A REVIEW OF RESERVOIR SIMULATION FOR PRESSURE MAINTENANCE PROJECT IN FIELD-X, INDONESIA

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ABSTRACT

Pressure maintenance is a secondary oil recovery method which involves injecting another immiscible fluid (e.g. water) to support the oil sweep from a depleting zone. Through reservoir simulation, Tately NV Company attempts to evaluate the benefit of pressure maintenance through water injection on oil recovery from one of its zones in its field in Indonesia. This is because in this particular zone, the pressure around some of its producers has depleted severely after only the first few years of production. This paper attempts to review the process Tately NV has used to perform history matching in order to validate the reservoir dynamic model and obtain the optimum water injection well count, injection schedule, and injection rate.

INTRODUCTION

In this zone, Tately NV, a Production Sharing Contractor of the Government of Indonesia, operates several producers. The first producer was opened in May 2013, so this reservoir simulation study conducted in May 2015 was based on the two years of available data to help produce simulated results until January 2024. The simulated results after history matching showed that the pressure around some of its producers had depleted severely after only the first few years of production. Meanwhile, the pressure around another producer had started to show the considerable depletion in just the first half of 2015 alone. Thus, these simulated results support the idea that a pressure maintenance project needs to be considered.

HISTORY MATCHING

History matching is a process of adjusting the reservoir model properties such that the simulated production and pressure data match the historical field data as closely as possible. When a match is obtained, simulation cases can be run to predict the future performance of the reservoir. Using Eclipse Reservoir Simulator, Tately NV performed this stage using “ORAT” (Oil Production Rate) control mode to match “WTHP” (Well Tubing Head Pressure). This is the particular order which Tately NV followed in matching those two parameters:

1. Altering the skin factor of the well

History matching should be conducted with care. Skin factor is considered to be the first property to alter in order to match the field and simulated data because changing the skin factor of the producer’s grid does the least damage to the reservoir model while aiming to update the reservoir model. In this case, changing the skin factor of any of the producers turned out to be a failure; this step did not accomplish the mission at all. Therefore, it was not used.

2. Altering the permeability of the well grids

Since the skin factor technique failed, all the skin factors were brought back to their initial values before any alteration. The next technique was to alter the permeability of the producer’s single grid. This task was performed by using “MULTIPLY, PERMX, PERMY, and PERMZ” keyword in the model script. If altering one producer’s grid permeability did not show significant success, the next step was to alter a much larger region which still includes the producer’s grid. For example, 3X3 grids, instead of 1X1 as it was before, were included in the MULTIPLY keyword (the producer’s grid was located at the center of the 3X3 square). If this was still not sufficient, 5X5 or 7X7 grids could be used instead.

3. Creating a permeability barrier(s) around the well grid

It turned out that step 2 above seemed to accomplish the match, only in the earlier life of the well, while the later portion of the simulated and the field data did not quite match yet. Therefore, the result obtained from step 2 was maintained, while step 3 was performed afterwards: creating a permeability barrier(s) some grids away from the region covered in step 2. This was called a permeability barrier because using the same technique to alter the permeability as discussed in step 2, the factor of MULTIPLY used was a very small fraction.

This step turned out to contribute the most success compared to the previous two, because this step allowed a change in the simulated result at a specific point of time. For example, it was randomly given that the oil spread horizontally for 200 meters each year. Meanwhile, the field WTHP curve of one well showed a sudden drop six months after its opening. This meant that creating a permeability barrier 100 meters away from that well grid might help match the field data and simulated result; in fact, this step brought a remarkable success (Figure 1). The same technique was applied to another producer, and an equally notable match between the simulated and field WTHP was achieved (Figure 2).

INJECTION WELL PROPERTIES

After the history match had already been completed, several water injection cases were created. The first thing to consider was where to locate the injectors. There are some criteria which Tately NV has considered in order to optimally position the injection wells:

1. Location of severe pressure depletion

Injectors should be located surrounding the area of not only severe pressure depletion but also higher oil saturation. For example, Figure 3 shows that more severe pressure depletion occurred in the region bounded by the circle, while that region actually still had a fairly higher oil saturation level. This criterion becomes the ultimate one because after all, the concept of pressure maintenance is to increase oil recovery in a low pressure area. Therefore, the injectors should be located along the circle.

