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The Effect of Drainage Radius Interference on the Design of Infill Well in FA Field

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ABSTRACT

In mature fields like FA Field, addressing production decline involves strategic infill well drilling to boost output from active structures. The location and number of infill wells are determined through bubble map analysis during development planning. The research methodology includes calculating recovery factors, estimating remaining reserves, predicting production increases post-infill drilling, and assessing infill well impacts. FA currently operates 13 development wells yielding approximately 346 bbl/day. Calculations reveal 5.41 MMSTB in remaining reserves with a 22.55% recovery factor. Bubble and iso-saturation maps identified locations for INF-1 and INF-2 infill wells, affecting specific observation wells. INF-1's placement near A-1, A-3, A-5, and A-7 resulted in a 10.69 BOPD decline offset by 54 BOPD additional production. INF-2, affecting 2 wells, saw a 6.37 BOPD drop and 44 BOPD increase. These scenarios illustrate how overlapping areas from infill wells decrease surrounding well production rates.In the base case scenario, without optimization, the recovery factor stands at 28.09%. With one infill well affecting 4 drainage radius, it rises to 29.6%; with two, to 30.92%.

INTRODUCTION

Field development is a crucial activity in planning future steps to achieve an optimal recovery factor. Adding infill wells is one strategy to maximize reservoir drainage with the goal of increasing the field's recovery factor. Infill wells are usually added to areas that still have parts of the reservoir that are not fully depleted. The planning method described in this paper involves the use of reservoir simulation.

Reservoir simulation involves creating a model of the reservoir that resembles the actual conditions. The parameters in the model match the actual reservoir parameters. With this model, development planning can be carried out with various scenarios without having to conduct direct exploration in the actual reservoir. This approach helps reduce field development costs. The results of the reservoir simulation include various development scenarios that provide cumulative production data to determine the optimal recovery factor. The purpose of reservoir simulation is to create an artificial reservoir model that is similar to the actual reservoir in the field. With the help of reservoir simulation, development planning can be done more easily and efficiently, resulting in development scenarios that are then practically implemented. The optimization of infill well addition in development planning aims to achieve optimal results from the addition of infill wells, measured by production effectiveness, production efficiency, and economic aspects. Several studies show different approaches to adding infill wells and their impacts in the field.

LITERATURE REVIEW

Ahmed, T. (2010) in his research on optimizing infill drilling in old oil fields using reservoir simulation methods concluded that infill drilling can increase oil recovery by up to 15% in old oil fields with heterogeneous reservoirs. The reservoir simulation method used in this study allows for the identification of areas with high oil saturation, which are the primary targets for placing infill wells. By using this approach, oil production can be optimized without excessive new well drilling, significantly reducing operational costs. Furthermore, this study highlights the importance of detailed reservoir characteristic analysis to ensure optimal infill well locations, which also helps minimize overlap with existing wells. Adding infill wells in heterogeneous reservoirs can increase cumulative production by up to 20%, especially when wells are placed in areas with high oil saturation. This research emphasizes the importance of advanced simulation technology in designing effective infill drilling strategies. By mapping the oil saturation distribution in detail, operators can determine the best locations for infill wells, thereby reducing resource wastage and maximizing oil extraction, according to Chen and Liu (2014) in their research on the simulation of infill drilling impact on oil recovery using numerical reservoir simulation methods.

Sajjad *et al.*, (2024) in their research on efforts to increase oil production through infill drilling aimed to provide a comprehensive overview for determining the optimal infill well locations using decline curve analysis and volumetric methods to estimate the required number of infill wells. First, using empirical methodology that considers the number and distance between production wells and infill wells, and second, using simulation and numerical optimization methods that evaluate the potential of production wells with planned infill wells. The results of this study indicate that infill drilling has proven to be an effective method for increasing reserves

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in several reservoirs, and reservoir homogeneity can be used to predict additional reserves resulting from infill drilling.

Most oil fields in Western Siberia are marginal, making horizontal infill drilling in these fields difficult. Conventional drilling often fails due to mud loss issues, significantly increasing the need for drilling fluids. Using existing geological data, an oil-in-water emulsion system was developed for drilling fluids to avoid formation damage and blind drilling in low/depleted reservoir pressure conditions (Sokovnin *et al.,* 2015).

Infill drilling plays an important role in the development of oil and gas fields. Planning infill drilling in marginal reservoirs poses significant success challenges. Conventional evaluation approaches require considerable time and cost. Optimal planning simulation can support the success of infill drilling using sequential inversion algorithms and historical well matching. This approach can complete infill drilling planning more quickly and cost-effectively (Cheng *et al.* 2006).

Increasing production in old fields is very important. One way to accelerate and enhance field production is through infill drilling. Optimizing well spacing is crucial to reduce interference with existing wells and increase the well drainage radius. It is estimated based on correlation methods and adjacent wells, and the Proved Developed Non-Producing (PDNP) reserve polygon map can serve as the basis for determining infill wells. The results of this analysis can estimate the well drainage radius behind the casing based on the correlation method and adjacent wells (Amal *et al.,* 2021).

