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Horizontal Well Spacing and Hydraulic Fracturing Design Optimization: A Case Study on Utica-Point Pleasant Shale Play

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Abstract

Recent drilling and hydraulic fracturing activities in the Utica-Point Pleasant shale play have recorded true vertical depth of over 13,500 feet. Drilling wells at this depth is very costly and challenging. With the current commodity pricing, drilling in such conditions becomes unaffordable.

One immediate solution to the current low energy prices is optimizing well spacing to enhance hydrocarbon recovery and, thus, the commercial feasibility of the project. Horizontal well spacing constitutes a fundamental parameter for the success of a shale-drilling venture. Determining the optimum horizontal well spacing in shale reservoirs represents a challenging task because of the complexity of controlling factors. These factors can be categorized into three groups: geological, engineering, and economic.

Geological modeling and reservoir simulation are the standard tools utilized in the industry to integrate these controlling factors. In this study, we employed these tools to perform sensitivity analysis of reservoir characteristics and future production optimization for a deep drilling case study in the Utica-Point Pleasant formations. We sought to find the optimum horizontal well spacing scenario as well as hydraulic fracturing design, in order to attain the highest net present value for 50 years of gas production. Our reservoir model represented a portion of Utica-Point Pleasant formations at the depth of 13,000 feet and the dry gas window. A commercial reservoir simulator was coupled with an optimization algorithm to reach the best solution with a minimum simulation cost. Although the outcome of our study is subjective to the chosen asset, the workflow provides a good example of horizontal well spacing and hydraulic fracturing design optimization.

Introduction

Inter-lateral spacing (well spacing) is one of the biggest decisions in a field development in unconventional shale plays. Not having an optimized well spacing can either cost the operators a lot of money or leaves a lot of money on the table. The well spacing must be close enough to help create as much of the stimulated reservoir volume (SRV) as possible; however, it must be wide enough to minimize fracture interference (Awada, Santo, Lougheed, Xu, & Virues, 2016)(well to well interference and “frac hits”) and over-capitalization in a field development (Barree, Cox, Miskimins, Gilbert, & Conway, 2014). Various tools such as rate transient analysis (RTA) and numerical simulations can be used to optimize well spacing (Lalehrokh & Bouma, 2014; Ziarani, Chen, Cui, Quirk, & Roney, 2014). At the very beginning of a field development, little data is available; therefore, it is very important to run sensitivity analysis and uncertainty investigation to assess the effect of uncertainties involved in reservoir characteristics of the field performance. Once pressure and production history data are available, the model can be calibrated to insure all of the assumptions are practically feasible.

Well spacing is impacted by a combination of three types of factors defining the geological characteristics, the engineering process, and the economic constraints. The geological and reservoir characteristics assure the quality of the reservoir and the hydrocarbon presence. The engineering design provides the deliverability of the well. Finally, the economic factors warrant that the engineering project leads to profit (Frick, 1958).

The most important parameters that must be heavily studied are matrix permeability, fracture half-length (impacted by completions design), reservoir properties, capital expenditure, operating costs, and hydrocarbon pricing. In a high commodity pricing environment, it would make more sense to place the wells closer apart; however, low commodity pricing will dictate farther well spacing. A rock that has high matrix permeability would be better suited for a larger well spacing, but a rock that has lower matrix permeability is better optimized in a tighter well spacing. When designing well spacing, it is crucial to take completions design into account. For example, if 1,000 feet well spacing is designed for a field development, it is very important to design the completions job in a fashion that would yield 500 feet fracture half-length by pumping enough sand and water along with optimizing stage spacing, cluster spacing, and perforations design. Therefore, a big portion of achieving the desired well spacing is creating completion jobs that would guarantee the attainment of such goals.

Deep dry Utica located in both Pennsylvania and Ohio has sparked the interest of a lot of the operating companies in the past two years due to its attracting geology, massive production volumes, and the advantageous time value of money created in the production of as much volume as possible in the first 3 to 5 years of the life of the well. The biggest challenges in developing deep dry Utica have been high capital expenditure, lack of production history and reservoir rock characteristics, and optimal management of pressure drawdown to avoid proppant crushing/embedment and geo-mechanical effects. All of these challenges will be resolved and understood with time as this has been the case for all of the other shale plays developed to date.

In order to create long-term value for the shareholders, the well spacing must be selected based on a spacing paradigm that yields the highest NPV. Production volumes could be important to the strategic development of a company, but the single economic parameter that creates long-term value for the shareholder of a company is NPV (Frick, 1958). In this study, the well spacing was optimized using NPV. Optimal economical well spacing is achieved by having a good understanding of fracture half-length, conductivity, and matrix permeability, which are typically very hard to obtain in unconventional shale plays and reservoir modeling. Therefore, various sensitivities must be run to understand the impact of these variables.

In this study we utilized a numerical reservoir simulation in order to model a dry gas reservoir 13,000 feet deep into a formation that resembles the Utica-Point Pleasant play. Initially by drilling one well, we studied the recovery after 50 years of production over a constant drainage area. Next, we looked for increasing the recovery factor by adding multiple wells. Finally, we wanted to find the optimum number of wells that leads to the highest NPV over 50 years of production.