2. Injector's perforation depth

The water injection wells should be perforated at a certain distance below the Oil Water Contact (OWC) to allow the water to permeate into the larger aquifer so the pressure support will be piston-like pushing the oil upward, instead of sharply piercing into the oil zone as in the case in waterflooding. If that desired depth below the circle circumference line as discussed in criterion 1 referred to an inactive grid (which meant that the perforation depth already reached the underlying shale formation), the injector should then be moved further away from the circle such that the perforation depth still stayed in the active reservoir rock grids. Figure 4 helps show the cross sectional view of the layers.

3. Injector's well grid permeability

This criterion suggested the injector should be located at a perforation grid which was of better permeability than the surrounding grids and had a path of good permeability between the injector's perforations to the producer's perforations. This criterion ensured that the injected water would have an easier path towards the oil zone.

4. Thickness of each perforated layer

This criterion helped ensure that the perforation grids were not in a pinch-out structure. This criterion also made sure that there was a space for the injected water to accumulate. In fact, a thicker grid enabled a faster simulation run. In this model, the grids were fairly thick to accomplish the mission so not much attention was paid to this criterion in locating the injector.

PREDICTION CASES AND RESULTS

Based on those criteria, several injectors were initially located (indicated by small circles), as shown in Figure 5 (which juxtaposed the view of the pressure-depletion region with the high oil saturation) and Figure 6 (which showed that the injectors were perforated at a distance below the OWC and having good permeability). The base case, which had no injector opened, was then run to predict the field initial performance without pressure maintenance. Run until January 2024, the recovery factor of the base case was obtained.

The first batch of injection cases was finally run. In each case, only one injector was opened throughout the entire simulation period. Every injector was also run under several different WTHP values as the control mode: ranging from the THP value which would fracture the formation to a few hundred psi less than that. The purpose of this step was to obtain the optimum THP value which would result in the highest “FWIR (Field Water Injector Rate)” and “FOPT (Field Oil Production Total).” After all cases from this batch were run, some of the injectors turned out to result in barely less than 1% additional recovery factor. Therefore, those injectors were eliminated.

Of the remaining or “successful” injectors, which would be called the second batch, another running procedure was conducted. Initially, all these injectors were opened altogether since January 2016 under their corresponding optimum THP values. After each run, the injector with the least “WWIT (Well Water Injection Volume Total)” was eliminated. The injection case consisting of the next remaining injectors was run again. The same elimination process proceeded until only one injector remained. WWIT was chosen to be the elimination factor because this parameter helped eliminate the redundant injection well. This means that even if this redundant injector was operated in addition to an effective one, it would not contribute as much incremental oil recovery as would be obtained by only opening the effective injector(s).

Since this simulation project aimed to evaluate the optimum injection well count, it was necessary to plot the injection well count against the “FOPT (Field Oil Production Volume Total)” as shown in Figure 7. Figure 8 helps emphasize the decisive result by plotting the injection well count against the field additional recovery factor (an injector count of 0 refers to the base case). It was further analyzed that the “FWPT (Field Water Production Volume Total)” was not sufficient to support the large “FWIT (Field Water Injection Volume Total)” (as shown in Figure 9), so that another source of compatible water would have to be prepared. This simulation result was finally summarized in Figure 10, which included the three most important parameters in this simulation project: FWIT, incremental FOPT, and injection well count. From this figure, it was preferable to pick a dot which tended to go more to the upper-left corner (which meant a higher incremental oil recovery despite a lower volume of injected water) and which had a smaller diameter (which represented a smaller number of injection wells opened). Figure 11 helps further emphasize the significance of pressure maintenance to this zone by showing the additional recoverable oil volume.

CONCLUSION

Pressure maintenance is considered to be one of the effective secondary oil recovery methods. It is necessary to evaluate the effectiveness through reservoir simulation. The benefit of simulating the reservoir, when adhering to the best practices, is to produce a wise framework for the pressure maintenance project given the high cost to execute it in the field. Tately NV has evaluated the benefit of pressure maintenance through reservoir simulation and accepted the proposed injection schedule for future pressure maintenance frameworks.