Determining infill well locations is a complex challenge that takes considerable time. Calculating remaining oil saturation to evaluate remaining reserves is deemed less effective. Researchers comprehensively consider other factors in determining remaining reserves by developing a quantitative evaluation method with a mathematical model to determine the optimal infill well location by optimizing the coordinates, depth, and inclination of the well. This method successfully assesses remaining reserves comprehensively and characterizes reservoir conditions. Thus, effectively determining the range of infill well locations for reservoir development (Liu *et al.,* 2024).

Adding infill wells is a quick and significant effort to increase field production. The analysis is carried out in an integrated manner by determining the rock type in the target reservoir and determining the Hydrocarbon Pore Volume (HCPV). Infill well locations are determined based on good HCPV values, followed by production forecasting using the decline curve method, and then economic analysis is conducted to determine the success rate of the infill well plan. The rock type classification in the studied formation (Duri Formation) uses the Hydraulic Flow Unit (HFU) method.

MATERIALS AND METHODS

The research flowchart can be seen in Figure 1

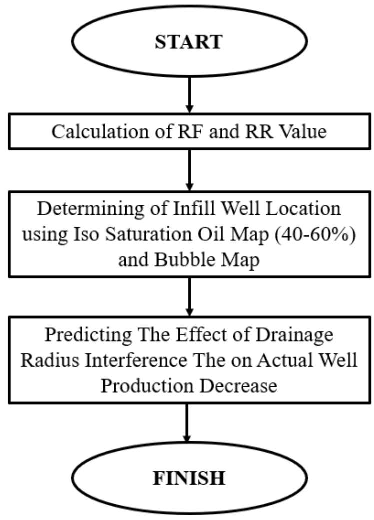

Figure 1: Research Methodology Flowchart

The OOIP (Original Oil in Place) of a field also needs to be calculated to determine whether a field is still feasible for development by evaluating the advantages and disadvantages of each field development option. The OOIP of a field can be calculated using the following formula:

$$OOIP = (7758 \times A \times h \times \emptyset \times (1-Swi)) / Boi \quad (1)$$

The calculation of the Recovery Factor at this stage aims to determine the maximum reserves obtained after infill drilling. The RF value is calculated using the following equation:

$$RF = 54{,}898 \times \left[\frac{\emptyset\,(1\text{-}S_{wi})}{Boi}\right]^{A} \left(\frac{1000.k.\mu_{wi}}{\mu_{oi}}\right)^{B} (S_{wi})^{C} \left(\frac{Pb}{Pa}\right)^{D} \quad (2)$$

The determination of the Estimated Ultimate Recovery (EUR) aims to ascertain the maximum reserves that can be extracted during the primary recovery stage. The Estimated Ultimate Recovery can be determined using the following equation:

$$EUR = RF \times OOIP \quad (3)$$

Remaining reserves are the residual reserves that have not yet been produced. The remaining reserves in the FA field can be calculated as follows:

$$RR = EUR - NP \quad (4)$$

The accuracy of a reservoir model in reflecting the actual reservoir greatly depends on the completeness and processing of available data, particularly in terms of reservoir data processing [9]. The goal of reservoir data processing is to optimize limited information through detailed analysis and processing, resulting in an accurate model that represents the actual reservoir [10]. Reservoir data processing includes: Determining the rock area, Processing Special Core Analysis (SCAL data: core sample data, endpoint data, average data region, normalization, and reconstruction of relative permeability curves), Processing PVT data, and Processing production history data.

Before starting the history match stage, the reservoir model begins with initialization to check and establish the initial equilibrium conditions of the reservoir and determine the initial volume in the reservoir. The calculation of OOIP (Original Oil in Place) is done during the initialization stage of the reservoir model and serves as a reference parameter during the history matching process (Ahmed, 2006).

History matching is conducted to test the accuracy of the reservoir model's production against actual field data. In this process, the key parameter is the production flow rate, meaning the production flow rate entered into the simulation model must match the actual production flow rate from historical field data (Dake, 1978). Additionally, various factors such as oil production rate, water production rate, pressure, gas-oil ratio, and water cut percentage must be adjusted to match the actual field data(Ding, (1995):

$$r = \sqrt{\frac{43560 \text{ x } Np \text{ x } Boi}{7758 \text{ x } 3.14 \text{ x } h \text{ x } 3.2 \text{ x } \emptyset \text{ x } (1\text{-}Swi) \text{x } RF}} \quad (5)$$

Where:
r = Drainage radius, ft
Np = Cumulative oil production, stb
Boi = Oil formation volume factor, stb/bbl
h = Net pay thickness, ft
Φ = Porosity, fraction
Swi = Initial water saturation, fraction