Methodology

The base reservoir simulation model

Our reservoir model covers 1,003 acres area. For the sake of comparison, we kept the drainage area constant for the different well spacing scenarios. The drainage area is divided into 35,000 grid blocks, and the grid block size is 50 feet by 50 feet. The top of reservoir is 13,000 feet deep, and the pay zone thickness is 200 feet allotting into two layers of 100 feet thickness. These layers resemble the structure of Utica-Point Pleasant play. The reservoir contains dry gas, methane.

We used a commercial reservoir simulation package—CMG-BUILDER and IMEX (Computer Modeling Group, 2015)—to build and run the reservoir model. Table 1 lists the reservoir reference data for this study. The reference data was selected after consulting with multiple operators in the region. Figure 1 depicts a 3D view of the reservoir. In addition, Figure 2 shows the relative permeability curves utilized in this study. These curves are modified from the correlations available in the CMG-BUILDER. The base reservoir model has eight percent porosity and one micro-Darcy permeability.

Table 1: Reservoir characteristics of the base reservoir model.

Base Model Reservoir Characteristics			
Rock Compressibility	**5.8e-6 1/psi**	**@**	**3000 psi**
Reservoir Temperature	**175**	**F**	
Gas Density at Standard Condition	**0.58**	**Air=1**	
Reference Pressure and Depth			
Pressure	**12,350**	**psi**	
Depth	**13,000**	**ft**	
Gradient Pressure	**0.95**	**psi/ft**	
Water-Gas Contact (DWGC)	**14,000**	**ft**	

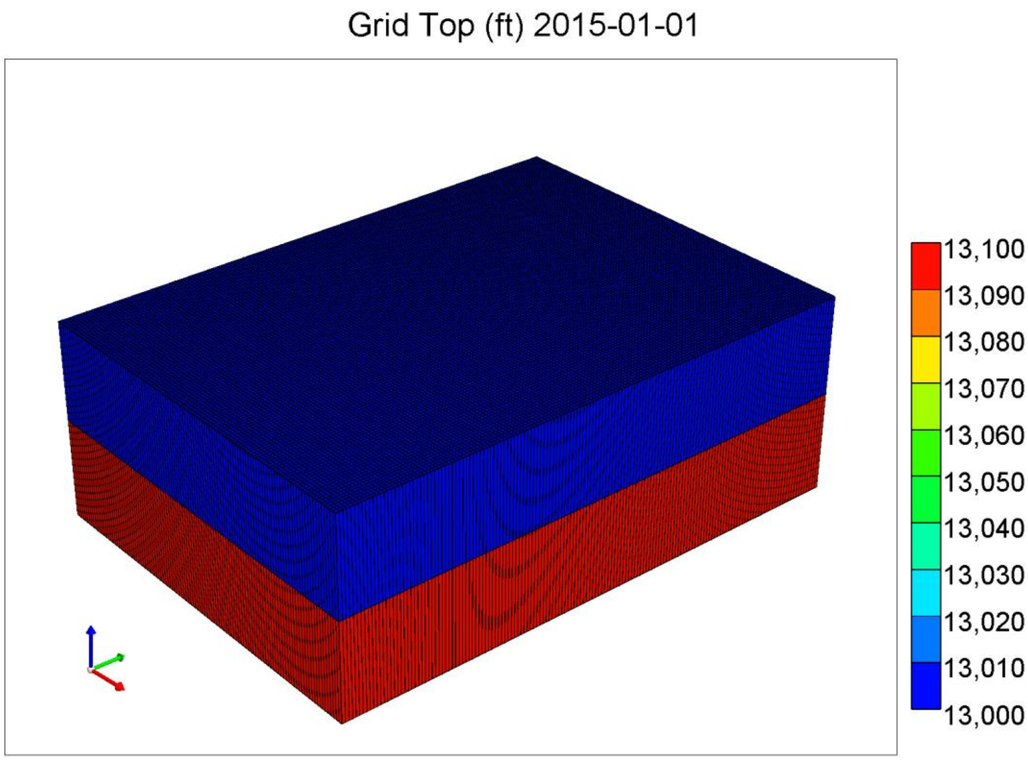

Figure 1: Reservoir top 3D model built in CMG-BUILDER. The drainage area covers 1,003 acres and the reservoir includes 200 feet pay zone divided into two layers.