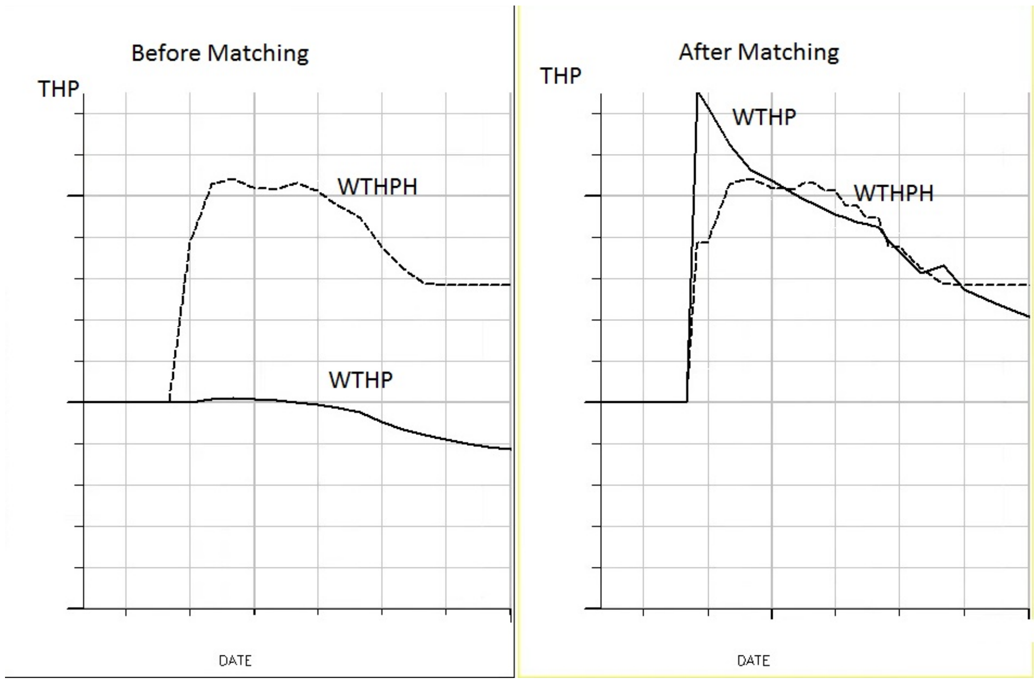

Figure 1 – History Matching for Well-1

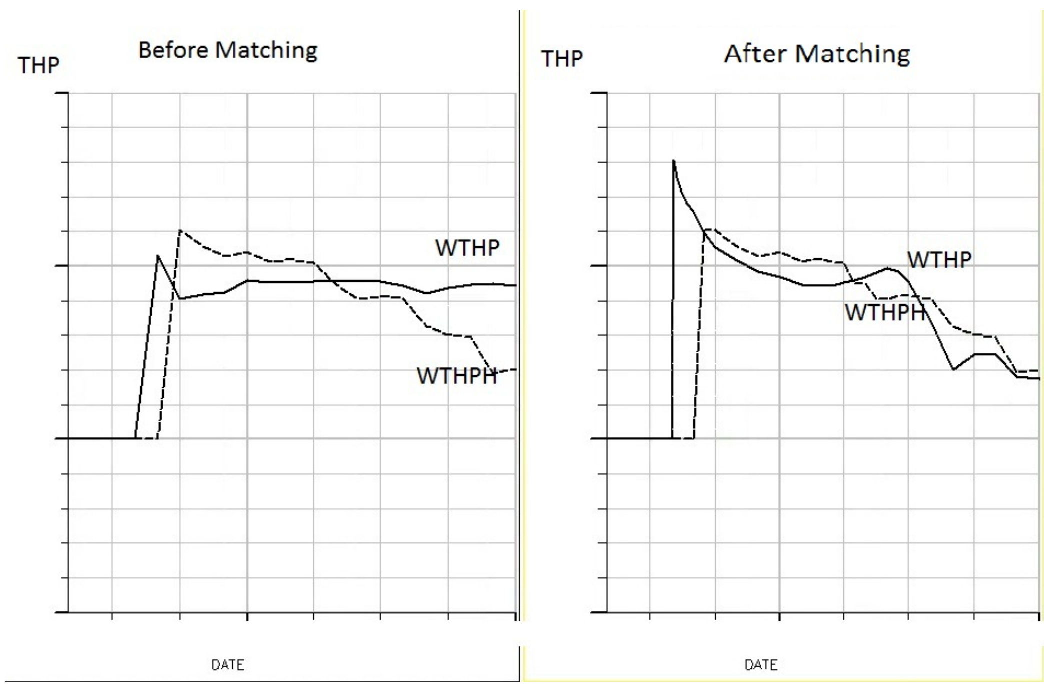

Figure 2 – History Matching for Well-2

