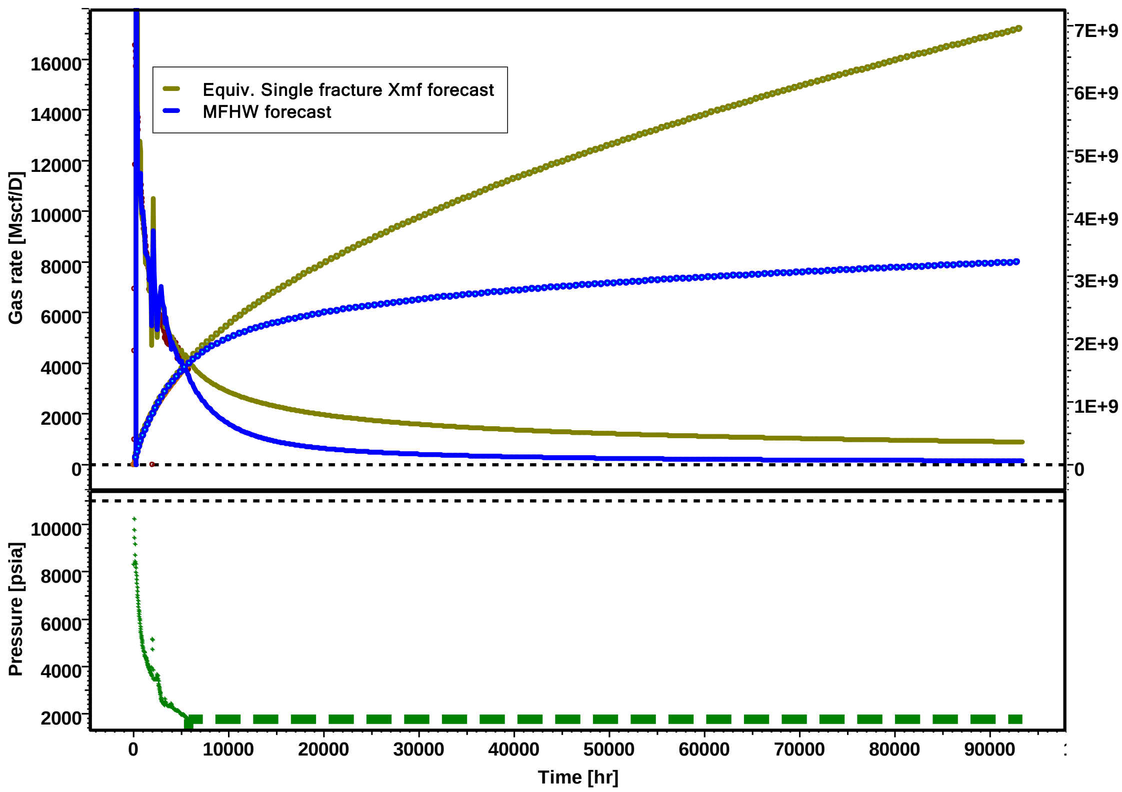


Skin	2.7E-4	
Flow type	Flow in fractures onl	
hw	3900	ft
Zw	50	ft
Number of fractu	42	
Xf	307	ft
Hf	100	ft
Fracture angle	90	°
Fracture model	Infinite conductivity	
Reservoir & Boundary parameters		
h	100	ft
Pi	11005	psia
k.h	0.00935	md.ft
kz/kr	1	

Loglog match and analytical model parameters after nonlinear regression

The parameters obtained from the match are within possible estimations of the well, we do notice though that the fracture half-length falls into the high ends of the Xf estimates from our preliminary estimations. We will get to an explanation later.

Both straight line and analytical model reasonably match the data. They differ completely when we compare the 10-year forecast. The analytical model gives a significantly lower total cumulative production and this could be critical for the economic value of the well.

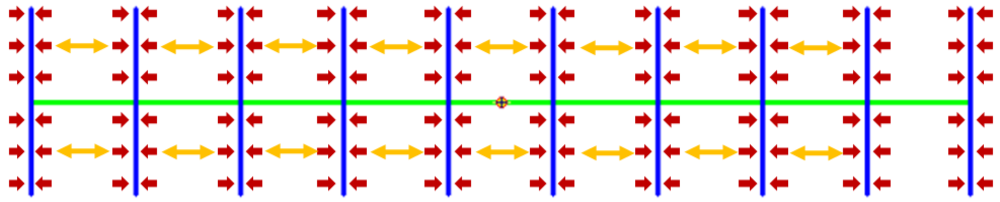


Comparison of forecast for both straight line and analytical models

3.2 - Discussion

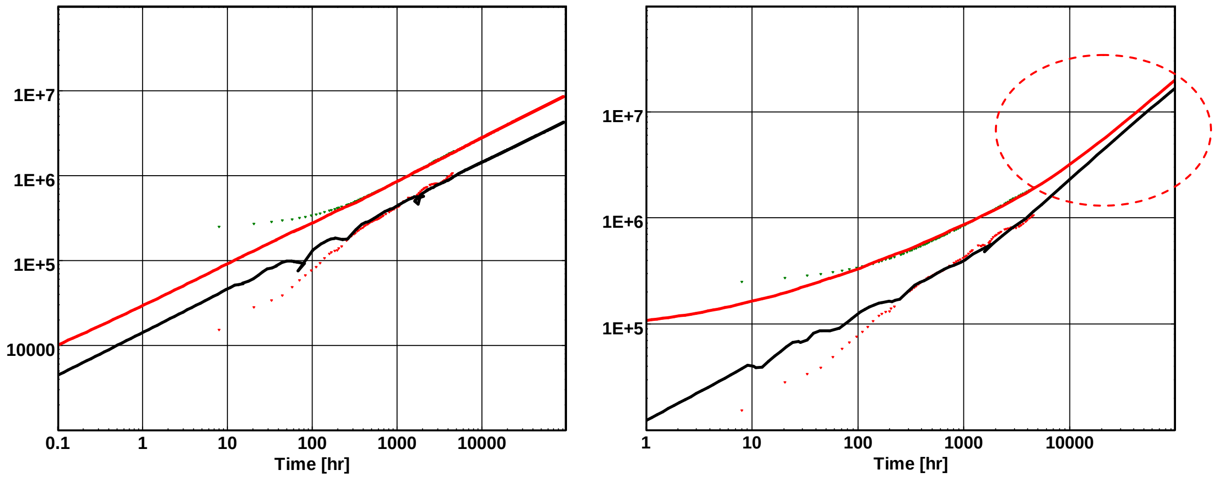
In the single fracture equivalent model, all fractures are represented by a single one. Interaction between fractures is not taken into account.

