Property Study and Reservoir Modeling of Marcellus Shale, PA

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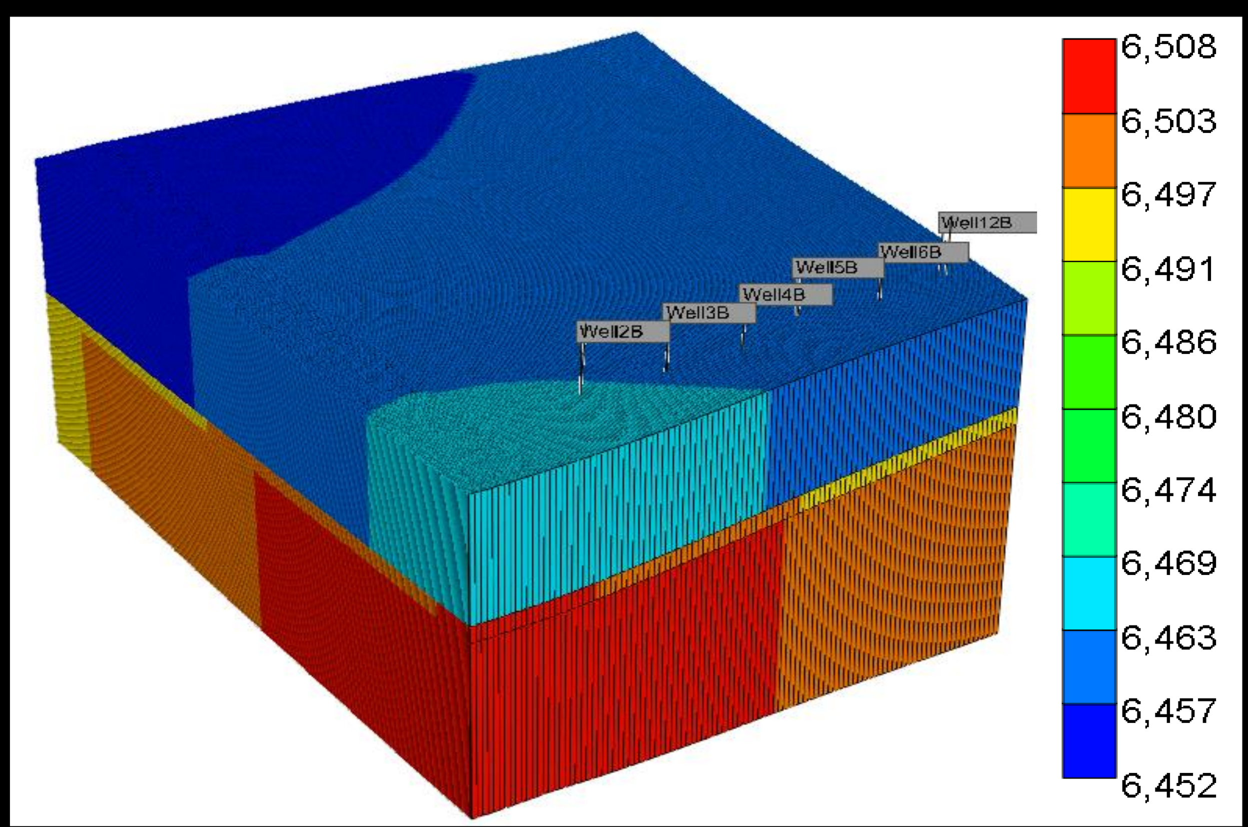
Introduction

Shale Revolution brings a huge change in terms of energy supply and consumption in the United States. Marcellus Shale plays an important role in this energy game, which is deposited throughout the Appalachian Basin running through portions of New York, Pennsylvania, West Virginia, Ohio, and Maryland with huge amounts of natural gas reserve.

