Research Journal of Applied Sciences, Engineering and Technology 10(4): 357-372, 2015
DOI:10.19026/rjaset.10.2499
ISSN: 2040-7459; e-ISSN: 2040-7467

Submitted: October 28, 2014 Accepted: December 18, 2014 Published: June 05, 2015

Research Article

Recovery Optimization of an Oil Reservoir by Water Flooding under Different Scenarios; a Simulation Approach

M.A. Ayoub, A. Shabib-Asl, A.M. AbdellahiZein, K.A. Elraies and I. Bin MohdSaaid
Department of Petroleum Engineering, Universiti Teknologi PETRONAS (UTP), Bandar Seri Iskanadar, 31750, Tronoh, Perak, Malaysia

Abstract: Water flooding used in secondary oil recovery to level up reservoir pressure can be enhanced in order to fit the reservoir conditions to optimally recover oil. The main goal consists in maximizing oil recovery while minimizing water production. As the dynamic of two immiscible flows is governed by its flow and rock properties and reservoir condition, the water flood optimization must be appropriately performed for a single reservoir. In this case study, it is shown theoretically and by means of Eclipse 100 that according to the basic elementary reservoir characteristics, certain parameters can be added and changed to obtain an optimum oil recovery for a faster and a slower water case. In each run reservoir characteristics and oil properties were fixed while water flooding parameters were changed. Both homogeneous and heterogeneous reservoirs were tested. Then, the graphs generated at each run are interpreted and the variables are adjusted accordingly. Much care was taken to minimize the cost while achieving high oil cut versus water cut (or water production) for the longest time interval within water flood life if not the whole duration. A single major problem which Eclipse 100 does not take into account is starting injection at an optimum time. As a result, both injection and production were started at the same time. Despite this, the cases were able to be compared with each other as with the initial base case (no injection). Moreover, conclusion and recommendations were drawn based on the results and analysis with regard to the recovery optimization.

Keywords: Eclipse 100, immiscible, oil cut

INTRODUCTION

The leveling of reservoir pressure at some withdrawal rate is a measure of water-drive capability. If the aquifer cannot supply sufficient energy to meet desired fluid withdrawal rates while maintaining reservoir pressure, an edge water injection program-water flooding, may be used to supplement natural reservoir energy. This technique should lower the economic limit of the development phase by extending the well life. This is desired as when the economic limit is reached the well becomes a liability and is abandoned when there often is still a significant amount of unrecoverable oil left in the reservoir.

In the start two choices are available: the repeating and the peripheral flood patterns. Both are illustrated in Fig. 1 and 2 (Singh and Kiel, 1982; Ahmed, 2006).

Water flooding design success can be evaluated based on Callaway equation of estimating total recoverable reserves:

$$\text{Npwf} = Vp, \frac{1-Swc}{Boi}.\{1 - Rp - \frac{\text{Boi}}{\text{Bof}}, (1 - Evo.ED)\}$$
(Callaway *et al*., 1959)

where,

- V_p = Floodable reservoir pore volume (7758 Ah_{Φ}), barrels
- B_{oi} = Original formation volume factor, RB/STB
- B_{of} = Formation volume factor during water flooding, RB/STB
- S_{wc} = Connate water saturation, fraction
- S_{or} = Residual oil saturation after water flooding, fraction
- R_p = Primary recovery efficiency, fraction of Original Oil in Place (OOIP)
- E_{vo} = Overall volumetric sweep efficiency, fraction of reservoir volume
- E_D = Maximum unit displacement efficiency (to be defined later), fraction
- Npwf = Water flood reserves, STB

The oil Recovery Factor (RF) is the product of volumetric sweep efficiency (Evo or EA x Ev) and fractional oil being Displaced (ED): (RF = ED×EA×Ev) in the cumulative oil produced (Np) can be calculated from this oil Recovery (RF) as such: (Np = OIIP (Initial Oil in Place) × RF). Another major phenomenon affecting the oil recovery is marked by the difference in velocity between oil and water and has an impact on the

Corresponding Author: M.A. Ayoub, Department of Petroleum Engineering, Universiti Teknologi PETRONAS (UTP), Bandar Seri Iskanadar, 31750, Tronoh, Perak,Malaysia, Tel.: +60 5 368 7086

