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Investigation and Optimization of Infill Well Spacing Using Geomechanical and Simulation Studies on Shale Gas Reservoir to Maximize Performance and Financial Return

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Abstract: The process of developing shale reservoirs has proceeded to the point where new wells are drilled in close proximity to the "parent" well. These new wells pose a problem for operators because they can lead to complicated interactions between wells, reducing the performance of either one or both of the parent and child wells. A successful field development near producing wells requires careful consideration of the distance between wells to minimize the volume of unproduced gas and loss of revenue. In the oil and gas industry, appropriate horizontal well spacing is often determined by a combination of geological modeling with reservoir simulation. The goal of this research is to identify the best field development approach that maximizes both gas production and financial return. In the course of our study, a shale gas reservoir is modeled using flow simulation-based reservoir simulation, to carry out a sensitivity analysis that will help optimize shale gas production in the future, and we took into account the adsorption/desorption phenomenon, the geomechanics effect coupled with the heterogeneity property, which are very characteristic of real shale gas reservoirs. For 20 years of gas production, we sought first to find optimal well numbers and geometries scenarios. Then we decided to intelligently down space the horizontal wells with multiple hydraulic fracturing stages by adjusting the distance at different completion times between parent well(s) and child well(s). We investigated both lateral and vertical well spacing in order to achieve the highest possible volume of gas production and amount of net present value (NPV). According to the findings of our simulations, ten wells with aligned well geometry provide the most economic benefit for the optimization strategy. In order to maximize the gas recovery, the lateral well spacing needs to be greatly increased, and the vertical well spacing needs to be decreased to a point where more gas can be produced from each well. In addition, the findings of the economic analysis indicated that increasing the distance between wells may result in more great financial value for the lateral wells spacing. However, all wells must be drilled in the same pay zone for vertical well spacing to provide a better economic return. In spite of the fact that the outcomes of our work depend on the selected asset, they provide a significant illustration for determining the optimal spacing between hydraulically fractured horizontal wells for shale gas reservoirs.

Keywords: Shale Gas, Multistage Hydraulic Fracturing, Numerical Simulation, Multiple Horizontal Well, Well Spacing Optimization, Sensitivity Analysis, NPV

1. Introduction

The oil and gas enterprises have spent the better part of the last century and the beginning of the 21st century concentrating on what is known as "conventional reservoirs." Resources and capital expenditures are required to investigate these reservoirs due to the fact that the permeability of the porous media provides conductive pathways for fluid to move through the porous media. In recent years, while unconventional reservoir exploration has grown more cost-effective, the porous media's nanodarcy permeability has made it more challenging to produce. In order to economically develop shale gas resources, many horizontal wells and multiple stages of hydraulic fracturing are required [1]. Multi-hydraulic fractures may significantly increase the wellbore contact area in low- or ultra-low permeability formations. Drilling a significant number of freshly drilled wells, often known as infill wells, is challenging in sections that already have wells that are considered to be the "parent" wells. This challenge is because of the impact that a "child well" can have on the performance of the parent well, which is sometimes referred to as a "frac-hit" (Negative or Positive frac-hits). The factors influencing production performance are classified as uncontrollable (e.g., porosity, water saturation, initial pressure, permeability, and natural fracture distribution) and controllable (e.g., well spacing, completion pattern, and working system) [2]. Controllable parameters may be modified to enhance well deliverability. Adjustments must be made to the horizontal well spacing that has a direct bearing on the shale gas recovery factor and economic advantages [2]. Therefore, it is crucial to check well spacing before drilling begins. Lack of optimized well spacing can cost or leave a significant amount of money on the table for operators [3]. For efficient and cost-effective asset development, knowing the optimal well spacing in a given region is crucial since the well spacing issue involves stimulated multi-wells, which can drive interference and communication between wells. Several practical developments of unconventional gas wells have observed the existence of interference between wells, and it is frequently seen that as the distance between wells is decreased, the total gas produced by a single well decreases. Consequently, shale gas development is assumed to correspond with an ideal spacing between wells or an optimal number of wells [4]. Proper spacing between wells is required for the effective exploitation of unconventional resources, the recovery of the gas reservoir may be increased [5], and so can the investment. The influence of reservoir permeability, fracture half-length, fracture spacing, fracture conductivity, reservoir compaction, and natural fractures on the well spacing decision was explored by Sahai et al. [4]. They hypothesized that the fracture half-length and the fracture spacing were equivalents. They concluded that the fracture half-length, along with reservoir permeability, was the most critical factor in well spacing. He et al. [6] suggested an optimization of the space between wells for tight sandstone gas reservoirs that integrates sand size limitations, dynamic model analysis, and economic assessment but does not account for the geological properties of shale gas reservoirs. In the Eagle Ford shale, Lalehrokh et al. [7] use a reservoir simulation-based workflow to provide well spacing guidance in the black oil and condensate reservoir. According to the study, a well spacing of 330 to 400 feet maximizes the NPV of a black oil Eagle Ford. The study makes the assumption that the effective fracture half-lengths are between 100 and 150 feet and was based on rate transient analysis, but it does not discuss predictive controls on these assumptions. Awada et al. [8] suggest that maximizing stimulated reservoir volume (SRV) requires that wells be spaced closely together yet far enough apart that fracture interference can be diminished, and over-capitalization in field development be kept to a minimum [9]. Well spacing may be optimized using a variety of methods, including rate transient analysis (RTA) and numerical simulations [7, 10]. Wells should be spaced out according to a spacing paradigm that maximizes net present value (NPV). Production volume may be essential to a company's strategic development, but the NPV is the sole economic measure that produces long-term shareholder value [11]. The selection of optimal well spacing and configuration depends on various geological, engineering, and economic parameters [12]. A workflow based on reservoir simulation and data analytics for 400 wells in the Eagle Ford formation has been developed and implemented by Rafiee et al. [13] in order to maximize NPV by calculating the optimal well spacing. It was demonstrated that the current close well spacing reduces the performance of the reservoir and must be increased for economic improvement. It was looked into how the distance between wells affects the productivity of parent and infill wells in the Permian Basin, taking production volumes into account [14]. By adjusting hydraulic fracturing and simulating a variety of scenarios to get insight into well's distance and completion designs, a single or multi-well pad optimization technique in the Permian Basin has been shown by Pankaj et al. [15]. Reservoir modeling was employed to identify the optimal well spacing in the Delaware Basin [16]. They adjusted a multi-well reservoir model and studied oil recovery deterioration within various well configurations. An integrated workflow has been applied to evaluate well spacing for a pad in the Bakken [17]. The result of the analysis was used for the nearby pad development plan by rising well spacing and lessening the number of wells. The application of dynamic stimulated reservoir volume (DSRV) was extended to the DJ basin [18]. They explained how the completion size and well spacing could be co-optimized to maximize the economic profitability of the project.

In this work, a heterogeneous shale gas reservoir is modeled using flow simulation-based reservoir simulation, and we take into account the effects of geomechanics and adsorption/desorption, which are characteristics of a real shale gas reservoir. Furthermore, to anticipate future reservoir performance better, we will refer to the classification terminology as the Spacing Classification System ("SCS") proposed by Valdez et al. [19]. At first, we drilled shorter wells by changing the number and geometry of wells. Later, to study how the reservoir performs, we simulated a three, four, and five horizontal well pad asset by varying the lateral and vertical well spacing at different completion times between parent well(s) and child well(s). The aim is to figure out the optimum number, geometry, and distance between wells that led to the highest volume of gas and NPV over 20 years of production.

2. Methodology

Reservoir simulation, particularly early in the field development process, is a useful technique for modeling multiphase flow (gas-water) in a shale gas reservoir. This investigation uses the commercial compositional reservoir simulator CMG-GEM (CMG, 2020) [20] to model various well optimization configurations in a shale gas reservoir. To predict fluid movement from matrix to fractures in fractured reservoirs, the Local Grid Refinement (LGR) method is applied. To examine the impacts of well density and geometry, we firstly developed a numerical model based on dual-porosity-dual-permeability (DPDP) principles, and secondly, the well spacing on the reservoir performance. This approach can accurately and effectively mimic transient gas flow from hydraulic fractures of the horizontal wells in shale gas reservoirs [21-24]. The logarithmically spaced, locally refined, dual permeability (LS-LR-DK) approach is often utilized to simulate gas flow in hydraulically fractured shale gas reservoirs. The grid blocks that include hydraulic fractures have a 7×7×1 local grid refinement. The flow from matrix to fracture is modeled by using a matrix-fracture transfer term [25]. It is defined by:

$$\text{Transmissibility} = 4k \times \left(\frac{1}{(L_x)^2} + \frac{1}{(L_y)^2} + \frac{1}{(L_z)^2} \right) \times V_{matrix} \qquad (1)$$

where, L represents the fracture spacings in the x, y, and z directions (m), and k is the matrix permeability (mD).