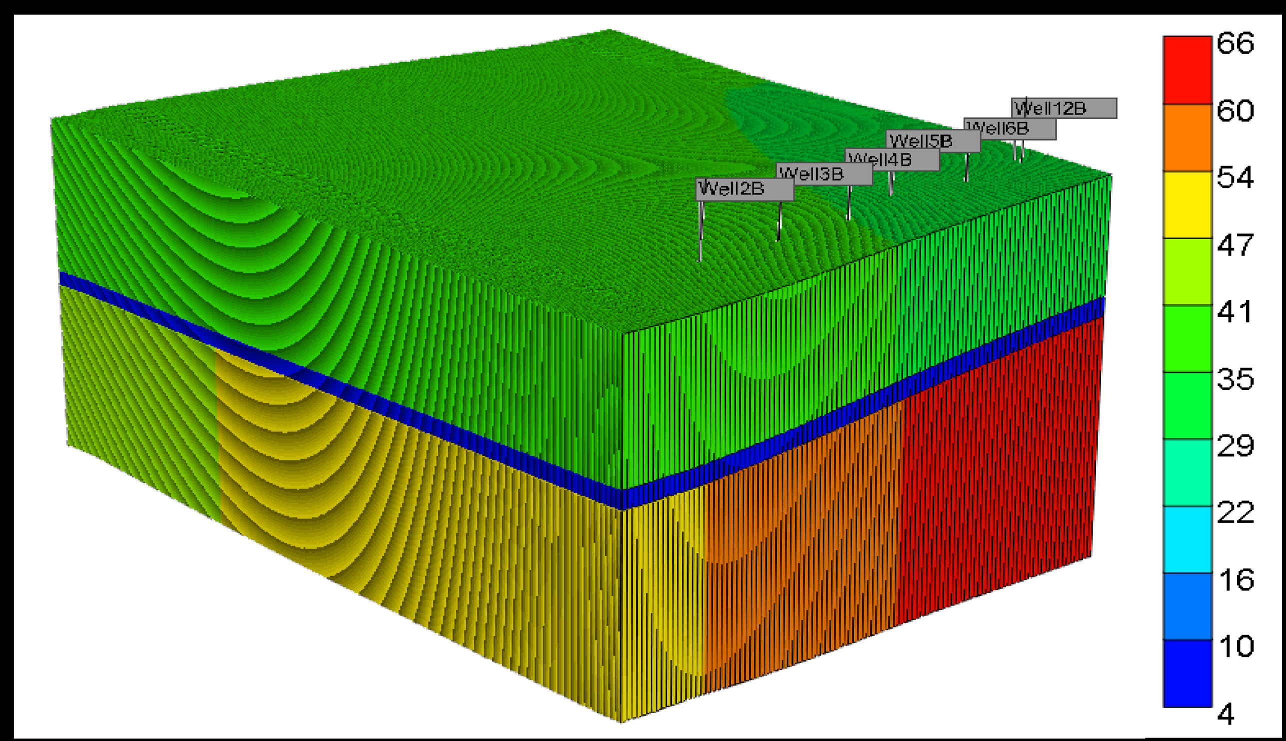
Reservoir properties includes porosity, permeability, thickness, etc. are essential for Petroleum Engineers to understand the formation below the surface. One commonly adopted method to predict reservoir performance is reservoir modeling and simulation in the oil and gas industry. It typically involves the construction of a computational model of a petroleum reservoir, which requires all reservoir properties, geological information, and well information in order to have a valid model.