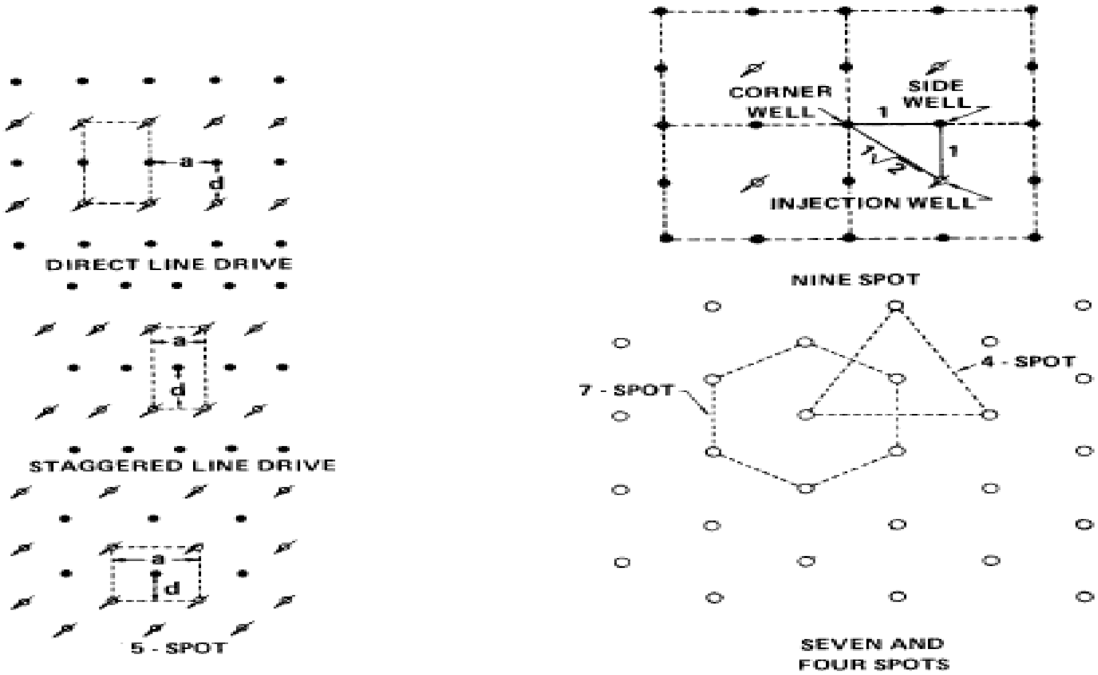


Fig. 1: Water flood regular patterns

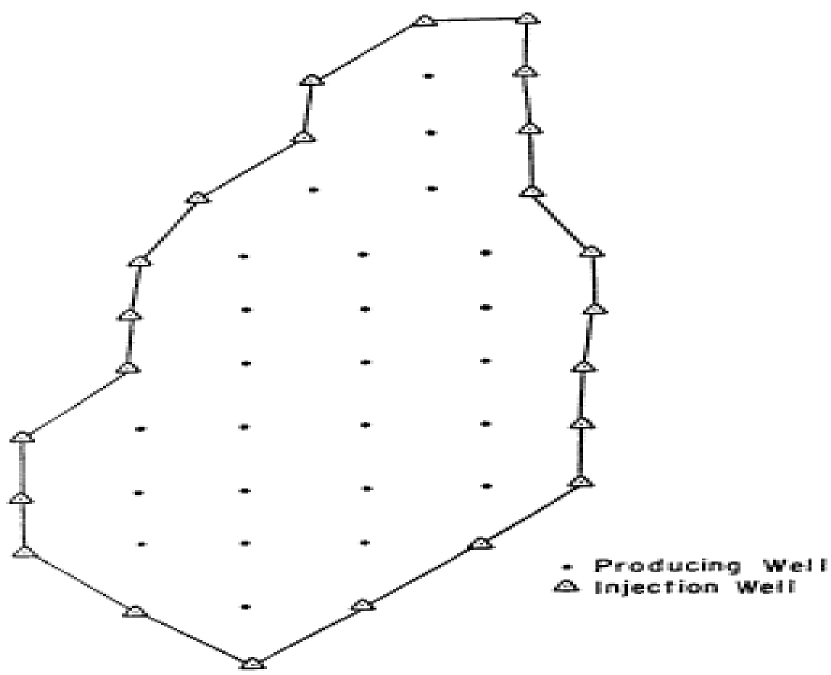


Fig. 2: Water flood peripheral pattern

sweep efficiency by mean of bypassing can be interpreted through the mobility ration equation:

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$$

As the conditions are rarely ideal in an oil reservoir, in most cases a large percentage of oil is left behind after the water flood reaches its economic limit. Furthermore, in attempting to recover oil, the oil produced is generally accompanied with some of the connate water and the water injection. Producers are now required to resort for beneficial re-uses or treatment to government-issued standards before disposal or supply to users.

Other main challenges to optimal oil recovery are as listed below:

- The heterogeneity and particularly the variation of permeability in the vertical direction of reservoir (e.g., result in water crossing to only high permeability layers). Reservoir discontinuity can prevent the water flood from contacting a large amount of pore volume in the reservoir.
- The displacement is usually aerially expanded, thus, neither water saturation nor permeability are not uniform distributed with respect to thickness. Heterogeneity and gravity forces are the main barrier for seep efficiency.
- Some of the methods of adding chemicals to adjust viscosity or to reduce surface tension between oil and water are technically vary successful but expensive. High oil production maybe accompanied with high produced water which needs to be treated before disposition.
- The reservoir structure and geometry, the economic feasibility, the limited number of injection wells can hinder the use of infill wells to optimize oil recovery. On the other hand, a too small injection-production well spacing can cause unfavorable rapid water cut increase. Furthermore, where an alternative can be high injection rates, it can be costly. Increasing rate is also not realistic as it may fracture formation pressure.
- A higher oil viscosity results in less efficient displacement: and increased injected water volume is required. However, although substantial oil recovery may be achieved, oil will be produced at high water cut values.

The main goal is to maximize oil recovery and minimize water production with the least amount and number of water flood variable in order to minimize the secondary recovery investment cost. The least complex well pattern with the highest FOE (Field Oil recovery) and the least FWPT (Field Water Production Total) is the more oil preferred.

METHODOLOGY

There are fixed variable which are the reservoir and oil properties and Variable parameters which are water injection facilities and properties (Fig. 3).
Consideration to take account:

- The same rate is given to all producers and the same rate is also given to the injectors. The reason to do so is so that there is no breakthrough from a producer caused by a high injector rate long before the breakthrough occurs from the other injectors. This will reduce excess of water-cut. In doing so, well spacing between input wells and between output and input wells were kept constant (constant well spacing ratio). Well cost is the most expensive in a water flood project, thus an optimal pattern and number of wells is required.
- Mind the effect of mobility ratio (whether water/oil runs waster) to decide quickly what variables should be played on in simulation (as to slow down or fast up water displacement).

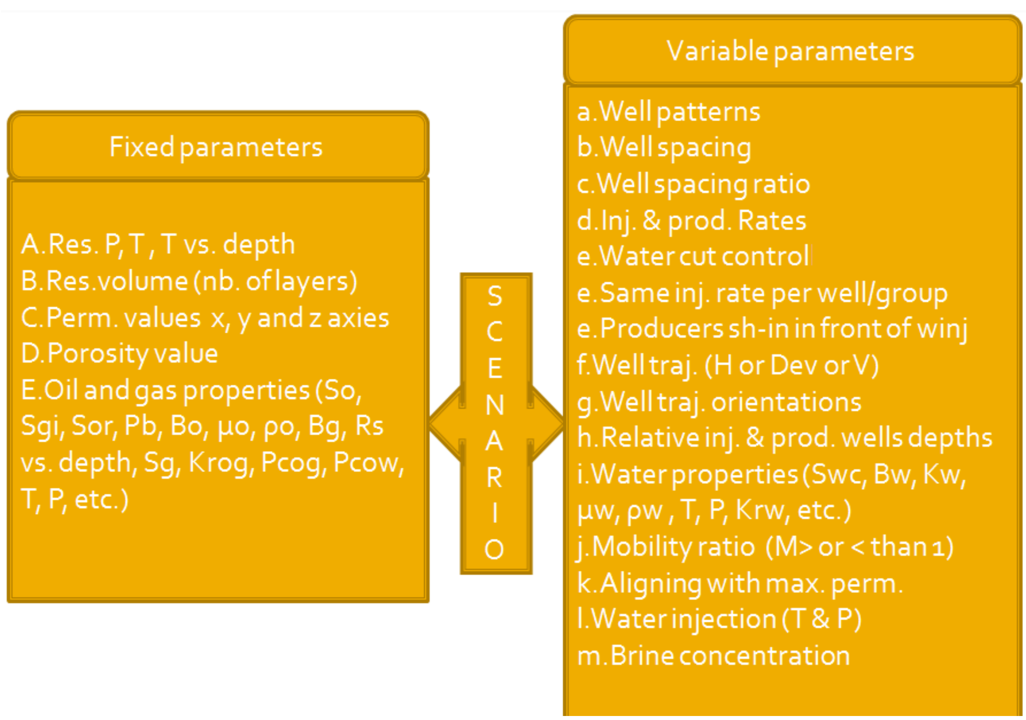


Fig. 3: List of fixed and variable parameters

- Increasing injection rate indefinitely is impossible as pumping facilities are limited in capacity and high injection rate might fracture formation. High injection rate may also induce high water-cut in a short time before the project pay-back time is attained.
- Decreasing the injection rate is neither preferable as it might slows down the recovery which may be against the project economy.
- Increasing indefinitely oil production is also not allowable as oil storage and processing facilities are limited in volume and capacity.

