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A Study on Optimal Well Spacing for Unconventional Tight Oil Reservoirs Utilizing 3D Reservoir Simulation

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Abstract

In this study, three-dimensional (3D) reservoir simulation models were developed to perform different simulation runs which aim to get an estimate for the optimal well spacing in such unconventional very low permeability reservoirs. It will take into consideration the limitations, uncertainties, and capabilities of each parameter like matrix permeability, hydraulic fracturing spacing, half-length, height, and conductivity to get an enhanced estimate of the optimal distance between wells. The estimated recovery factor and production forecasting using the reservoir simulation with its capabilities to get computational cases with different combinations will get the optimal well count with optimum economic evaluation. Utilizing 3D reservoir simulation modeling can help create a variety of scenarios with various arrangements of affecting factors, such as well design, pore volume, matrix permeability, and petrophysical parameters. Characterizing hydraulic fracture parameters, such as fracture spacing, fracture half-length, and fracture conductivity, is fraught with uncertainty. Furthermore, drilling, and fracturing procedures are expensive. As a result, it is crucial to quantify these fracture parameters using different data to optimize the fracture design for both single and many wells using economic analysis. A general production trend analysis and comparisons are run for various well spacing with different numbers of wells per 100 acres. The impact of the oil price and the other operational costs required for various instances will be considered in an economic evaluation based on a new well spacing optimization process. The net present value was calculated for several cases by changing the number of wells 2, 3, 4, 5, 6, 7, and 8 wells and showed that the optimum well spacing is 300 feet.

Keywords: *Unconventional; Tight Oil; Simulation; Fracturing; Well Spacing; Sensitivity.*

1. Introduction

Unconventional resources like tight oil have exploded domestically and internationally due to technological breakthroughs in horizontal drilling and multistage hydraulic fracturing. To economically produce these unconventional reservoirs, the efficacy of the fracturing-stimulating treatment is crucial [1]. To access the trapped hydrocarbons, tight rocks, shale, or source rocks are examples of low permeability formations that hydraulic fracturing is used to improve oil and gas output. Fracturing fluid must be injected for this to happen consisting of water under pressure high enough to fracture the rock and produce a constructed conduit for oil and gas to flow from the reservoir to the crack in the formation in the wellbore [2].

The permeability of tight reservoirs ranges from 0.1 to 0.001 mD, shale reservoirs range from 0.001 to 0.0001 mD, and conventional reservoirs, which are more permeable than unconventional reservoirs, range from 10 to 100 mD [3]. The ranges of permeabilities for different reservoir types are shown in (Fig.1). Effective fracturing design necessitates a thorough comprehension and consideration of the elements that influence how well this treatment works, like proppant concentration and its size, kind, fracturing fluid characteristics, rate of pumping, number of fractures, and both fracture spacing and geometry. The schematic showing the hydraulic fracturing configuration in the horizontal well is shown in (Fig. 2).

The numerical approach often uses local grid refinement (LGR) to explicitly describe the hydraulic fracture with a modest and constant fracture width but a larger permeability [4]. However, modeling and simulating the impact of nonplanar fracture geometry on well productivity and transient flow behavior remains difficult using different numerical methodologies [5]. The majority of them have some difficult practical problems, such as complex model setups brought on by complicated fracture gridding and high computation costs [6].

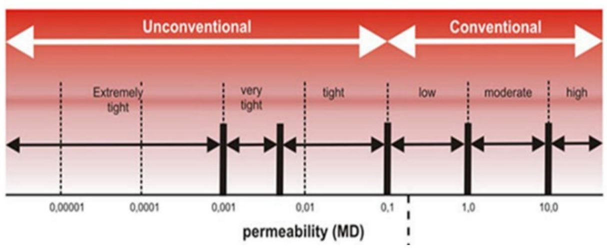


Fig. 1. Scales of permeability for tight oil (modified after [3]).

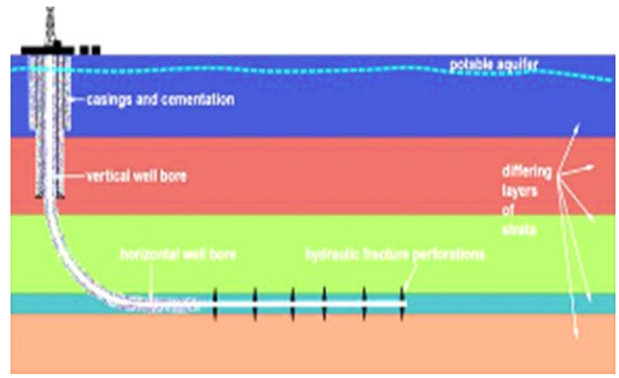


Fig. 2. Hydraulic fracturing in horizontal well (modified after [6]).

In this study, reservoir simulation calculations will be used firstly to study the impact of different reservoir and hydraulic fracturing parameters by sensitivity analysis and several simulations runs for each input parameter to get the information about the most influencing parameters affecting the productivity trends and the ultimate recovery of the tight oil reservoir system. After that, a simulation run will be constructed utilizing multi-horizontal wells to get the effect of different numbers of wells in certain reservoir accesses are in tight oil reservoirs. Optimum well spacing and number of wells will then be calculated based on the relation between the net present value and ultimate cumulative oil producer per each case.

2. Tight oil reservoirs

Tight oil reservoirs can exist in every geological setting and oil-bearing accumulations. The lithology, lithofacies, sand bodies, physical qualities, oil-bearing properties, and reservoir types are considerably heterogeneous as a result of the combined impact of deposition, diagenesis, and tectonics [7]. Natural fractures are widely scattered in confined reservoirs [8].

2.1. Characteristics of tight oil reservoirs

The types of lithology and lithofacies are numerous and intricate. They are impacted by tectonic characteristics, sedimentary environment, and diagenetic evolution as well as aspects related to basin type. The distribution stability is poor, the vertical and horizontal properties fluctuate rapidly, and there is significant heterogeneity. The reservoir lithology and lithofacies change rapidly and discontinuously for the horizontal distribution.

A tight reservoir is divided into four types based on this classification (Table 1). The distribution of sand bodies, lithology, and lithofacies all play a role in the discontinuous distribution of various reservoir types [9].

Table 1. Classification of tight oil reservoirs.

Physical properties	Classification			
	I	II	III	IV
Lithology	Fine sandstone	Fine sandstone and siltstone		Siltstone
Porosity, %	> 12	8-12	5-8	< 5
Permeability, mD	> 0.12	0.08-0.12	0.05-0.08	0.01-0.05
Pore-throat radius, μm	> 0.15	0.1-0.15	0.05-0.10	< 0.05

2.2. Fractures in tight oil reservoirs

In tight reservoirs, a complex fracture network can be created by natural fractures and hydraulic fractures. They contain a variety of different types and scales of fractures [9]. These natural fractures display a discontinuous characteristic in their spatial distribution across scales [10]. They have vastly different geometrical characteristics from one another [11]. Surface distribution is highly diverse and possesses numerous scale features [12]. The development degree, fracture density, fracture number, cluster number, and fracture direction are varied, and the differences in spatial distributions are also not trivial, as a result of the changes in lithology, lithofacies, reservoir thickness, and rock characteristics [13].

Large-scale fractures, middle-scale fractures, small-scale fractures, micro-fractures, and nano-fractures are the five categories that may be distinguished based on the geometrical characteristics of extension distance and fracture width [14].

Large-scale fractures are built on 3D seismic information. Highly accurate fractures with a broad distribution and big scale can be found using a hydraulic interpretation. Their extension length is typically greater than 100 m, and their extension width is greater than 10 mm. This kind of reservoir fracture has a sizable scale and a high flow capacity. However, the percentage is quite tiny [9].