In the analytical model we take the real flow geometry into account. Interference happens between nearby fractures, as all fractures start "competing". Productivity decreases compared to a system where fractures would be aligned side by side.



Schematic of interferences

During the first 8 months of production, the interference is negligible thanks to the very low permeability of the system. Each fracture drains fluid separately from the other. This however is not negligible anymore when planning a 10-year forecast, as we will move from an independent linear flow for each fracture into a flow behavior where interferences are dominating. Let us illustrate this in the log-log plot:



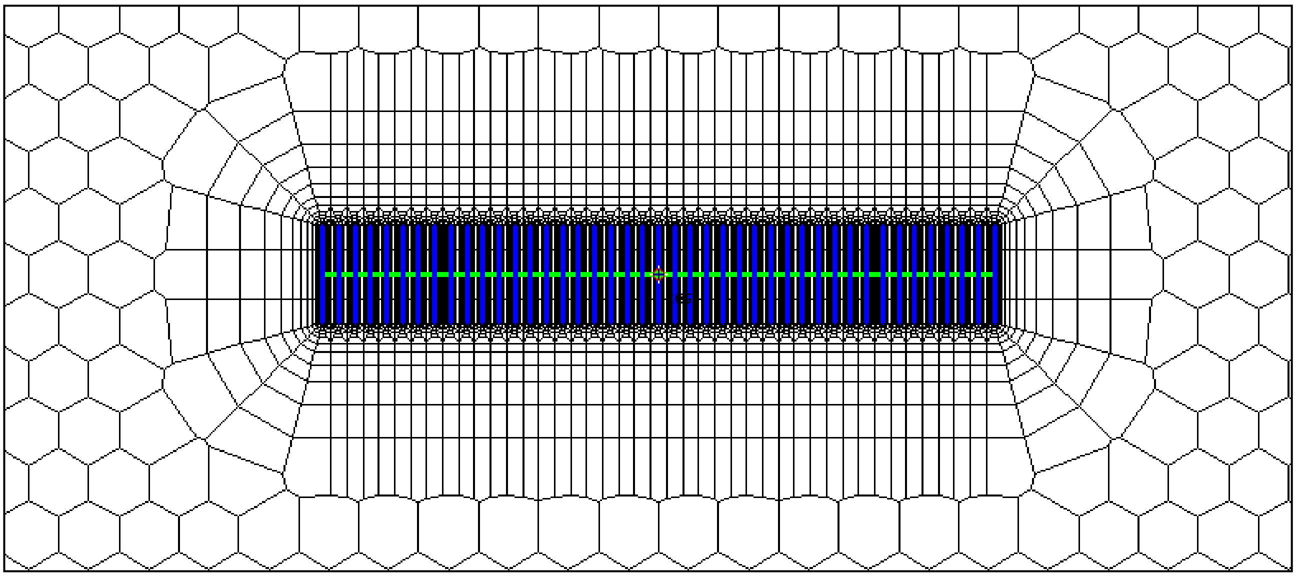
Comparison of the loglog response for both straight line and analytical models

The left hand side plot shows the single fracture equivalent model and the right hand side the MFHW model. The log-log model is extended beyond data points as a 10-year forecast is made in both cases.

We can see that although both models match reasonably well the data and look similar within the data matching period, the flow behavior changes significantly later on: the single fracture model continues its linear behavior, while the MFHW model shows that after 3000 hours the slope increases due to interferences.

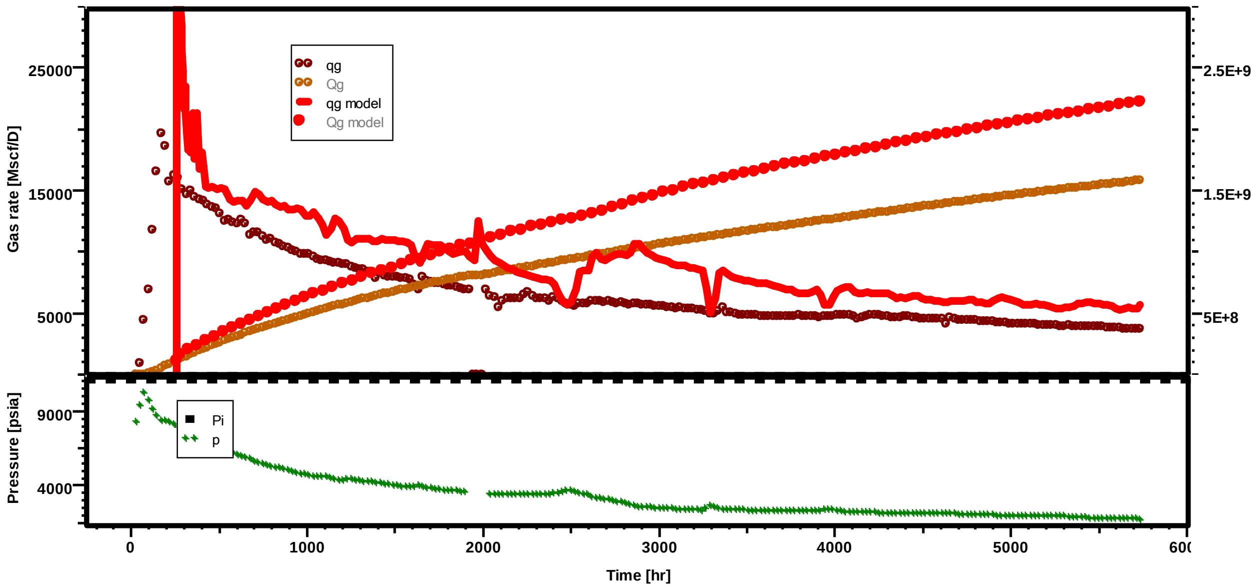
4 - Nonlinear numerical model without desorption

In the next stage we use the numerical model. We match the same geometry as the analytical model, and fracture interferences are taken into account. However, instead of using pseudopressures we account for nonlinearities and simulate the real gas diffusion. At this stage we do not take the desorption into account.