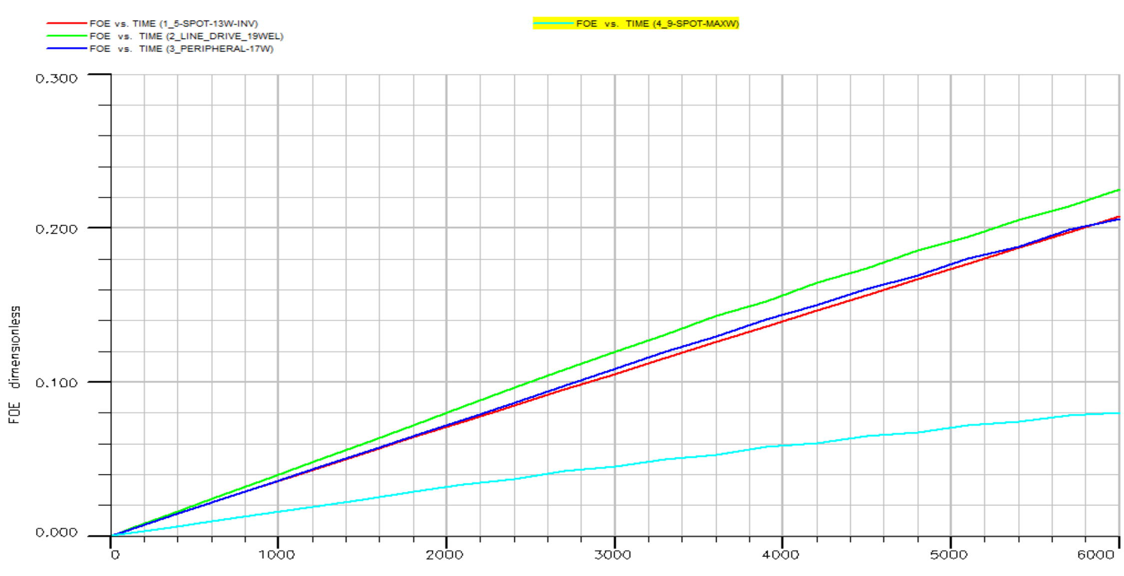
RESULTS AND DISCUSSION

Acronym:

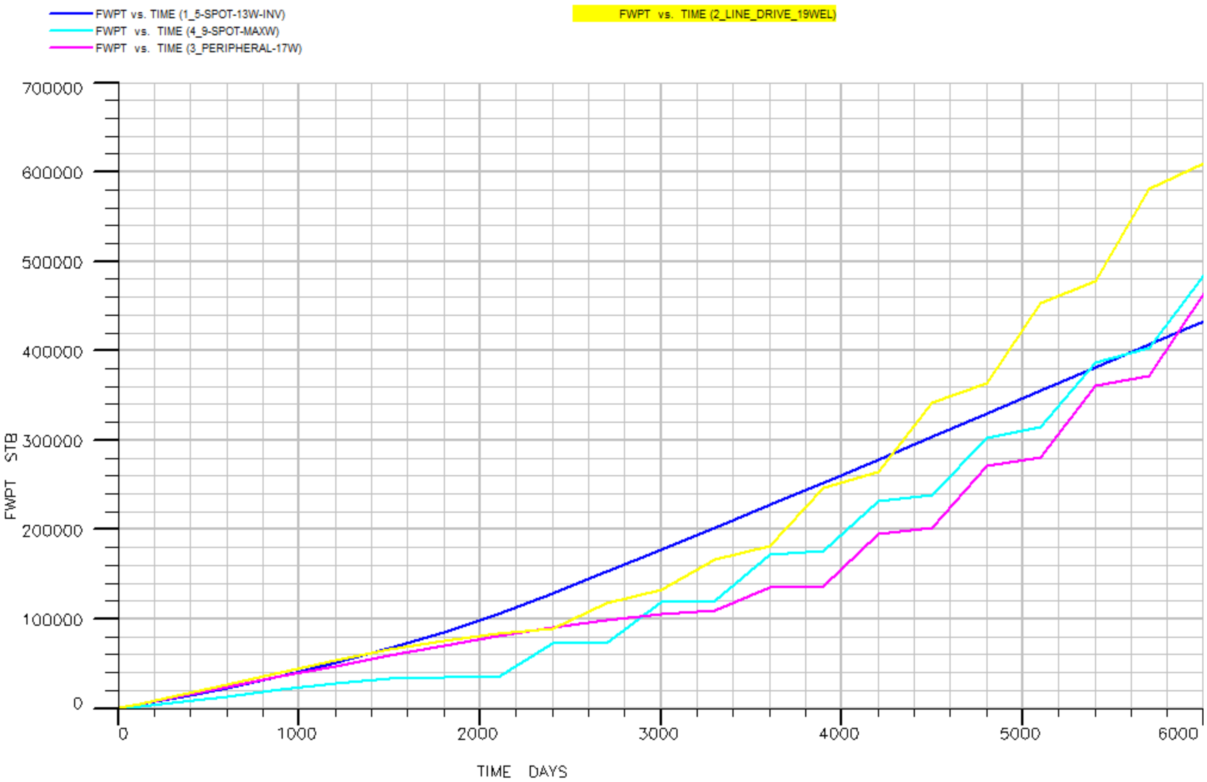
U : With the added effect of
M : Mobility ratio

Data used for the simulation:

- The reservoir model consists of a 5×5×3 reservoir with live-oil with dissolved gas
- Average axial permeabilities:
  1st layer (K_x = 120; K_y = 100; K_Z = 250)
  2nd layer (K_x = 800; K_y = 800; K_Z = 800)
  3rd layer (K_x = 1000; K_y = 1000; K_Z = 250)
- R_s is equal 1.4, constant versus depth
- S_{wi} = 0.15
- oil density = 49 lb/ft^3
- Oil bubble point pressure in interval (400-5200psi):
  - In (3600-4400 psi) Rs is above 1.4, hence gas is not dissolved but Pcow is positive to allow for immiscible water-oil displacement. Water temperature may then, lowers oil pressure to prevent high gas formation. Also, as flooding pressures are high enough most water floods force the gas back into solution
  - There should be noted that some of the oil displaced by the water flood will fill the pore space occupied previously by gas in the un-swept portion of the reservoir. This part of the displaced oil is not recovered. Hence water flood response is delayed as much as the gas filled-up space is bigger. But, in our case, gas is such that the breakthrough is not delayed:
- Oil viscosities in interval (0.9-1.17)
- Rock pressure = 4500 psi
- Rock porosity = 0.2
- GOC (Gas Oil Contact) = 8000 ft (top of the reservoir)
- WOC (Water Oil Contact) = 8150 ft (bottom of the reservoir)
- Gas pressures in interval (400-5600 psi)
- S_{gi} (initial gas saturation) = 0.04
- Water pressure = 4500 psi
- Water viscosity = 0.8 cp (for M>1 case)
- Water density initially taken as 63 lb/ft^3
- S_{wi} (initial water saturation) = 0.15
- K_{rw} (water relative permeability) = from 0.0 to 0.55
- K_{row} (oil relative permeability) goes from 1 down to 0.0. This means that water runs faster than oil
- S_{or} (residual oil saturation) = 0.1
- Production wells minimum BHP (bottom hole pressure) = 1000 psi
- Injection wells maximum BHP (bottom hole pressure) = 10000 psi
- All wells are controlled by BHP
- Initially, injectors have same rate = 100 stb/day and producers as well, have 100 stb/day production rate
- Water flood life limit = 6000 days (16 years)