Middle-scale fractures. The fractures between wells with a middle scale can be found using a tracking or coherent body technique [15]. Their width is 1-10 mm, and their extension length is 10 to 100 m. This type of fracture has a high fracture density, a long extension distance, and a reasonably high flow ability in a reservoir [16]. The proportion is higher when compared to fractures of a significant size.

Small-scale fracture information from coring, traditional logging, and image logging is used to identify small-scale cracks. The measured fracture network surrounding a well and the precisely documented fracture network between wells are examples of this type of fracture. The extension has a 0.1-1.0 m length and 0.1-1.0 mm width. In a reservoir, the extension distance and flow capacity are not excessive. However, the percentage is quite large [17].

Micro-fractures. Core observation and thin section analysis serve as the foundation for micro-fractures. Their width is 0.001-0.1 mm, while their extension length is 0.005-0.1 m. At various scales, it links pore systems. There is little extension distance. The ratio is substantial.

Nano-fractures are based on thin sections and SEM data; the breadth and extension length are both less than 0.001 mm and 0.005 m, respectively. Different scales of pore systems can be connected by it. There is little extension distance.

2.3. Fluid flow properties in tight oil reservoirs

The capillary pressure and relative permeability curves are the fundamental indicators of the flow behavior of fluids in media with varying scales, holes, and fractures [18]. Distinct scales of media's pores and cracks result in distinct geometrical scales as well as different physical characteristics.

2.3.1. Capillary pressure

The capillary pressure data behaves differently in media with various scale holes and fractures. In porous media, the capillary pressure decreases as the pore radius rises [19]. The capillary pressure increases with decreasing pore radius [18]. The highest capillary pressure is seen in nano-pores as the ability for fluid to flow is poor [9].

2.3.2. Relative permeability

The relative permeability curves of porous media at various sizes exhibit various qualities as a result of the impacts of geometrical scale, physical parameters, and fluid properties [20].

Relative permeability reaches its maximum point at 1.0, the relative permeability curves of micro and nano-fractures are comparable to those in large-scale porous media, although they are superior to large-scale porous media [21].

2.4. Production delineation for tight oil reservoirs

Tight oil reservoirs primarily use horizontal well drilling, hydraulic fracturing, and depletion processes as part of their development mode.

2.5. Hydraulic fracturing and horizontal drilling

The intricacy of the fracture network, the size of the matrix rock separated by the fracture network, and the SRV (stimulated reservoir volume) all have an impact on the effect of a stimulated reservoir under the given circumstances of the geological characteristics of tight reservoirs and a fracturing technique [23].

2.5.1. Why hydraulic fracturing is essential for tight oil reservoir

A geological model based on reservoir lithology, brittleness, natural fracture, and spatial distribution, and features geomechanical stresses [24]. Hydraulic fracturing is a mandatory option to produce from tight reservoirs to maximize the producible reservoir volume and connect with naturally fractures existing in the reservoir [25].

2.5.2. Hydraulic fracturing process

A complex fracture network is created by hydraulic fracturing, a method of reservoir stimulation [26]. Using the techniques of many cluster horizontal well perforations, a high production rate, and large liquid quantities, we may effectively connect natural fractures and rock bedding [27].

2.5.3. Hydraulic fracturing flow between reservoirs and wells

According to Darishchev *et al.*, in tight oil and gas reservoirs, the development mode of horizontal well drilling and hydraulic fracturing results in complex contact mode and flow behavior between reservoir media and wellbore [29].

2.5.4. Hydraulic fracturing fluid

However, it must be viscous enough to deliver proppant to the fracture's tip if it is to serve its intended purpose of forming a fracture with the required geometry. Today, water is the primary component of fracturing fluid. Slickwater, liner gel, and crosslinked gel are the most common fracturing fluids based on water [28].

2.5.5. Hydraulic fracturing proppant

Sand or artificial ceramic materials are examples of proppant, which is a solid substance. Keeping fractures open during and after the fracturing therapy, when the pressure is released, is the major purpose of a proppant. The three primary kinds of propellants utilized in the sector are ceramic, resin-coated sand, and pure silica sand [28].

2.5.6. Development with horizontal wells

The wellbore direction, trajectory, and horizontal wellbore length all have an impact on how well horizontal wells perform during development in confined reservoirs [30]. Increases in single-well production, cumulative production, and well control reserves can all be achieved by horizontal well development. Drilling more natural cracks, increasing the drilling ratio of high-quality reservoirs, and drilling more sand bodies are the major goals.

2.6. Flow behavior of hydraulic-fractured horizontal wells

2.6.1. Single porosity models

Single porosity models (SPM) are frequently regarded as the modeling gold standard, regardless of the solution approach and numerical approaches used. The entire reservoir is represented as a continuum model since these models explicitly describe fractures in the computational domain [31].

2.6.2. Dual porosity models

The numerical systems in which fractures and the rock matrix are, which represent two networks that overlap in the computational domain are called Dual Porosity Models (DPM), and the interaction between the matrix and fractures is described by experimentally derived transfer functions.

2.6.3. Discrete fracture models

The discrete fracture network (DFN) model is a simplification of single porosity models in which fractures are represented as a lower dimension for the meshing process but are nevertheless explicitly taken into account during the mathematical formulation modeling process [31].

3. Methodology and data

A 3D mechanistic reservoir simulation model of a tight oil reservoir was built in this work utilizing a 3D reservoir modeling simulator. The constructed model has dimensions of 3000 feet in length, 1500 feet in width, and 300 feet in height, with 175x75x15 grid cells in the x, y, and z axes (Fig. 3). A horizontal well was intended to penetrate the reservoir to the center of the reservoir and produce oil with a constrained minimum bottomhole pressure of 500 psi. The reservoir has an initial pressure of 4300 psi at datum -6,000` TVD. The reservoir and rock parameters utilized in the base model used for different sensitivities are provided in (Table 2). The relative permeability used is obtained from published rock data for tight oil reservoirs (Fig. 4). The oil producer was hydraulically fractured after drilling. All the hydraulic fractures are assumed to be propped fractures. LGR was used in grids that include hydraulic fracturing to account for the pressure drop across the reservoir.

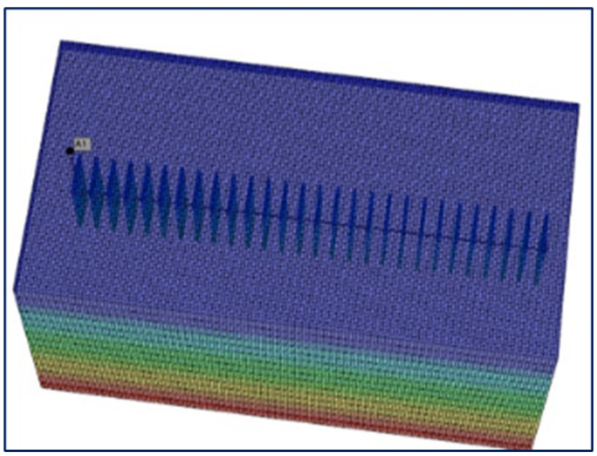


Fig. 3. Base 3D simulation model.

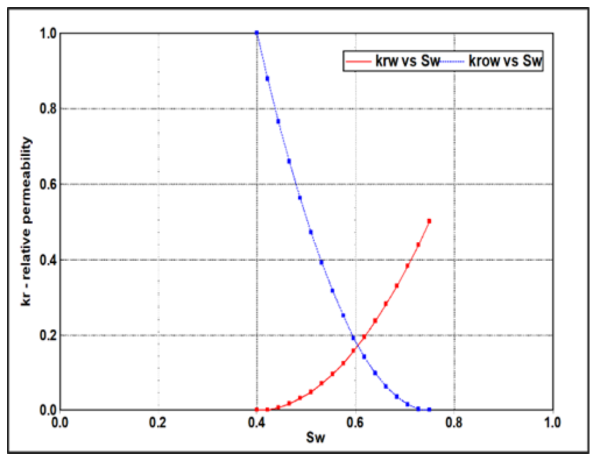


Fig. 4. Relative permeability data.

