The Impact of Natural Fractures in Hydraulic Fracturing of Tight Gas Sands

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Abstract

The presence of natural fractures in hydraulic fracturing candidates can present an array of well completion problems. Natural fractures can be very difficult if not impossible to model without adequate pre-job diagnostic testing to calibrate simulation.

Left undetected natural fractures can cause premature screen-out as well as gel damage. In tight gas sand formations, natural fractures can be the predominate production mechanism in the reservoir. If polymer residue is left in the natural fractures after drilling, stimulation or work-over, a substantial amount of potential production may be left behind. Often this type of damage may be documented by the sheer fact that production may decrease after these types of operations.

Techniques have been perfected to determine the impact on leakoff due to natural fractures. In many cases production may exceed the predictive capability of production simulators without the introduction of permeability numbers that might be considered high for that area. This could lead one to believe that some portion of the production is dominated by natural fractures. A better understanding this type of leakoff could help in the development of methods to predict production results or economics of a well based on pre-job testing.

It is the intention of this paper to discuss methodology to predict the presence of natural fractures and show key considerations when trying to simulate their behavior. This paper will also investigate damage mechanisms and describe methods that may be used to help minimize their impact.

Introduction

Naturally occurring fractures in petroleum and gas bearing reservoirs can present a number of completion design challenges. The number one problem in stimulating these types of reservoirs is the unpredictive nature surrounding these phenomena. Advanced Stimulation Technology (AST)[1] introduced by the Gas Research Institute (GRI) in the early 90's formed the groundwork that presented methodology that would prove instrumental in developing techniques to help characterize the challenges encountered in the design and analysis of hydraulic fracturing treatments in tight gas sands. These techniques have proven invaluable in developing a systematic method to evaluate the complex issues encountered when modeling.

A number of key considerations must be examined to help insure optimum success when modeling natural fractures. The number one concern is developing criterion that will aid us in predicting the existence and magnitude of naturally fractured systems. Before any attempt at developing an accurate design can be achieved methodology must be developed to aid in the prediction of natural fractures. The next major concern is which stimulation technique will achieve the desired results and optimize the treatment.

Based on the evolution of AST many have developed tool kits to aid in this task. These tool kits consist of a series of computer programs that employ various techniques designed to assist in expedient implementation of this design methodology. Many of these tool kits are commercially available, while others may be considered proprietary in nature and therefore may not be readily available except for exclusive use by the developer company, but adequate literature exists to develop these tool kits if desired.

A third concern is the all-encompassing damage issue. In naturally fractured systems a major portion of production can originate from these fractures. If the stimulation treatment damages this natural fracture network, then post frac production can actually decrease.

Key Considerations

The main consideration in stimulating tight gas sand is completing the well in the most unintrusive manner possible to achieve the optimum performance for the reservoir. In many tight gas sandstone formations damage can be a major issue, especially in depleted or low-pressure reservoirs. Damage can be induced by water, polymer and chemicals used in the drilling and stimulation process. If it is determined that the reservoir has been damaged or will need to be stimulated to make it more economically attractive, great care should be given to any stimulation considerations. Sometimes there may be a tradeoff between creating the optimum fracture geometry and minimizing formation damage.

Once it is determined stimulation is required, an in-depth core analysis as well as geological study should be performed to help determine the stimulation technique that would be best suited for the reservoir. Permeability, porosity, clay content as well as water saturation play an extricate role in fluid selection and stimulation technique.

The frequency and likelihood of natural fractures should also be considered. Natural fractures may be evaluated through core and log analysis. More advanced logging techniques such as FMI (Fullbore Formation MicroImager) and EMI (Electro Micro-Imaging) may be used to help determine the existence of natural fractures.[2,3,4] Other techniques include enhancements in pressure fall-off analysis and pre-job injection diagnostics to determine the impact of natural fractures.[5,6]

Prediction

As previously stated the complex nature associated with these phenomena not only make it difficult to determine what should be done to implement successful stimulation, but also whether or not natural fractures exist. One technique was developed in 1996 by Dr. Robert D. Barree.[7,8] Barree continues where Nolte [9,10,11] and Castillo[12] left off, with a systematic approach to determine pressure-dependent leakoff due to natural fractures and incorporating these ideas into a simulator that can utilize the leakoff values.

The original Nolte technique utilized an additional leakoff component to account for leakoff while pumping (i.e. leakoff multiplier). Barree's technique is more sophisticated, in that it derives a pressure dependent leakoff component to be incorporated into fully 3D-grid simulator. Both techniques are important advances in understanding leakoff behavior due to natural fractures.