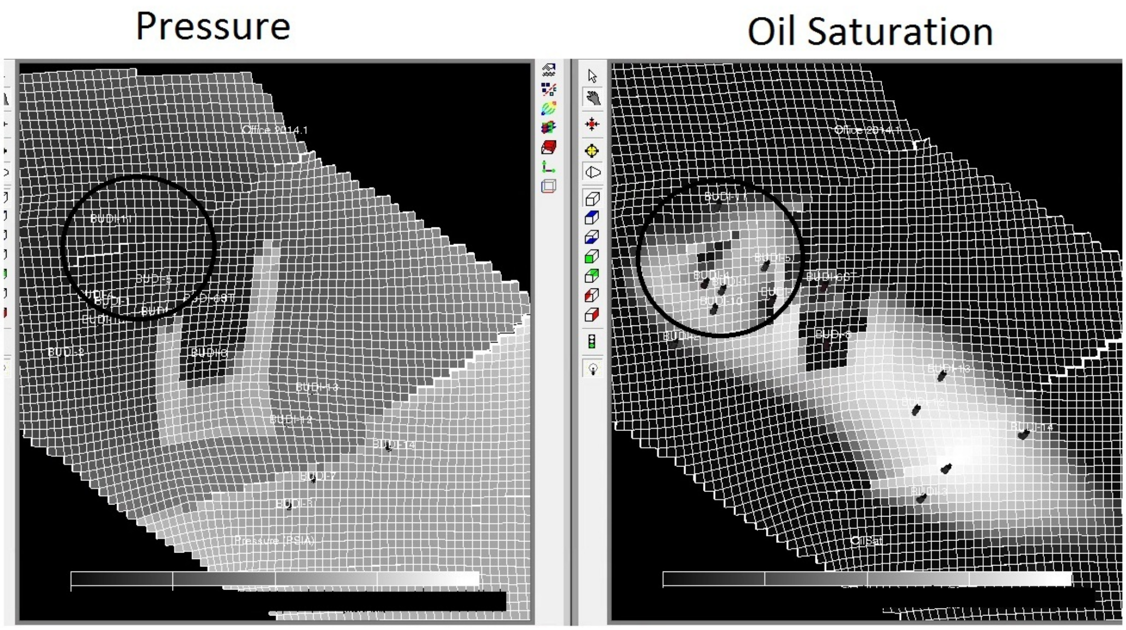

Figure 3 – Pressure vs Oil Saturation Simulation Screenshot

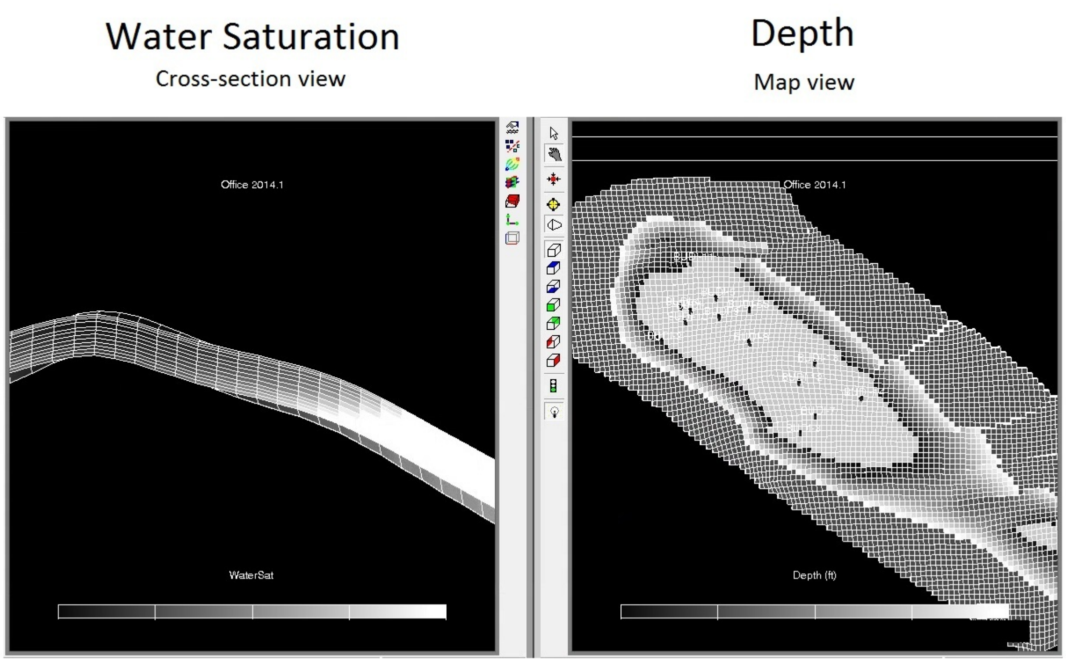

Figure 4 – Water Saturation Simulation Screenshot