Table 2. Parameters used for the base simulation model.

Parameter	Unit	Value
Initial reservoir pressure	psi	4300
Reservoir temperature	ºF	150
Reservoir permeability	mD	0.05
Total compressibility	psi-1	3x10-6
Grids	i, j , k	150 x 75 x 15
Porosity	fraction	0.12
Total pore volume	MMSTB	28.85
Oil density	lb/ft^3	56.75
Bubble point pressure	psi	2810
GOR	ft^3/bbl	500
Initial water saturation	fraction	0.2
Horizontal well length	ft	2700

Parameter	Unit	Value
No of Clusters	cluster	28
Cluster spacing	ft	100
Time	years	10
Fracture half-length	ft	100
Bottom hole flowing pressure	psi	500

The validity of any developed model is an important parameter for outcomes. To ensure the reliability of the results, reservoir 3D numerical simulation models containing natural and hydraulic fractures were reviewed and compared with published reservoir properties data and validated with field data before sensitivity analysis and long-period production forecast. Several simulations were run to examine the influence of three major types of characteristics on production behavior of tight oil reservoirs: reservoir parameters, reservoir heterogeneity, and hydraulic fracture parameters. Sensitivity parameters for reservoir parameters include matrix permeability. However, the sensitivity conducted for the influence of fracture parameters on tight oil production performance includes fracture height, fracture half-length, cluster number, cluster spacing, and fracture conductivity. After studying the different parameters affecting tight oil production, a sensitivity analysis is done for the multiple horizontal wells to study the optimal well spacing of horizontal wells in tight oil reservoir systems for certain reservoir delineation areas.

3.1. Effect of reservoir matrix permeability

The tight oil matrix has a low permeability, typically in a range of 0.01 to 0.1 mD. The tight oil matrix permeability plays an important role in the oil recovery in a hydraulic fractured horizontal well. The matrix permeability highly affects the production rate from tight oil reservoirs. It also affects the ultimate recovery in terms of cumulative oil volumes produced. The data from the base case model mentioned are used as base values for the model.

Three cases, case 1, case 2, and case 3 were developed to check the effect of variable matrix permeability with 0.01 mD, 0.05 mD, and 0.1 mD, respectively. The oil rate showing the results from the three cases is shown in (Fig. 5) and shows a higher initial rate for the highest permeability, however, at the later time of production, the curves from case 2 (0.05 mD) & and case 3 (0.1 mD) emerge and produce nearly the same rate.

The cumulative oil production curves for the three cases are shown in (Fig. 6), revealing that the highest ultimate recovery is for case 3, with the highest permeability (0.1 mD). The cumulative oil production is in a direct proportional relationship with the matrix permeability. The pressure response at three different time steps (1 year, 5 years, and 10 years) for the first and the third cases is shown in (Fig. 7).

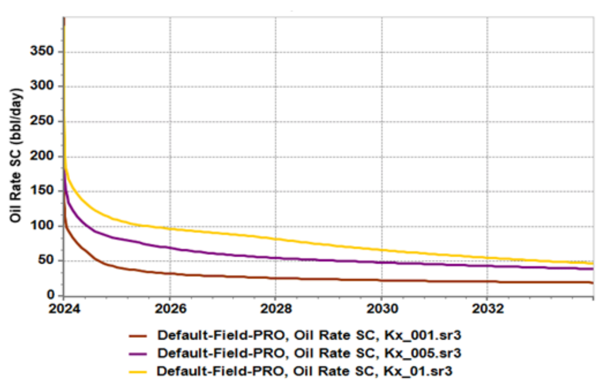


Fig. 5. Effect of matrix permeability on oil rate.

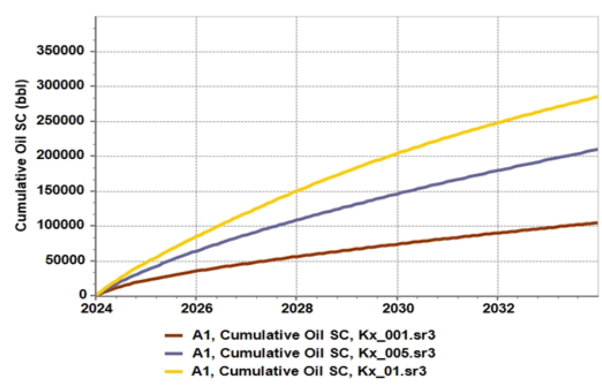
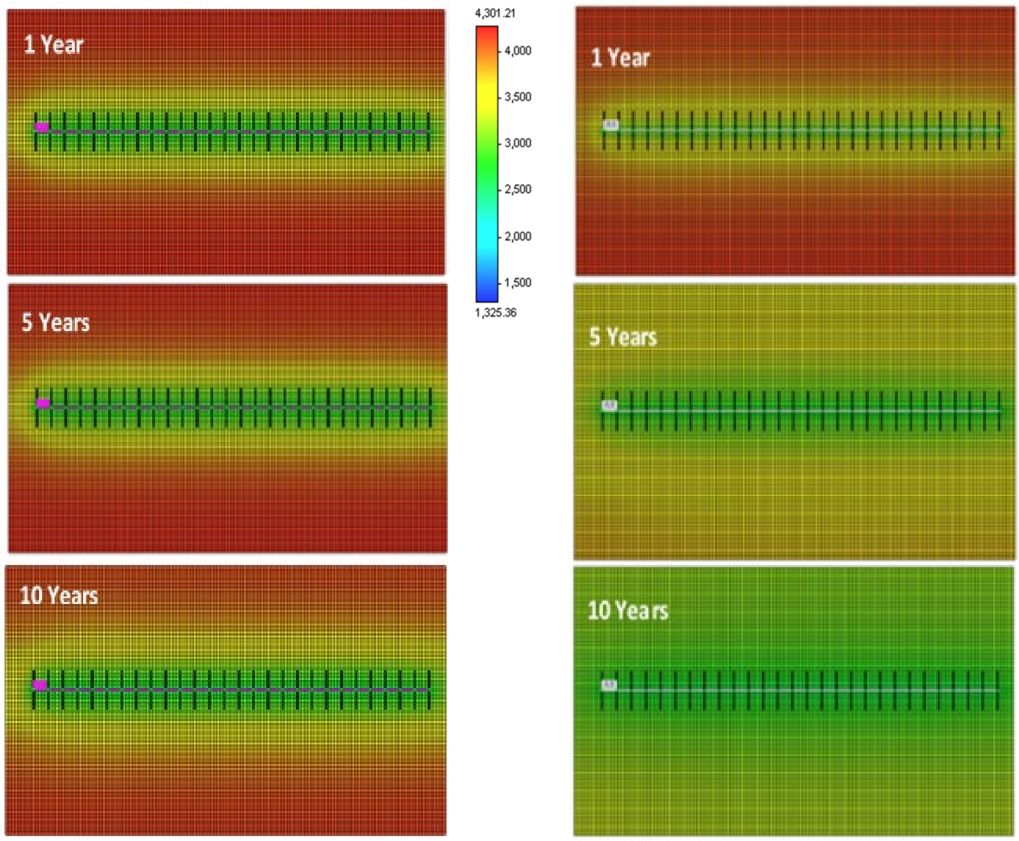


Fig. 6. Effect of matrix permeability on cumulative oil.

3.2. Number of fracturing stages

Multi-stage fracturing is typically used in tight oil reservoirs to gain access to additional stimulated reservoir volume (SRV). The effect of additional fractures is exactly proportional to the cumulative oil produced and the production rate at the commencement of production, as illustrated in (Fig 8) and (Fig 9). Three examples, case 1, case 2, and case 3, were designed to test the effect of varying the number of fracturing stages using 7, 14, and 28 fractures, respectively. The pressure response at 3 different time steps (1, 5 and 10 years) for the three cases is shown in (Fig. 10).