We completed the optimization of numerous horizontal wells inside of a spacing unit of 1440000m^2 (≈356 acres) based on the fracture characteristics we selected. Firstly, the number and geometry of well were investigated for shorter well where nine (9) hydraulic fracturing stages were compared from four (4), six (6), height (8), ten (10), and twelve (12) wells to determine the optimal gas volume and profitability. Lastly, well spacing sensitivity was investigated for longer well with three (3), four (4), and five (5) wells with eighteen (18) hydraulic fracturing stages by varying lateral and vertical spacing and the completion date difference between the parent well(s) and infill (child) well(s) to find the optimal gas volume and financial gain.

2.1. Geomechanics Effect

This study examines geomechanical impacts with a particular emphasis on stress-dependent fracture permeability. In other words, fracture permeability is not a constant but reduces somewhat when the closure stress rises owing to proppant embedding. This simulation model utilized the Barton-Bandis permeability model [26, 27]. The Barton-Bandis model illustrates the connection between fracture opening and permeability. In this model, the secondary fracturing system is characterized by a dual porosity formulation grid structure. Here, secondary fracturing illustrates the system's natural fractures. As shown in Figure 1, fracture permeability is dependent on the value and history of normal fracture effective stress σ_n'.

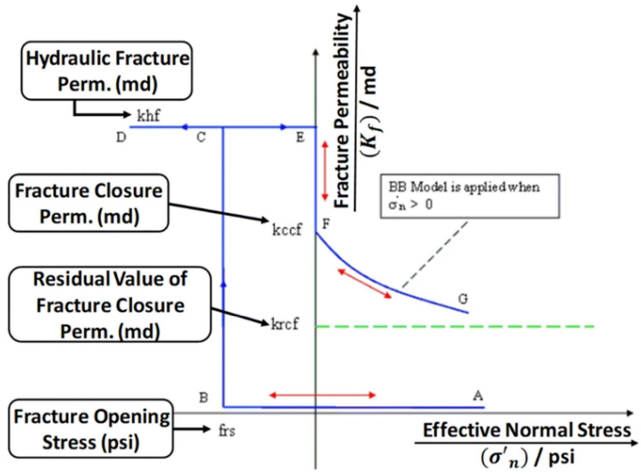


Figure 1. *Automatic modification of fracture permeability under the influence of the Barton–Bandis Theory.*

Fracture permeability depends on the value and history of normal fracture effective stress σ_n'. It should be noted that the normal fracture effective stress σ_n' is equivalent to the minimum principal effective stress.

1. Path AB: Normal fracture effective stress σ_n' is larger than critical opening fracture stress-frs. The fracture is almost sealed and has low permeability. The whole process is reversible.
2. Path BC: During the pumping process, the pore pressure increases and σ_n' becomes smaller. Once σ_n' is smaller than frs, a fracture opens suddenly and the fracture permeability increases along path BC to the khf-hydraulic fracture permeability.
3. Path DCE: Fracture permeability is at khf when σ_n' is negative.
4. Paths EF and FG: During the development stage, pore pressure decreases and $\sigma n'$ increases. Once σ_n' becomes positive, fracture permeability drops from khf to fracture closure permeability (kccf). Then, the Barton-Bandis model (curve FG) is applied to mimic the crack closure process. The dotted asymptotic line represents the residual value of fracture closure permeability (krcf). Like path AB, path GFED is reversible.

The geomechanical parameters (stress and strain) calculated from the Barton Bandis model are only coupled to the matrix blocks; however, the model allows the calculation of the fracture permeability from the normal fracture effective stress. The fracture closure permeability krcf (mD) is calculated by the following equation:

$$k_f = k_{ccf} \times \left(\frac{e}{e_0}\right)^4 \geq k_{rcf} \qquad (2)$$

Where kccf is the fracture permeability at zero stress (mD), (e) is defined as the current fracture aperture (m), e_0 is the initial fracture aperture (m); that is

$$e = e_0 - V_j \qquad (3)$$

and V_j is the stress to fracture stiffness ratio and is calculated as follows:

$$V_j = \frac{\sigma_n'}{k_{ni} + \frac{\sigma_n'}{v_m}} \tag{4}$$

In Equation 4, V_m is the minimum fracture aperture correlated to closure permeability (m).

$$V_m = e_0 \left[1 - \left(\frac{k_{rcf}}{k_{ccf}}\right)^{1/4}\right] \tag{5}$$

2.2. Adsorption/Desorption Phenomenon of Shale Gas

The Langmuir isotherm is the most used model for describing the gas adsorption/desorption process. With the Langmuir equation [28], it is possible to figure out how much gas is on the surface of a rock.

$$V_{ad} = V_L \frac{P}{P + P_L} \tag{6}$$

Where V_{ad} is the gas adsorption, m^3/kg; V_L is the Langmuir volume, m^3/kg; p_L is the Langmuir pressure, MPa; p is the pressure, MPa.

The Langmuir pressure and Langmuir volume play critical roles in the gas adsorption process. Variations in the Langmuir volume and pressure of various shale gas deposits result in a unique gas content pattern.

3. Reservoir Simulation Description

In this simulation study, we constructed a basic 3D reservoir model with the dimensions of 1200m (length) × 1200m (width) × 100m (thickness), as illustrated in Figure 2. Shorter horizontal wells are drilled in the center of the shale gas formation and stimulated layer number 5. Its length is set at 500m with 9 perforations, as illustrated in Figure 3a. In a later section, we drilled longer horizontal wells with a length of 1040m with 18 perforations in the middle layer, as illustrated in Figure 3b. Each perforation has fractures emanating from it. The interval between two adjacent fractures is 60 meters, which is the cluster spacing.

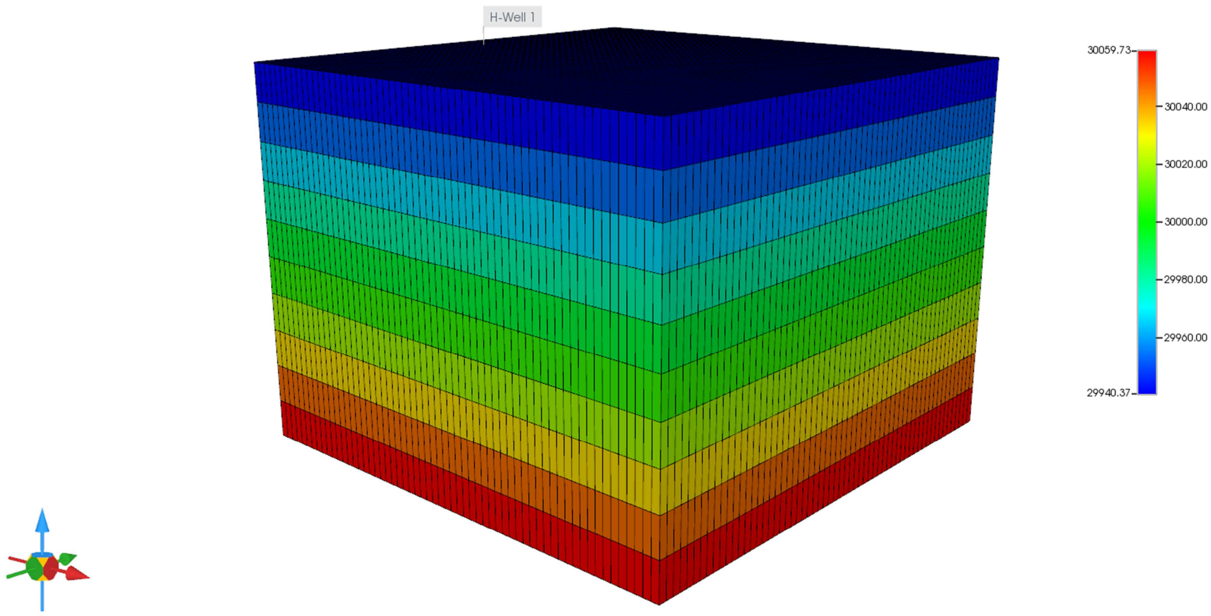
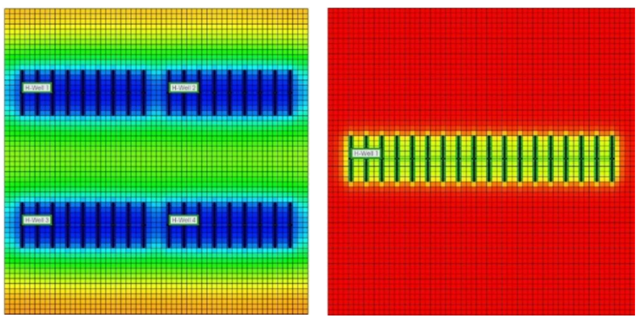


Figure 2. *3D gridding scheme used for building the reservoir simulation model.*



(a) Shorter Well (b) Longer Well

Figure 3. *Illustration of horizontal wells number drilled.*

The reservoir model utilizes a bi-wing fracture model. The complete reservoir and fracture parameters evaluated in this investigation are summarized in Table 1. The reservoir is considered to be heterogeneous, and the fractures are equally distributed, with stress-dependent permeability. Table 2 presents the selected fracture and well parameters used in the simulation.