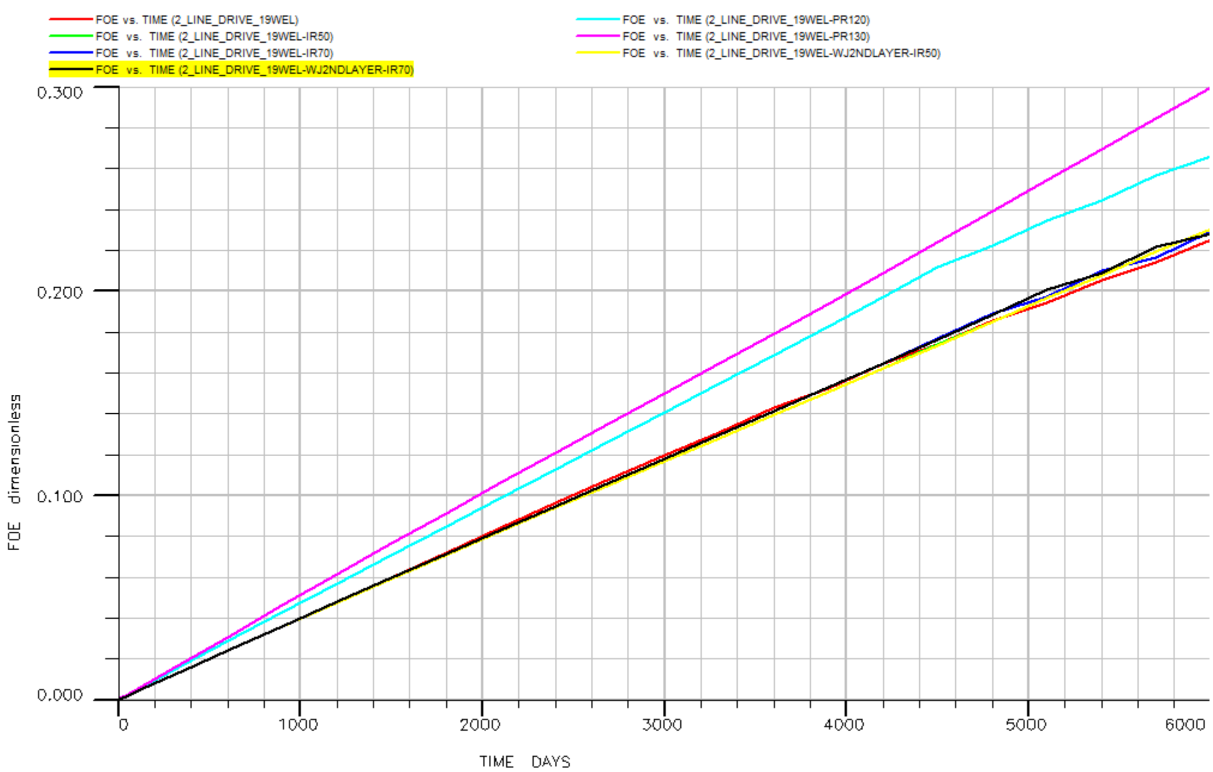


(A) FOE (dimensionless) vs. time (days)

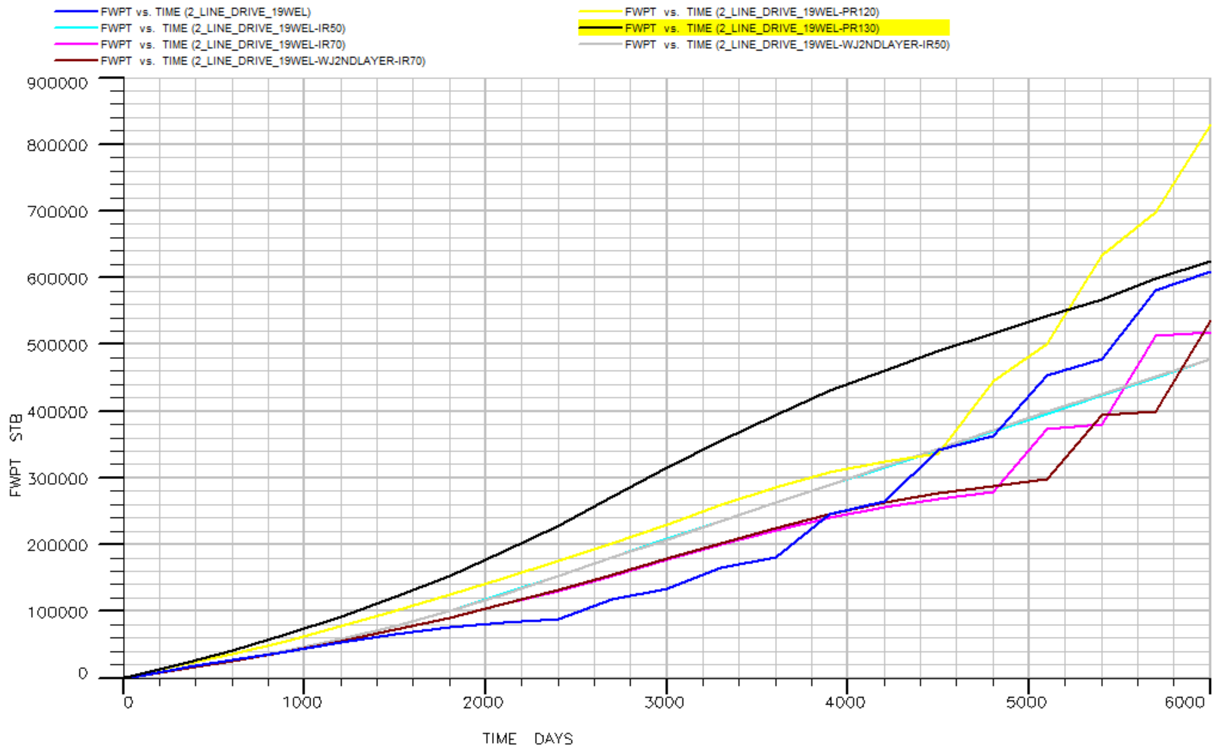


(B) FWPT (STB) vs. time (days)

Fig. 4: FOE & FWPT for all patterns



(A) FOE, line drive 19 w versus low injection rate, high production rate and injection from 2nd layer



(B) FWPT, line drive 19 w versus low injection rate, high production rate and injection from 2^{nd} layer

Fig. 5: Base case FOE-red curve; FWPT-blue curve line drive (19 wells), 100 stb/day injection production rate, injection from the 2^{nd} layer

Pattern selection: First there should be noted that water and oil produced are linked by the balance material equation: $W_{inj} = N_pB_o + W_pB_{W.}$ thus, for a certain cumulative water injection W_p must be small so that N_p is big. Different well patterns of same type but different well numbers were simulated and the highest in oil recovery and lowest in water production were chosen. These difference chosen well pattern types were subject to simulation and the resulting graphs were put in Fig. 4 for selective comparison.

