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# Shale Resource Modeling Using Numerical Simulation

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## Abstract

Shale gas reservoirs are one of the unconventional resources that have a huge amount of hydrocarbon reserves having ultra-low permeability on a nano-darcy range. They comprise of typically two distinct porous media: the shale matrix containing majority of gas storage in the formation but with a very low permeability, and the fracture network with a higher permeability but low storage capacity. Moreover, significant amount of gas is also present in the adsorbed state in these reservoirs. The impact of adsorbed gas is seen in the late life of the well when the pressures are low. Due to these characteristics, the reservoir dynamics becomes very complex and requires extensive approach to be modeled correctly.

Most of the analytical and conventional single or dual porosity models usually fail to capture the very long transient behavior in the matrix blocks and as well as desorption of adsorbed gas. Advances in numerical simulation have made it possible to model the complexity in shale using multi porosity models.

This paper presents the comparison of simulation modeling results from single porosity, dual porosity and multi porosity models for modeling and history matching of a shale gas reservoir. The paper concludes that multi porosity model is the most representative for modeling shale gas reservoirs. Further for better understanding of how multi porosity model works for shale reservoirs, a sensitivity analysis of most important parameters of this model was carried out. Later on the history matched multi porosity model was connected to the surface facilities by incorporating vertical lift performance curves to show the effect of compression on production profile of the shale reservoir.

For simulation model development and history matching, monthly production data of 3 years for one of the US shale well and few reservoir properties were available. At first single porosity simulation model was developed. It is a general understanding that shale wells can only produce from the area of the reservoir exposed to the well and hydraulic fractures and recovery factors for them are usually 10-15%. Therefore, a sector model was created in which model dimensions along x axis was chosen as 2000ft representing horizontal section length of the reservoir and along y axis as 450 representing total fracture length. The thickness of the reservoir was taken as 104ft. The reservoir properties such as depth, gas content, pressure, initial water saturation, matrix porosity and matrix permeability were assigned as per the general available data for the shale resource. When the model was initialized based on these properties, the calculated gas in place volumes were 7.44BSCF. Most shale wells possess a recovery factor from 10-15%. So, this in place value looked to be representative as it was corresponding to a recovery factor of 10-15% based on available production data.

The fluid properties were assigned based on the EOS for 4 pure components containing $C_1$, $C_2$, $N_2$ and $CO_2$ so as to form a dry gas fluid. A horizontal well with 5 stage hydraulic fracturing was modeled. The hydraulic fractures were modeled by improving the matrix permeabilities in cells representing the hydraulic fractures.

When the model was simulated, the simulated gas rates were almost negligible and were far below the observed rates. The matrix permeability was increased in hydraulic fractured cells but still simulated gas rates were very small. The reason was that no gas could be transported to hydraulic fractures due to ultra-low permeability of matrix cells.

Shale reservoirs usually contain natural fractures which provide the major contribution to gas production as the matrix permeability is very low. So, to incorporate natural fractures along with matrix, dual porosity model is used in which each cell is divided into a natural fracture cell and a matrix cell. Dual porosity model is unable to simulate desorption of adsorbed gas in shale. In dual porosity model, properties of both matrix and fractures are defined independently. The model dimensions and static properties for matrices were kept the same in this model as they were in single porosity model. The fracture porosity is generally very low as compared to matrix porosity therefore a value of 0.25% was assumed for this model. When the model was initialized, the results were almost the same as were in single porosity model.

The fluid properties and well completions were kept the same in this model as compared to single porosity model. The hydraulic fractures were modeled by not just improving the matrix permeabilities but also the natural fracture permeabilities in cells representing the hydraulic fractures. An initial value of matrix to fracture transmissibility factor was also defined which was fine-tuned during history matching.

When the model was simulated, the simulated gas rates were far below the observed rates. For history matching, extensive sensitivity of various values of matrix and natural fracture permeability in hydraulically fractured areas and matrix to fracture transmissibility factor was carried out. It was observed during history matching that dual porosity model was not capable of representing the shale reservoir mainly because of two reasons. The first reason was the incapability of this model to simulate desorption of adsorbed gas. The second reason was that this model could not simulate the long transient behavior when hydrocarbons flow with in a matrix block prior going to the fracture cell.

The short comings of dual porosity model are addressed by the multi porosity model. In this model, the discretized matrix cell of dual porosity model is further divided into sub matrix cells. In these sub matrix cells, some cells can be treated as normal matrix cell (cell with free gas in the pore space only) and rest can be treated as coal cells (cell with adsorbed gas only).

Using this model, a total of 9 matrix sub cells were created for each matrix cell. In these 9 matrix sub cells, every alternate cell was defined as the coal cell and rest were defined as the normal matrix cells. In this way a single matrix cell now contained both the adsorbed and the free gas which is typically found in shale reservoirs. The properties of matrix and fracture cells were kept the same here as were in dual porosity model. However for coal cells, Langmuir isotherm was defined to estimate the adsorbed gas volume at any pressure in these cells. When the model was initialized, the results were almost the same as were in previous two models.

Dynamically, this model was a replication of dual porosity model in terms of fluid properties, completion strategies and modeling of hydraulic fractures. In addition, a value of coal diffusion rate was defined in this model to account for the diffusive flow of adsorbed gas.

When the model was simulated, the simulated rates were low as compared to observed rates. So, the first step in matching the rates was to match the initial rates. For this, natural fracture and matrix permeabilities were increased in hydraulically fractured cells. Once the match of initial 2-3 months was obtained, then the second step was to match the middle and late time period of the production data. For this, values of matrix to fracture transmissibility factor and coal diffusion rate were changed. This resulted in an excellent history match of the observed production data.

In order to further develop the understanding of multi porosity model for modeling shale reservoirs, the sensitivity results of various model parameters are explained here to show their effect on simulated production profiles of shale reservoirs. These parameters include natural fractures permeability, matrix to fracture transmissibility factor and coal diffusion rate.

The sensitivity of different values of natural fracture permeability showed that improving this parameter improves the initial production rate with little effect on late time production.

The sensitivity of different values of coal diffusion rate showed that increasing its value does not change the production rates at initial period but they significantly improve the rates at the late time period.

The sensitivity of different values of matrix to fracture transmissibility factor showed that as the value of this parameter is increased there is small increase in the initial rates but large increase in the late and middle time rates.

In order to incorporate the well bore hydraulics and pressure losses in surface pipe lines VLP curves were generated using PROSPER. These curves were incorporated in the simulation model to operate the well at tubing head pressure (THP) control. With this model, a sensitivity of two THP values was carried out. This showed that by decreasing the THP (or installing compressor), recoveries are improved.

Numerical simulation models were developed for a shale reservoir using single, dual and multi porosity models. The history match results of the three models showed that multi porosity model is the most representative for modeling shale reservoirs. Furthermore, sensitivity of various multi porosity model parameters was carried out to develop better understanding of multi porosity models. VLP curves were also incorporated in the history matched model to account for the well bore and surface pipe lines hydraulics. This model was then used to show the effect of compression on production profile of the shale reservoir.