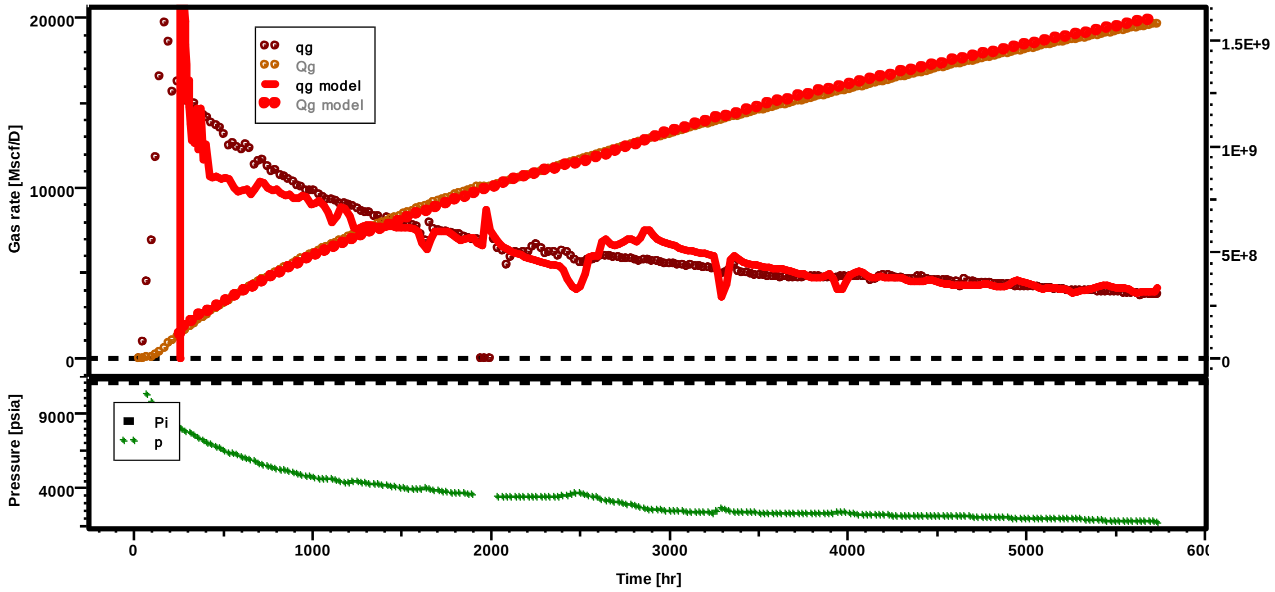


4.1 - Matching with the nonlinear numerical model

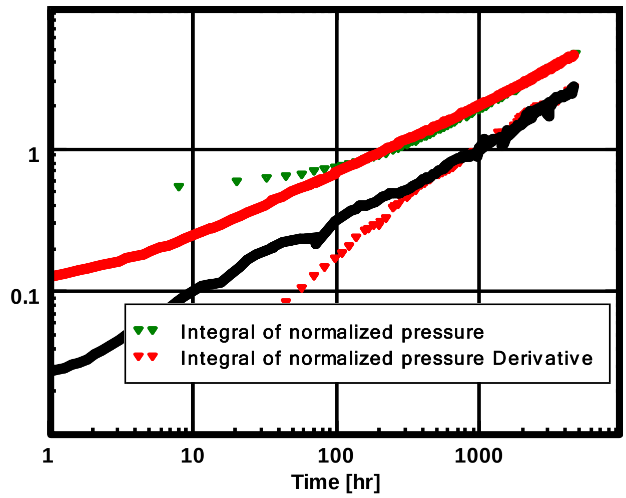
As in the previous section we start with the current parameters, coming from the nonlinear regression using the analytical model. The simulated production is far above the real data. We then fine tune the parameters in order to get a better match.