The 5-spot 13 wells, the peripheral 17 wells and the line drive 19 wells selected as the best type of patterns. In Fig. 4, it appears that the 19 wells line drive pattern has the highest oil recovery but its FWPT is the second highest after the inverted 5-spot pattern (until the day 4300^{th}). The 17 wells peripheral pattern is also a very good candidate had its FOE was not lower than the line drive's; The 17 wells peripheral pattern may be the best alternative to save high produce water disposal cost in case 19 wells line drive optimization still reveals to be relatively costly. Using the 19 wells line drive (our case) entitles us to resort to a strategy to lower FWPT as much as possible in order to keep FOE high.

Pattern optimization: Optimize by injection from an upper layer and less injection rate.

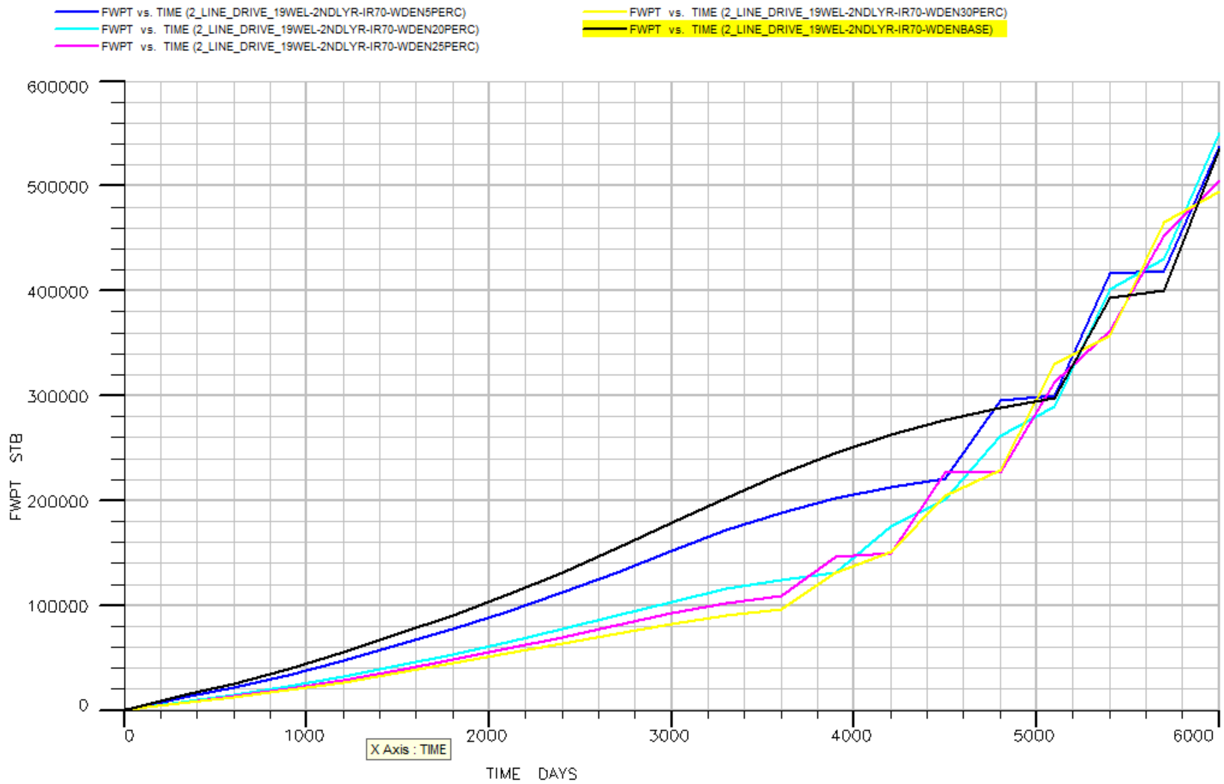
In the next page Fig. 5. As shown the blue and the black curve improvement to the FOE of the line drive pattern due to the injection from the 2^{nd} layer. The red curve (base case IR = 100 stb/day) improved to the blue curve (IR = 70 stb/day) which in turn improved to the black curve (IR = 70 stb/day and injection from the 2^{nd} layer). Thus the improvement occurs but only minimally.

On the other hand, in Fig. 5B the FWPT of the 70 stb/day curve (pink) is less than the 50 stb/day curve (aqua) and the "50 stb/day injection from the 2^{nd} layer" curve (grey). The 70 stb/day injecting from the 2^{nd} layer seems to have slowed down the water for better sweep efficiency and less oil by-passing (whence low FWPT) (Fig. 5B - maroon curve: injection from 2^{nd} layer is lower than pink curve: injection from 3^{rd} layer). This can be because of the drop pressure between the injectors and producers increases with the increase of the distance between both wells bottom-holes ($q\mu L = K.A.\Delta P$, if L increases, q and/or ΔP has to decrease to maintain the equation balance).