(A) (B)

Fig. 7. Pressure response at three different time steps 1,5 and 10 years.
(A) Case 1: Matrix permeability is 0.01 mD. (B) Case 3: Matrix permeability is 0.1 mD.

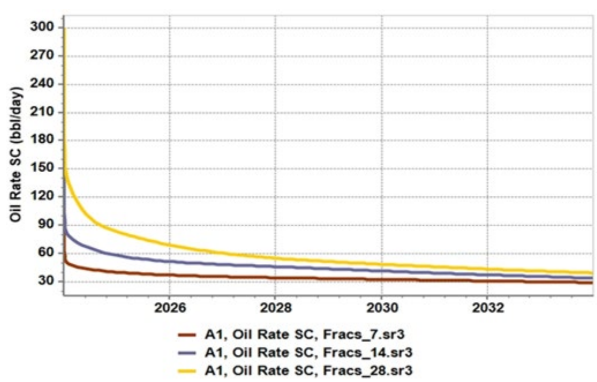


Fig. 8. Effect of number of fractures on oil rate.

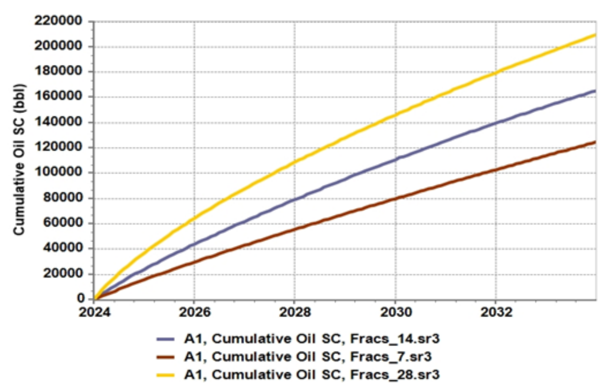


Fig. 9. Effect of number of fractures on cumulative oil.

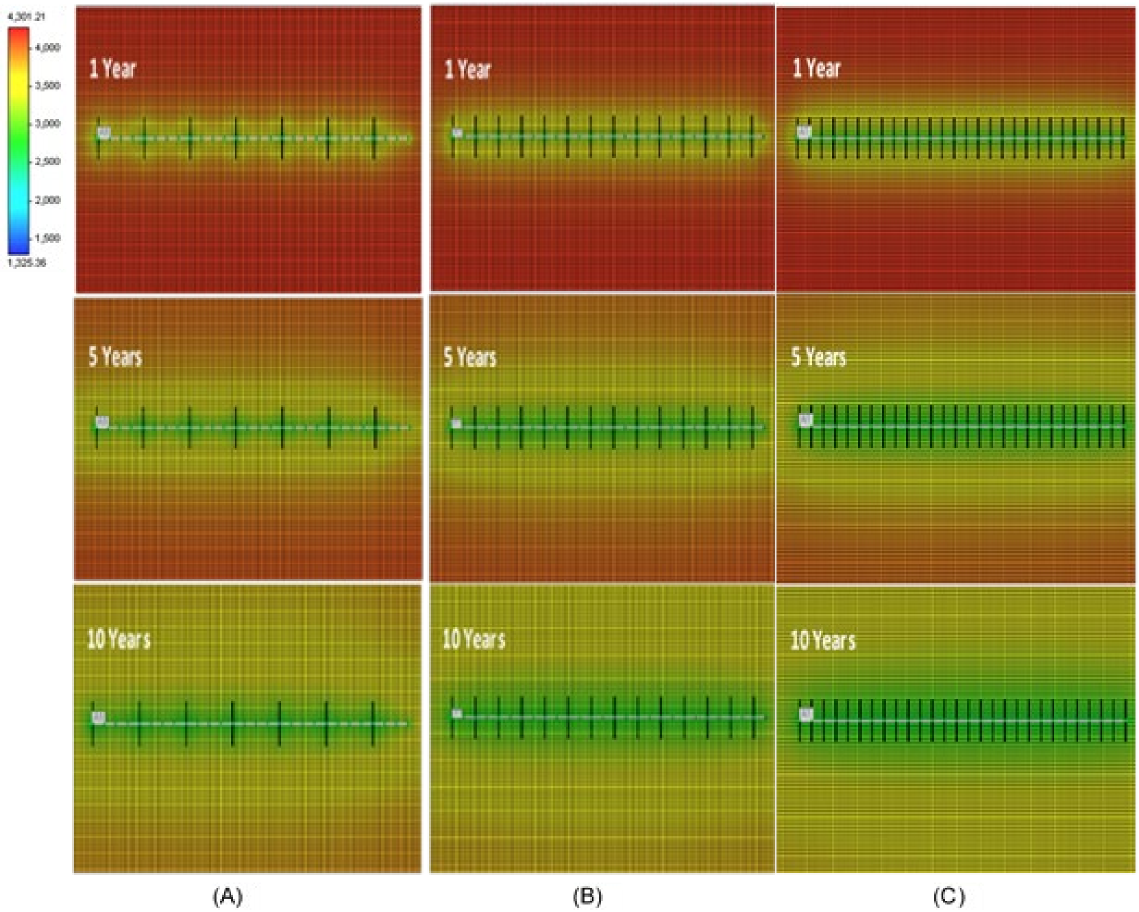


Fig. 10. Pressure response at three different time steps (1, 5 and 10 years).
(A) Case 1: Stages are 7 fractures. (B) Case 2: Stages are 14 fractures. (C) Case 3: Stages are 28 fractures.

3.3. Effect of hydraulic fracture cluster spacing

When there are numerous fractures inside the reservoir, it is critical to examine the hydraulic fracture cluster spacing influence on tight oil production rate. It goes without saying that if the number of fractures rises, more cash will be required to invest. When the number of fractures increases, more capital is required to invest, and the return on investment may take longer. As a result, the fracture spacing impact must be assessed for tight oil reservoir production performance. As a result, the current study performed a sensitivity analysis on fracture cluster spacing. This study investigated and compared the effect of fracture spacing on a total of seven fractures. The simulation was run for ten years to investigate the influence of altering fracture spacing on tight oil. Three cases were constructed to account for the effect of different cluster spacing.

Case 1 has a constant cluster spacing of 400 ft between the seven clusters. Case 2 has an asymmetrical cluster spacing of 100-200-300-400-500-600 ft between the seven clusters. Case 3 has symmetrical cluster spacing of 200-200-400-400-200-200-200 ft between the seven clusters. The effect of different cluster spacing on the oil production rate is shown in (Fig. 11), while the effect on the cumulative oil production is explained in (Fig. 12). The effect of asymmetric and symmetric cluster spacing is nearly the same, however, the case with constant spacing showed higher oil rate production and higher cumulative production. The pressure response at 3 different time steps (1, 5 and 10 years) for the three cases is shown in (Fig. 13).

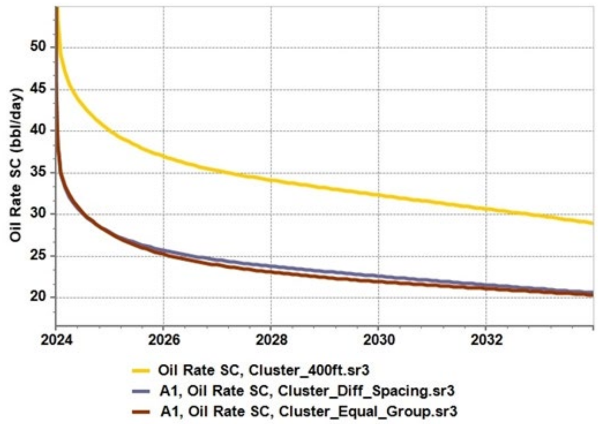


Fig. 11. Effect of different cluster spacing on oil rate.