History match with the numerical model before refinement



History match with the numerical model after refinement



Loglog match

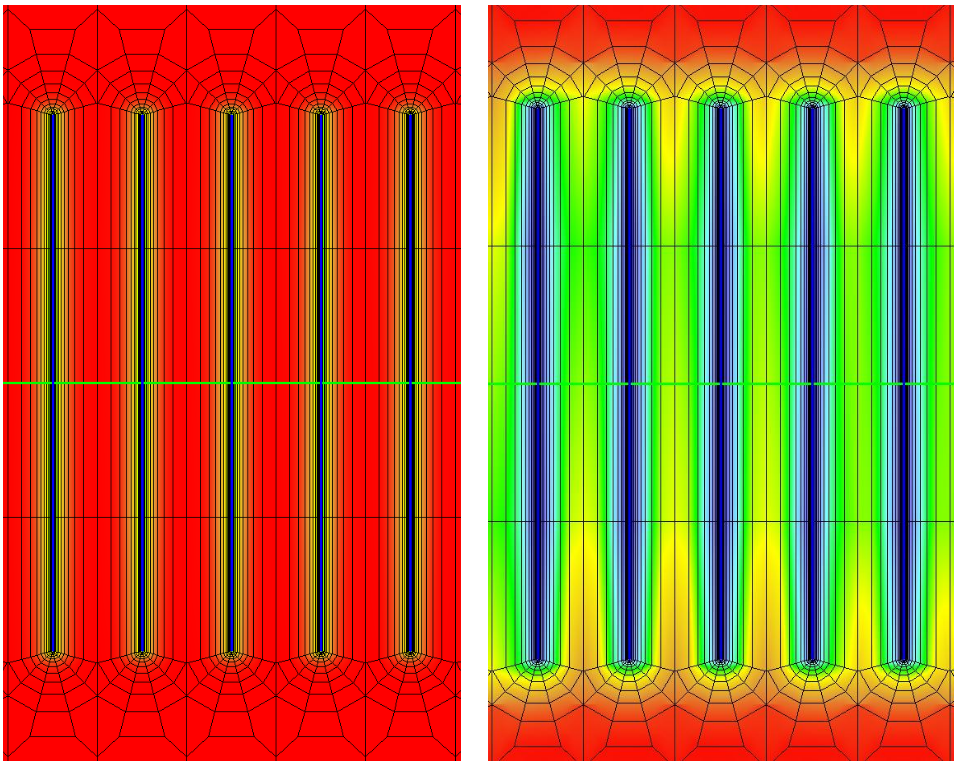
rw	0.3	ft
Flow type	Flow in fractures only	
well length	3900	ft
Zw	50	ft
Number of fractures	43	
Theta	0	°
Xf	245	ft
Pwf min	14.7	psia
Pwf max	15000	psia

Well & Wellbore parameters (test)		
Skin	1E-3	
Fracture model	Fracture - Infinite conductivity	
Xf	245	ft
Width	0.0328084	ft
well length	3900	ft
Zw	50	ft
Reservoir & Boundary parameters		
Pi	11005	psia
Swi	0.25	
k.h	0.0072	md.ft
kz/kr	1	
h	100	ft
reservoir model	Homogeneous	

Model parameters

After refinement we get a shorter Xf around the lower end of the fracture half length estimates, and a lower permeability: for a kh = 0.0072 md.ft, we have k = 7.2e-5 md. That is reasonable as estimation, especially when significant uncertainties can lie within shale permeability and fractures lengths. We also have little change in skin and an increase of fracture number by one; this is within acceptable uncertainties range.

Since we are running a numerical simulation, we can observe the change of pressure over time in the numerical grid. The pressure range varies from red (max) to blue (min) and we are comparing an early time (after one month) production snapshot (right) with the final production time one (left):

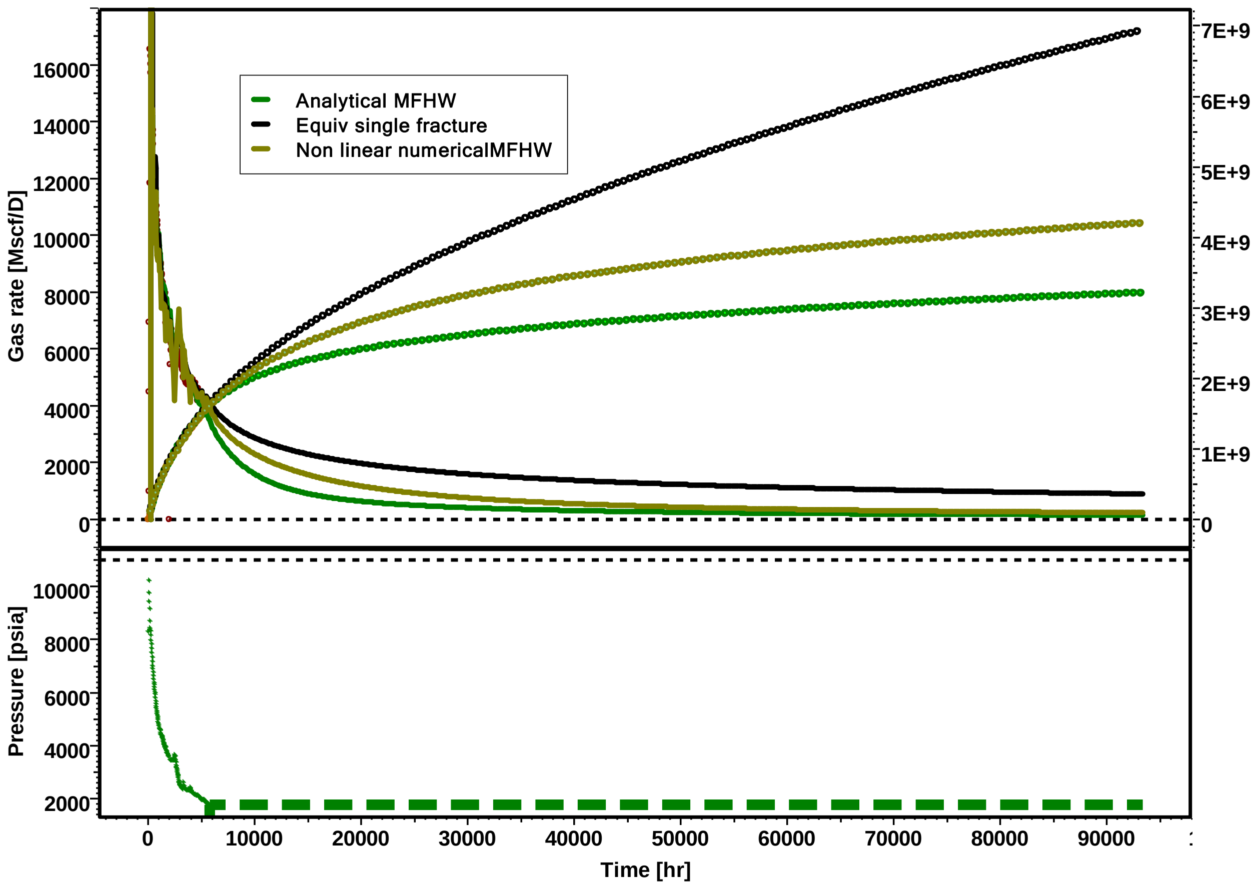


Pressure profile after 8 months and 10 years

At early time, each fracture is producing as if independent, but that after a few months of production, we are transiting towards an interference regime where fractures are interacting with each other. This verifies what we explained earlier in our analytical MFHW model.