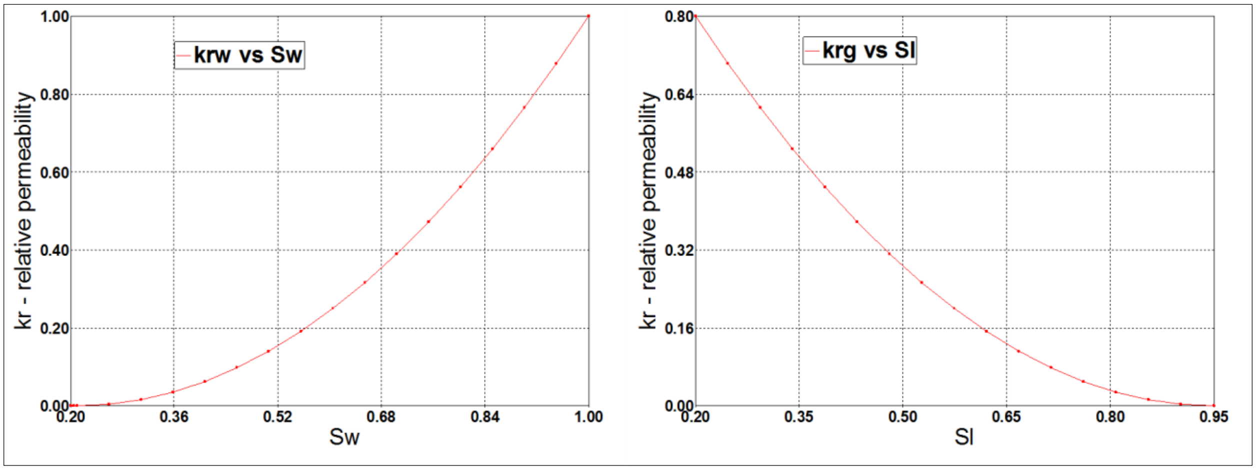

Figure 2: Relative permeability curves for this study. These curves are modified from the correlations available in the CMG-BUILDER.

The wells are drilled and perforated in the bottom layer of the Point Pleasant formation. The length of the horizontal lateral is 7,000 feet. In order to simulate the hydraulic fractures, we refined the grid blocks in a planar direction perpendicular to the wellbore. Figure 3 demonstrates an example of planar hydraulic fracturing design.

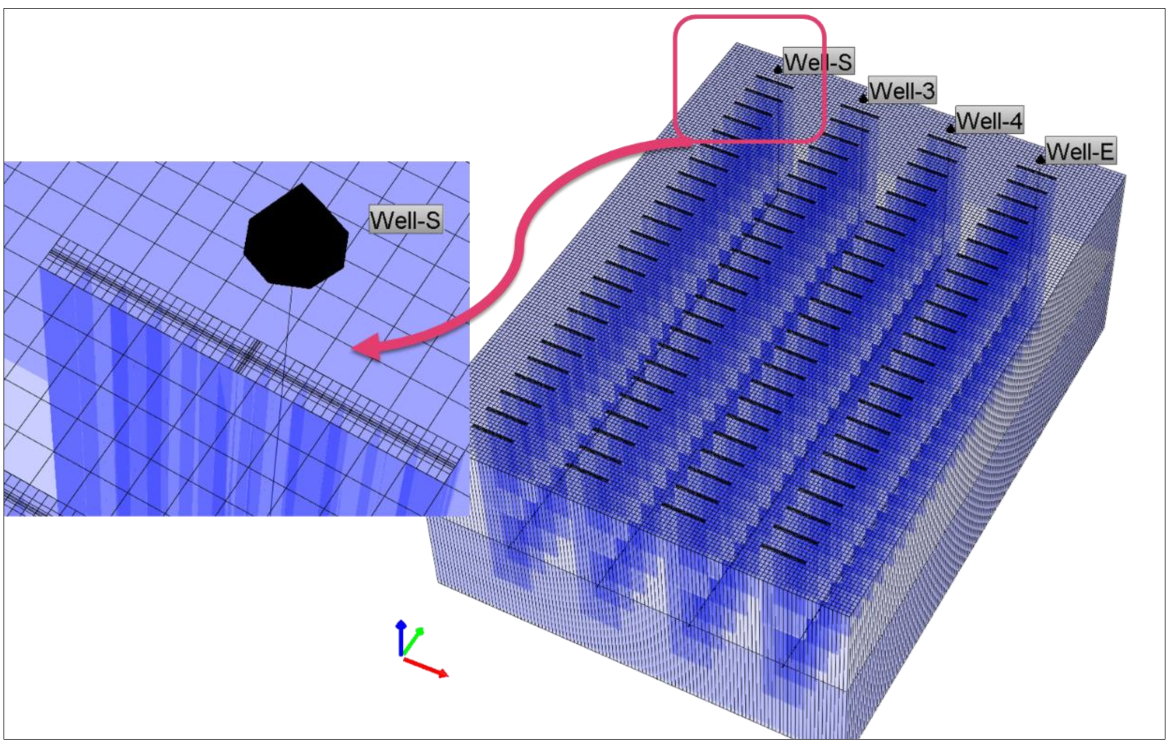

Figure 3: Horizontal wells and planar hydraulic fracturing design.

The production is performed under the constant bottom-hole pressure of 2,000 psi for a period of 50 years, starting in 2015. The volumetric estimation of initial gas in place is 316.69 BCF. Table 2 summarizes the economic inputs required for the economic analysis study.

Table 2: Economic analysis inputs.

Economic Analysis Inputs		
Drilling Cost	**$ 5,000,000**	**per 7,000 lateral**
Hydraulic Fracturing	**$ 300,000**	**per stage**
Royalty	**20%**	**of Production**
Operating Cost	**$ 1.00**	**per MCF**
Natural Gas Price	**$ 2.50**	**per MCF**
Yearly Discount Rate	**10%**	

Optimization scenarios

In order to address the main objective of this study, well spacing optimization, we created five drilling scenarios in a constant drainage area (1,003 acres). Table 3 summarizes the number of wells and the corresponding well spacing selections. In addition to the well spacing, we wanted to find the optimum number of completion stages, and hydraulic fracture characteristics such as permeability, width, and half length. Table 4 shows the selected ranges for these parameters.