RESULTS AND DISCUSSION

Remaining Reserve of FA Field

The calculation of the Recovery Factor (RF) in Field FA aims to determine the maximum reserves obtained after infill drilling. The calculation of the RF value is performed using the following equation:

$$RF = 54{,}898 \times \left[\frac{\emptyset\ (1\text{-}Swi)}{Boi}\right]^{A} \left(\frac{1000.k.\mu_{wi}}{\mu_{oi}}\right)^{B} (S_{wi})^{C} \left(\frac{Pb}{Pa}\right)^{D}$$

$$= 54{,}898 \times \left[\frac{0.1415.(1\text{-}0.42)}{1.62}\right]^{0.422} \left(\frac{1000.2{,}73.0.89}{16.46}\right)^{0.77} (0.42)^{1.903} \left(\frac{3400}{100}\right)^{-0.2159}$$

= 65%

Dimana:
A = 0.422
B = 0.77
C = 1.903
D = -0.2159
Boi = 1.62 RB/STB
Swi = 42%
Φ = 14.56%
k = 273 mD
Visc. Oi = 16.46 cp
Visc. Wi = 0.89 cp
Pb = 3400 psi
Pa = 150 psi

By incorporating the known data into the equation above, the Recovery Factor (RF) for Field FA is found to be 65%.

The determination of the Estimated Ultimate Recovery (EUR) aims to identify the maximum reserves that can be extracted during the primary recovery phase. The Estimated Ultimate Recovery can be determined using the following equation:

RF = 65%
OOIP = 12.73 MMSTB
EUR = RF x OOIP
= 8.27 MMSTB

Remaining reserves are the leftover reserves that have not yet been produced. The remaining reserves in Field FA can be calculated using the following formula:

Diketahui data :
EUR = 8.27 MMSTB
NP = 2.87 MMSTB
RF = NP/OOIP x 100%
= 2.87 MMSTB/12.73 MMSTB x 100%
= 22.55%
RR = EUR - NP
RR = 5.41 MMSTB
RFcurrent = NP /OOIP x 100%
= 2.87 MMSTB /12.73 MMSTB x 100%
= 22.55%

Infill Well Point Plan of FA Field

Determining the locations for infill wells in the field begins with identifying the rock regions. For Field "FA," rock regions are determined using permeability analysis plots imported from the simulator along with sample numbers. The tabulation of rock region distribution for Field "FA" can be seen in Table 1.

Table 1: Rock Region Distribution "FA" Field

No.	Well Name	Permeabili1y,DID	Porosity,%	So,%	Sw,%
1	A_13	202	0.11	60	40
2	A_11	212	0.12	60	40
3	A_7	227	0.12	56	44
4	A_10	235	0.13	56	44
5	A_9	240	0.13	59	41
6	A_12	252	0.13	56	44
7	A_6	271	0.14	57	43
8	A_8	274	0.15	61	39
9	A_4	285	0.15	56	44
10	A_2	300	0.15	57	43
11	A_S	323	0.16	57	43
12	A_l	346	0.17	57	43
13	A_3	370	0.18	61	39

From Table 1, it can be seen that there are 2 regions, namely region 1 and 2. Region 1 represents an area with an average permeability distribution below 8.7596 mD, while region 2 has an average permeability value distribution of 30.4179 mD, and region 3 has an average permeability distribution value of 59.1931 MD. Figure 3 below shows the graphical representation of rock region or rock type based on rock permeability distribution.

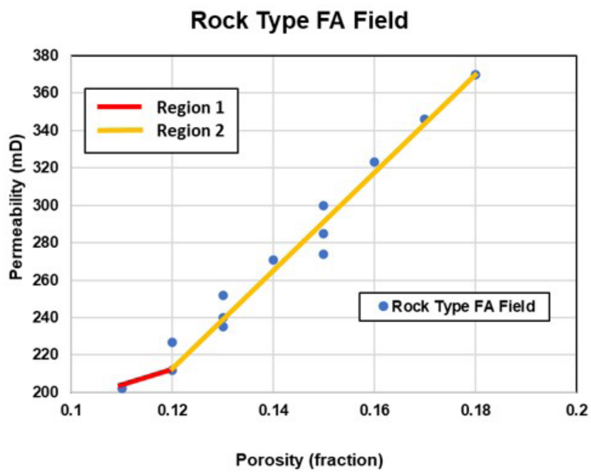

Figure 2: Rock Region Distribution "FA" Field

Based on Figure 2, which depicts the division of rock types into two different categories based on the distribution of rock permeability and porosity, the current wells are situated in productive zones with high permeability and porosity values. For further clarity, the iso-saturation map of Field FA used to determine infill points can be viewed in the following Figure 3.