Let us now make a 10-year forecast and compare it against the previous analytical models:
We see that the numerical one gives a better cumulative production compared to the analytical MFHW one, but is still very much lower than the single fracture cumulative production forecast.

A note for the drainage area limitation: this shale gas play has such low mobility that in fact most drainage is happening in the immediate vicinity of the well, thus it does not make a difference whether to enclose the well within a bigger or smaller drainage area for forecasting, since we do not impact the reservoir once further away from the fractures. More on this in a later section of this paper.



Comparison of 10-year forecasts

4.2 - Discussion

For the same parameters and geometry, the productivity is better in the numerical model compared to the analytical solution, thus requiring smaller fracture sizes and permeability to match the same set of data. The same is observed when comparing 10-year forecasts

Explanation: Even though we use pseudopressures instead of pressure in the case of gas, we still have to consider constant PVT properties at a reference pressure (generally the initial pressure) for the other terms of the linearized diffusivity equation. Because of the low permeability the pressure gradients are very high and the pressure substantially drops around the wells. This creates a substantial increase of the gas compressibility which helps the diffusion. This increase is not taken into account when using pseudopressures based analytical models, and therefore the productivity is under-estimated compared to the "real" productivity simulated by the numerical model.

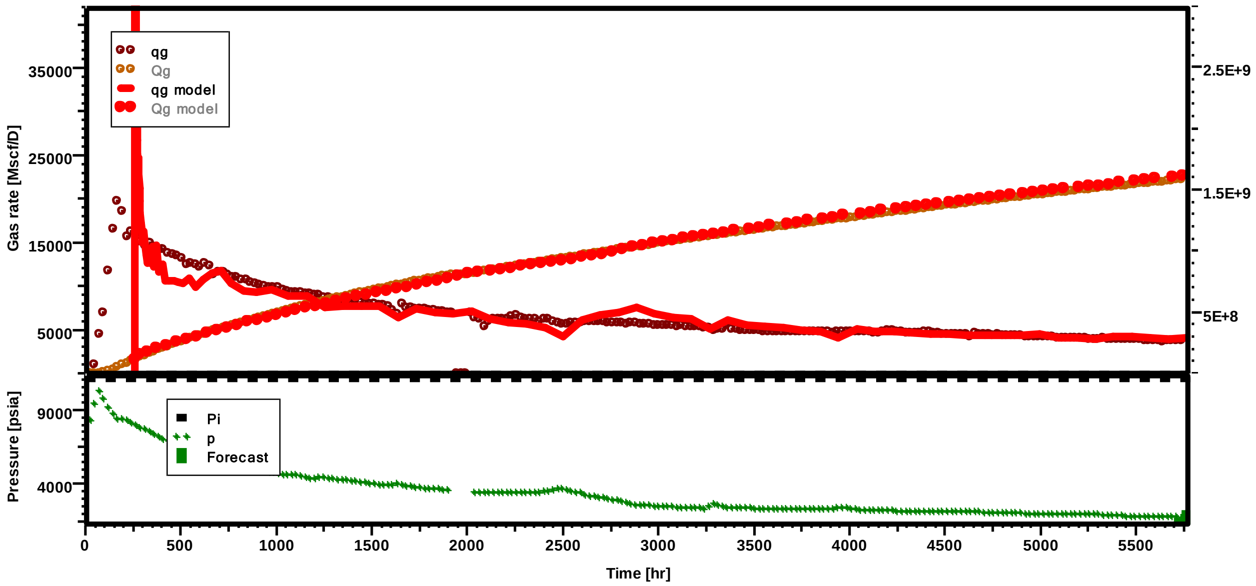
While the straight line extrapolation was optimistic, the analytical model is pessimistic for production forecasting.

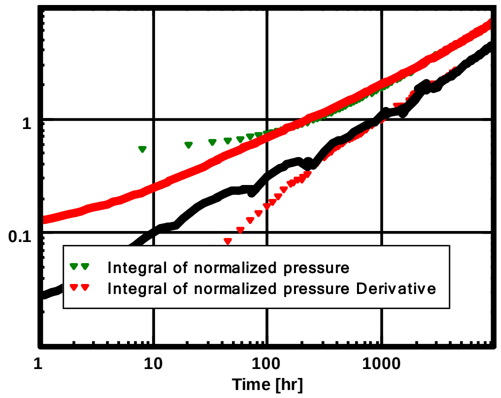
However the analytical MFHW model was useful, as it captures the correct flow geometry and it was useful to get a first parameter estimate for the numerical model, which should be preferred for the 10-year forecast.

5 - Nonlinear numerical model with desorption

Finally, let us integrate desorption to account for another process possibly at play in this shale gas case. From our laboratory studies, we can expect that the desorption effect may play a very limited role in the gas production of this shale gas well, as we can see that the Langmuir pressure (pressure needed to desorb half of the Langmuir volume) is quite low compared to our FBHP, and the Langmuir volume in this shale play is low as well.