Another technique that has proven to be very reliable, is the use of history matching to determine the magnitude of pressure dependent leakoff. Barree introduces the idea of history matching into his model, which can be utilized in a variety of fracture simulators available today. In each case the goal is to analyze pressure decline data from pre-job injection test. The best method seems to be that of history matching the fall-off character of the pressure decline. Once pre-job injection fall-off behavior is modeled, these numbers may be applied to the stimulation design. Even with Barree's more sophisticated technique, matches are not always easily obtained.

The major determining factor comes into play when leakoff cannot be described without the introduction of a multiplier. In short, if the model that is being utilized cannot describe the falloff character of the pressure decline utilizing reasonable numbers for permeability and reservoir pressure, then more than likely leakoff is dominated by some other mechanism. This mechanism could be natural fractures or some type of additional void space that may not be detected by conventional log and core analysis.

Damage Mechanisms

There are three dominant damage mechanisms in hydraulic fracturing. Damage to the proppant pack, damage to matrix permeability and the plugging of natural fractures.[13] Recent advances in fluid and breaker technology have been effective in limiting the impact of damage due to polymer residue left in the fracture after a stimulation treatment. Novel stimulation fluids have also been successfully utilized to minimize damage by reducing the polymer loading required. These new systems achieve superior viscosity and sand transport with less polymer.[14] The new systems, Advanced Polymer Technology (APT) can develop equivalent crosslinked viscosity with about half of the polymer required in conventional systems. An added benefit to these novel fluid systems is lower yield stress that in turn will enhance stimulation fluid recovery.[15] The yield stress of a fluid is the force required to initiate flow or Flow Initiation Pressure.

Improved breaker systems show even greater benefit when used in conjunction with the lower loading polymer systems.[16] By the use of less polymer and improved breaker technology many types of formation damage may be reduced to a minimum when applied properly. In tight gas sands with low water saturation it is not only important to achieve the cleanest break possible, but also to remove the fluid as soon as possible. In formations with low water saturation reservoirs, the base fluid can be leached out of the polymer leaving a residue that may only be removed via costly remedial cleanup treatments.[17] The newer fluid systems enhance load recovery and reduce formation exposure time to potentially damaging polymer residue.

Terrell County Wolfcamp

The target wells were selected for this study due to their close proximity and relatively self-similar formation characteristics and net pay thickness. The original designs used a criterion of 300 to 400 feet of propped fracture length based upon 65 to 85% of 20 acre well spacing. In these tight gas sands length optimization was a critical issue. Based on 3D simulation and Return on Investment considerations 300 to 400 feet was considered optimum due to excessive height growth when greater lengths were attempted.

A lumped parameter 3D model was utilized for most of the original design work, with some verification with a fully 3D-grid simulator. Pre-job injection tests were utilized to calibrate the models. **Table 1** shows the possible link to natural fractures and production. Well 5 had to be modeled with a leakoff multiplier to compensate for excessive leakoff that could not be simulated using reasonable parameters for leakoff in this area. None of the other wells in the table were modeled using this multiplier. **Figure 1** shows the results from the history match of bottom-hole pressure with and without a leakoff multiplier.

Even though the original treatment design was not pumped to completion on well 5 and 3D modeling indicated shorter propped fracture lengths, this well outperformed it's offsets. Several factors indicate that natural fractures may be a major production mechanism in well 5.

Well 5 had the lowest initial pre-frac pressure of any of the offset wells, yet production exceeded the others. A leak-off multiplier was required to model the pre-frac fall-off data, indicating that excessive leakoff might be a problem. In many cases prior to this treatment 100 mesh sand was used to help circumvent this type of leakoff. 100 mesh was not used on this well due to proppant pack damage and fines migration concerns.[18]

Initial post frac results for well 5 were disappointing at first due to well cleanup delays created by the screen-out, but once these problems were resolved the well began a gradual cleanup and production began to exceed that of the offset's. After two years of production it remains to be seen what the effects of a smaller job volume and shorter frac length will have on long term production, but initial results look encouraging.

Smaller fluid volumes may be better due to the damage potential that exists in this area. Production decreases are not uncommon when excessive amounts of water and or polymer are allowed to enter these formations. Many wells in this area have been successfully remediated by the use of 100% CO_2 treatments.[19]

Well 2 of the study is a good example of this phenomena. Job problems were encounter prior to the main frac. On the first stimulation attempt a treatment iron failure was encounter prior to the first sand stage. Almost the entire pad had been pumped into the formation prior to the line failure. Even though attempts were made to recover the excessive pad prior to the second stimulation attempt, this well has not produced as strong as the offset wells have. In two of the other wells in the study 100 mesh was used as a fluid loss material. Damage due to excessive fluid exposure seemed to have a greater impact on production than did the 100 mesh. The formation in well 2 was exposed to twice as much pad as the other wells in this study. A CO_2 treatment was performed on well 2 to help remediate some of the damage generated by the excessive fluid exposed to the formation. **Figure 2** shows a moderate production increase after the treatment.