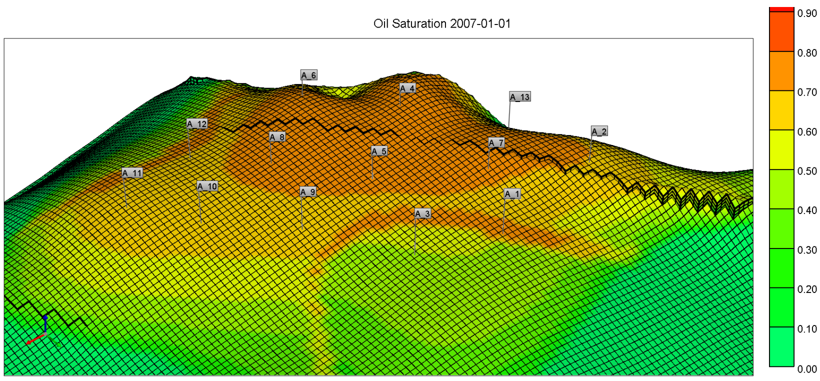

Figure 3: Oil Saturation Map of "FA" Field

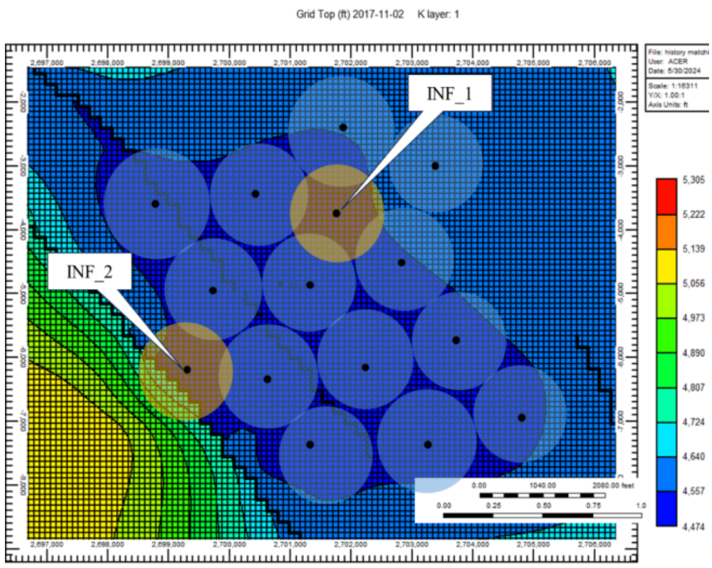

Figure 4: Bubble Map with 2 Infill Wells Locations of "FA" Field

Based on the analysis of the iso-saturation map, it can be concluded that at depths ranging from 4541.0 ft to 4550.3 ft, the oil saturation ranges from 40% to 80% until the end of forecasting, making it suitable for planning infill wells at two pre-determined points with saturations between 40% and 80%. By analyzing the drainage radius of each well, production can be maximized. In Field FA, there are 13 development wells already drilled, with additional points capable of development through infill well planning to accelerate field production. Based on this bubble map analysis, two potential infill well planning points have been identified to expedite field production. These two infill well planning points can be seen in the following Figure 4.

Based on the Bubble Map (Figure 4), it can be observed that there are two locations with oil saturation values between 40-60%, suitable for planning infill wells to expedite field production. At the INF-1 infill well location, it is noted that there are four surrounding wells (A-1, A-3, A-5, and A-7) with overlapping drainage radius, theoretically affecting the production of each influenced well. Meanwhile, at the INF-2 infill well location, there are only three surrounding wells with overlapping drainage radius (A-10 and A-12). These two locations are therefore candidates for infill well sites.

The Effect of Drainage Radius Interference on Actual Well Production Decline

The initial step before conducting simulations in the "FA" Reservoir Field involves preparing the necessary data for the simulation purposes. The processed RCAL data will generate rock grouping based on permeability uniformity, known as "rock regions." Determining rock regions is done to understand the distribution of reservoir properties.

The initialization process involves a reassessment of the data input into the simulator, which includes adjusting simulation data to match the initial conditions or aligning reservoir simulation calculations with actual data. In this context, matching is done to ensure that the simulated Oil in Place (OOIP) aligns with volumetric calculations. Initialization aims to reconcile volumetric OOIP with simulation results. Based on volumetric OOIP calculations yielding 12.73 MMSTB and simulated results also at 12.73 MMSTB, the % error between simulation and volumetric results is 0.0014%, well below the maximum % error tolerance of 1%, indicating alignment between simulation and volumetric results.

History matching is the process of aligning simulation models with actual conditions based on measurable parameter data over a period of time, involving adjustments to dynamic parameters to achieve alignment. To match production history, adjustments are made to SCAL data to align oil, gas, and water production rates by modifying parameters such as Kro, Krg, and Krw. History matching for the "FA" field was conducted from January 1, 2007, to January 1, 2024, by plotting cumulative production rate parameters for oil, water, and gas in the "FA" field. The results of the history matching for the "FA" field can be seen in the following Table 2.