Table 1. *Reservoir parameters used for shale gas simulation.*

Parameter (s)	Value	Unit
Model dimension (length × width × height)	1200 × 1200 × 100	m
Grid size	20 × 20 × 10	m
Initial reservoir pressure	30	MPa
Minimum BHP	6.89	MPa
Reservoir temperature	150	°C
Production time	20	Year (s)
Initial gas saturation	0.80	Fraction

Parameter (s)	Value	Unit
Total compressibility	1.5×10^{-10}	Pa^{-1}
Average Matrix porosity	0.046	Fraction
Average Natural fracture porosity	0.000876	Fraction
Average Matrix permeability	0.000086	mD
Average Natural fracture permeability	0.00087	mD
k_h/k_v	10	Number (s)

Table 2. *Well and Fracture parameters data.*

Parameter(s)	Shorter Well	Longer Well	Unit
Horizontal well length	500	1040	m
Fracture permeability	5000	5000	mD
Fracture width	0.004	0.004	m
Fracture half length	90	90	m
Fracture spacing	60	60	m
Number of fractures	9	18	Number(s)

4. Economics Analysis

When assessing the financial sustainability of a project, the net present value (NPV) is an essential measure to consider. For the purpose of this investigation, the NPV was computed in terms of royalty, production revenue, operating expenditure (OPEX), and capital expense (CAPEX) using equation (7):

$$NPV = (1 - \text{Royalty}) \sum_{j=1}^{n} \frac{\text{Revenue}_j}{(1+i)^j} - \sum_{j=1}^{n} \frac{\text{OPEX}_j}{(1+i)^j} - \text{CAPEX} \quad (7)$$

Where i is the discount rate, revenue is the product of gas production and gas price, OPEX is operating expenditure, and CAPEX is a capital expense, including drilling and completion costs. The research by [29, 24] serve as the basis for the NPV calculations (Table 3).

Table 3. *Economic data for calculating the net present value (NPV) of shale gas projects.*

Horizontal Well Length (m)	Cost (USD)	Fracture Half-Length Per Stage (m)	Cost (USD)	Parameter	Value
305	2,000,000	76	100000	Interest rate, %	10
610	2,100,000	152	125000	Royalty tax, %	12.5
915	2,200,000	229	150000	Gas price, USD/Mscm	140
1220	2,300,000	305	175000	Operating cost, USD/Mscm	30

5. Sensitivity Analysis and Optimization Scenarios for Multiple Horizontal Wells

When it comes to developing unconventional plays, the multibillion-dollar question is how to develop horizontal wells and how far apart wells should be. The ultimate goal of this study is to find the optimum spacing between parent and child well(s) that gives the highest rate of net present value (NPV). In this study, we utilized the reservoir simulations to carry out various sensitivity analyses of reservoir characteristics to properly plan future production optimization, the heterogeneity of the reservoir coupled with the geomechanics and adsorption/desorption effects are taken into account in order to determine the optimal number and geometry of horizontal wells, and the lateral and vertical spacing between wells for 20 years of gas production.

5.1. Impact of Horizontal Well Number and Geometry on Well Performance and NPV

To fulfill this section's primary goal, obtaining the optimal number and geometry of wells. All the drilling scenarios will be in a constant drainage area (1440000 m2 ≈ 356 acres).

5.1.1. Well Number(s)

In this section, we created six drilling scenarios in a constant drainage area. The number of wells we drilled is summarized in Table 4. Figure 4 depicts the positioning of each of the simulated well numbers. In the current field development of our shale gas, we simulated four (4), six (6), height (8), ten (10), and twelve (12) horizontal wells.

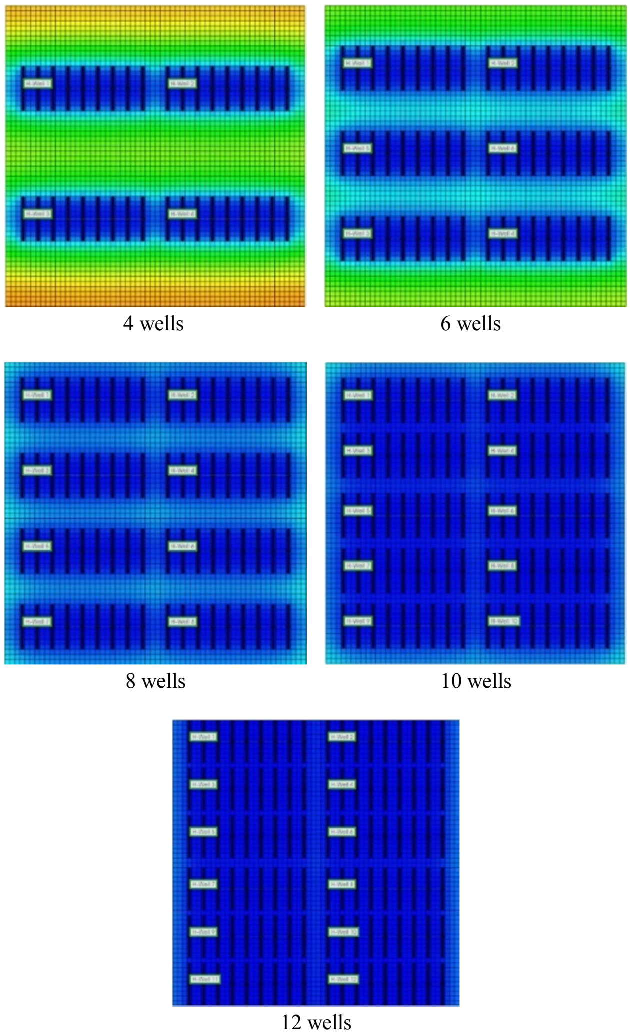


Figure 4. *Illustration of horizontal wells number drilled.*

Table 4. *Six scenarios of well number.*

Scenario	Well Number
1	4
2	5
3	6
4	8
5	10
6	12

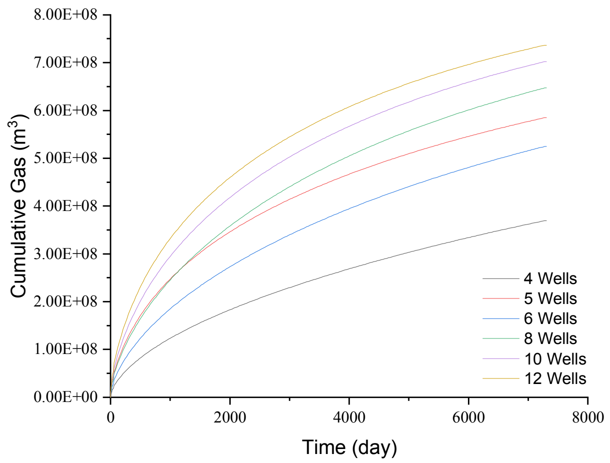


Figure 5. *Impact of well number on the gas production.*

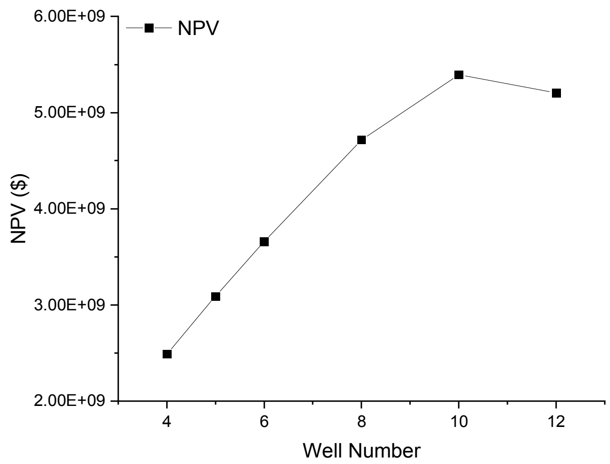


Figure 6. *Revenue versus well number.*

As shown in Figure 5, the number of wells dramatically affects how much gas is produced. Increasing the number of wells from 4 to 12 causes more pressure to drop, which means more gas can be recovered. Based on the total cumulative gas produced, according to the optimization results, the configuration with 12 wells seems to have the highest production, and it is possible that ten (10) wells would be the second most productive drilling scenario. In general, to determine the profitability of a project, we use the net present value (NPV). Therefore, Figure 6 compares the profit for each drilling scenario for 20 years of production to find the maximum NPV. Knowing that the drainage area of our reservoir is constant, the ten (10) horizontal wells drilling scenario yields the highest NPV, and it is determined to be the best choice. Nevertheless, we shall not ignore one crucial fact, drilling more wells will definitely result in rising up capital expenditures (Capex), as shown in Table 5.