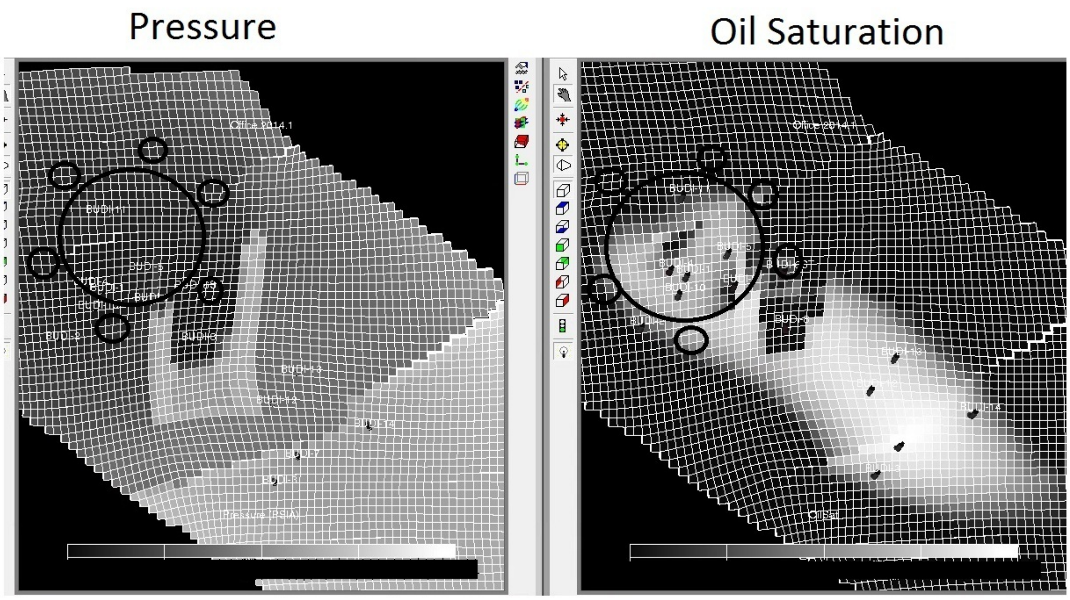

Figure 5 – Pressure vs Oil Saturation Simulation Screenshot

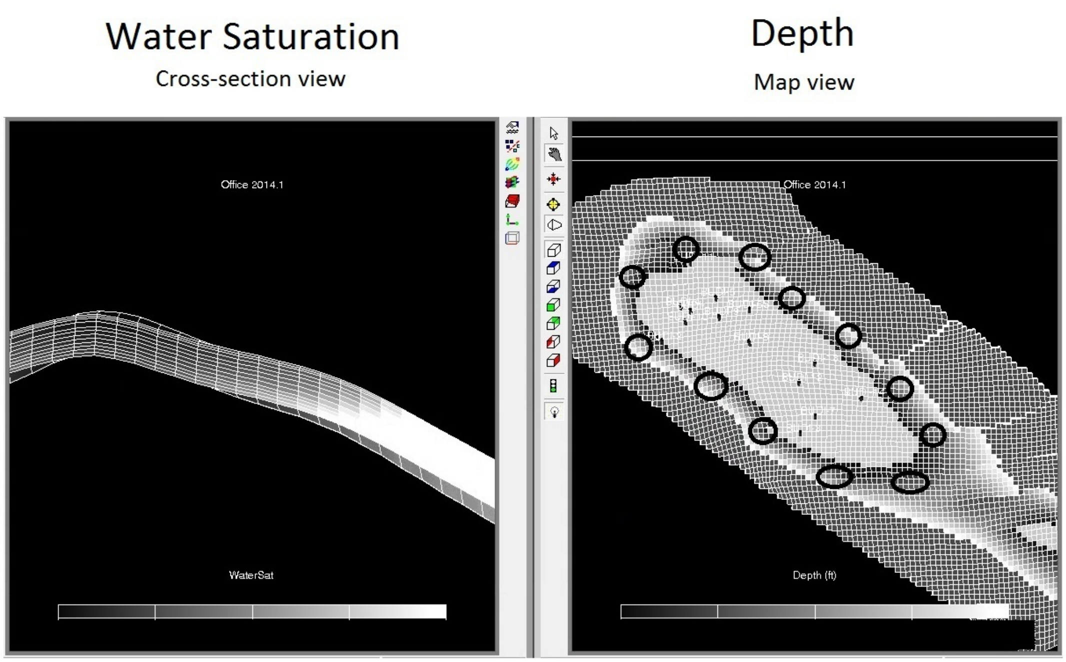