Table 3: Five scenarios of inter-lateral spacing and the corresponding well spacing over a constant drainage area (1,003 acres) in this study.

Scenario	Well Spacing (ft)	#Wells
1	500	8
2	750	6
3	1,000	5
4	1,250	4
5	1,500	3

Table 4: Range of completion parameters.

Parameters		
Hydraulic Fracture Spacing	**150-450**	**ft**
# Stages	**46-15**	
Fracture Permeability	**1-10**	**Darcy**
Fracture Width	**0.0001-0.005**	**ft**
Fracture Half Length	**150-400**	**ft**

Figure 4 demonstrates the workflow that we followed in this study. This workflow comprises five general steps. The first two steps include building the base model and defining the ranges for the key parameters. Next, we create our objective function considering the field net present value (NPV) as the global goal to maximize. The process continues with coupling the reservoir model with an optimization algorithm. The optimization algorithm selects the values of the adjustable parameters from the range that the user has provided earlier. Then the optimization algorithm calls the simulator, and, in turn, the simulator runs the models and calculates the NPV values based on the economic analysis parameters. The output of this workflow is a collection of reservoir models, which allows us to select the optimum parameters based on the highest field NPV value. In this study, the whole process of optimization was carried out using CMG-CMOST (Computer Modeling Group, 2015).

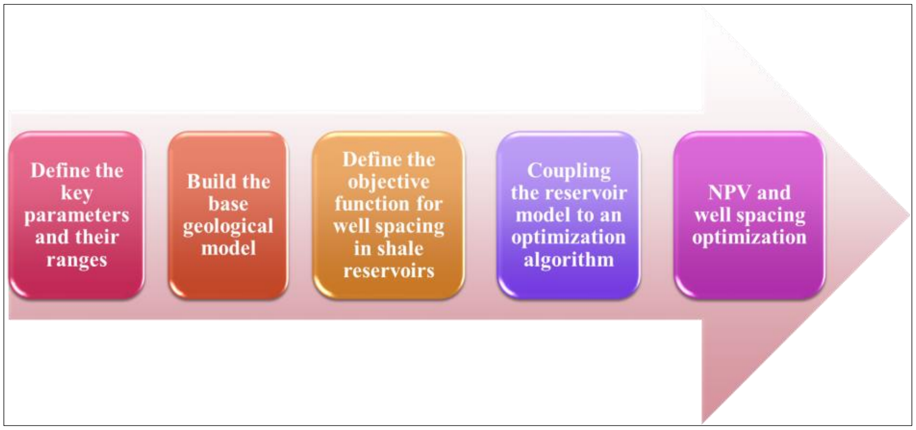

Figure 4: The workflow for the well spacing and completion parameters optimization study.

Results and Discussion

Base Reservoir Model – A Single Well Case

Figure 5 shows a scenario of the reservoir model with the base reservoir characteristics (Table 1) and just one well drilled. The figure shows the profile of gas rate (blue curve) and cumulative gas production (orange curve) for 1, 5, 10, 20, 30, and 50 years after production starts. On the right side of each graph, the corresponding pressure distribution is also pictured. As it is clear from Figure 5, after 50 years of production, a significant portion of the reservoir is still untouched and does not contribute to gas production. This is a good example of how reservoir management methods may leave hydrocarbon behind. In addition, the total recovery factor in the scenario depicted is around 25%. Therefore, the need for drilling more wells is expected.