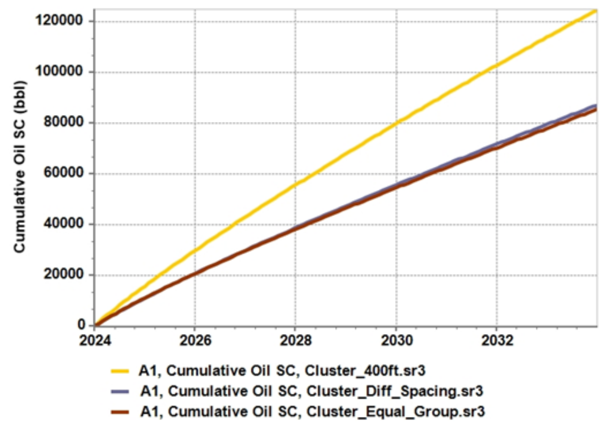


Fig. 12. Effect of different cluster spacing on cumulative oil.

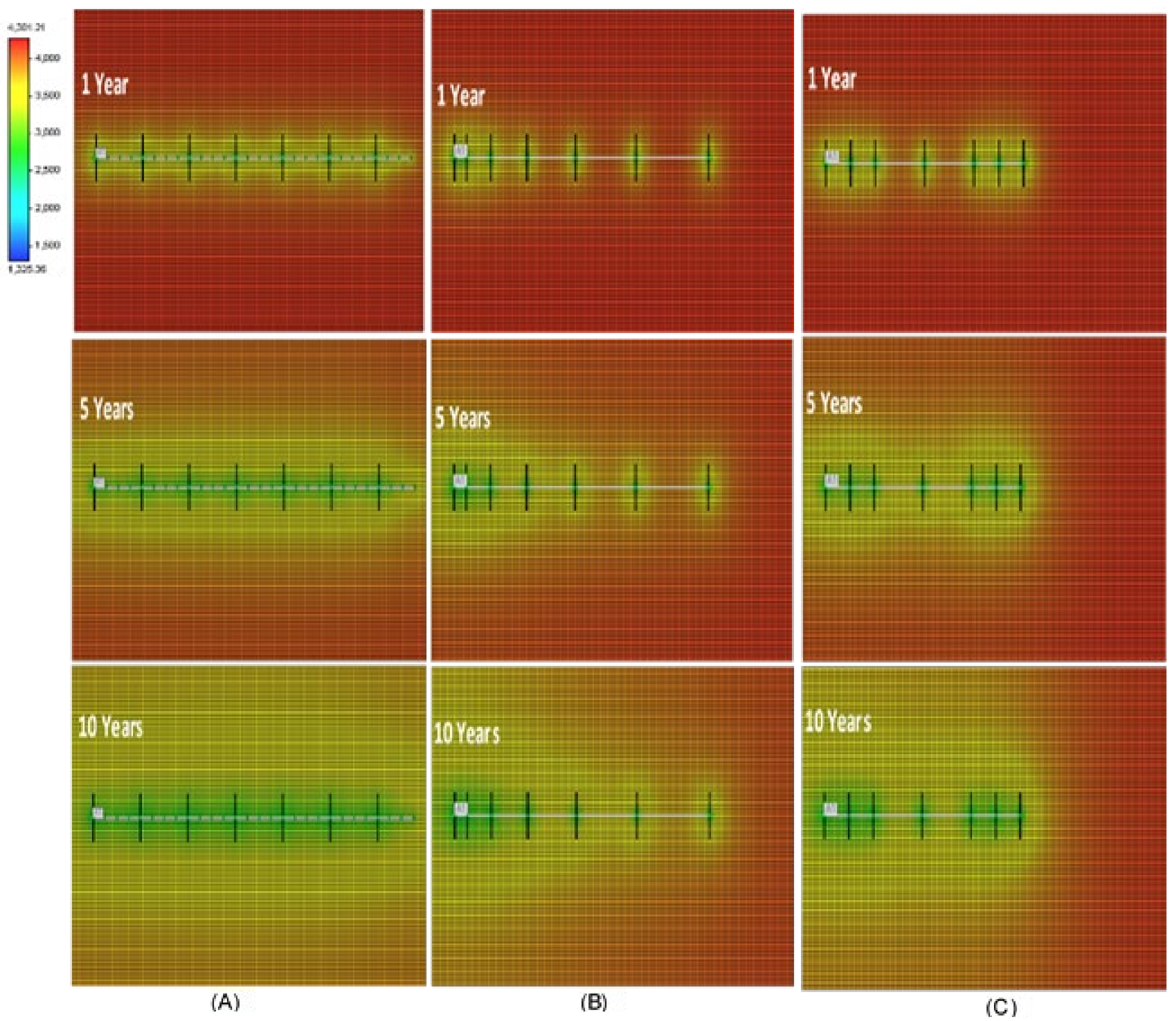


Fig. 13. Pressure response at three different time steps (1, 5 and 10 years).
(A) Case 1: cluster spacing of 400 ft. (B) Case 2: Asymmetric cluster spacing. (C) Case 3: Symmetric cluster spacing.

3.4. Effect of hydraulic fracture height

Hydraulic fracture height decreases as the in-situ stress increases. The geomechanics of the rock heavily influences fracture propagation. When modeling the hydraulic fracture in tight oil, the fracture height should be considered, as well as how much will propagate into the upper and lower grids. Three examples were created, each having a fracture height of 60, 100, and 200 feet. The effect of different fracture heights on the oil rate is illustrated in (Fig. 14), while the effect on the cumulative oil production is shown in (Fig. 15).

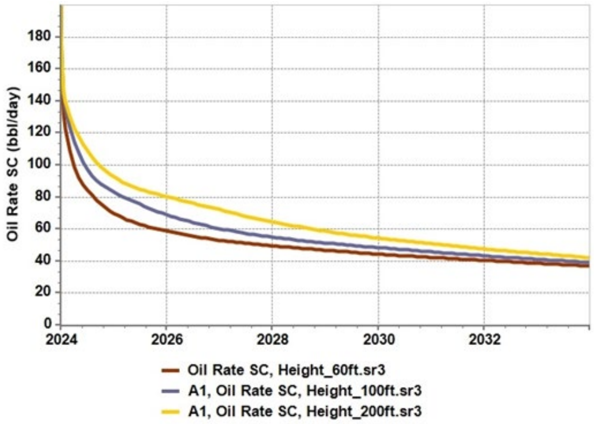


Fig. 14. Effect of fracture height on oil rate.