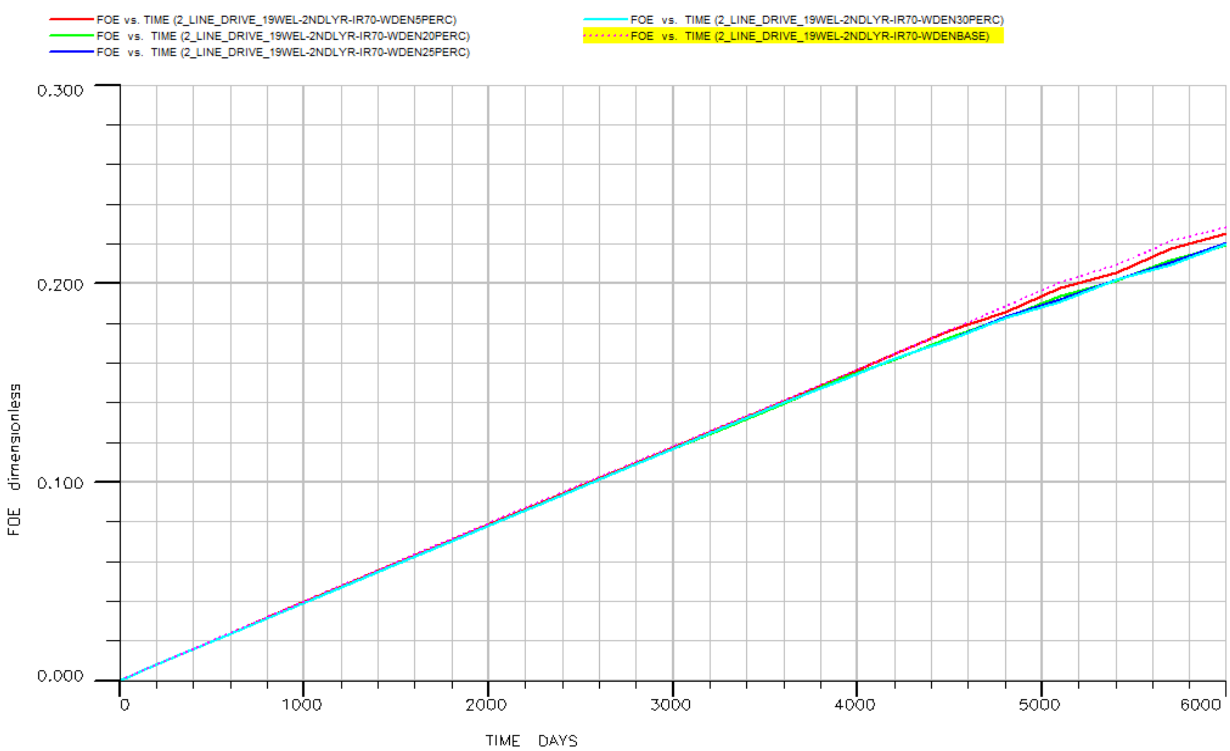
Consider the fractional flow (water-cut) equation:

$$f_w = \frac{1+\left(\frac{0.001127(kk_{ro})A}{\mu_o i_w}\right)\left[\frac{\partial p_c}{\partial x} - 0.433\Delta\rho\sin(\alpha)\right]}{1+\frac{k_{ro}}{k_{rw}}\frac{\mu_w}{\mu_o}}$$

First there should be noted that water and oil produced are linked by the balance material equation:



(A) FWPT-effect of lower water density



(B) FOE-effect of lower water density

Fig. 6: Base case: (FWPT: black; FOE: dashed pink curve): 19 wells line drive U 2^{nd} layer injection 70 stb/day U 63LB/ft^3 water density

$$W_{inj} = N_pB_o + W_pB_w$$

Thus, for a certain cumulative water injection W_p must be small so that N_p is big.

The tilting of the formation in our case is done using injection from 2nd layer while producing from the 3rd layer. If α is positive (up-dip flow) the f_w will decrease as α increases and reciprocally. Notice that if the injectors and producers bottom-holes are at same level (α = 0) f_w is at its maximum if all other variables are kept constant. The FOE lowered a bit (yellow curve (IR = 50 stb/day) lower than the black curve (IR = 70 stb/day) in Fig. 5A) as the injection seem lowered much to the point no high recovery achieved in the expected period. The lowering of IR to 50 stb/day increased FWPT as well (maroon curve levelled up to grey curve in Fig. 5B).

Optimization by water density increase: In the next page Fig. 6A, shows increasing water density by 20% has lowered the FWPT curve (aqua curve) substantially. The FWPT became smoother (no fluctuations) until the 3100th day (here, max. gap = 100,000 stb with before (magenta curve: no density increase). The lowered density curve then rises but still lowest until the 5900th day where it rises up to 10,000 stb above the curve of before (without density increase). In Fig. 6B, FOE curves shows that the increase successively by 5 20, 25 and 30%, (respectively aqua, blue, green, red and dashed line) the water density lowered minimally FOE comparatively with the injection rate effect. On the other hand, from the same Figure FWPT curves are distinctively a part for the base case (black curve) and 5% water density (blue curve) with the blue curve being lower. But, for 20, 25 and 30%, the curves are respectively lower with early fluctuations. Therefore, in addition to the lowering of FOE increasing water density decreases water accumulation but accumulation decrease becomes unstable at very high density water density value.

The purpose of increasing water density in this case (M>1) is as decreasing Injection Rate (IR) previously, to encounter water bypassing due to relatively high water velocity versus oil. However, there was seen that further decrease of IR will increase FWPT whence the usefulness of water density increase providing that the decrease of FOE is permissible. Furthermore, from interpretation, it seems that water density is more effective than the injection rate as at 5% water density FOE lowers down while it is not until 40% decrease (60 stb/day (Fig. 6B) that FOE starts reducing and FWPT increasing.

Theoretically, by assuming a constant injection rate and realizing that (ρ_w-ρ_o) is always positive and in order to isolate the effect of the dip angle and injection rate on f_w equation above, is expressed in the following simplified form:

$$f_w = \frac{1 - \left[X \frac{\sin(\alpha)}{i_w}\right]}{1 + Y}$$

$$X = \frac{(0.001127)(0.433)(k\,k_{ro})A(\rho_w - \rho_o)}{\mu_o}$$

$$Y = \frac{k_{ro}}{k_{rw}}\frac{\mu_w}{\mu_o}$$

The above equation shows that if sin (α) is positive, the oil is displaced up-dip, the term X sin (α)/i_w will always be positive. By consequence, for f_w to be low, the numerator in f_w equation has to be minimized. The minimization of f_w is then achieved by decreasing the injection rate (i_w), thus a greater number is subtracted from 1 in the numerator, thus decreasing it and as a result f_w decreases given that all other variables are constant. Additionally, if ρ_w in X equation above is increased, X will increase in return. Consequently if α is positive such as in our case (injection from 2nd layer) and ρ_w increases, the numerator of fw less thus f_w is decreased.

On the other hand it is seen that by increasing water density and from the capillary pressure (P_c):

$$P_c = p_o - p_w = \left(\frac{\partial p_o}{\partial x} - \frac{\partial p_w}{\partial x}\right) - g(\rho_w - \rho_o)\sin\alpha$$

That P_c will increase thus interfacial tension between water and oil increases as water gains more leverage on oil. Also, the term X in f_w equation will increase. Thus, giving that α is positive; f_w will decrease as X and/or α increase.