Table 5. *Well Number with corresponding Capex value.*

Well Number	Capex, USD
4	12,040,000
6	18,060,000
8	24,080,000
10	30,100,000
12	36,120,000

5.1.2. Well Geometry

We built two types of geometries, one we call the Aligning geometry, and the other one is the Alternating geometry; an illustration of six horizontal wells is shown in Figure 7. These two different geometries have a different impact on gas production and NPV as well.

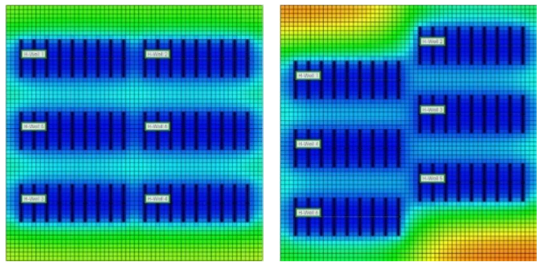


Figure 7. *Illustration of different types of well geometry for six (6) horizontal wells.*

Figures 8, 9, 10, 11 and 12 illustrate how well geometry affects gas production. It is clear that well geometry has little impact on gas production, and the difference between aligning and alternating well geometry can be overlooked. On this basis, we determined the relevant NPV values for each geometry type. The relationship between NPV and well geometry is shown in Figure 13 for 20 years of production. Knowing that the drainage area of our reservoir is constant, ten (10) horizontal wells are determined to be the best choice for both geometry types. Here the aligning placement of wells can drain more volume of the reservoir, which might be the reason why the aligning geometry has the highest economic profit compared to the alternating geometry.

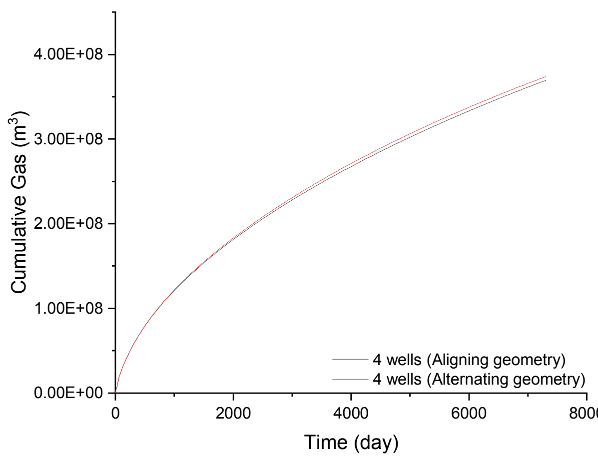


Figure 8. *Effect of well geometry type on the cumulative gas production of 4 wells.*

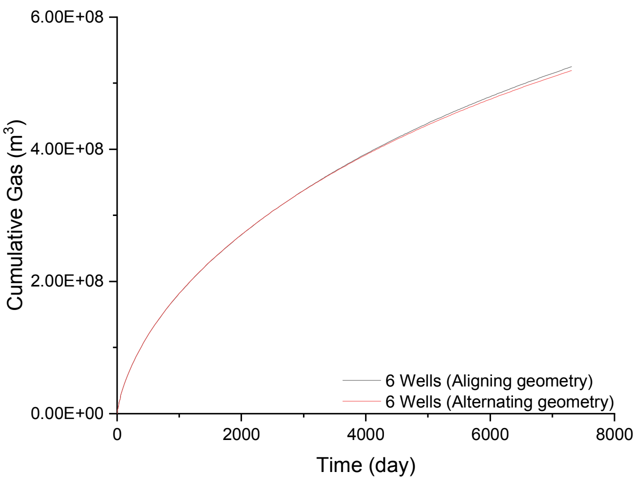


Figure 9. *Effect of well geometry type on the cumulative gas production of 6 wells.*

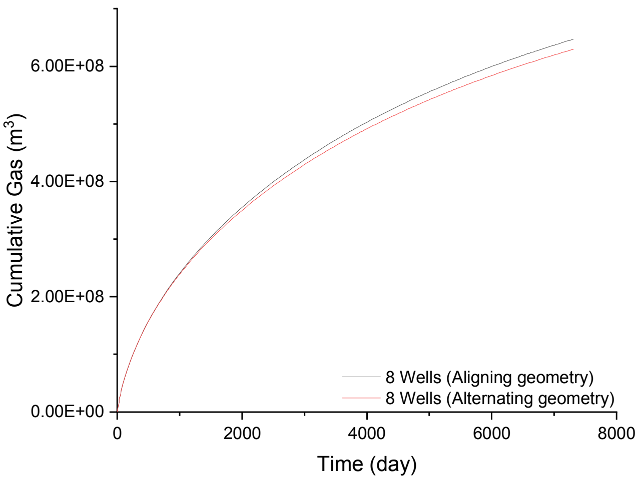


Figure 10. *Effect of well geometry type on the cumulative gas production of 8 wells.*

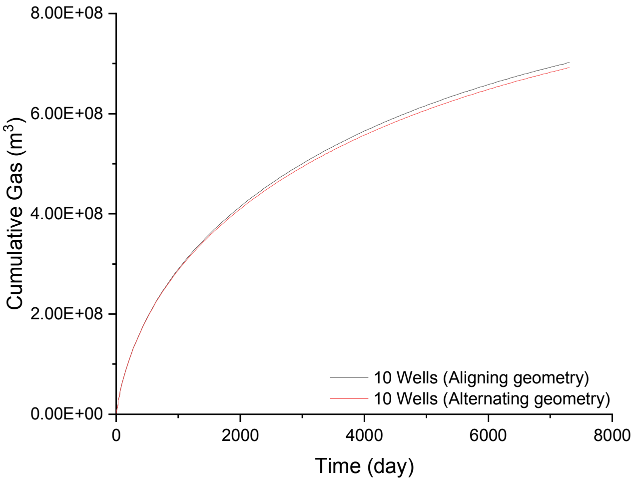


Figure 11. *Effect of well geometry type on the cumulative gas production of 10 wells.*

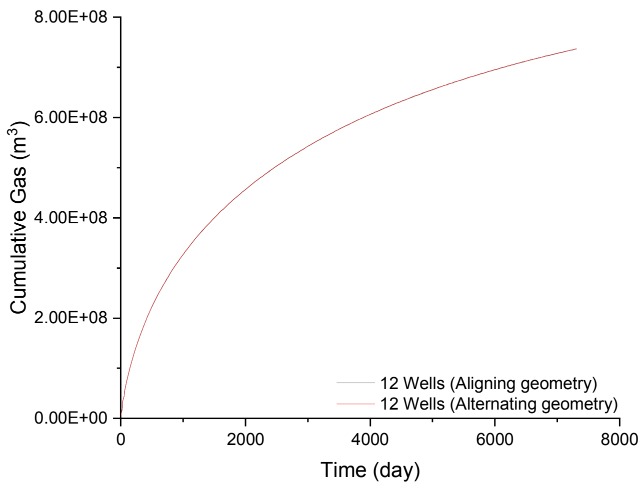


Figure 12. *Effect of well geometry type on the cumulative gas production of 12 wells.*

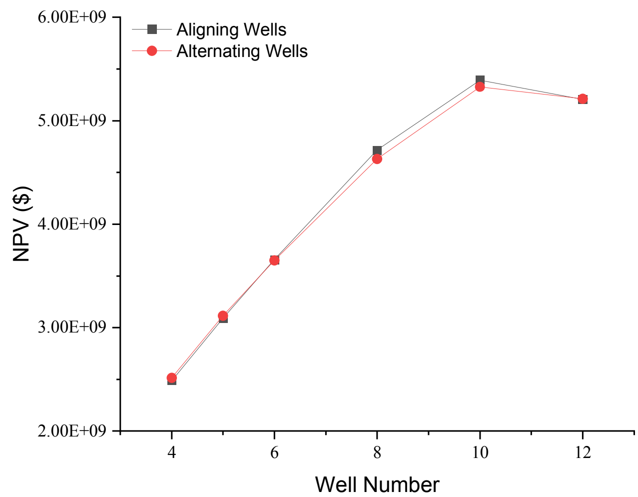


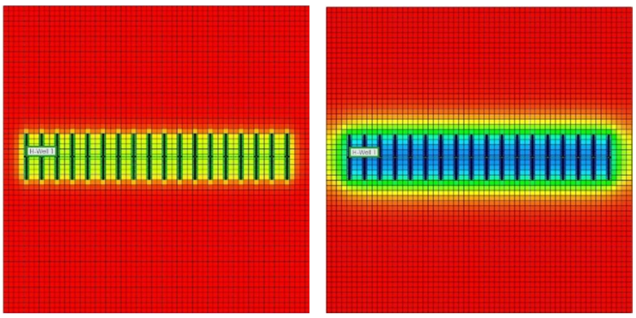
Figure 13. *The relationship between the NPV and well geometry.*