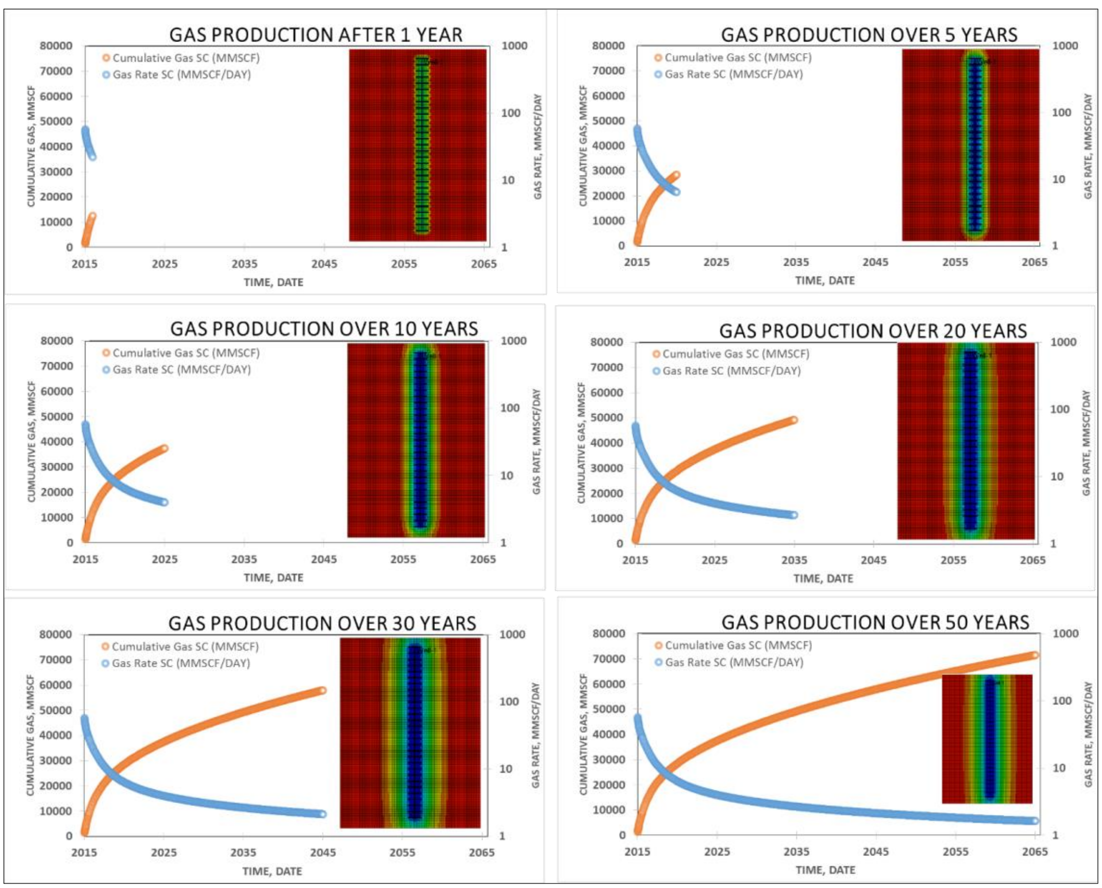

Figure 5: The cumulative gas production, gas flow rate, and pressure distribution for different time steps (1, 5, 10, 20, 30, and 50 years).

Multi-lateral depletion – Finding the Optimum Number of Wells

Varying the well spacing, we designed five drilling scenarios on a fixed drainage area (Table 3). The optimization results suggest that the highest production belongs to 1,000 feet spacing between the laterals (Figure 6), which corresponds to the 5 wells. The second most prolific drilling scenario could be a 4 wells scenario with 1,250 feet spacing. In general, we judge the profitability of a project based on the NPV. Therefore, Figure 7 compares the optimum NPV for the drilling scenarios. While the 5 well scenario yields the highest NPV for this field, the 4 well scenario produces our second best NPV. The 4 well scenario could be an acceptable decision, particularly if there is limited capital budget for drilling and completion.

In oil and gas development plans, short-term production could be vital in returning the initial investment. Figure 8 compares the recovery factor (RF) after 5, 30, and 50 years for all of the drilling scenarios. As it is shown in this graph, the 5 well scenario at 1,000 feet spacing has the highest recovery factor during all three time periods. In addition, considering just the 5 year recovery factor, a 6 well project built at 750 feet spacing could lead to a higher recovery factor than a 4 well scenario built at 1,250 feet spacing. However, we should also consider the limitations on capital budget. An important observation resulting from these scenarios is that almost all of them, except the 3 well (1,500 feet) scenario, yield more than a 50% recovery factor (almost two thirds of the ultimate production) after just 5 years of production. This is mainly because production of wells is limited to the stimulated reservoir volume.

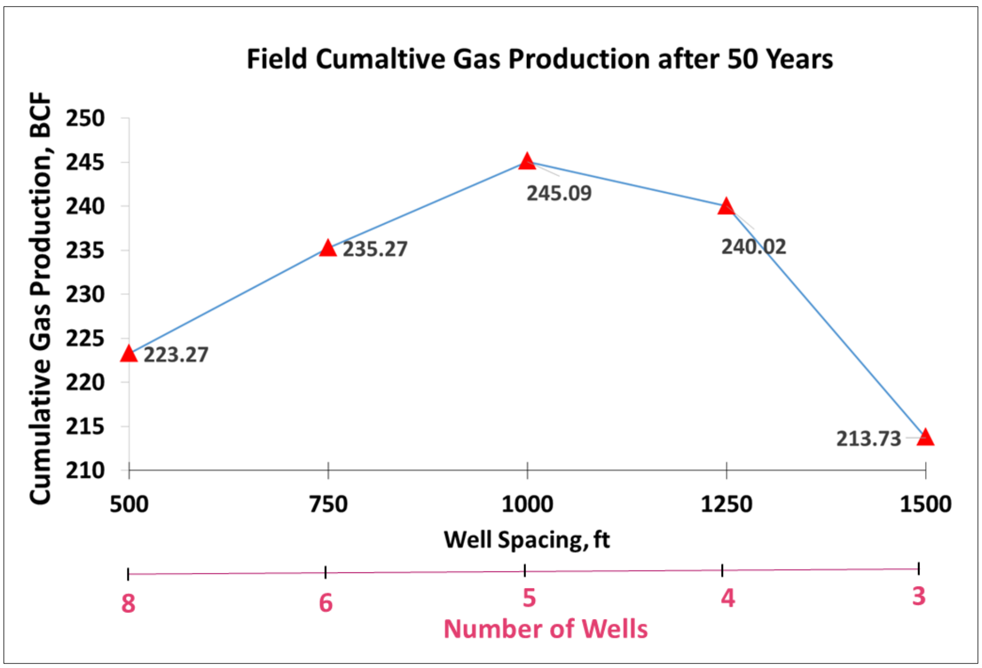

Figure 6: Field cumulative gas production after 50 years for five drilling scenarios.