Effect of directional permeability: The result shown in Fig. 7A and B consists of the representation the next simulation on axial permeability:

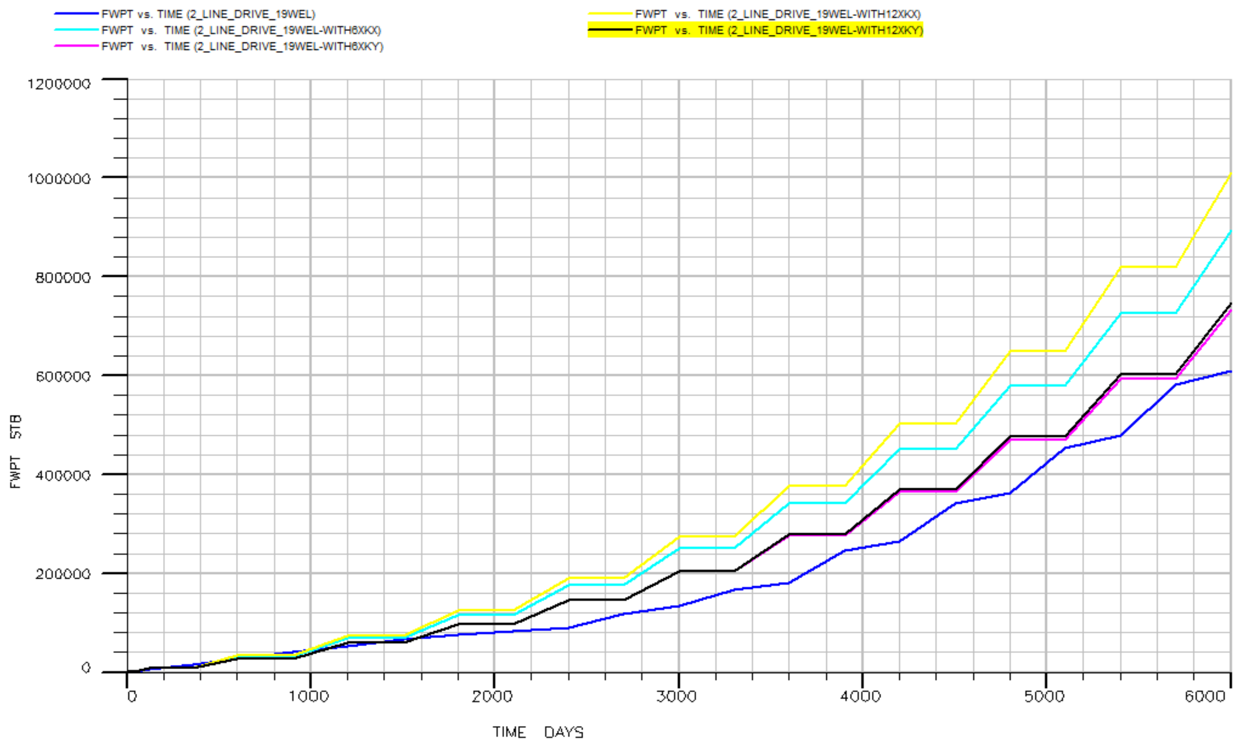
- Increasing only x permeability 6 times, then 12 times in a separate run.
- Increasing only y permeability 6 times, then 12 times in a separate run.
- Alternation (producer-injector) is along the axis while injector-injector is along y axis.

The interpretation of the two figures above is as such:

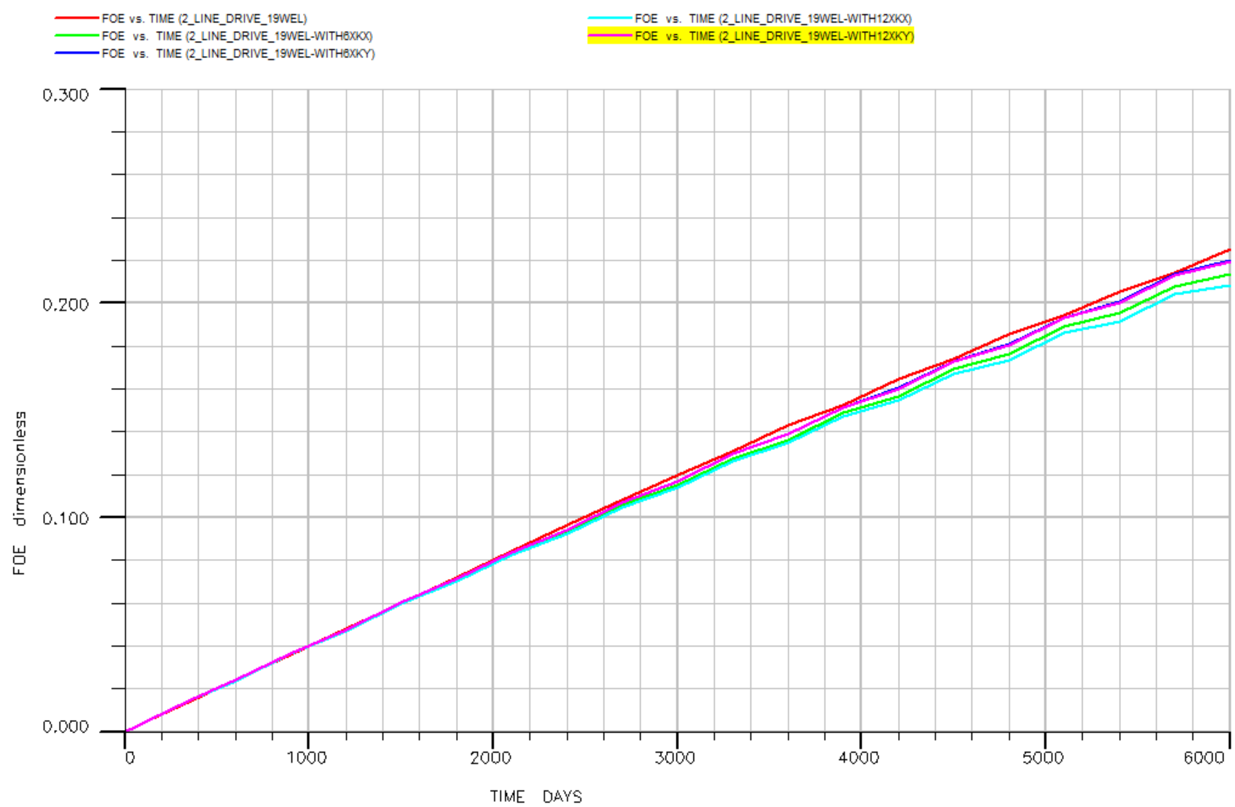
- Decreasing permeability along either axis (x and y) decreases water production. This is seen in Fig. 7 as:

  → Yellow curve (kx is 12 times ky) went down to aqua curve (kx is 6 times ky)

  → Black curve (ky is 12 times kx) went down to pink curve (ky is 6 times kx)