5.2. Impact of Well Spacing and Timing on the Performance and NPV of the Reservoir

The objective is to establish the optimal lateral distance (well spacing) between horizontal wells within this spacing unit region (1440000 $m^2 \approx$ 356 acres) after six (6) or sixty (60) months of completion difference between parent and infill (child) well(s). We will refer to the classification nomenclature as Spacing Classification System ("SCS") to provide a specific methodology to select analogous wells to predict future well performance better. The six designations in the SCS include the following: 1) Parent (unbound); 2) Half-Bound Co-Developed; 3) Half-Bound Child; 4) Fully-Bound Co-Developed; 5) Fully-Bound Child, and 6) Infill. Due to our method's computational efficiency, we can conduct a massive number of simulations to identify the point of diminishing returns and determine the optimal well spacing. In the sensitivity analysis, the only things that can change are the well spacing and the timing. Parameters like reservoir and fracture properties, both of which can have an effect on the findings, are held constant in this part of the analysis.

5.2.1. Lateral Spacing Between One Parent Well and Two Children Wells

To maximize hydrocarbon production from multiple horizontal wells in unconventional plays, finding the correct well spacing is essential. For the context of this research, the first criterion for the addition of a well pair is a disparity in completion dates of no more than six (6) months. Eventually, it increases that to a difference of sixty (60) months. The inclusion of this limit prevents the incorporation of well pairs that are completed simultaneously, which are not regarded to be parent and children wells. Figure 14 shows the pressure profile of parent well production before child wells placement. In the 2D reservoir model from Figure 14, we saw the difference in reservoir pressure, and a part of the model was taken apart to show the change in pressure inside the fifth (5th) layer. This helped us find a good place to drill the child wells. We can see that the pressure difference is most pronounced in the reservoir's stimulated region, whereas outside of the stimulated zone, the pressure decrease is nearly null. Therefore, the hypothetical future wells can be placed in the red area. At this point, because additional simulation modeling work has not been completed, we cannot assess whether the pressure depletion of the parent well will negatively impact the placement of some new wells in this area.



(a) After 6 months (b) After 60 months

Figure 14. *Areal view of parent well pressure depletion.*

As shown in Figure 15, After the parent well had been depleted for sixty (60) months or six (6) months, we made the decision to drill two (2) infill wells (also known as child wells) and model how all of the wells would perform. Based on the SCS, the parent well is situated in the center of the reservoir., and two half Bounded (HB) child wells close to the reservoir boundary.

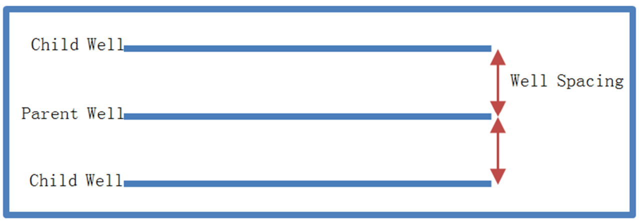


Figure 15. *Infill wells are completed 6 or 60 months after parent well.*

Table 6 summarizes the simulation parameters; we tested seven (7) different well spacing scenarios. The spacing between the parent well and each child well of the seven (7) configurations vary from 220m to 460m, with an increment of 40m.

Table 6. *Seven well spacing scenarios.*

Scenario	Distance between parent well & child wells
1	220m
2	260m
3	300m
4	340m
5	380m
6	420m
7	460m

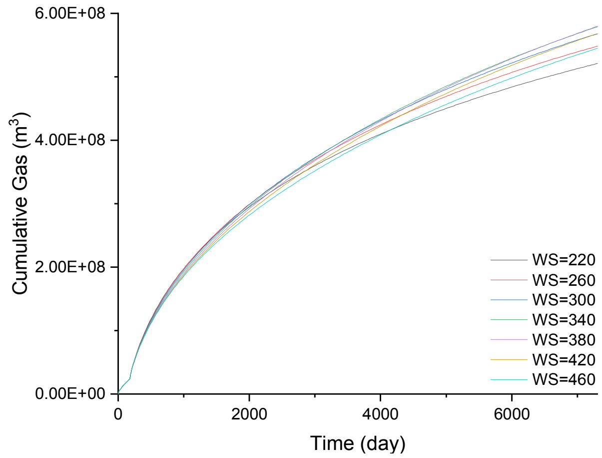


Figure 16. *Relationship between the total cumulative gas and the well spacing for 6-months completion difference between wells.*

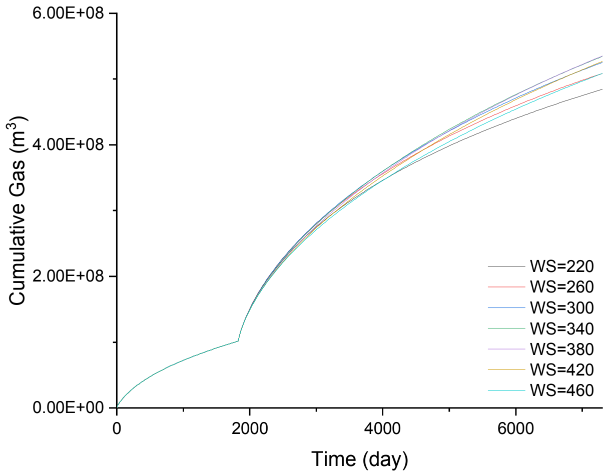


Figure 17. *Relationship between the total cumulative gas and the well spacing for 60-months completion difference between wells.*

From the sensitivity analysis, we have established a direct relationship between the well spacing and the total gas field production, as shown in Figures 16 and 17. The total cumulative gas production increases as we increase the lateral spacing between the wells from 220m to 380m, but after 380m, the gas production begins to decrease. We can infer that some productivity loss hurts the performance of all of the wells when they are too close to one another, as this may cause the wells to compete with one another. The production of child wells may be impeded as a function of their distance from the parent well. Additionally, if the wells are too far apart from one another, there will be a non-negligible quantity of shale gas left between the wells. For the 6- or 60-month completion difference case, if the objective is to extract a tremendous amount of gas, then, in this case, 380m will be the ideal separation between the parent well and the child wells. Whereas using the NPV as economic metrics, we came to a different conclusion, finding that 340m is the optimal lateral distance between parent and child well(s). Moreover, whether one shortens or lengthens the distance between the wells, the end consequence will be a reduced economic profit, as shown in Figures 18 and 19.

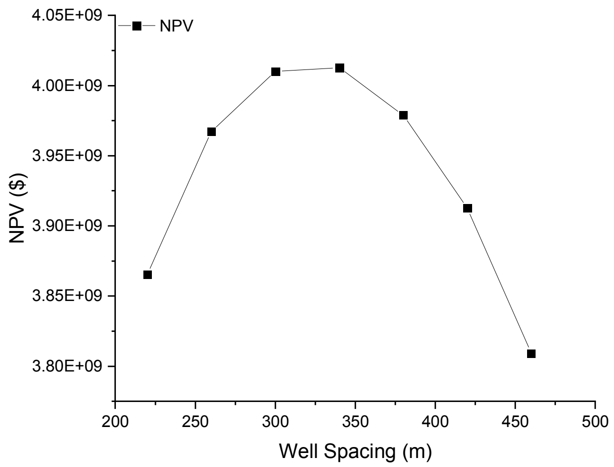


Figure 18. *Relationship between the total cumulative gas and NPV for 6-months completion difference between wells.*

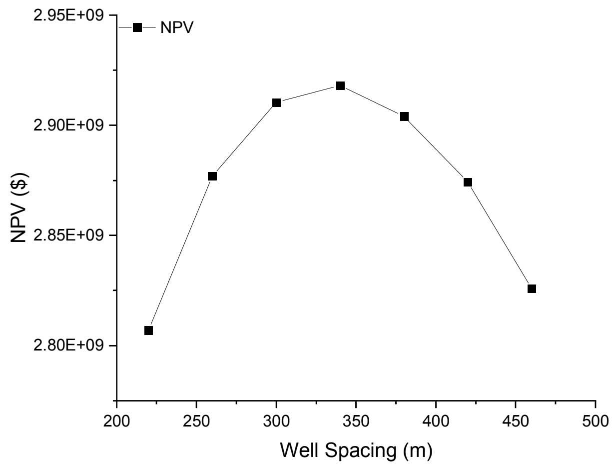


Figure 19. *Relationship between the total cumulative gas and NPV for 60-months completion difference between wells.*

5.2.2. Lateral Spacing Between One Parent Well and Three Child Wells

In this study, After the parent well had been producing on its own for 6 or 60 months, we drilled three infill (child) wells and ran the simulation to analyze the performances. The perforation and stage spacing of the three horizontal wells were the same across all three wells. Based on the Spacing Classification System ("SCS"), we have one parent well close to the reservoir boundary, and 6 or 60 months later, two Fully Bounded (FB) and one half Bounded (HB) child wells are drilled, as shown in Figure 20.