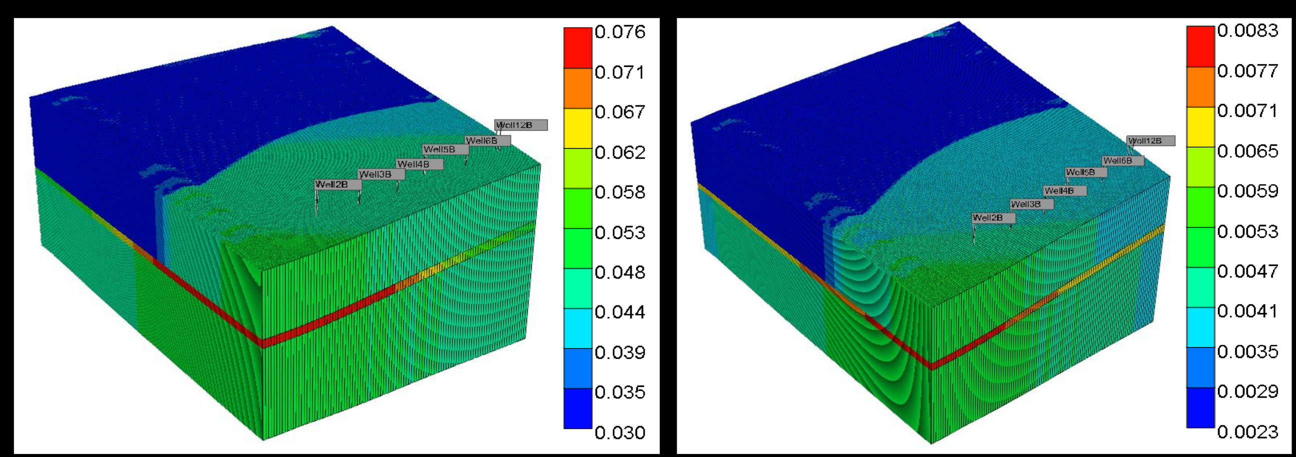


This reservoir model can be directed to estimating reserves and making decisions regarding the development of the field, predicting future production, placing additional wells, and evaluating alternative reservoir management scenarios. In this research project, shale reservoir properties were studied along with the reservoir modeling process that has been practiced for future production analysis.

Reservoir Modeling

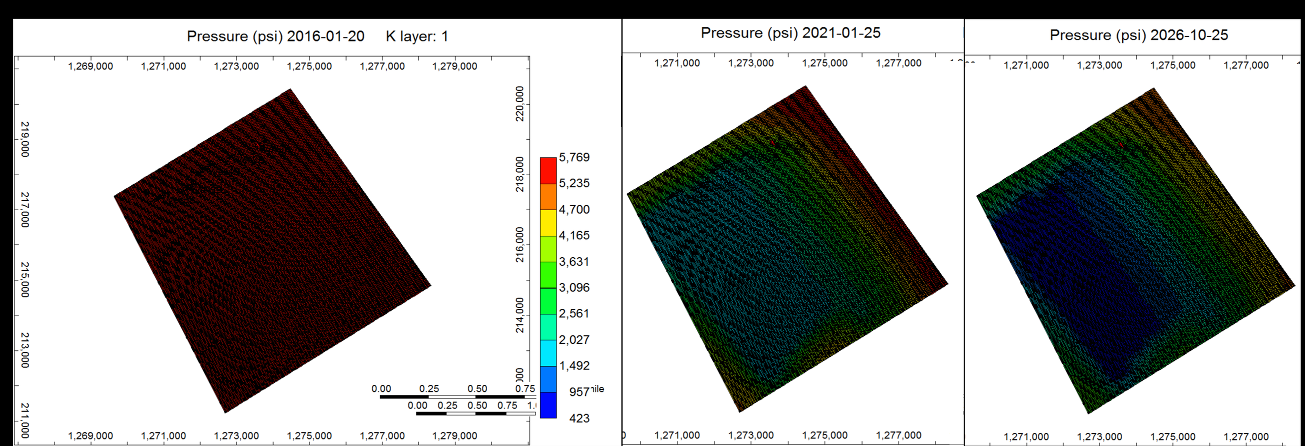
Reservoir modeling has been rapidly advancing with technology. The reservoir modeling software used was IMEX which is a black oil simulator developed by the Computer Modeling Group (CMG). The model requires information on the reservoir such as grid top, grid thickness, porosity, and permeability. This data is commonly obtained from the use of gamma logs and testing core samples. Each set of data can then be mapped in 3-D.