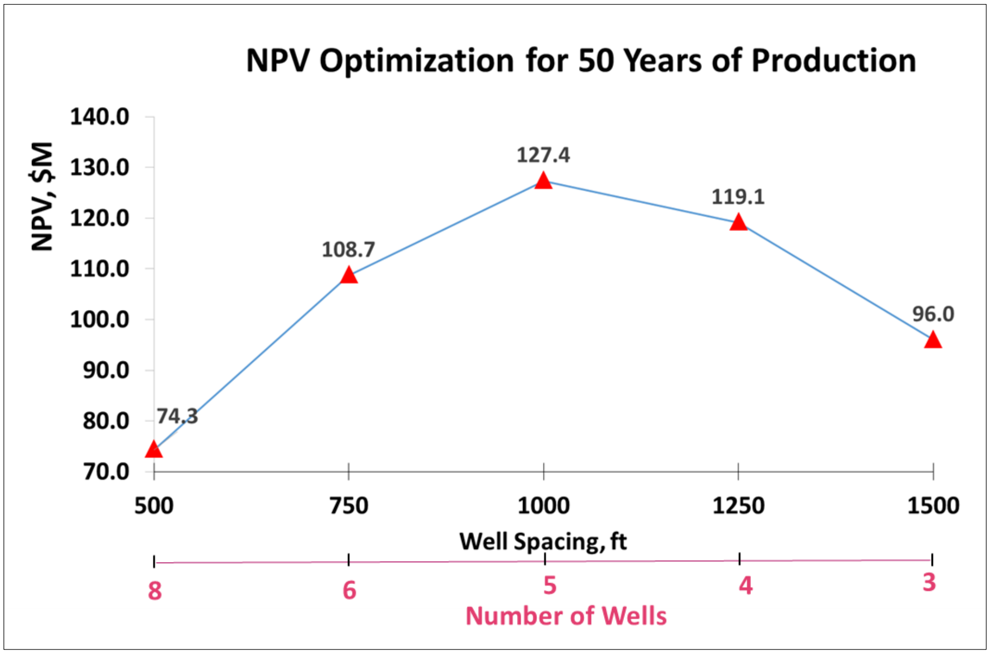

Figure 7: The results of Net Present Value optimization study for five drilling scenarios.

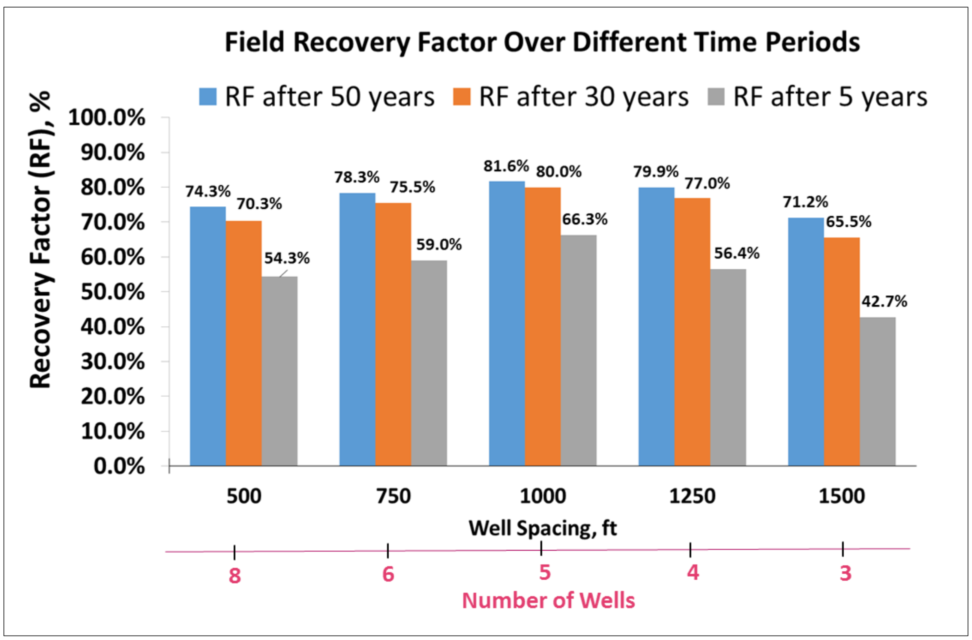

Figure 8: Field recovery factor (RF) over different time periods for all the drilling scenarios.

Figure 9 compares the capital and operating costs of these projects with the NPV values. As it is expected, a higher number of wells will lead to a higher capital cost. However, completion projects typically require a significant share of capital cost. In addition, a higher production will increase the operational cost.