Figure 6 – Final Injection Well Coordinates Simulation Screenshot

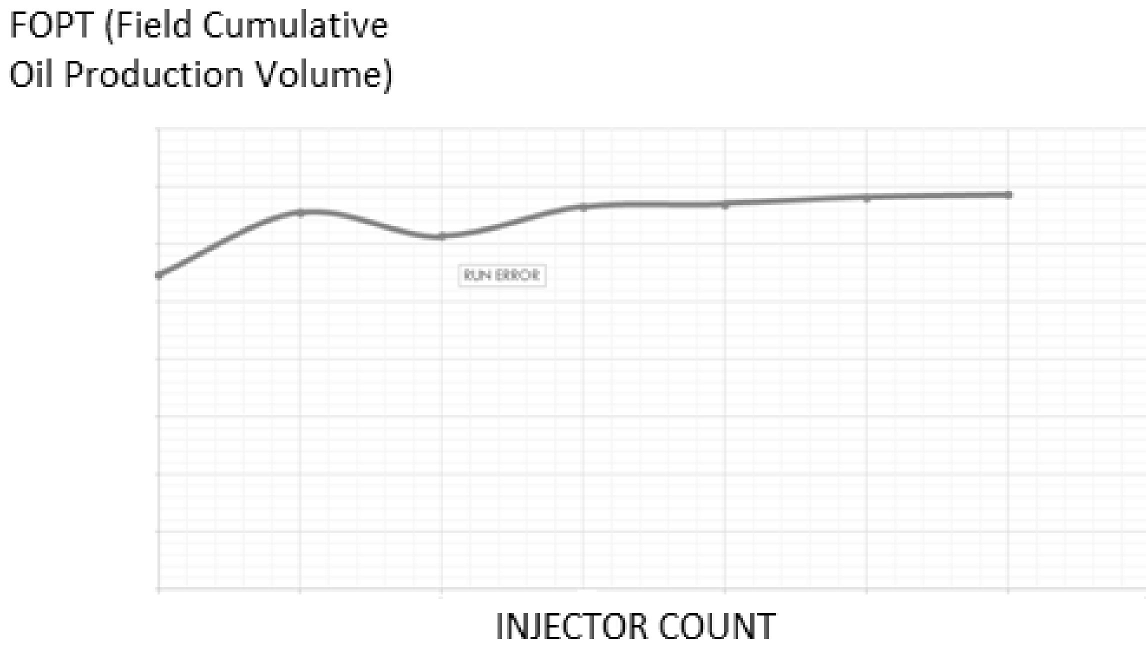

Figure 7 – Graph to Analyze the Optimum Injection Well Count