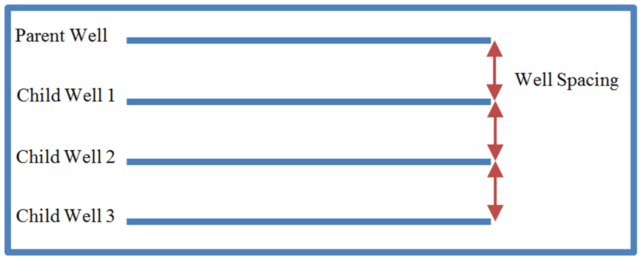


Figure 20. *Infill wells are completed 6 or 60 months after Parent well.*

A predetermined distance separates the parent well from each child well. The length of the four situations or combinations varies from 220m to 340m, 460m to 580m, 700m to 820m for parent well-child well 1, for parent well-child well 2, for parent well-child well 3, respectively, with an increment of 40m. Table 7 summarizes the simulation setting, and we tested four (4) different well-spacing scenarios.

Figures 21 and 22 show that, according to the sensitivity analysis, there is a direct link between the well spacing and the total field production. We have observed that increasing the distance between wells increases the overall cumulative gas production. The maximum volume of gas produced is achieved in scenario 4, regardless of whether the parent well has been producing for six or sixty months previous to the stimulation of the child wells. The most significant profit is achieved in scenario 3 for the parent well's shorter production history (6 months), as shown in Figures 23 and 24. As a result of pressure depletion, the extended production history of the parent well, which has been five years, poses a threat to the long-term production of the child wells. For a more extended production history of the parent well, the ideal distance for the reservoir to obtain a higher economic advantage is scenario 4. Still, for a shorter production history of the parent well (6 months), the optimal configuration is 3. When the parent well is the sole producing well for an extended period, it depletes a substantial volume of the reservoir; consequently, drilling new infill wells adjacent to the old well will result in well interference or frac hit, as found in prior studies. Therefore, the ideal distances for child well 1, child well 2, and child well 3 to be drilled after five years of parent well production will be 340m, 580m, and 820m, respectively.

Table 7. *Four scenarios of well spacing.*

Scenario	The lateral distance between parent well & child well 1	The lateral distance between parent well & child well 2	The lateral distance between parent well & child well 3
1	220m	460m	700m
2	260m	500m	740m
3	300m	540m	780m
4	340m	580m	820m

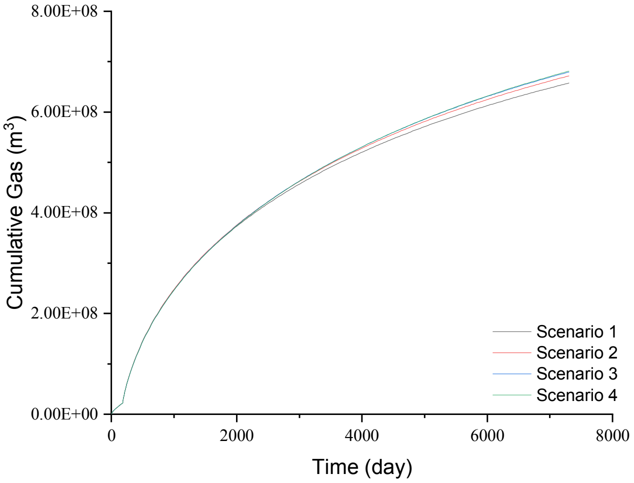


Figure 21. *Relationship between the total cumulative gas and the well spacing for 6-months completion difference between wells.*

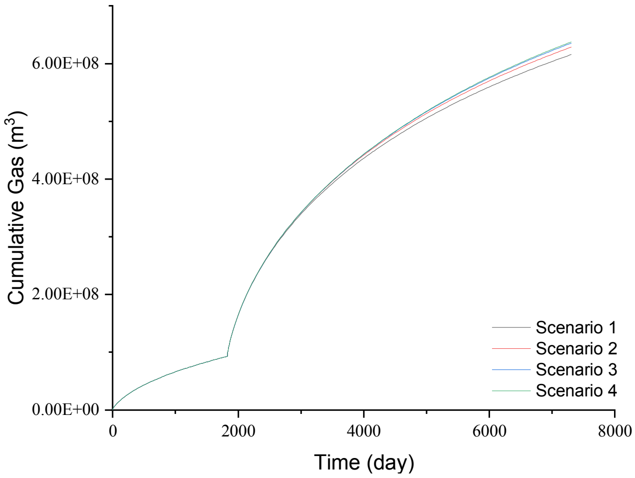


Figure 22. *Relationship between the total cumulative gas and the well spacing for 60-months completion difference between wells.*

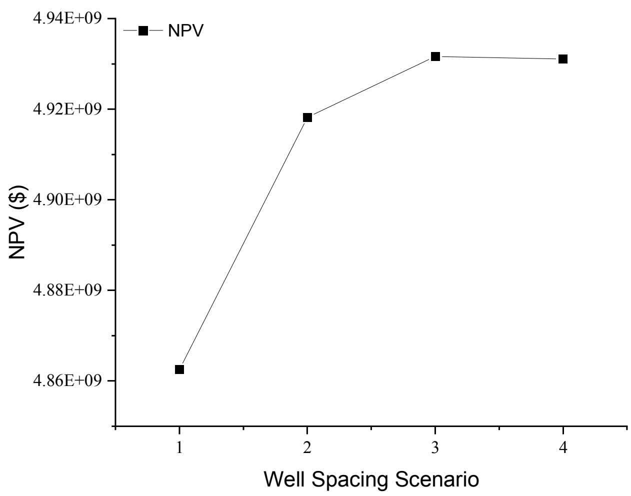


Figure 23. *Relationship between the total cumulative gas and NPV for 6-months completion difference between wells.*

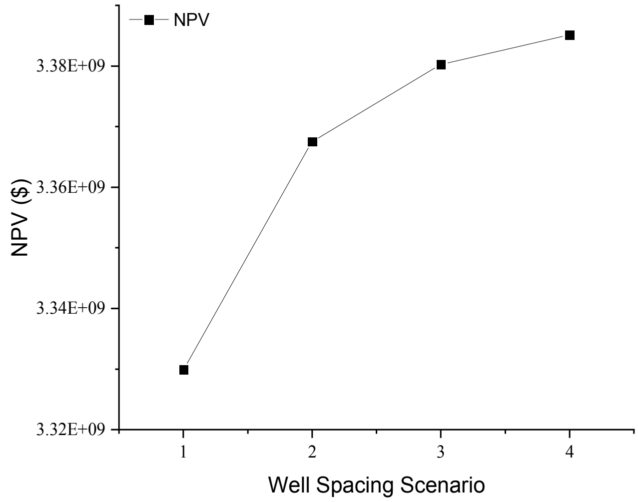
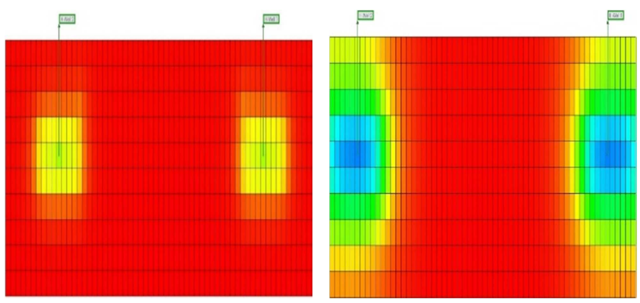


Figure 24. *Relationship between the total cumulative gas and NPV for 60-months completion difference between wells.*

5.2.3. Vertical Spacing Between Two Parent Wells and Three Child Wells

In this investigation, we also evaluated how the reservoir will be depleted, particularly in the near future, with a focus on the child wells. Development planning is aided by a more profound familiarity with reservoir depletion, allowing us to investigate the asset's prospective returns better. Figure 25 depicts the contrast in reservoir pressure in the j-k cross-section (i = 30) of the 2D reservoir model. The parent wells were completed and started production 6 or 60 months earlier than the three offset child wells. Due to the formation's low permeability, the bottom and top reservoir layers seldom suffer a pressure change. At the same time, the parent wells' surroundings have experienced a significant depletion after five years (60 months) of production. The infill wells will utilize the upside potential pay zones because our reservoir is heterogeneous, and the bottom layers have very low permeability in comparison to the upper levels. As a result, we opted to start drilling the child well in the same layer as the parent wells and gradually increase the vertical space between the parent wells and the child well, as shown in Figure 26. Table 8 summarizes the simulation setting, and we tested four (4) different well-spacing scenarios.