Table 2: History Rate Production "FA" Field from 7 Observation Wells (A-1, A-3, A-5, A-7, A-10, and A-12) from 2007 - 2024

Date	OilRate SC - Yearly lbbl.fcbv'\	Water Rate SC -Yearly lbbl.fcbv'\
2007	137.7925	198.29
2008	237.6853	343.74
2009	307.8323	447.40
2010	369.9000	540.29
2011	384.3503	588.29
2012	450.3800	663.75
2013	442.3044	667.85
2014	434.5151	662.10
2015	427.2759	666.07
2016	419.3950	659.91
2017	411.5813	654.81
2018	408.1646	719.26
2019	403.8601	769.67
2020	395.1215	749.94
2021	386.5960	733.58
2022	377.1895	703.29
2023	367.3057	665.45
2024	358.9988	652.56

Based on Table 2, it can be observed that there is a decrease in production rates each year in the field, indicating a need for further optimization and acceleration of production to maximize yields from the field. According to the bubble map analysis, considering oil per unit area, infill well placement is determined. Based on the bubble map, the planned locations for infill wells affect the drainage radius of surrounding wells, including wells A-1, A-3, A-5, A-7, A-10, and A-12. Figure 5 shows the results of history matching for oil and water rates in Field "FA".

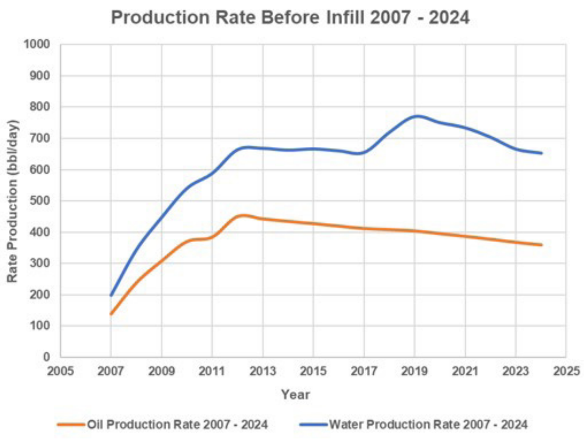

Figure 5: Oil and Water Production Rate History Graphic

Based on Figure 5, it can be concluded that the simulation results show a significant decline in annual oil and water production rates during the first five years in Field “FA”. Therefore, optimization is necessary to increase the production rates in the field by implementing infill well planning in Field “FA”. Before engaging in development scenarios, the initial step is to run the basecase. In this scenario, no development activities are carried out (no future action). During this phase, the simulator runs for 10 years to evaluate the field production performance without any development plans.

Scenario 1 (Basecase)

The basecase predictions will serve as a benchmark for comparison in planning subsequent scenarios, allowing us to determine the expected increase in oil recovery and Recovery Factor for Field “FA” without any development scenarios. Figure 6 shows the plot results of the oil rate basecase up to the end of January 2024, illustrating the production performance until the end of the prediction period without implementing any optimization activities.

Based on the graph in Figure 6, the cumulative oil production from the total of 7 observation wells amounts to 3.58 MMSTB. Therefore, the recovery factor is calculated to be 28.09%.

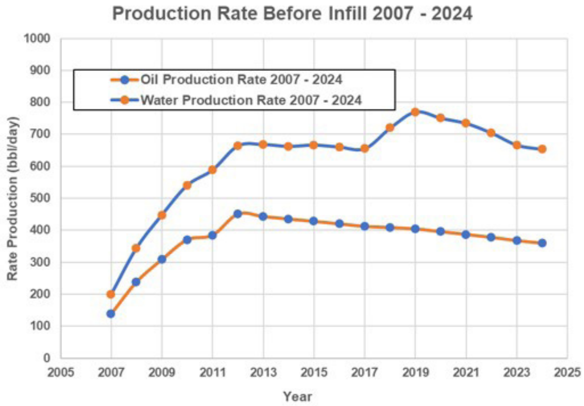

Figure 6: Base Case Oil and Water Rate “FA” Field

Scenario 2 (Baseline + 1 Infill Well with 4 Drainage Radius Interferences)

In this scenario, one infill well planning was conducted based on the analysis of the iso-saturation map to observe the oil saturation at the designated infill point. Below is the bubble map depicting the scenario of planning one infill well affecting four surrounding wells. The drainage interference radius of the planned infill well can be seen in the following image.

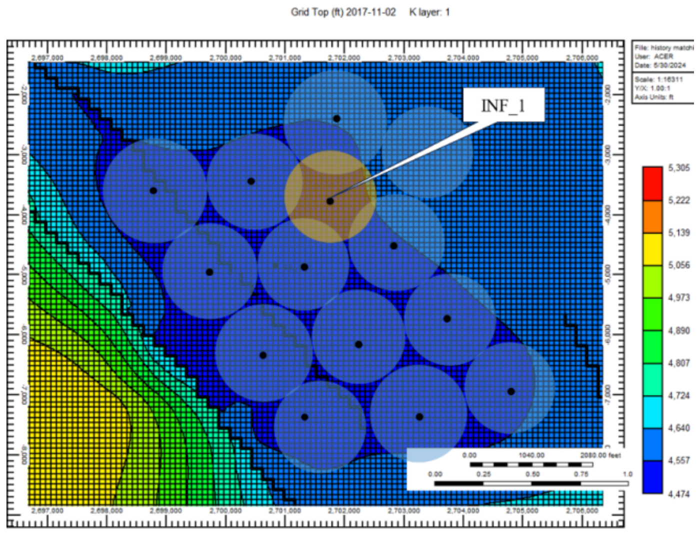

Figure 7: Drainage Radius Interference with 1 Infill & 4 Drainage Radius Interferences Well Plan