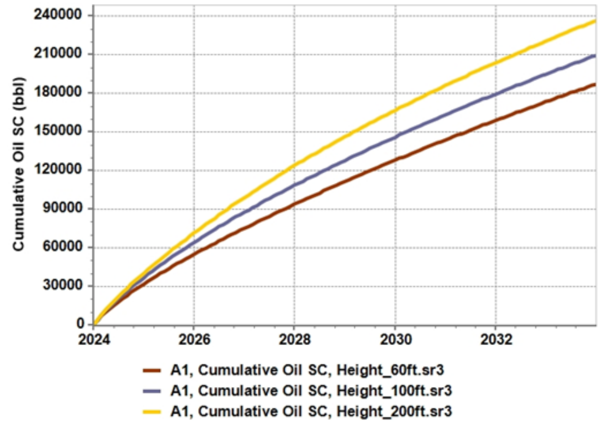
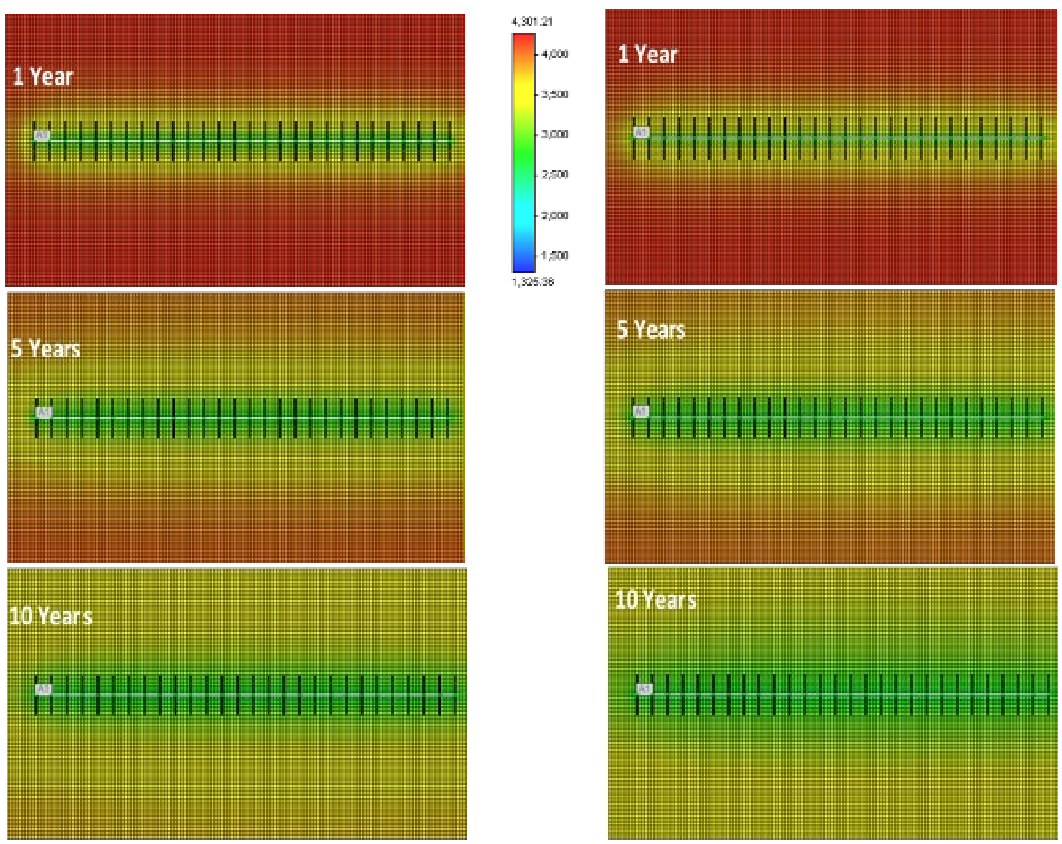


Fig. 15. Effect of fracture height on cumulative oil.



(A) (B)

Fig. 16. Pressure response at three different time steps (1, 5 and 10 years).
(A) Case 1: Fracture height of 60 ft. (B) Case 3: Fracture height of 200 ft.

The oil rate for case 3 of 200 ft height showed the highest production and highest cumulative oil, however, the three cases emerge at the end of the 10-year production period. The cumulative oil increased by 15% only, notwithstanding the fracture height nearly quadrupled from 60 ft to 200 ft. The pressure responses at the three different time steps (1 year, 5 years, and 10 years) for case 1 (60 ft height) and case 3 (200 ft) are shown in (Fig. 16).

3.5. Effect of hydraulic fracture half-length

Because of their extremely favorable flow channels that provide ample space for fluids to flow towards the wellbore, fracture half-length (X_f) is the major characteristic that determines the productivity of low permeability tight oil reservoirs.

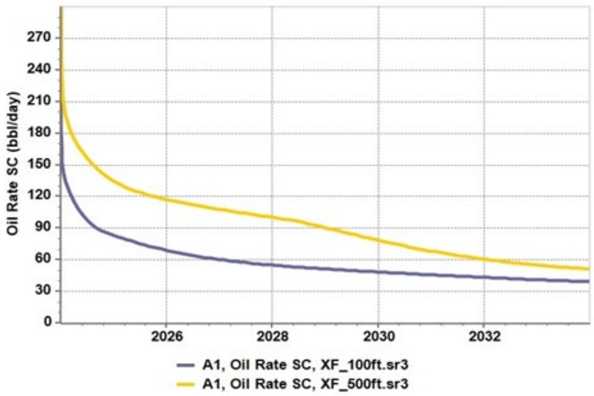


Fig. 17. Effect of fracture half-length on oil rate.

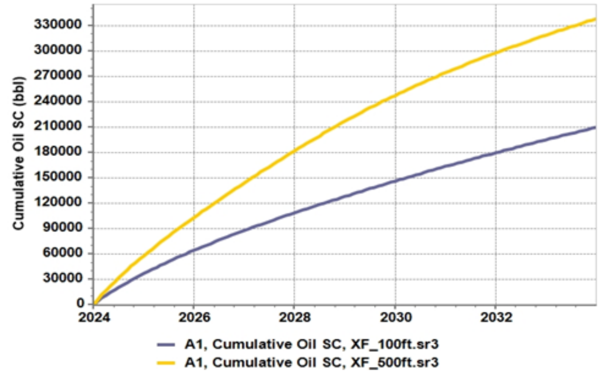


Fig. 18. Effect of fracture half-length on cumulative oil.

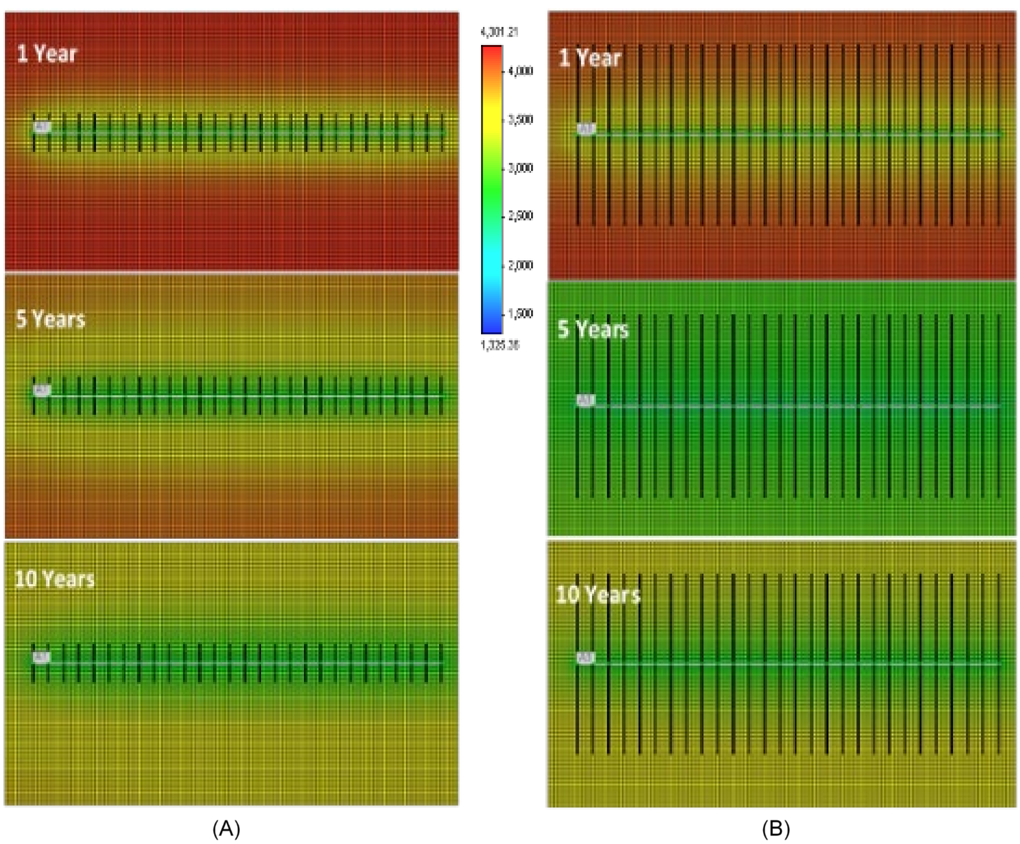


Fig. 19. Pressure response at three different time steps (1, 5 and 10 years).
(A) Case 1: Fracture half-length is 100 ft. (B) Case 2: Fracture half-length is 500 ft.