(a) After 6 months (b) After 60 months

Figure 25. *JK cross section of the pressure change around parent wells.*

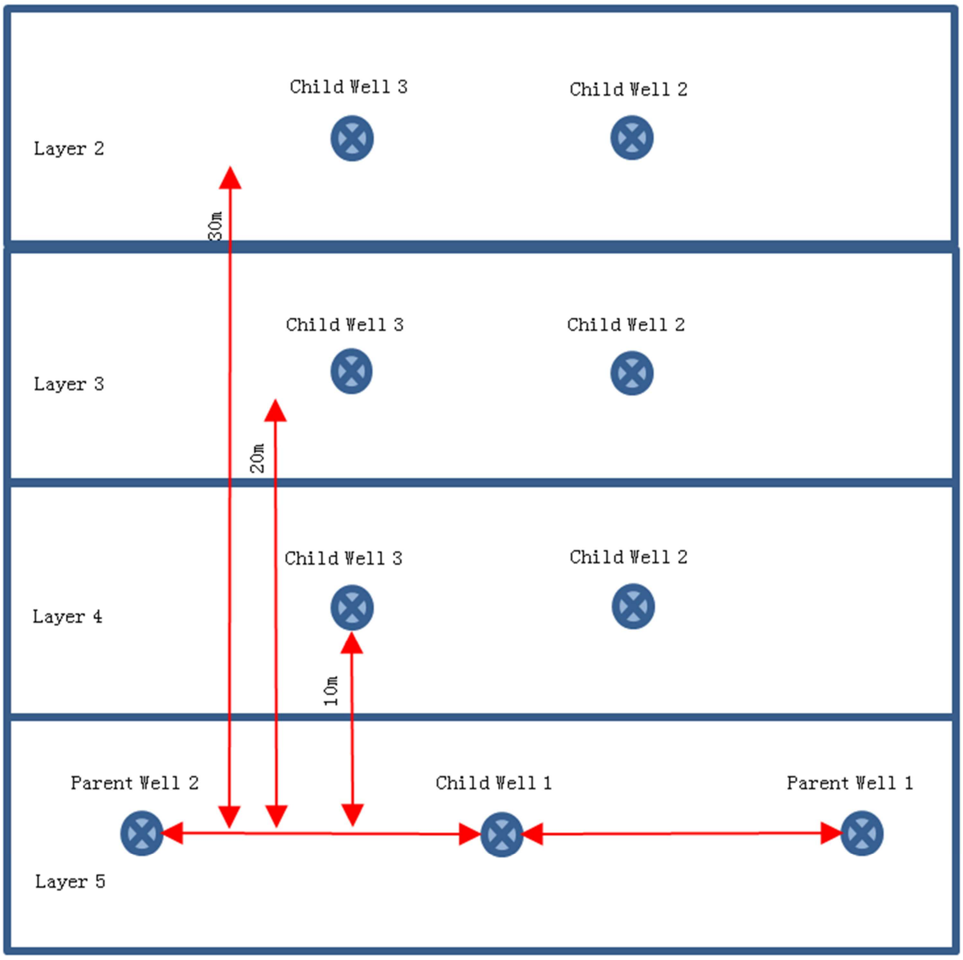
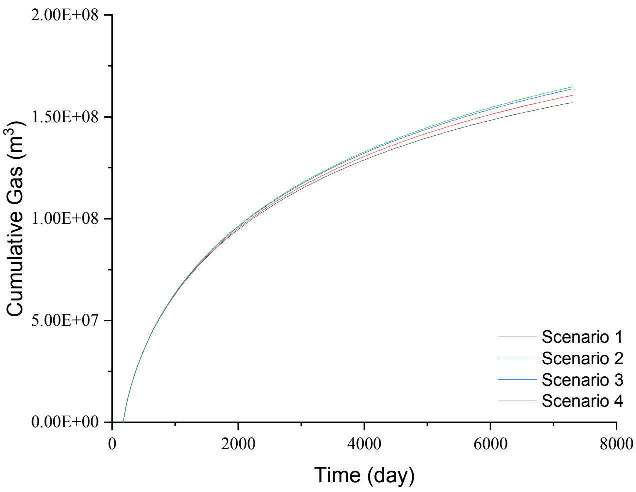


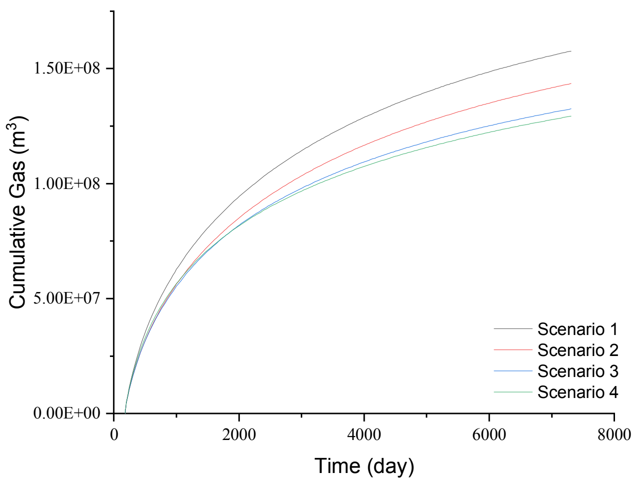
Figure 26. *The relationship between the NPV and the well spacing.*

Table 8. *Four scenarios of well spacing.*

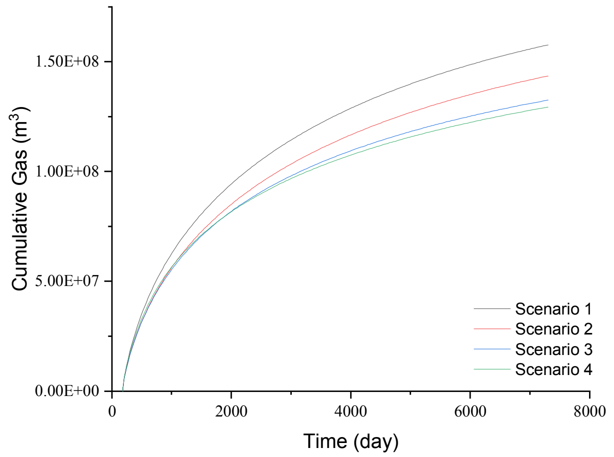
Scenario	The vertical distance between parent wells & child well 1	The vertical distance between parent wells & child well 2	The vertical distance between parent wells & child well 3
1	0m	0m	0m
2	0m	10m	10m
3	0m	20m	20m
4	0m	30m	30m



(a) Child well 1



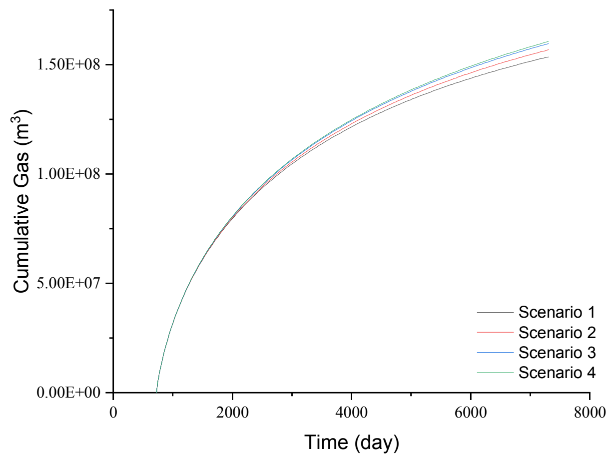
(b) Child well 2



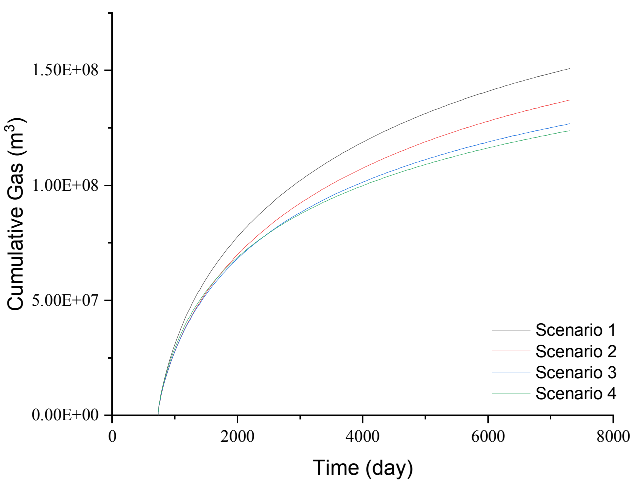
(c) Child well 3

Figure 27. *Cumulative gas production for each child well in all scenarios when drilled a half year after the parent well's production began.*