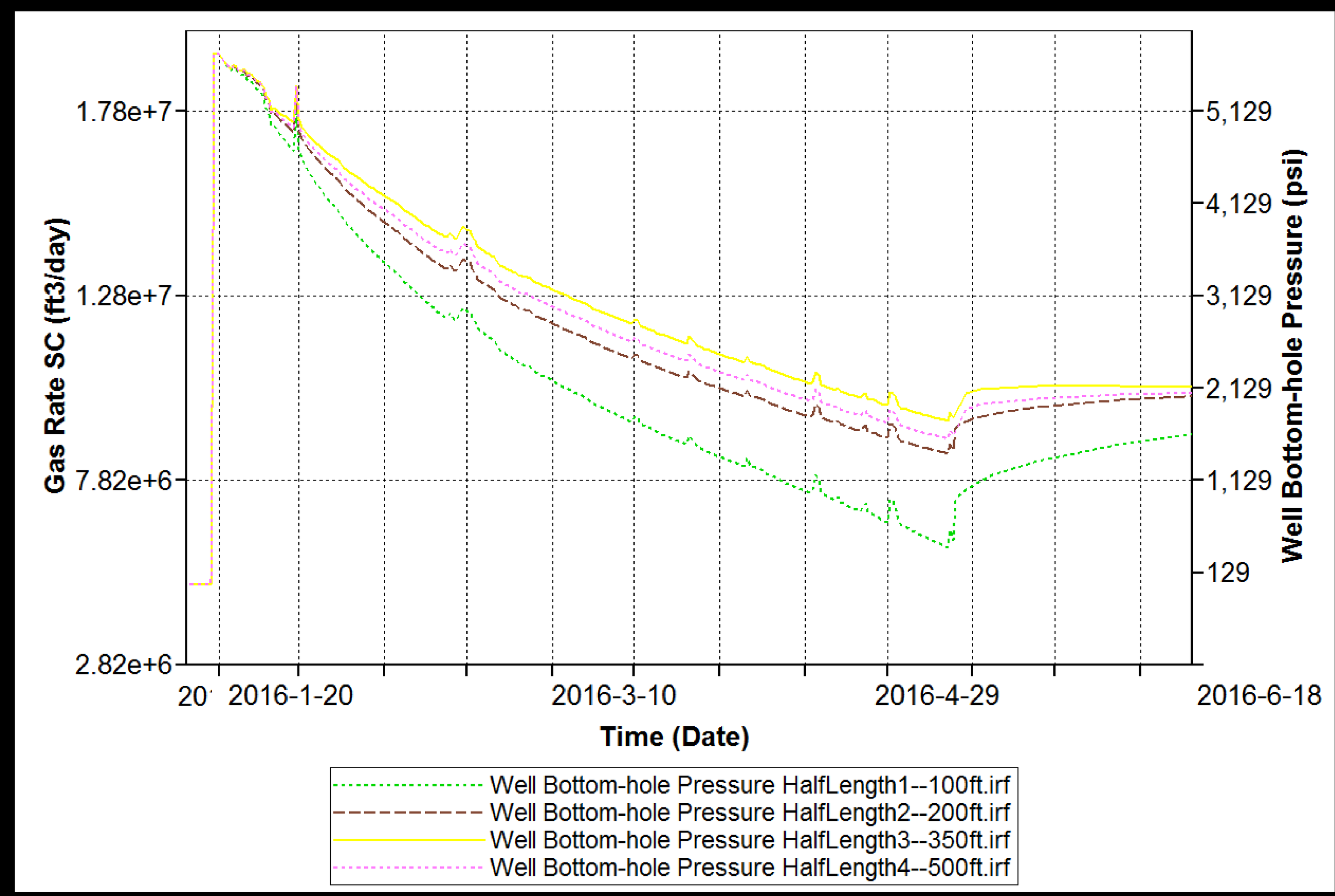


Sensitivity Analysis

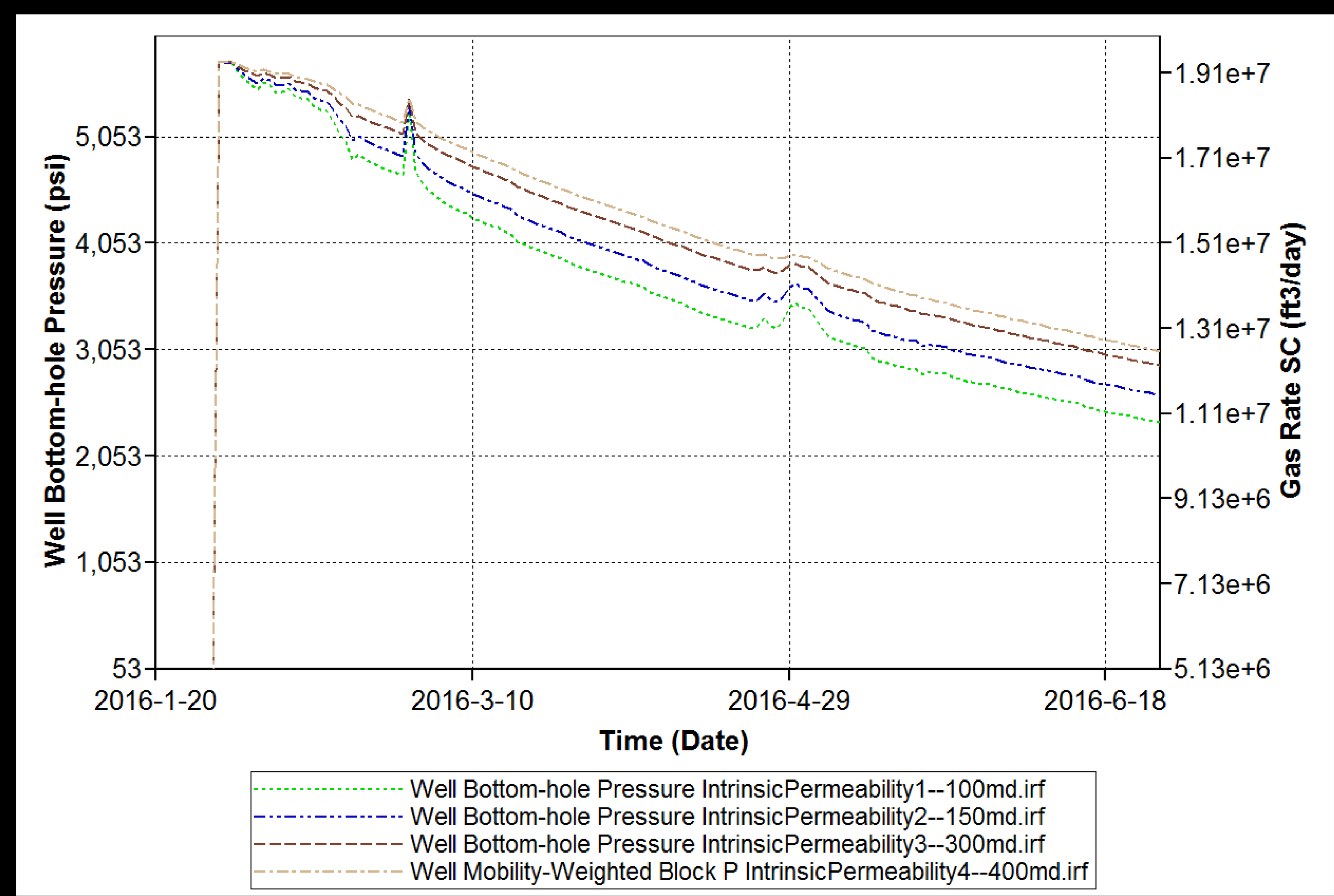
Reservoir simulations are most commonly utilized to predict and evaluate well performance. This simulation was run for approximately 10 years. In particular areas of the formation, the pressure decreases with production. When free gas from the fracture system is produced, the pressure will drop in fracture and micro-pores.



The half length represents the length of the hydraulic fractures on one side. This parameter was varied. The production was the greatest when the half length was 350 feet. When the half length was decreased to 200 feet the production decreased. When the half length was increased to 500 feet, the production also decreased. With the use of this simulation, production was optimized by manipulating the half length values.



Intrinsic permeability represents the ability for fluid to flow through a rock. The permeability values were varied to maximize the production. As permeability decreases, production decreases as well. The maximum production occurred when the permeability was 400 md. Therefore, high permeability is desired.



Future Work

1. Once the reservoir modeling is completed, history matching can be performed, which is to match the simulated bottom hole pressure data with the actual bottom hole pressure data.

2. Once history matching result is achieved, gas production can be predict using this validated reservoir model.

Acknowledgements

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