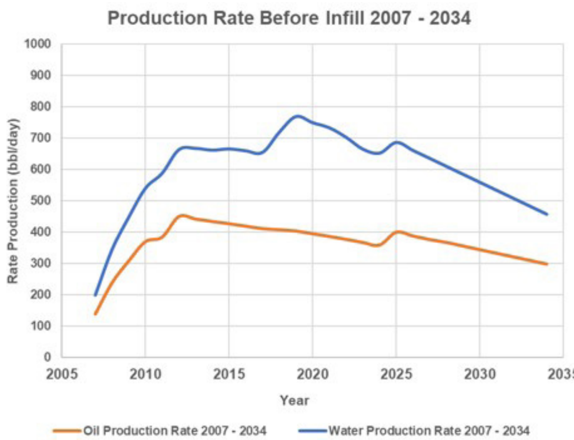

Figure 8: Oil and Water Production Rates Scenario 2

Based on the bubble map, planning one infill well INF-1 affects four surrounding wells: A-1, A-3, A-5, and A-7. Below is the tabulation of oil rates obtained after implementing the planning of one infill well to maximize oil recovery. The graph depicting the Oil and Water Rate Acquisition in Scenario 2 for Field "FA" can be seen in Figure 8 shows.

Based on Figure 8, it is evident that there is a decline in oil and water production rates over time as the wells are produced. In the first year after implementing the infill well planning, the cumulative oil production totals 3.77 MMSTB, resulting in a recovery factor of 29.6% for Field "FA" in Scenario 2 with one infill well planning and four drainage interference radius. For a comparison of oil production rates before and after implementing one infill well planning, refer to Figure 9 below.

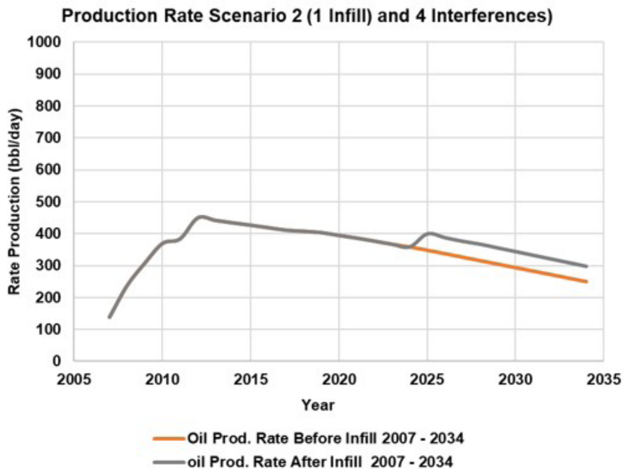

Figure 9: Comparison of Oil Production Rates Before and After Adding 1 Infill Well and 4 Drainage Radius Interference

Based on Figure 9, it can be concluded that planning one infill well increases the highest oil production rate in the field by 55 bbl/day, from 358 bbl/day to 413 bbl/day, in the first year after implementing one infill well planning with four drainage interference radius.

Scenario 3 (Baseline + 1 Infill with 2 Drainage Radius Interferences)

In this scenario, the simulation involves planning one infill well that affects two surrounding wells. The drainage interference radius of the planned infill well can be seen in the following image.

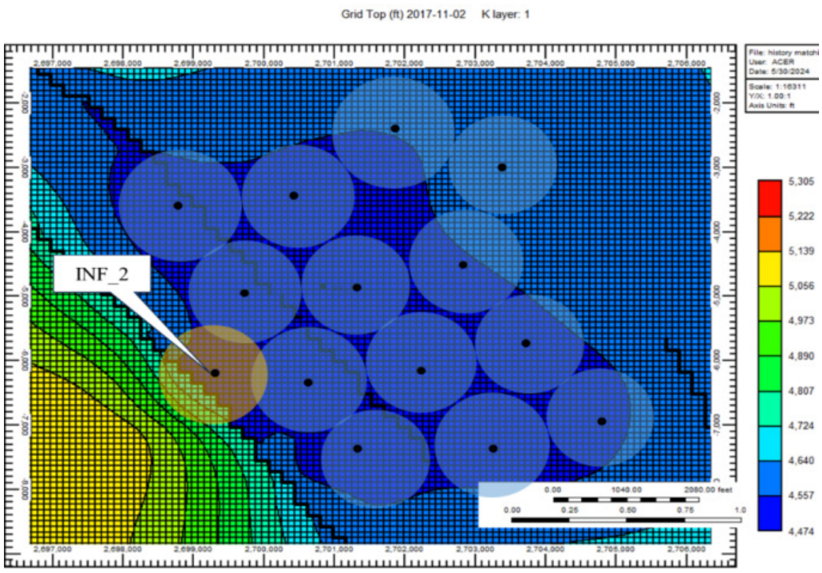

Figure 10: Bubble Map with 1 Infill Well Plan and 2 Drainage Radius Interferences