Let us check this with the model. After calibration of the model including the desorption effect, we have:



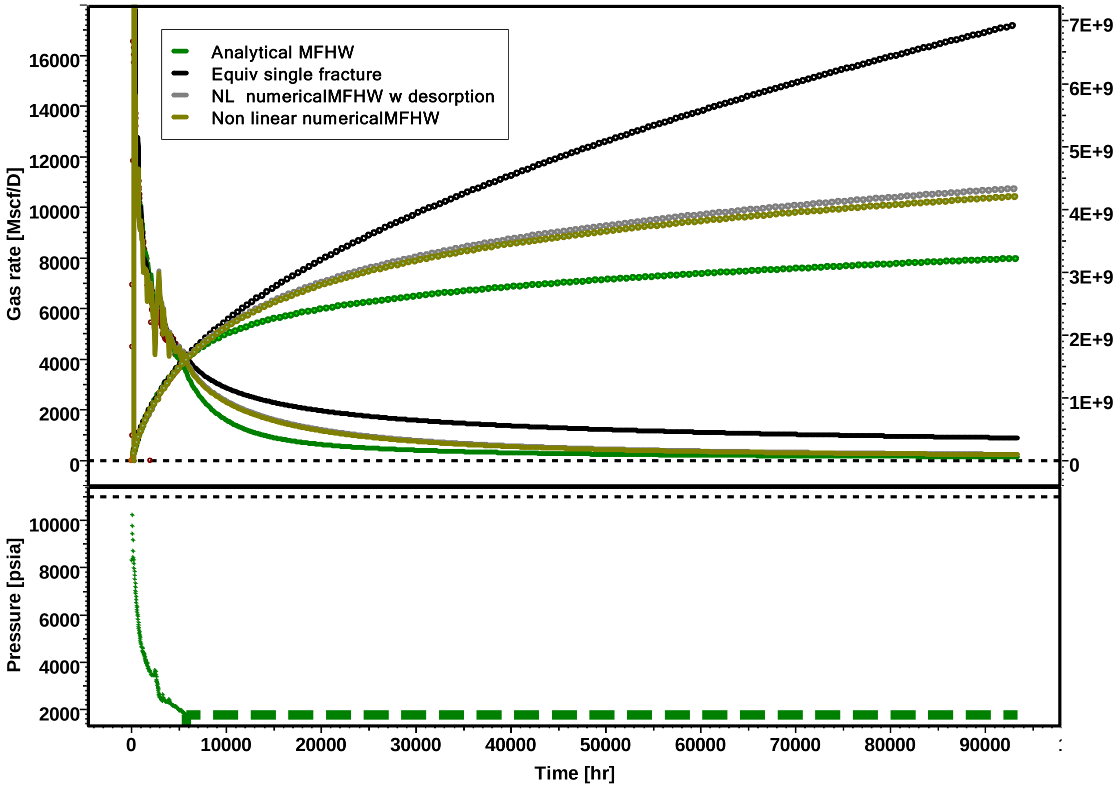


X	0	ft
Y	0	ft
rw	0.3	ft
Flow type	Flow in fractures only	
well length	3900	ft
Zw	50	ft
Number of fractures	43	
Theta	0	°
Xf	240	ft
Pwf min	14.7	psia
Pwf max	15000	psia

History match, loglog match, and model parameters

For desorption, we have used the parameters given in the first page of this document :Vl= 70 scf/ton, rock density = 2.6 g/cc, saturated condition with Swi = 0.25. As it is shown here, its effect hardly plays a role during the production time, as we only need to change by 5 feet the fracture half length to obtain a good match. This is as we expected.

Let us now compare the model performance with the other models over a 10-year production scenario:



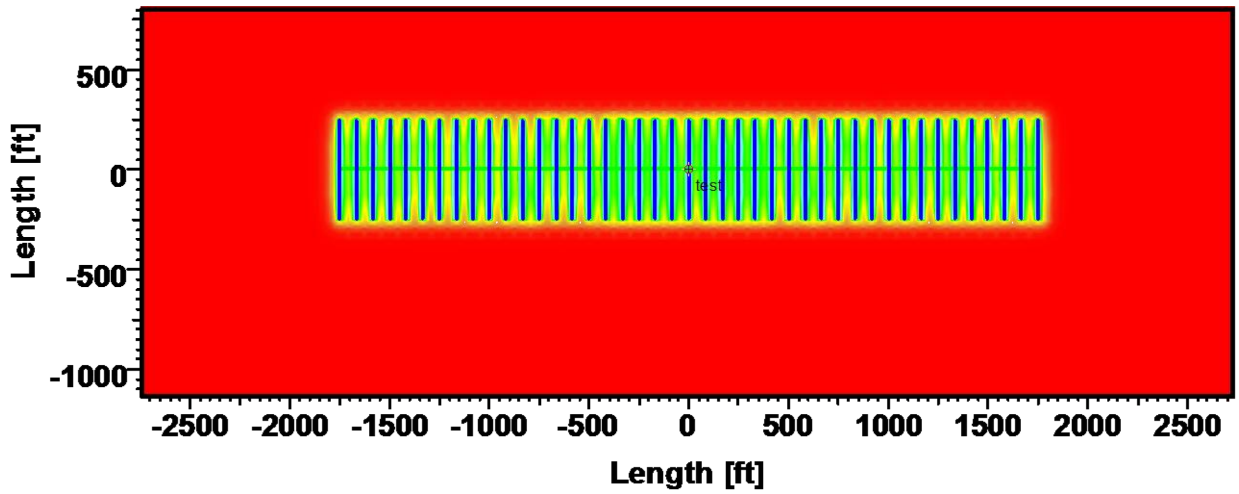
Comparison of 10-year forecasts

We can see that in this case, desorption is playing a small effect even after 10 years, because we are staying quite high above the langmuir pressure. This could change if we consider a lower operating FBHP for our 10-year production plan.