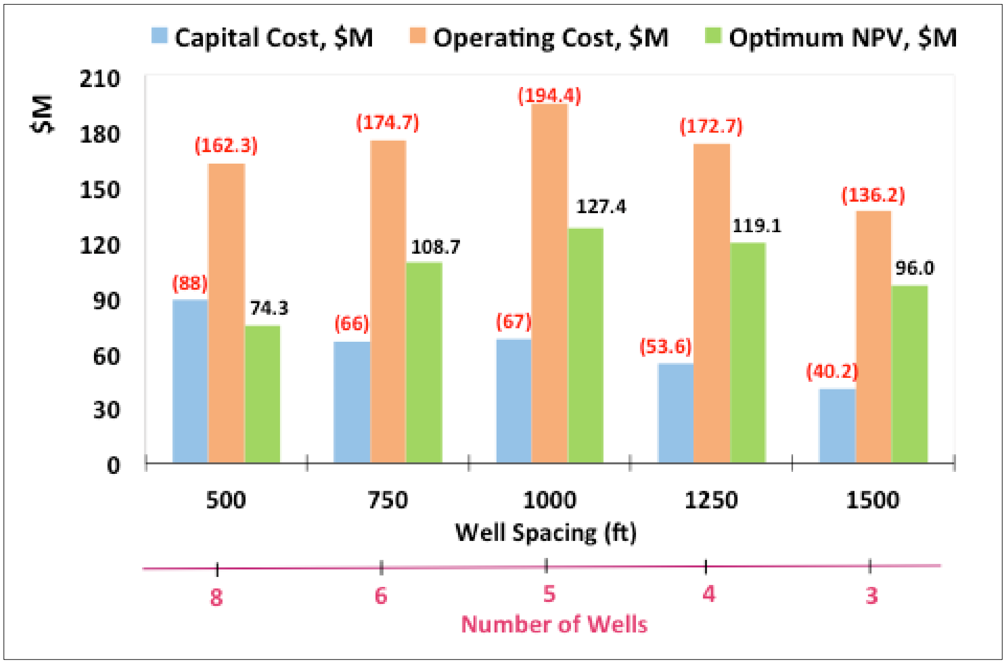

Figure 9: Comparison of capital and operating costs with NPVs for different drilling scenarios.

Completion parameters

Table 5 summarizes the outputs of the optimization process for the completion parameters. Based on these results, a higher fracture conductivity constitutes the best solution. However, the fracture half-length is regulated by the well spacing, as expected. For instance, for the well spacing values of 500 and 750 feet, fracture half-lengths are 250 and 350 feet, respectively. Obviously, higher values of fracture half-length will cause interference between the fractures ("frac hit") and loss of injected fluids. The number of fracture stages depends on the space between the stages (fracture spacing). In addition, the cost of completion has a direct relationship with the number of stages. Therefore, an economic optimization analysis is required. We could suggest a higher number of stages for a lower number of wells per a constant drainage area and vice versa.

Table 5: Optimized completion parameters.

Scenario	Well Spacing (ft)	# Wells	Fracture Spacing (ft)	# Stages	Fracture Conductivity (md-ft)	Fracture Half Length (ft)
1	500	8	350	20	50	250
2	750	6	350	20	47.69	350
3	1000	5	250	28	48.65	400
4	1250	4	250	28	50	400
5	1500	3	250	28	50	400

Second economic scenario, reducing the cost of completion:

The optimization process is driven by the commodity costs. We created another scenario by reducing the cost of completion from $300,000 to $200,000 per stage. Figure 10 compares the NPV values for the two scenarios of completion costs for all drilling cases. As it is clear from this image, over the 50 years of production, we observe almost a constant shift (11-12 % of NPV) between these scenarios.

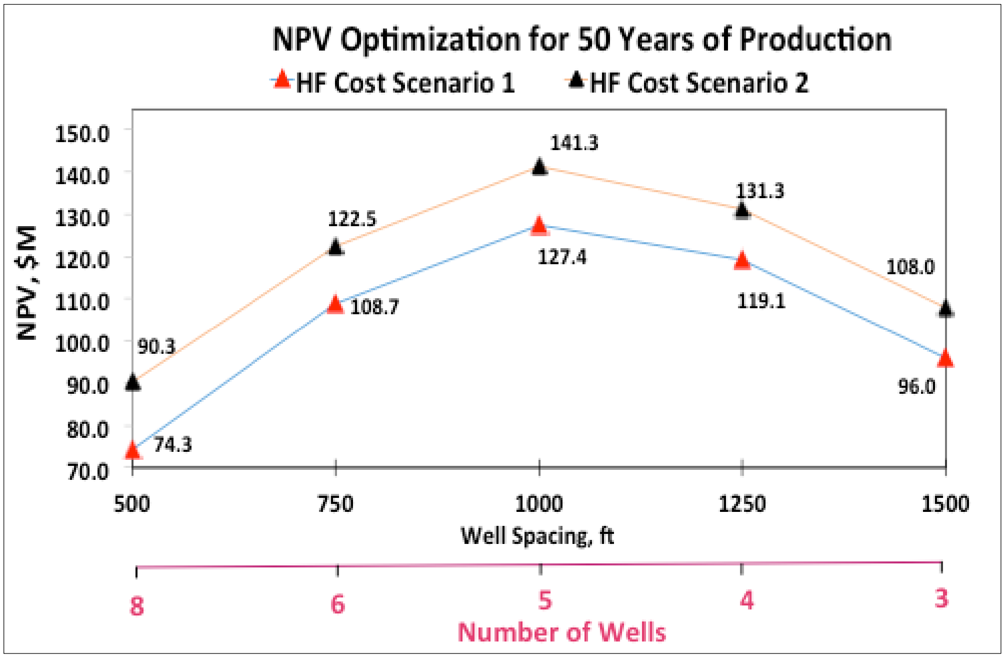

Figure 10: Comparison of NPV between two costs of completion scenarios.