All of the treatments were pumped as designed with the exception of well 2 and 5. On well 2 excessive fluid was pumped and well 5 the job was terminated prematurely due to screen-out. In every case state of the art breaker technology (polymer specific enzymes, and encapsulated oxidizers) were employed to help minimize damage left by polymer residue.[20,21,22,23] Well 2 was the only well that required a leakoff multiplier and has the best production of the five wells in the study

Edwards County Wells

The Edwards County wells were selected due to the unique challenges they present and additional points for consideration. As in the Terrell County wells these wells are tight gas sands, with a multitude of damage mechanisms to contend with, but these wells presented another hurdle. Due to high regional tectonic stresses and excessive leakoff these treatments were more difficult to pump to completion. Some evidence from FMI and core analysis suggests that natural fractures could be prevalent. Pre-job injection tests indicated excessive leakoff that could not be modeled without including leakoff multipliers.

Every well in the Edwards County study had to be modeled utilizing pressure dependent leakoff or some type of leakoff multiplier to obtain a good history match. **(See Table 2)** The best well in the field had to be modeled with the largest leak-off multiplier, once again pointing to evidence that natural fractures could be making a major contribution to production. When the multipliers are applied to the design, screen-out trends could be predicted from pre-frac injection test diagnostics. **Figure 3** shows the original history match with and without a leakoff multiplier. **Figure 4** shows the screen-out trend prediction. The question still remains, will larger fracs produce better results or will the increased fluid volume required simply generate more formation damage. Once again we are faced with a situation where certain tradeoffs will have to be made.

To further highlight the damage mechanism theory, marginal wells treated with lower polymer loadings appear to be responding better than the offsets. Although there isn't enough data to conduct a conclusive study on the benefits of APT in this area, it appears that the wells with lower pre-job production and reservoir pressure benefited the most. The same damage mechanisms exist in the better wells, but they tend to clean up easier, thus leaving less damage behind.

Conclusions

With the variety of advanced toolkits available today, stimulation design engineers are able to more effectively model fracture geometry. Although there may be considerable debate concerning the accuracy of any particular model, it should be duly noted that these models are merely tools that may be used to aid in the evaluation and design of more effective stimulation treatments.

It is recommended that a set of tools be identified from which a comfort level may be obtained by the user, then implemented in an area of interest for effective evaluation. With tool kits in hand we must diligently consider the impact that natural fractures may have on completion procedures and resulting production. Currently engineers have a wide variety of analytical tools available and most of them can be used to evaluate leakoff due to natural fractures.

History matching and efficiency correlations may be used in conjunction with most 2 and 3D hydraulic fracture simulators available on the market today.

Once natural fractures have been identified, then great care should be given to any treatment decision made concerning leakoff control and fluid selection. Application of Minimum Formation Damage Technology should be strictly followed.

Improved breaker combinations should be employed to enhance initial cleanup and prevent the plugging of natural fractures.

New low molecular weight polymers (APT) should be utilized when possible to prevent the build up of excessive fissure plugging.

Fluid loss material should be used sparingly and consequences should be weighed carefully against any perceived benefit. Many times the type of fluid loss material used can have a big impact on the ultimate outcome, but in some cases the benefit of fluid loss material may outweigh the detrimental effects of excessive pad volumes.

Longer exposure time of treatment fluids can lead to more formation damage. Treatment fluids should be recovered as soon as possible, especially in wells with lower reservoir pressure.

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Table 1 - Terrell County Study

						Cumulative Production MCF	
Well #	Leakoff Multiplier	Reservoir Pressure	Propped Length	LBS 100 Mesh	k LBS Propp.	12 Months	24 Months
1	0	3759	463	0	289	451262	635132
2	0	3219	510	0	328	271668	442936
3	0	2940	400	4300	288	305935	467099
4	0	2600	523	7400	291	315819	503890
5	5	2611	150	0	270	424113	727810

Table 2 - Edwards County Study

					Production MCFPD		
Well #	Leakoff Multiplier	Fluid Type	k LBS 100 Mesh	k LBS Propp.	Pre Job	Post Job	% Increase
Well # 1	19	50# Borate	10	150	4000.0	14000.0	250.0
Well # 2	5	50# Borate	0	200	100.0	300.0	200.0
Well # 3	15	50# Borate	4	65	200.0	1000.0	400.0
Well # 4	5	50Q Zirk	10	72	1000.0	1000.0	0.0
Well # 5	3	50Q Zirk	0	79	250.0	350.0	40.0
Well # 6	4	30# LPT	14	80	1000.0	2700.0	170.0