Based on the bubble map, planning one infill well INF-1 affects two surrounding wells: wells A-10 and A-12. The graph depicting the Oil and Water Rate Acquisition in Scenario 3 for Field "FA" can be seen in Figure 10 below.

Based on Figure 11, it can be observed that there is a decline in oil and water production rates over time as the wells are produced. In the first year after implementing the infill well planning, the cumulative oil production totals 3.71 MMSTB, resulting in a recovery factor of 29.2% for Field "FA" in Scenario 3 with one infill well planning. For a comparison of oil production rates before and after implementing one infill well planning, please refer to Figure 12 below.

Based on Figure 12, it can be concluded that planning one infill well increases the highest oil production rate in the field by 45 bbl/day, from 359 bbl/day to 404 bbl/day, in the first year after implementing one infill well planning with 2 drainage interference radius.

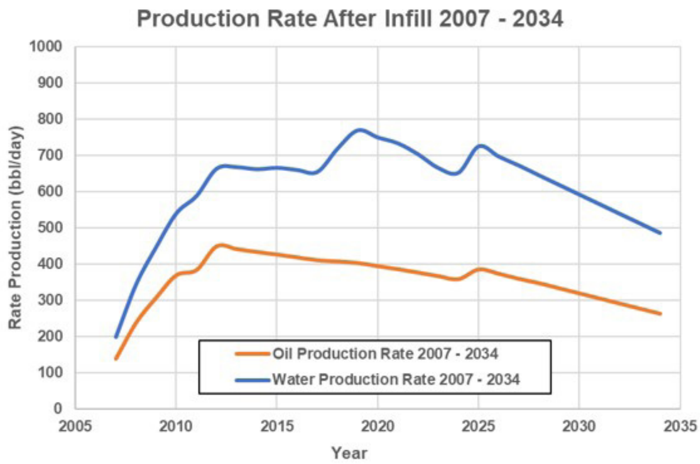

Figure 11: Oil and Water Production Rates Scenario 3

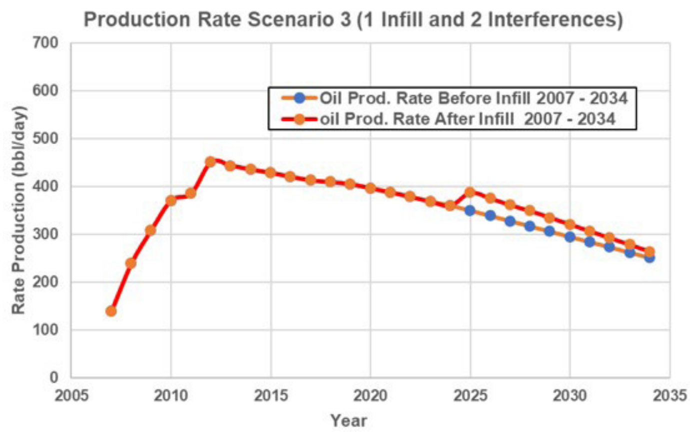

Figure 12: Comparison of Oil Production Rates Before and After Adding 1 Infill Well with 2 Drainage Radius Interferences

Scenario 4 (Baseline + 2 Infill Wells)

In this scenario, simulation is conducted by planning two infill wells that affect six surrounding wells. The drainage interference radius of the planned two infill wells can be seen in the following image.

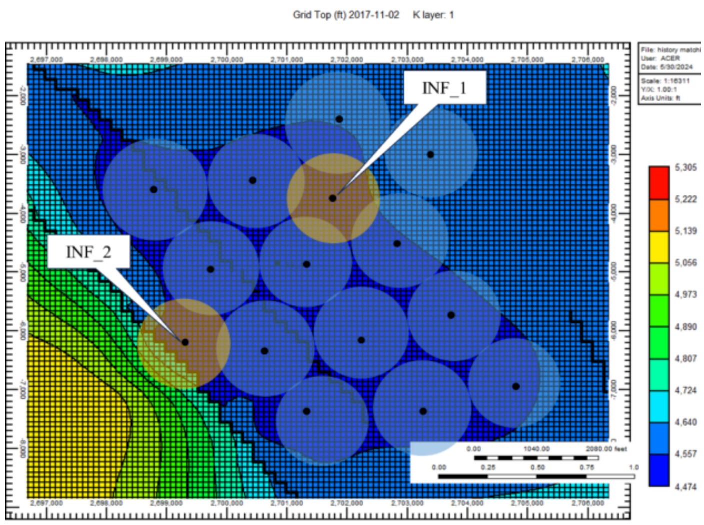

Figure 13: Drainage Radius Interference with 2 Infill Well Plan

Based on the bubble map, with planning for two infill wells INF-1 and INF-2, it can be seen that they affect six surrounding wells: wells A-1, A-3, A-5, A-7, A-10, and A-12. The graph depicting the Oil and Water Rate Acquisition in Scenario 4 for Field "FA" can be seen in Figure 14 below.