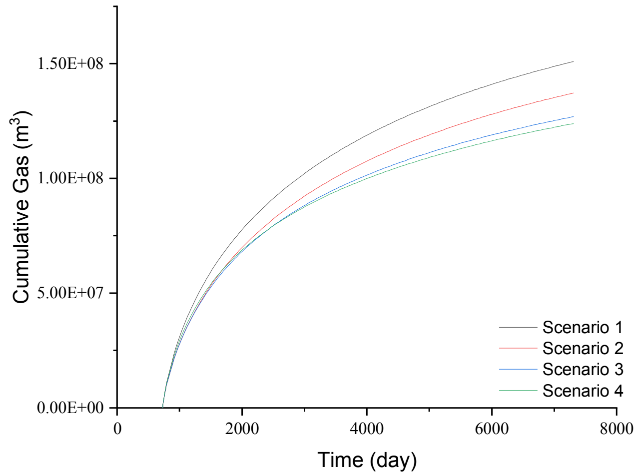
According to Figures 27 and 28, regardless of the amount of time the parent wells spent producing on their own, child well 1 performs better when the other child wells 2 and 3 are located further away from it. The proximity of child wells 2 and 3 to the fracture treatment of child well 1 and the depleted parent wells cause an increase in production, as depicted in the figures.



(a) Child well 1



(b) Child well 2



(c) Child well 3

Figure 28. *Cumulative gas production for each child well in all scenarios when drilled five years after the parent well's production began.*

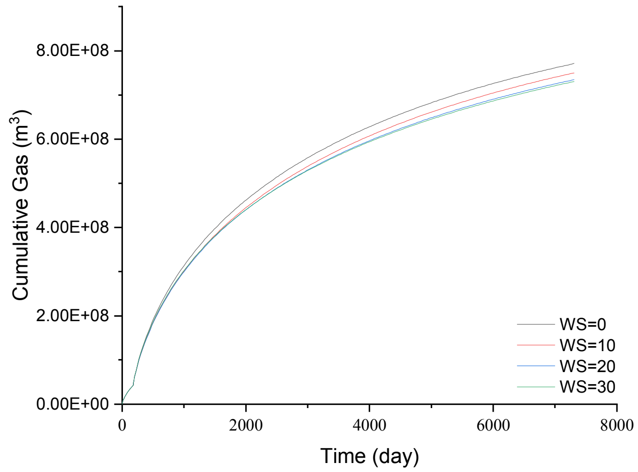


Figure 29. *Relationship between the total cumulative gas and the well spacing for 6-months completion difference between wells.*

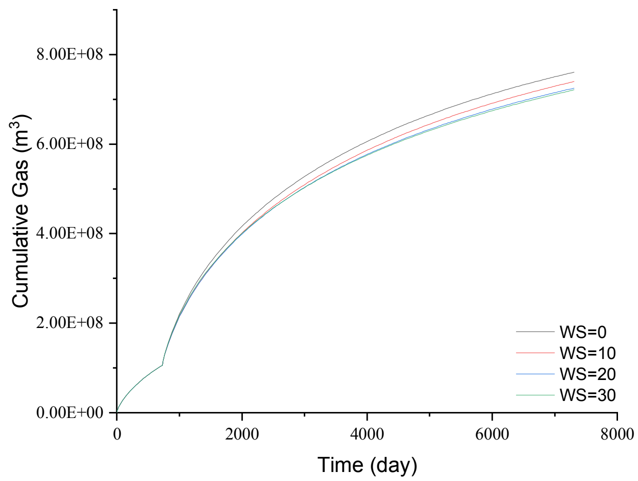


Figure 30. *Relationship between the total cumulative gas and the well spacing for 60-months completion difference between wells.*

Figures 29 and 30 illustrate a direct relationship between the well spacing and the overall gas field production. In contrast to the lateral distance, the result demonstrates that the total cumulative gas is growing as the child-well moves closer to the producing layer. Regardless of the gap in completion times between the parent and child wells, the optimum vertical space for the reservoir to perform at its maximum is when all wells are drilled at the same layer. We may suggest that the parent wells help increase the productivity of the child wells because the depletion triggered by the parent wells allows the child wells' perforation cluster to access the neighboring reservoir rock easily. In the event that the child wells are not located in the same layer as or close to the producing layer (5th layer), this cannot be accomplished. When child wells 2 and 3 are drilled in an upper zone, the total gas recovery is relatively low. Figures 31 and 32 present the impact of the well spacing on the total NPV of the field. Similar to the total cumulative gas, the highest profit is achieved when the vertical distance between the well is 0 meters, regardless of the gap in completion times between the parent and child wells. And raising the well distance vertically leads to a poorer economic profit.

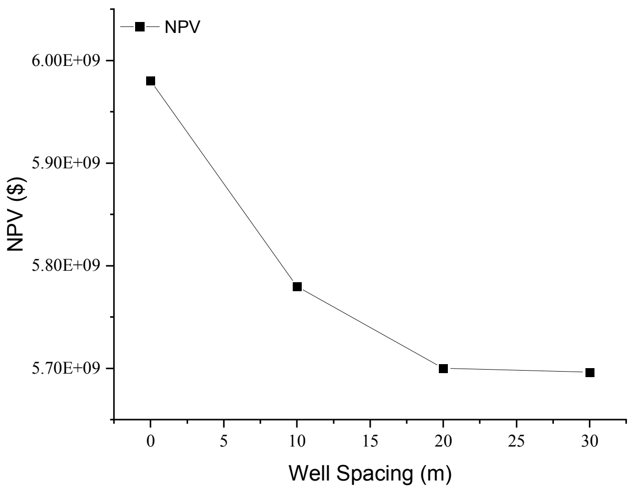


Figure 31. *Relationship between the total cumulative gas and NPV for 6-months completion difference between wells.*

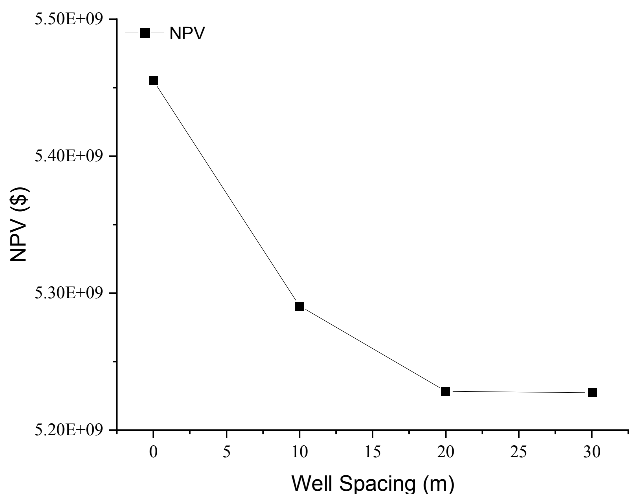


Figure 32. *Relationship between the total cumulative gas and NPV for 60-months completion difference between wells.*

6. Conclusion

Natural gas from unconventional reservoirs is typically extracted by a combination of horizontal well drilling and multi-stage hydraulic fracturing. Profitable development of unconventional resources involves finding the best well spacing. To determine the optimal well spacing in our shale gas reservoir regarding economic indicators, we used a commercial simulator (CMG simulator) to do the flow simulation-based reservoir modeling. Our gas reservoir was constructed by replicating the natural fractures, heterogeneous characteristics, adsorption/desorption phenomenon, and geomechanical effects that characterize real shale gas reservoirs. First, the number and geometry of the wells were looked at then, the sensitivity study of the lateral and vertical well spacing was investigated.

Based on the results of our simulation, we established that ten wells and aligned well geometry give the most economic advantage for the optimization approach.

For maximum gas recovery, the lateral well spacing must be increased significantly, and the vertical well spacing must be smaller enough for all wells to produce more gas. In addition, economic investigation reveals that extending the distance between wells might result in more excellent financial value for lateral well spacing. In contrast, for vertical well spacing to yield a superior economic return, all wells must be drilled in the same pay zone.

Although much progress has been made in the optimization of well spacing for shale gas reservoirs using reservoir modeling, one disadvantage of the local grid refinement approach is the incorrect assumption that hydraulic fractures are planar. Further study can analyze the influence of non-planar complex fracture geometry on the two-phase flow of shale gas wells through the use of a new, accurate, and efficient technique known as the embedded discrete fracture model (EDFM). It can give substantial insight into the degree to which fracture complexity can impact the performance of shale gas wells, allowing for the optimization of well spacing and design of multiwell completion techniques.

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