Sensitivity testing was performed on two instances in this investigation. Case 1 has a fracture half-length of 100 feet, whereas case 2 has a fracture half-length of 500 feet. The oil rate is higher in case 2 with a fracture half-length of 500 ft (Fig. 17), which is due to more accessed reservoir volume and more drainage to produce from. More pressure depletion to produce more oil with higher half-length. The cumulative oil is higher by 60% when changing the length is from 100 feet to 500 feet (Fig. 18). The pressure response at 3 different time steps (1, 5 and 10 years) for case 1 (X_f= 100 ft) and case 2 (X_f= 500 ft) is shown in (Fig. 19).

3.6. Effect of hydraulic fracture conductivity

Fracture conductivity (F_{cd}) is a critical parameter calculated by fracture design programs to estimate the hydraulic fracture productivity and the fold of increase after the fracturing job. A sensitivity was done on different inputs of fracture conductivity and the effect of these changes analyzed.

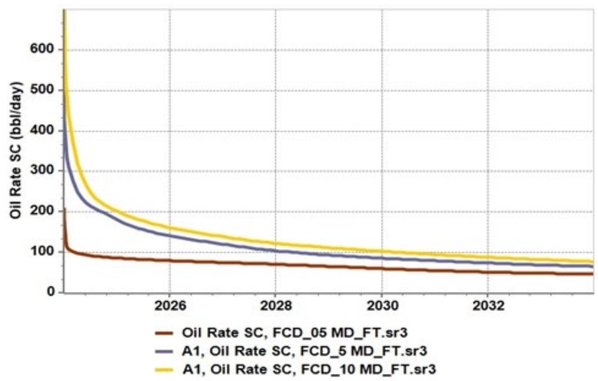


Fig. 20. Effect of fracture conductivity on oil rate.

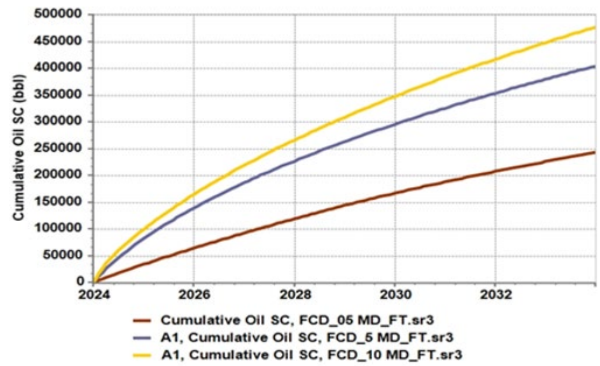


Fig. 21. Effect of fracture conductivity on cumulative oil.

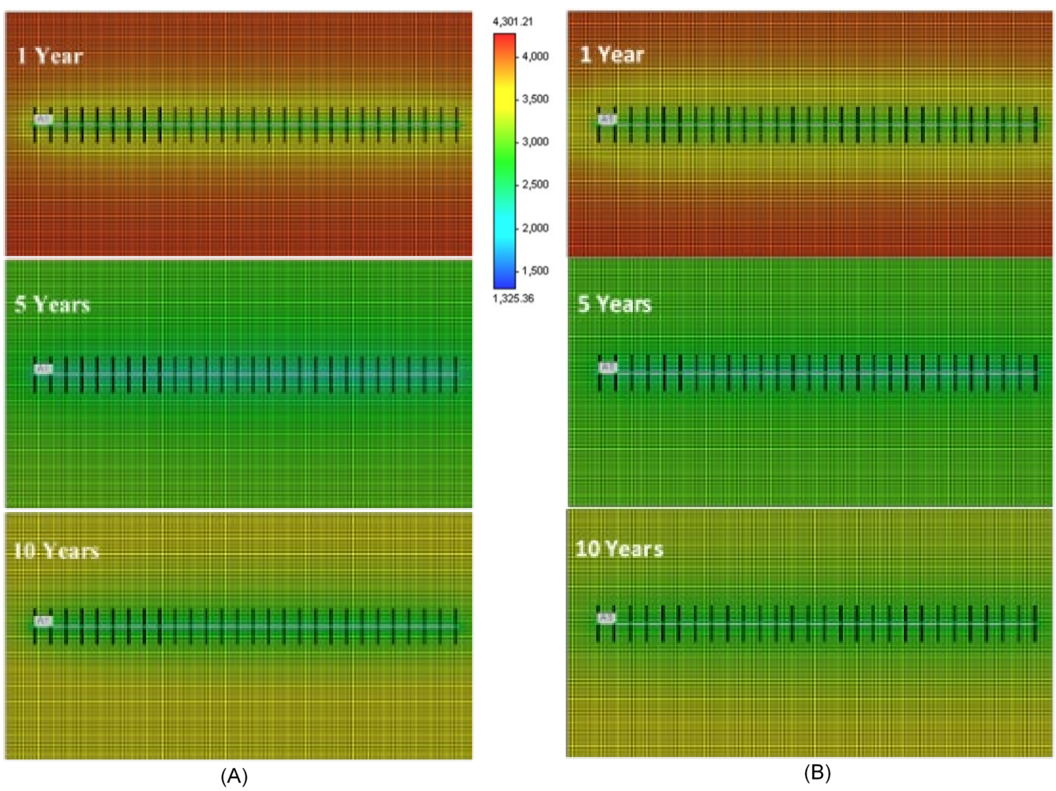


Fig. 22. Pressure response at three different time steps (1, 5 and 10 years).
(A) Case 1: Fracture Conductivity is 0.5 mD.ft. (B) Case 3: Fracture Conductivity is 10 mD.ft

Three cases for the fracture conductivity had been used as 0.5, 5 and 10 mD.ft as case 1, case 2 and case 3, respectively. The starting oil rate for case 3 (F_{cd} =10 mD.ft) was the highest; however, the three cases converged after 3 years and became nearly with the same performance (Fig. 20). The ultimate cumulative oil after ten years (Fig. 21) was analyzed and the results showed that the cumulative oil nearly doubled when the conductivity changed from 0.5 to 5 mD.ft, while it increased by 20% when the conductivity changed from 5 to 10 mD.ft. The pressure response at three different time steps (1,5 and 10 years) for case 1 (F_{cd} =0.5 mD.ft) and case 3 (F_{cd} =10 mD.ft) is shown in (Fig. 22).

3.7. Well spacing optimization for multi horizontal wells modeling

After studying the different parameters affecting the reservoir simulation model for a tight oil reservoir, and making sensitivity on these different parameters, different 3D mechanistic models were built to study the effect of well spacing on tight oil reservoir productivity targeting the optimal well spacing for such unconventional reservoir. The model dimensions were 3000 feet in length, 1500 feet in width, and 150 feet in height. The model grids are 175x75x15 with a grid size of 20x20 feet. The whole reservoir area is about 100 acres, so this study will estimate the optimal well spacing for such a tight oil reservoir. A horizontal well penetrating the whole reservoir is constructed in the model, which is hydraulically fractured with 26 clusters with a spacing of 100 feet. The hydraulic fracture is assumed to be planar with a half-length of 50 ft and fracture conductivity of 5 mD.ft. The wells are set to produce oil with a constrained minimum bottomhole pressure of 500 psi. The reservoir has an initial pressure of 4300 psi at datum -6,000` TVDss. The matrix permeability is set to be 0.1 mD and the porosity is 0.14. F or a reservoir area of 100 acres, seven models were built. The number of wells tested in this study is 2,3,4,5,6,7,8 wells, with a well spacing of 500, 365, 300, 240, 200, 175, 150 feet, respectively. All the wells are assumed to start at the same time of 1-Jan-2024. The models have been run for ten years. The cumulative oil for all the models is analyzed and shown in (Fig. 23).