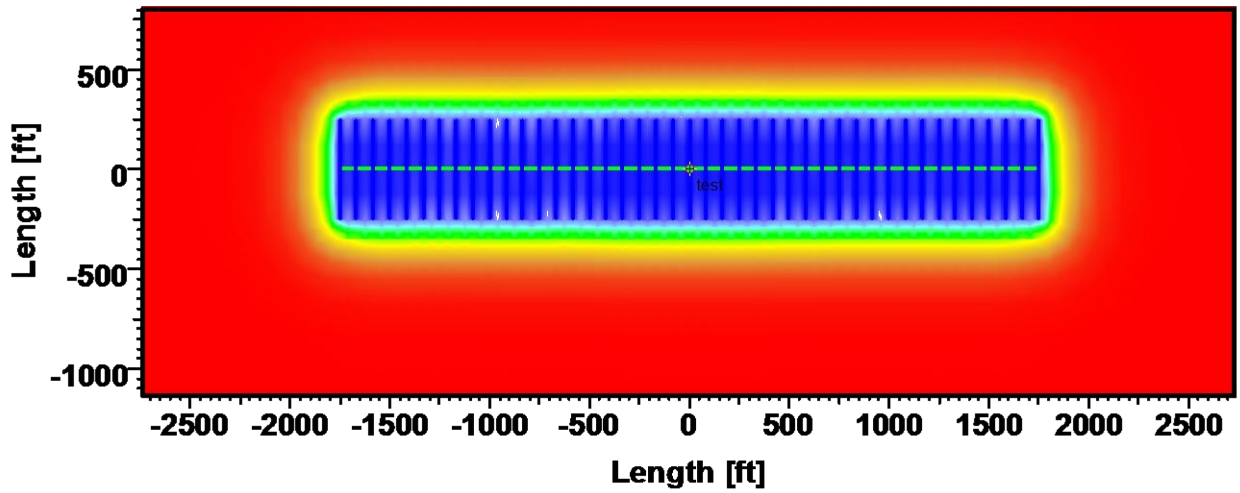
In conclusion, desorption effect plays a little role in the production contribution in our particular case. The nonlinear numerical MFHW is an interesting model for production forecasting, and the analytical MFHW can act as a starting model for calibration.

6 - Drainage area and reserves

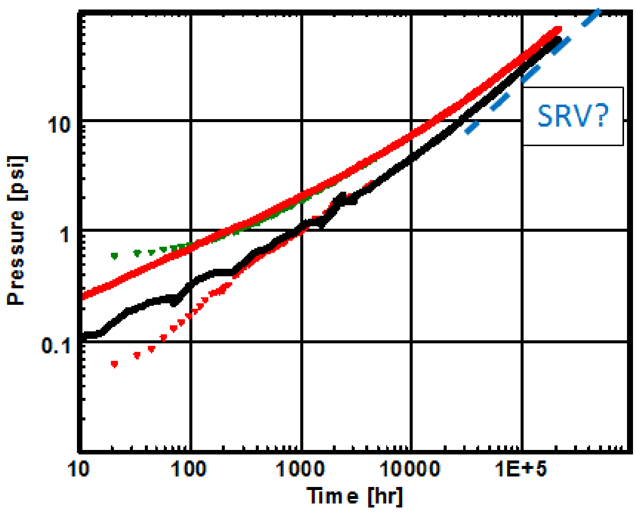
As we have said in the previous section, because of the extremely low mobility k/μ induced by a very low permeability formation, the well is draining mostly the immediate proximity of the reservoir only. This is in consistency with what we observe in existing operating shale gas wells. Let us observe the pressure field around the well for two time steps: one at the last pressure data points after 8 months of production, one after 10-year production forecast:



After 8 months of production (last available data point)



After 10-years of production (forecast)

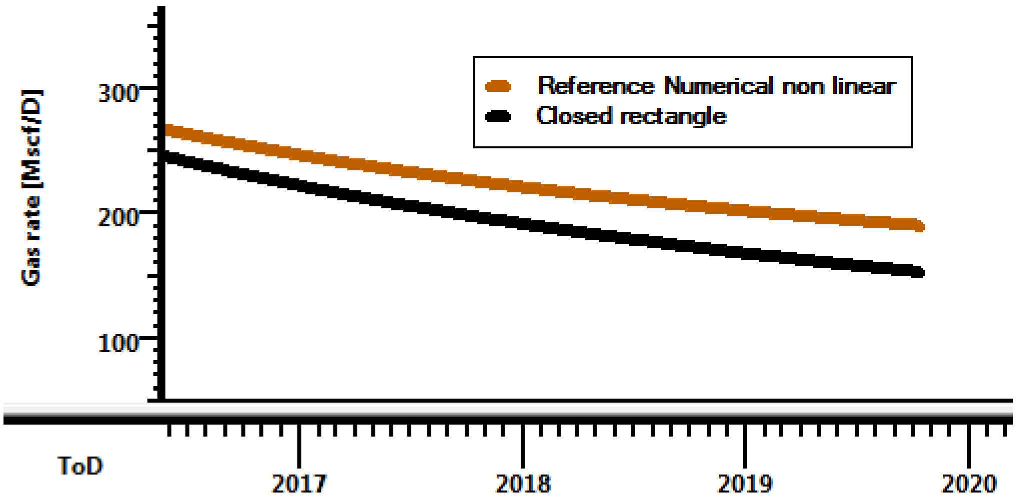


Log-log plot after 10-year forecast

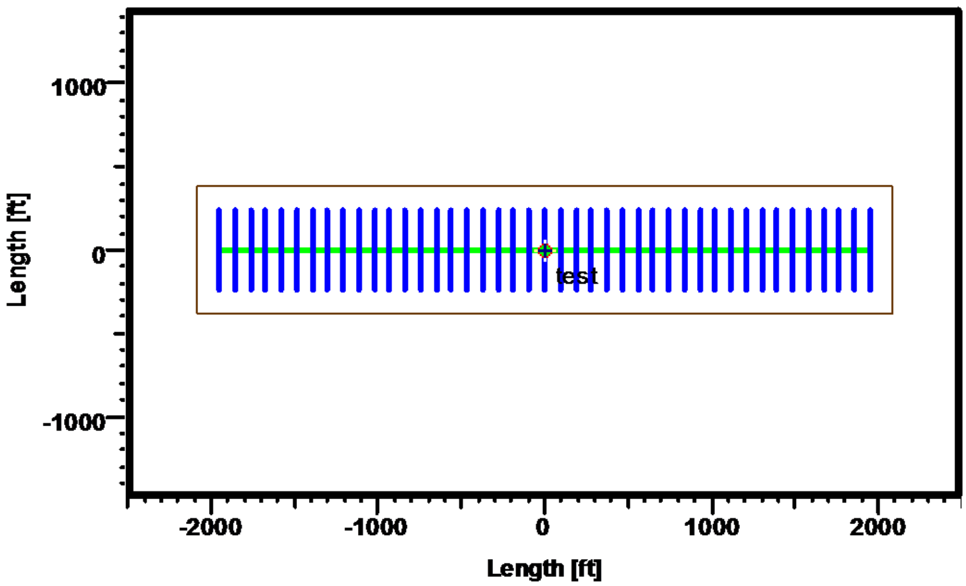
Because of the very low mobility, even after 10 years we have hardly reached any further from the well itself. This is in consistency with the theory of "SRV" stimulated reservoir volume: even if the well is drilled in a large reservoir area, it will only produce from a much more restricted volume (the SRV) during its operational life, because it would take us an unrealistic time period to reach the actual reservoir boundaries.

