Applying Innovative Production Modeling Techniques to Quantify Fracture Characteristics, Reservoir Properties, and Well Performance in Shale Gas Reservoirs

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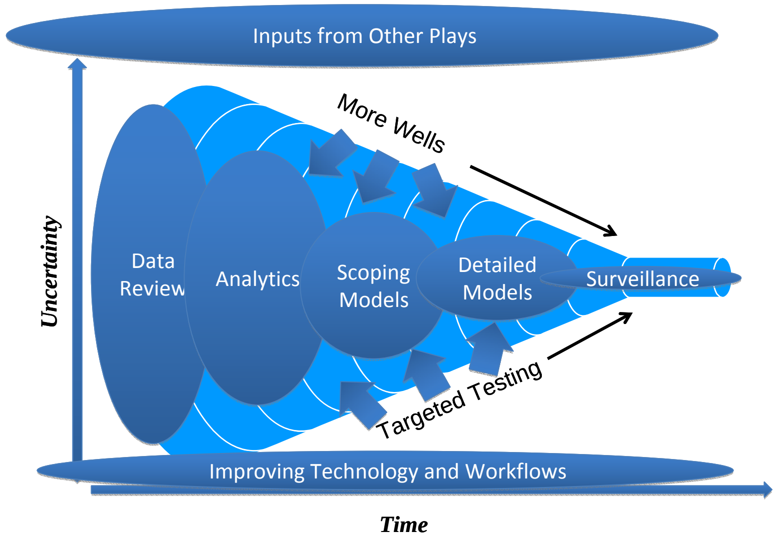
Introduction

Gas rates from shale gas wells are comparable to those of conventional wells as a result of rapidly-evolving horizontal drilling and stimulation technologies. However, an understanding of the factors controlling production rates and recoveries lags behind the knowledge derived from decades of gas production from conventional reservoirs. Some of the specific difficulties in characterizing shale gas production include:

- Incomplete knowledge about the geometries of staged hydraulic fractures in horizontal wellbores. It is not clear whether fractures are dominated by relatively simple planar geometries, or more complex structures controlled by natural fractures and local stresses.
- Uncertainty as to whether log and core analyses yield reliable values and ranges of petrophysical parameters including porosity, permeability, free gas saturation, and adsorbed gas volumes.
- An inability to distinguish between hydraulic fracture and reservoir contributions from limited production data. Early well behavior is dominated by the completion and provides little information about basic reservoir properties that control long-term performance.

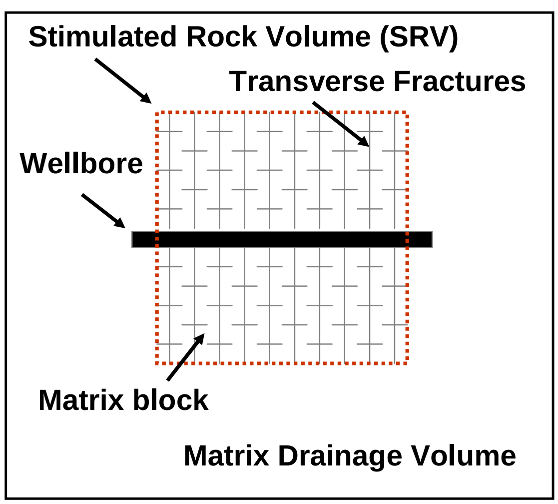
Method

In order to accurately characterize reservoir and hydraulic fracture properties from well performance data, appropriate workflows and analyses must be applied that effectively integrate variable quality data from a variety of sources. A recommended workflow for shale gas production characterization is shown in the figure below. This workflow uses an approach that incorporates more wells and the targeted testing of wells with time to reduce well behavior uncertainty. The initial steps in this workflow include a review of the available data and the application of analytical techniques to 1) identify groupings of like-performing wells, 2) detect wells with anomalous behaviors, 3) develop hypotheses about production mechanisms, and 4) choose specific wells for more detailed analysis and numerical modeling.

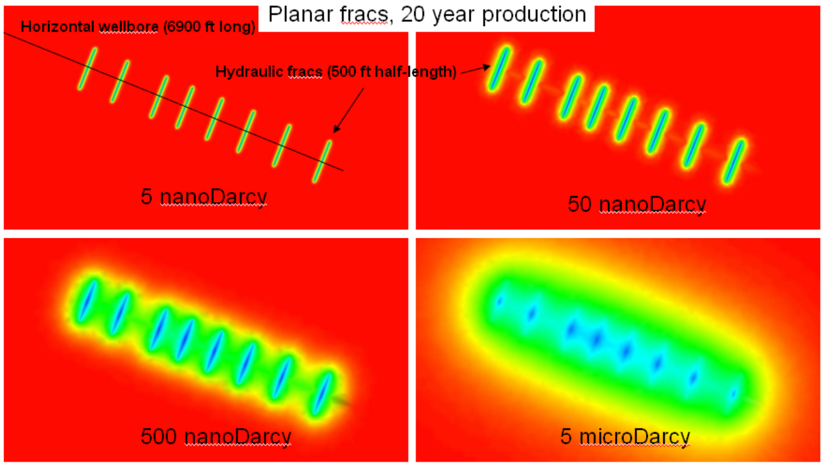


A number of analytical and semi-analytical methods have been proposed and are being applied to investigate the performance of shale gas wells. These approaches help increase our understanding of the basic mechanisms and physical property relations that govern well performance. Some of these approaches are logical outgrowths of pressure transient analysis (PTA) and rate transient analysis (RTA) techniques developed for conventional gas wells. However, there is still a need to develop specific analytical methods that incorporate the peculiar characteristics of complex hydraulic fracture systems in ultra-tight rocks.