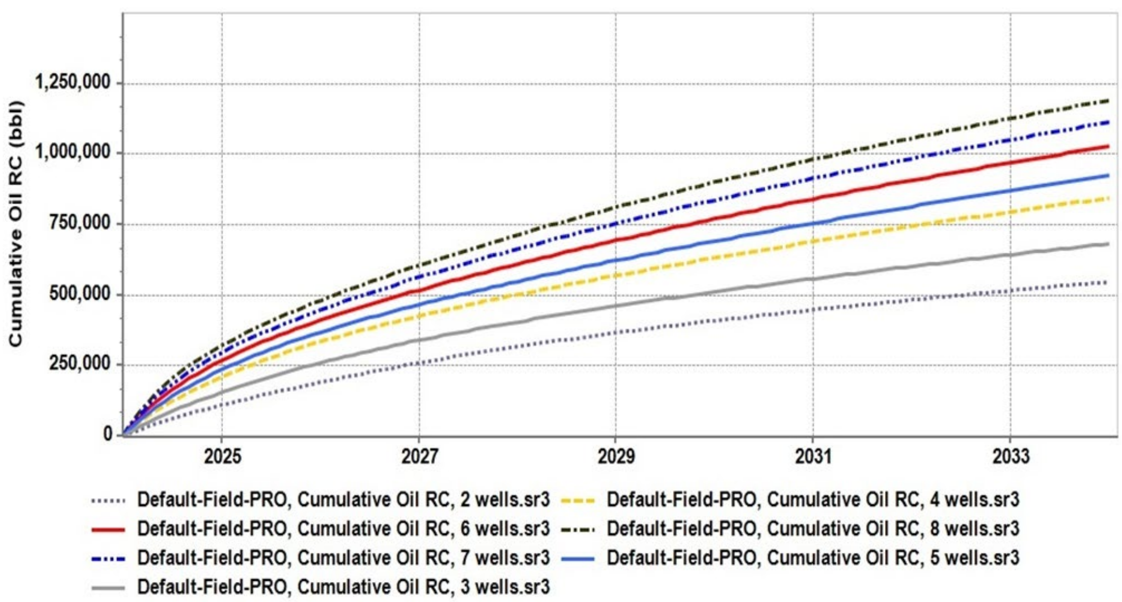


Fig. 23. Cumulative oil production for different well-spacing models.

3.8. Economic evaluation for well spacing optimization

Net present value (NPV) is evaluated for each case to achieve the optimum well spacing and optimum delineation development for such tight oil reservoirs. The cumulative oil production for each case from the calculated seven cases is obtained at two different time steps: i) 5 years and ii) 10 years, to calculate the NPV two times, after 5 years of production and 10 years of production. (Table 3) showed the cumulative oil production for the calculated at different well spacing.

Table 3. Cumulative oil production at different well spacing cases.

Number of wells	2 Wells	3 Wells	4 Wells	5 Wells	6 Wells	7 Wells	8 Wells
Well spacing, ft	500	365	300	240	200	175	150
Cum. oil after 5 years, MMSTB	0.37	0.46	0.57	0.62	0.69	0.75	0.81
Cum. oil after 10 years, MMSTB	0.55	0.68	0.85	0.92	1.03	1.11	1.19

To calculate the NPV at each time step, values for the costs of drilling, completion, and hydraulic fracturing jobs are needed to be inputs for the equation (1), where ΔTR_t is the total incremental revenue from oil production, i_r is the yearly discount rate, N is the total number of years and T is the total years of production. The total treatment cost includes the drilling, completion and hydraulic fracturing costs [32].

$$\textit{Net Present Value } (NPV) = \sum_{t=1}^{N} \frac{\Delta TR_t}{(1+i_r)^t} - \textit{Total Treatment Costs} \quad (1)$$

From different reported statistics for horizontal well drilling and completion, costs are estimated to be 2 \$MM per well. Also, the cost of hydraulic fracturing for a single propped fracture is assumed to be 20,000 \$ for creating a half-length of 50-100 ft with fracture conductivity of 2-4 mD.ft. The yearly discount rate is assumed to be 11% and the tax is 14%. The price of oil is set to be \$85/bbl.

The NPV vs well spacing is then calculated for the two mentioned time periods,5 and 10 years, and the results shown in (Fig.24) revealed that the optimum well spacing per 100 acres tight oil reservoir is 300 ft, which gives the highest NPV in the two time steps, at 5 years and 10 years. The optimum well count for this tight reservoir at these mentioned parameters is 4 horizontal, hydraulic fractured wells.

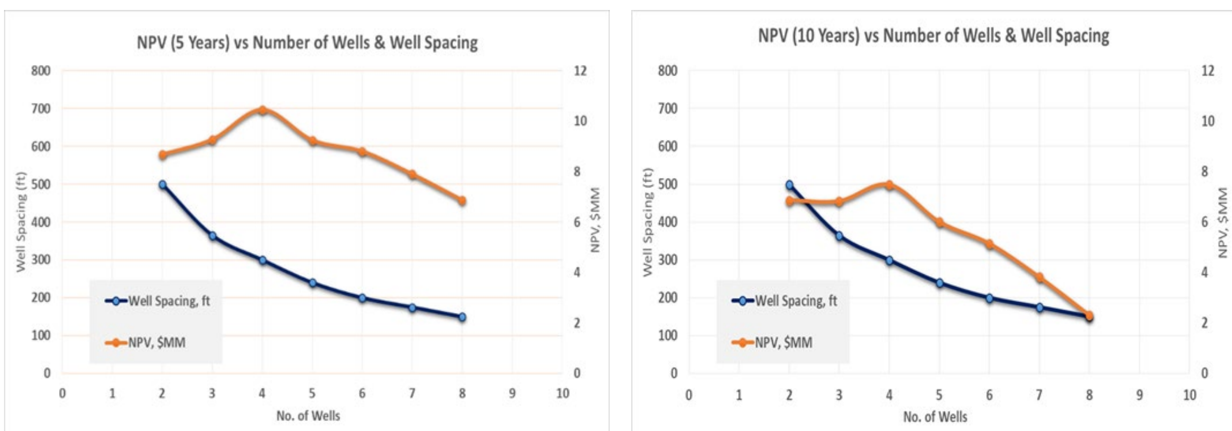


Fig. 24. NPV results versus well spacing and number of wells. (A) NPV for 5-year period. (B) NPV for 10-year period.

4. Conclusions

3D mechanistic model was constructed for tight oil reservoir via a reservoir simulation software to study the effect of different reservoir and hydraulic fracturing parameters on oil production rates and cumulative oil production. After that, several models were run with multi well configuration for a tight oil reservoir to assess the optimum well spacing in such unconventional tight oil reservoirs using certain reservoir and hydraulic fracturing inputs that studied via this work. NPV calculations were done to identify the optimum well spacing for horizontal wells in tight oil reservoirs. The main important parameters that should be considered in modelling a tight oil reservoir are the matrix permeability, fracture conductivity, and number of clusters. It was clear that the more fractures and clusters would lead to more cumulative oil, however, the cost per fracture and the NPV of the whole development should be considered. The horizontal well spacing for the tight oil reservoirs per 100 acres reservoir area is estimated to be 300 feet using 4 wells, which will give the maximum NPV calculated at two time steps; 5 years and 10 years to frame the whole development scope and timing for development.

Nomenclature

LGR	*Local grid refinement*	F_{cd}	*Fracture conductivity*
mD	*Millidarcy*	X_f	*Fracture half-length*
SPM	*Single porosity model*	*NPV*	*Net present value*
DPM	*Dual porosity model*	*MMSTB*	*Million stock tank barrel*
DFN	*Discrete fracture network*	ΔTR_t	*Total incremental revenue*
GOR	*Gas oil ratio*	i_r	*Discount rate*
CUM	*Cumulative*	*N*	*Total number of years*
TVD	*True vertical depth*	*T*	*Total years of production*

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