Bottom-Hole Pressure
With and Without Multiplier

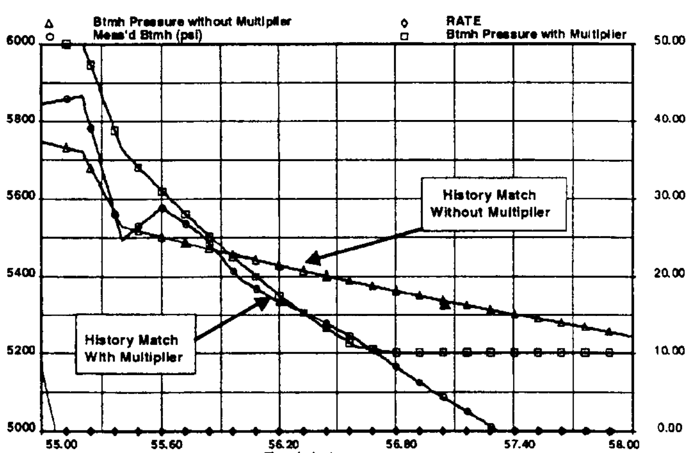

Figure 1 - History Match

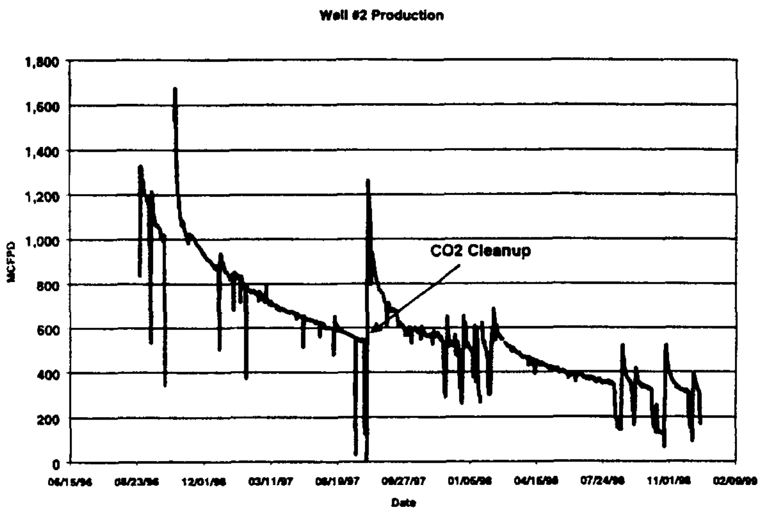

Figure 2 - CO_2 Effect

History Match of Bottom Hole Pressure
Screen-Out Trend Prediction

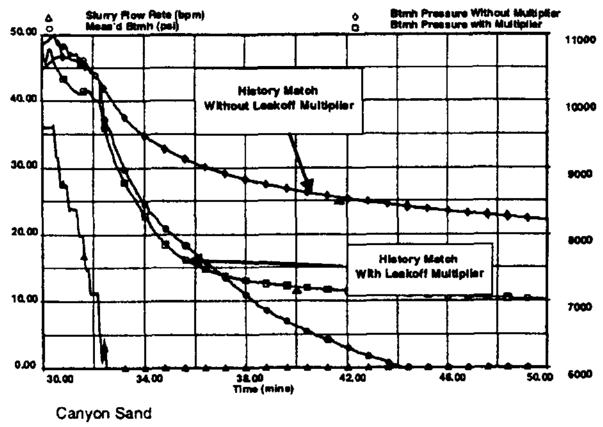

Figure 3 - Pre-Job History Match of Bottom-Hole Pressure
With and Without Leakoff Multiplier

History Match of Bottom Hole Pressure
Screen-Out Trend Prediction

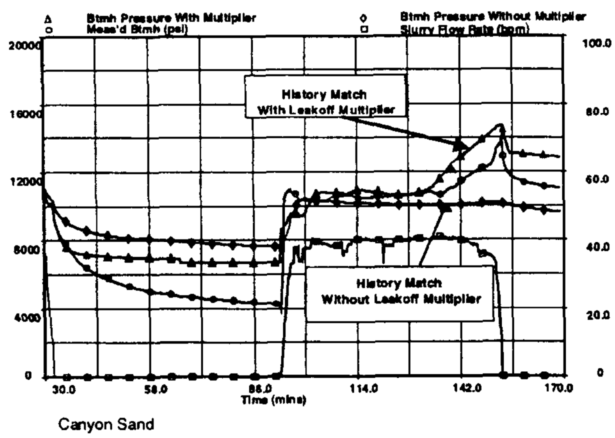

Figure 4 - Post-Job History Match of Bottom-Hole Pressure
With and Without Leakoff Multiplier (Screen-Out Trend)