The figure below illustrates some of these key characteristics. Horizontal well completions generate a series of transverse fractures that extend laterally from the wellbore. The volume containing these is called the stimulated rock volume (SRV) and beyond this is the matrix drainage volume. When wells are first completed, gas flows from matrix blocks within the SRV to the transverse fractures. This is referred to as the transient linear flow period. Later, within a timeframe of several months to many years, the fractures start to interfere with each other, resulting in boundary-dominated (steady-state) flow referred to as the internal depletion flow period. Eventually, the matrix beyond the SRV will begin contributing, and the well could return to another transient flow period dominated by the matrix drainage volume. Finally, once the boundaries of the matrix drainage volume are sensed (usually the drainage area of the offset wells) the well will again be dominated by steady-state flow.

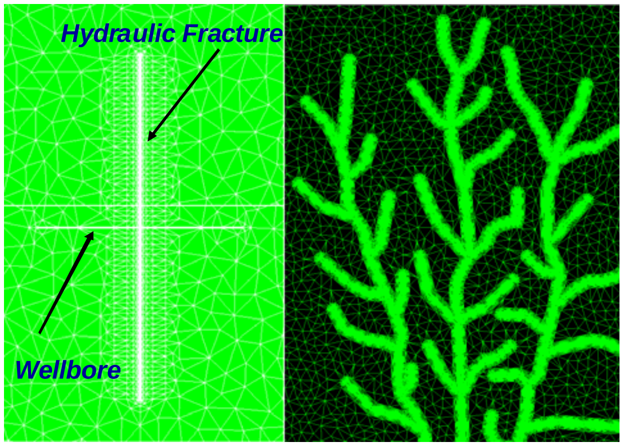


Whether the matrix drainage volume provides much uplift to well production depends on the permeability. As shown in the figure below, if the permeability is very low (5 nanodarcies) only small volumes adjacent to the emplaced hydraulic fractures will be drained. At high permeabilities (5 microdarcies) a large portion of the reservoir volume beyond the stimulated rock volume will be drained. However, since most shales are thought to have permeabilities in the hundreds of nanodarcies, only the stimulated rock volume (which extends out to the edges of the hydraulic fracture tips) will be drained effectively, requiring wells to be spaced so that their SRV's are essentially "touching" with no matrix drainage volume in-between. This means that understanding reservoir drainage behavior is critical for getting the well spacing right!



Equations have now been developed to help understand and quantify well performance in each of the flow periods discussed above, and these have been transformed into diagnostic plots that can be used to identify these flow periods. This analytical approach is very useful for understanding basic well behavior, but the techniques are incapable of addressing many other key issues that impact production in shales. For this reason, numerical modeling is used to provide a more detailed reservoir and completion characterization. This work begins with scoping models for 1) evaluating the possible controls on well performance, 2) providing procedures for testing wells and gathering additional data, and 3) identifying the key elements needed to build more complete and accurate numerical models.

Detailed numerical models provide the reliability needed for performance forecasting and completion optimization sensitivities. Conventional numerical models typically use finite-difference ("sugar-cube") 3-D grids, but these are neither sufficiently complex nor flexible enough for shale gas reservoirs. An alternative approach uses finite-element gridding as shown on the left side of the figure below. This technology places a large number of closely-spaced nodes near the hydraulic fracture, where all the action takes place in the early life of a well. Using an automated meshing technique, the node spacing is modified as the pressure drawdown extends farther from the fracture. Finite-element modeling also allows complex fracture geometries to be modeled, such as the dendritic fractures associated with a single stimulation stage shown on the right side of the figure below. These generic models can be further customized by fitting them to microseismic or other fracture mapping data.



Not only does the fracture complexity need to be captured, but information from fracture conductivity modeling and production logging need to be incorporated to understand the effectiveness of the hydraulic fractures along with which stimulation stages are contributing to production. In addition, the reservoir itself must be layered and assigned properties that represent an appropriate range of gas-in-place and permeability values. Key parameters can then be appropriately modified in a history-matching process. Once this matching is complete, forecasts can be run and various parameters can be displayed and assessed, such as reservoir pressures and drainage areas. As wells continue to produce and additional surveillance data is obtained, the models can be updated to provide more accurate forecasts.

The production forecasts resulting from this comprehensive workflow can be used to optimize development strategies, drilling and completion practices, and reserves estimates. For example, numerical models can help define the relationship between a well's net present value and variables such as the distance between horizontal wells, the length of the wells, and spacing of hydraulic frac stages along the wellbore.

Conclusions

This workflow incorporating analytical and numerical solutions has been applied to multiple shale gas projects, including industry consortia in the Haynesville (US) and Montney (Canada) shales. Through the application of these techniques, fracture and reservoir properties have been characterized and the uncertainty associated with forecasted well performance has been reduced. This work has profound implications for quantifying shale gas reserves, understanding those factors responsible for variations in well performance, and for optimizing well spacing, lateral lengths, and completion techniques. Development of these techniques continues, and they will need to be further modified as our understanding of these reservoirs increases and more well and reservoir data become available to constrain the modeling.