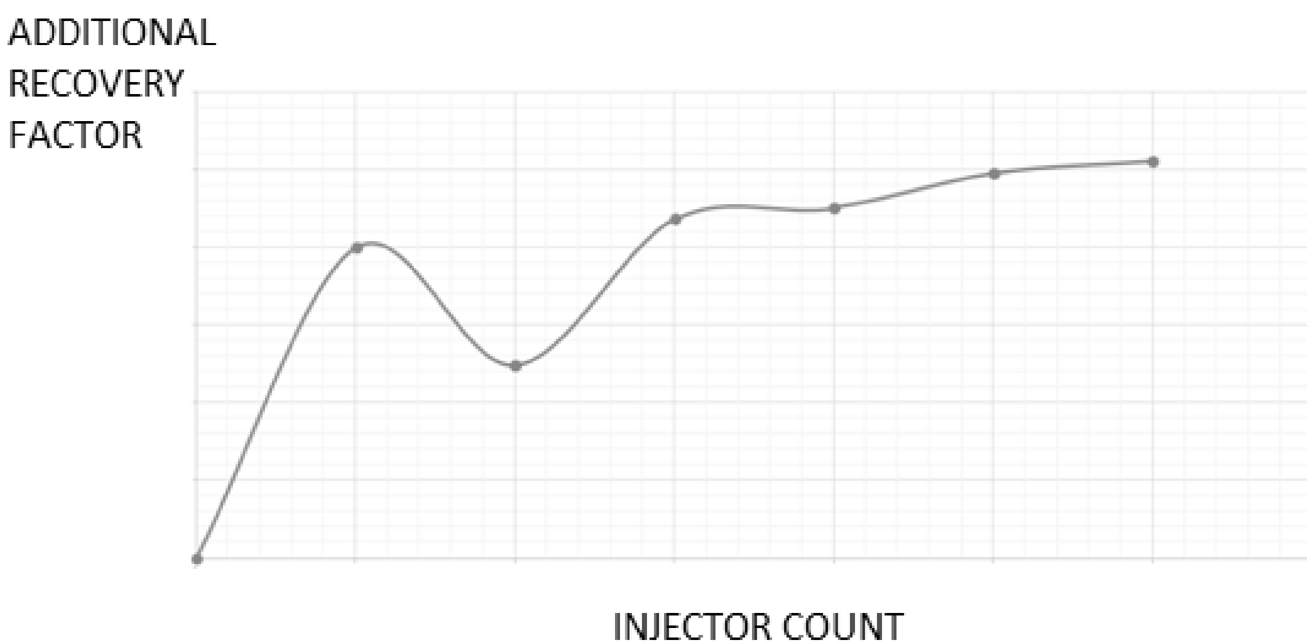

Figure 8 – Graph to Analyze the Optimum Injection Well Count

Figure 9 – Graph to Analyze the Water Injection Volume Availability