However this may not be always the case depending on the reservoir permeability and is not strictly restricted to the area defined by the fractures, thus a nonlinear numerical MFHW simulation is necessary to observe the drainage pattern.

To estimate the drained volume for 10 years of production, let us use a "closed box" approach: we surround the well area with a closed rectangle until the tail production rate q deviates from the original one by 20% after 10 years production. We then consider this volume to be the drainage volume for this production period.



Comparison of q rate deviation



Enclosed rectangle for drainage determination

Following the analysis, we obtained as drainage area dimensions: 4170*770 ft^2. From this we can deduce a closed box STGIIP of 6.7 bscf, where 4.2 bscf will be produced considering a producing period of 10-year using the last flowing well pressure as control.

Because desorption has little effect in this case, by applying the same technique we found a similar drainage area: 4170*770 ft^2. However STGIIP in this case would be 8.2 bscf, because of the adsorbed gas, despite a similar production of 4.3 bscf during our 10-year forecast. Consequently, one must take careful considerations when evaluating STGIIP because although the volume in place may be significantly higher when considering the adsorbed gas potential, it does not necessarily mean that production will increase significantly along with it.

7 - Conclusion

In this study we have evaluated the different analysis techniques to find a suitable match for our shale gas data and perform a reasonable forecast. The main results are summarized below:

	Linear flow straight line analysis	Material balance PSS	Analytical MFHW	Numerical NL	Numerical NL with desorption
Interferences between fractures?	no	no	yes	yes	yes
Nonlinear PVT?	no	no	no	yes	yes
(all percentages express differences relative to the numerical NL with desorption case)					
k (md)	--		9.35E-05 *(+30%)*	7.20E-05 *(0%)*	7.20E-05 *(--)*
Xf (ft)	--		307 *(+28%)*	245 *(+2%)*	240 *(--)*
Nb. Fractures	--		42 *(-2%)*	43 *(0%)*	43 *(--)*
Xmf (ft)	12090* *(+17%)*		12894 *(+25%)*	10535 *(+2%)*	10320 *(--)*
Lw (ft)	--		3900 *(0%)*	3900 *(0%)*	3900 *(--)*
Skin	0		2.7E-04	1.0E-03	1.0E-03
Drainage area after 10 yrs production (ft^2)	--	*No pss data*	--	3.13E+06 *(0%)*	3.13E+06 *(--)*
STGIIP based on above area (bscf)	--		--	6.70 *(-18%)*	8.20 *(--)*
Qg 10 yrs forecast (bscf)	**6.94** ***(+ 61%)***		**3.22** ***(-25%)***	**4.2** ***(-2%)***	**4.3** ***(--)***

**based on $k*X_{mf}^2$ = 13670 md.ft^2, assuming k = 9.35e-5 md*

The equivalent single fracture straight line analysis will match the initial months of production, but the response will inevitably deviate from that of a fractured horizontal well model after some time. This is due to the neglect of interferences between fractures. It can however be used as a method for finding an initial range of parameters of the analytical MFHW model.

In turn, the fractured horizontal well analytical model can correctly capture the interferences between fractures, but its simplified PVT assumptions make it miss the actual problem of non linearity induced by the gas properties - hence its pessimistic production forecast.

The nonlinear numerical fractured horizontal well model is not affected by those limitations. It is the most reliable model in our study. Gas desorption played a minor role here, given that our operating pressure is much higher than the Langmuir pressure.

All this is consistent with what we found in Part 1 when evaluating the different techniques available today. Overall, they all show that some of the most significant aspects occur to be:

- Nonlinearities: because of the very low permeability, the pressure gradients in the vicinity of the fractures are so important that the usual PTA analysis assumption of constant compressibility and viscosity does not hold anymore.

- Specific geometry: even if the permeability is very low effects such as interferences between fractures can become of upmost importance after a few months or years. This must be accounted for.

- Transient flow: the use of material balance related techniques for the determination of the SRV may introduce the belief that pseudosteady-state flow can be reached in shale gas formations. We must forget about this: fluid flow in a typical shale gas play is bound to remain transient for tens or even hundreds of years. The SRV depletion regime is merely a transition towards radial flow in the matrix, it can only in the best cases behave "like a" pseudosteady-state regime without ever reaching it.

Not surprisingly NL numerical modeling is the option that accounts for a maximum of those specificities, even if some work is required (e.g., downscaling) to adapt the model. But looking at real data showed that simpler methods are still valuable as long as the analyst keeps the various limitations in mind: results from straight line analysis can feed a model fitting with an analytical model, which in turn can be used as a starting point for a fit with a more complex NL numerical model. This analysis path is suggesting a workflow that goes through the different methods step by step, with increasing complexity

However forecasts should always be made with the most complex available model. In a simulation forecast, we cannot waive out with complete certainty the impact of a given effect until it is accounted for in the model…

The next question is then: is the best model we have good enough? We suspect that there remain many ruling processes (secondary fracture networks, stress dependency, multiphase flow, etc…) that we have to incorporate in our toolkit, even though the problem of unicity will remain acute as long as we do not have any source of information to constrain the results.