Based on Figure 14, it can be observed that there is a decline in oil and water production rates over time as the wells are produced. In the first year after implementing the infill well planning, the cumulative oil production totals 3.94 MMSTB, resulting in a recovery factor of 30.92% for Field "FA" with planning for two infill wells and six drainage interference radius. For a comparison of oil production rates before and after implementing the scenario, please refer to Figure 15 below.

Based on Figure 15, it can be concluded that planning for two infill wells with six drainage interference radii increases the highest oil production rate in the field by bbl/day, from 430 bbl/day to 510 bbl/day, in the first year after implementing the two infill well planning.

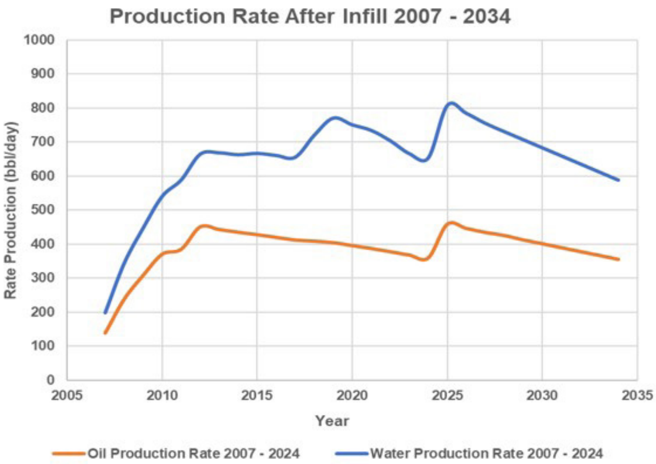

Figure 14: Oil and Water Production Rates Scenario 4

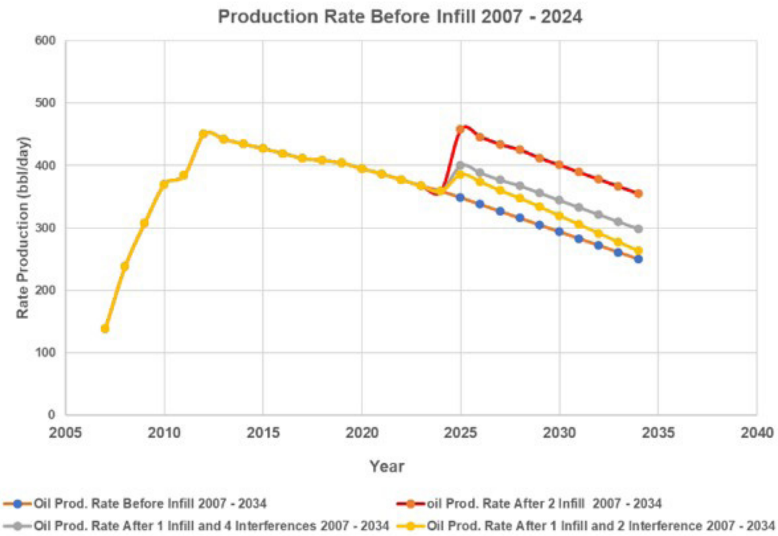

Figure 15: Comparison of Oil Production Rates Before and After Adding 2 Infill Wells with 6 drainage Radius Interferences

CONCLUSION

Based on the analysis and data processing, it is concluded that Field "FA" has remaining reserves of 5.41 MMSTB and a recovery factor of 22.55%. Therefore, Field "FA" is suitable for field development through infill drilling project planning. Based on the analysis of the bubble map and iso-saturation map, the location for infill well planning includes INF-1 affecting observation wells A-1, A-3, A-5, and A-7 within the interference radius of INF-1, and INF-2 affecting observation wells A-10 and A-12 within the interference radius of INF-2. Planning one infill well, INF-1, with four affected wells (A-1, A-3, A-5, and A-7), resulted in a production decline of 10.69 BOPD with an additional production of 54 BOPD. Planning one infill well, INF-2, with two affected wells resulted in a production decline of 6.37 BOPD with an additional production of 44 BOPD. From both scenarios, it is evident that the more overlapping areas caused by infill well planning, the more the actual production rate of surrounding wells will decrease. In the base case scenario without optimization, the recovery factor is only 28.09%. With planning for one infill well and four drainage interference radii, it increases to 29.6%. With two drainage interference radii, it reaches 29.2%. Finally, with planning for two infill wells, it further increases to 30.92%.

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