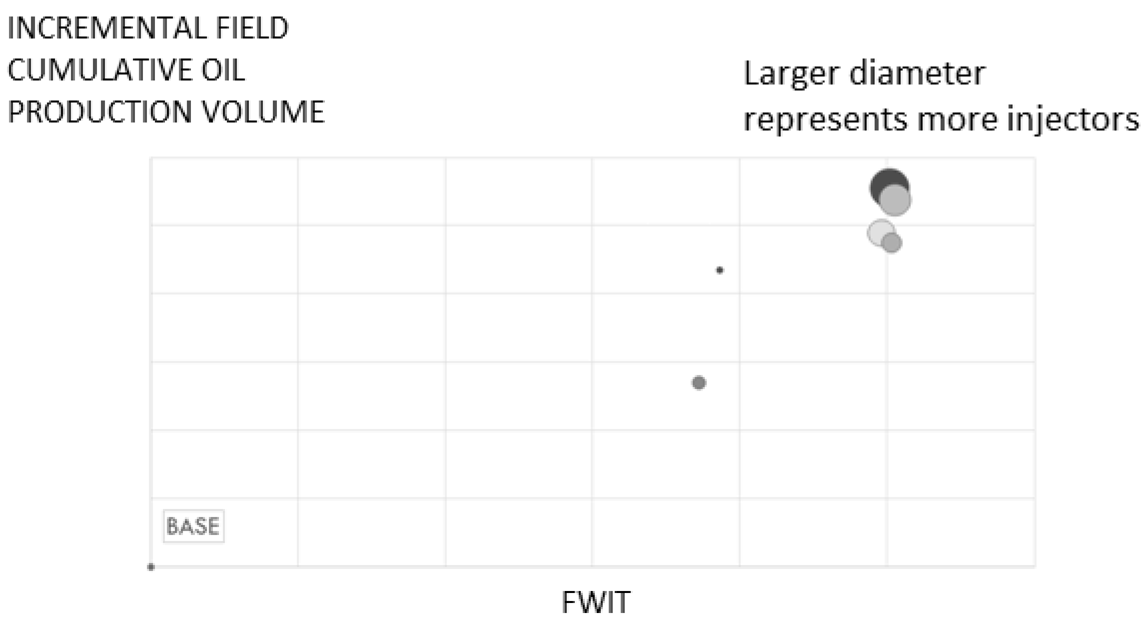

Figure 10 – Graph to Select the Proposed Case

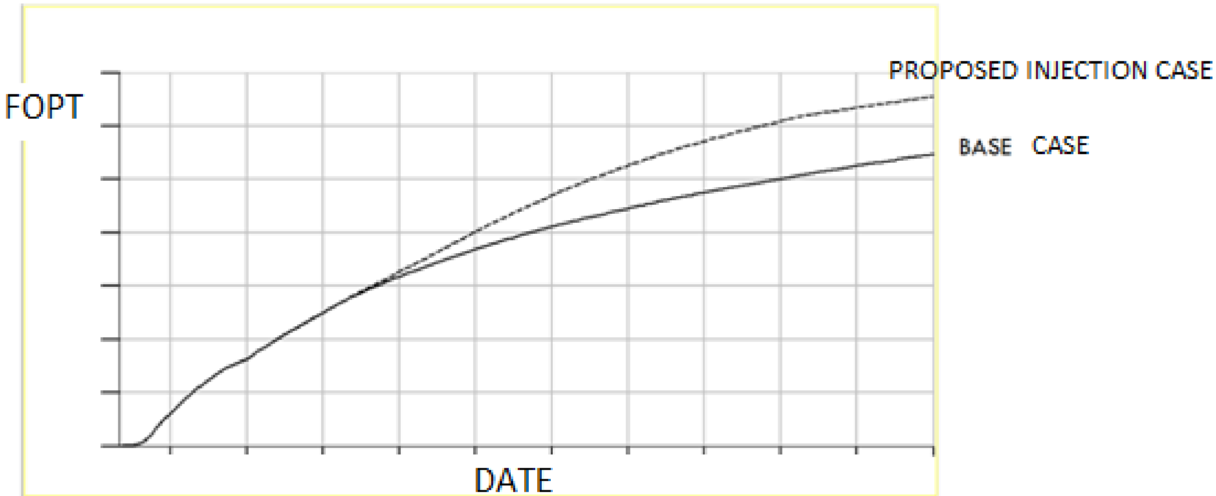

Figure 11 – Oil Cumulative Production with Pressure Maintenance