An interesting reflection results from comparing the recovery factor values after 5 years of production for the two cost scenarios depicted in Figure 11. For well spacing cases of 750 and 1,000 feet, the reduction of completion costs leads to a recovery factor increase of 4.6% and 2.4%, respectively. These changes could be pivotal in decision-making, since in 5 years of gas production shale reservoirs could bear more than 70% of ultimate production. The main reason behind the increase of recovery factor values goes back to having a higher number of completion stages due to the reduction of cost (Table 6). However, for the well spacing of 500 feet, the even increase of stages from 28 to 35 will not impact the production level after five years. This might be because of the tight well spacing that already covers all of the reservoir volume.

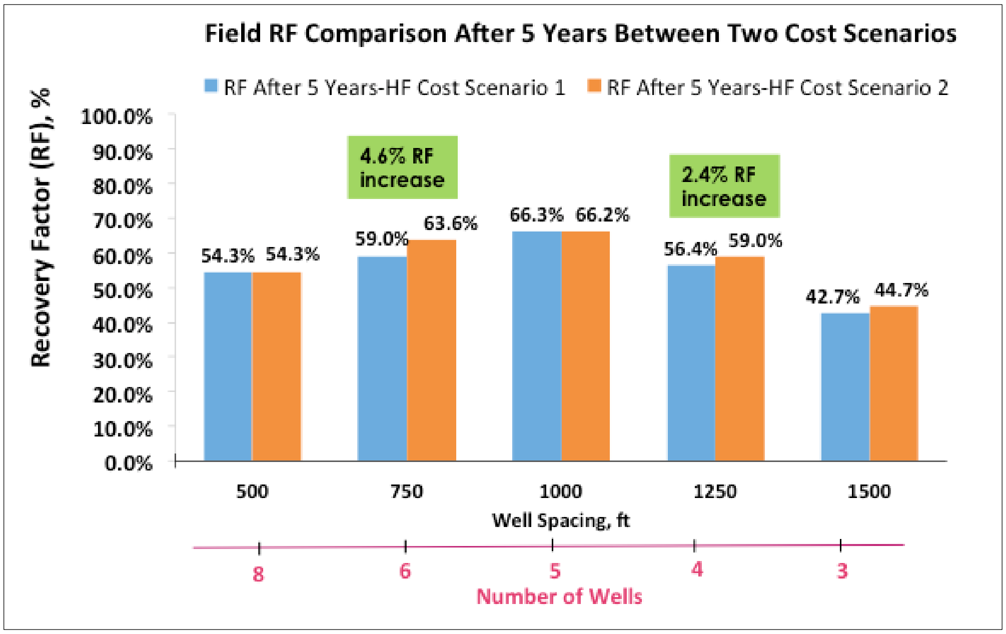

Figure 11: Field recovery factor comparison after 5 years between two completion costs scenarios.

Table 6: Optimized completion parameters for the completion cost scenario of $200K per stage.

Scenario	Well Spacing (ft)	# Wells	Fracture Spacing (ft)	# Stages	Fracture Conductivity (md-ft)	Fracture Half Length (ft)
1	500	8	350	20	47.8	250
2	750	6	250	28	36.8	350
3	1000	5	250	28	48.2	400
4	1250	4	200	35	49.5	400
5	1500	3	200	35	49	400

Conclusion

In addition to the reservoir quality and engineering factors, the commodity costs and capital expenditure guide oil and gas development plans. In this project, we utilized geological modeling and reservoir simulation to study the profitability of a shale dry gas asset in the Utica-Point Pleasant formations. Due to the very tight formations, horizontal drilling and multi-stage hydraulic fracturing were planned to increase the reservoir deliverability. Our reservoir model simulates a portion of Utica-Point Pleasant formations at 13,000 feet deep and 200 feet thick. The drainage area covers 1,003 acres. Our simulation results showed that due to the tight shale formation, drilling just one well would leave a significant amount of natural gas behind. We wanted to find the optimum number of lateral wells over the drainage area. By integrating the reservoir characteristics, economic data, and operational parameters the best drilling and completion scenarios were projected.

Based on two different completion cost scenarios, $300,000 and $200,000 per stages, the optimum NPV for 50 years of production results from a 5 well drilling project. This number of wells includes 1,000 feet well spacing and 28 stages for each well. According to our optimization analysis, this project leads to a 77.4% recovery factor over 50 years.

Drilling horizontal wells is a costly adventure and requires the availability of a significant capital budget. For this case study, a drilling scenario with just 4 well and 1,250 feet well spacing might be an attractive project. Although a 4 well scenario results in 6.5% less NPV compared to a 5 wells project, it will decrease the capital cost by 20%.

In shale formations, the main part of production happens in the first couple of years. In our case study, almost 70% of ultimate production occurs in the first five years of production. This could be considerable since it can return the initial investment quickly. Our results demonstrate that a 5 well scenario gives the highest production after 5 years. However, changing the cost of completion can render the 4 and 6 well scenarios.

Finally, although the outcome of our study is subjective to the chosen asset, the practice provides a good example of horizontal well spacing and hydraulic fracturing design optimization.

Acknowledgments

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