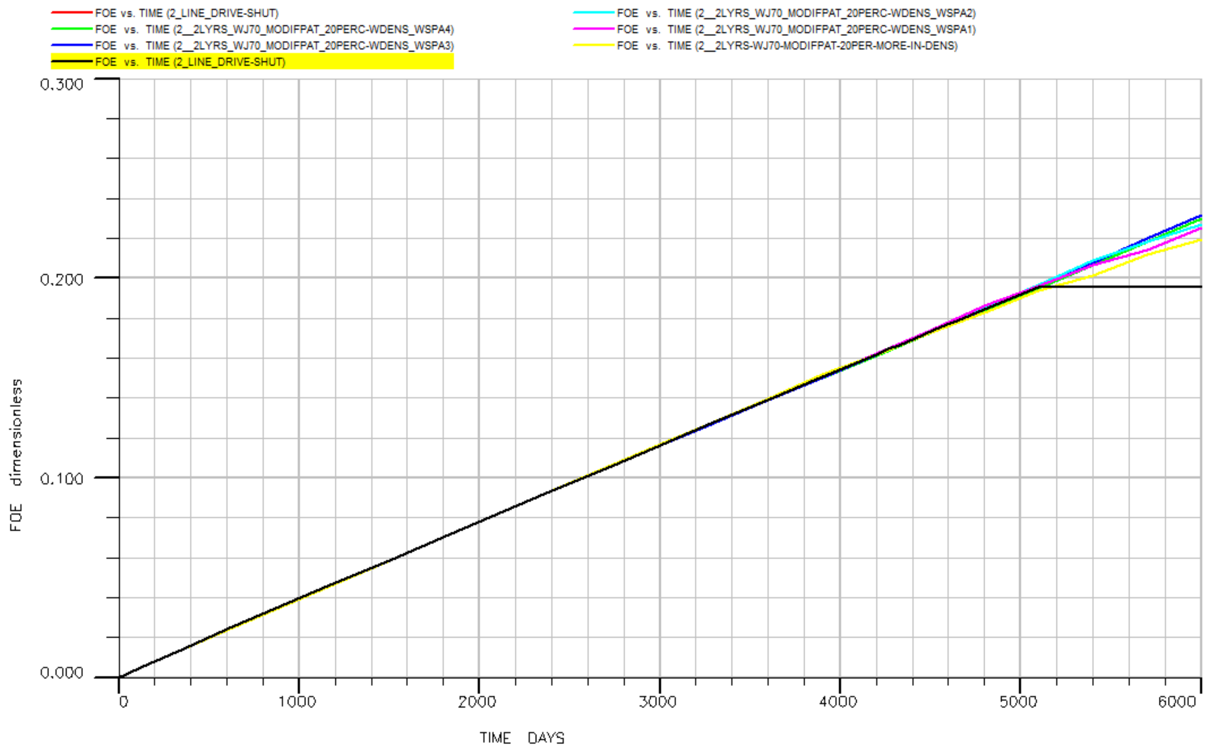


(A) Line drive-effect of aligning with high permeability axe on FWPT

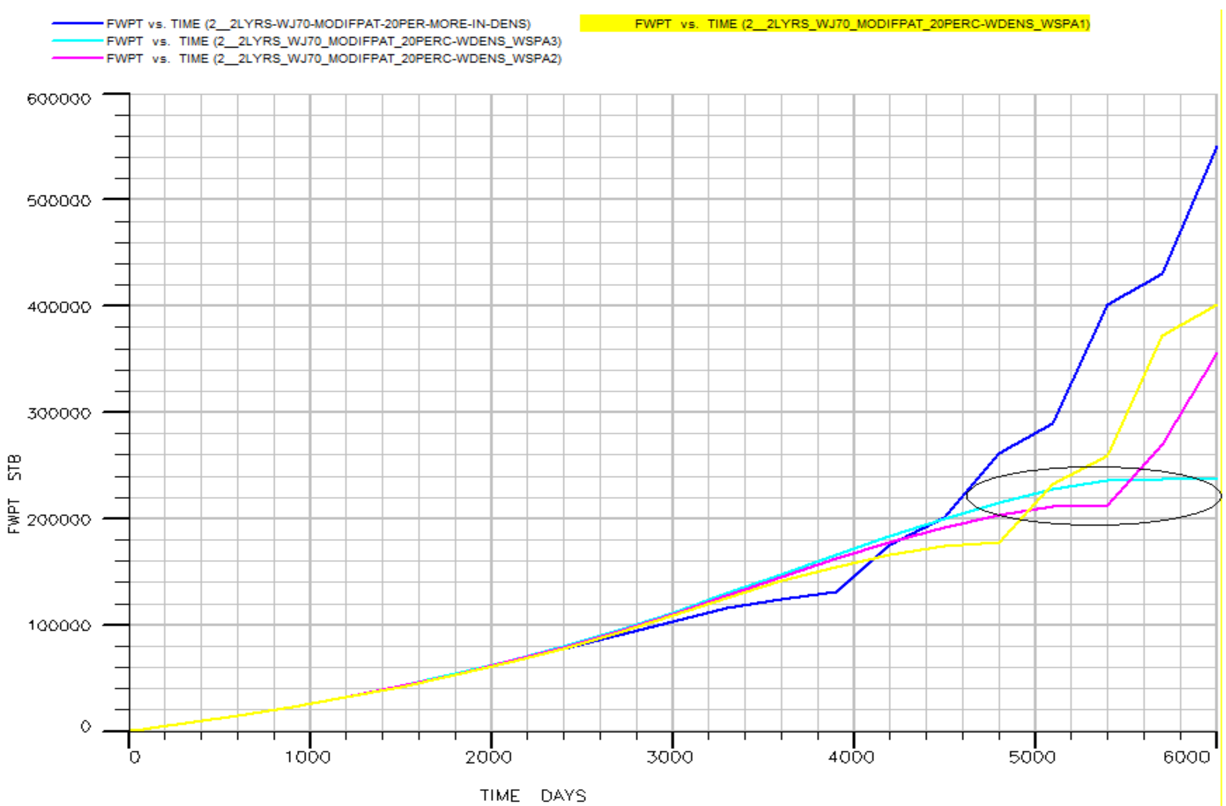


(B) Line drive-effect of aligning with high permeability axe on FOE

Fig. 7: Effect of aligning with high permeability



(A) FOE line drive 19 w-effect of well spacing ratio



(B) FWPT, line drive 19 w-effect of well spacing ratio

Fig. 8: Effect of well spacing ratio

- The decrease of FWPT is more emphasized for the x axis where lies producers and injectors alternation.
- The effect on FOE is adversely (FOE decreases) as permeability increases with more emphasis for the aligning with x axis and is practically similar in both cases (either the high permeability axis is x or y, the curves are not widely apart).

Therefore, it is better if the injector lines and not the alternation (injector-producer) to be aligned with high permeability axis in a line drive for the FWPT increase to be minimal for the alternation (injector-producer).

Effect of well spacing increase: In the next well spacing ratio (d/a: "d" being the distance between input and output wells and "a" the distance between input wells (injectors)) was increased along with the previously added water flood parameters.

The well spacing ratio was chosen as almost 2, 4, 8 and 16 times and represented along with the previous selected water flood parameters by respectively: _wspa1, _wspa2, _wspa3 and _wspa4 curves. The result being all 4 FOE curves are the same until the 5100th day where they split very within 0.01 FOE range. Besides, all the curves achieved around 0.24 FOE increment. On the other hand, _wspa1, _wspa2 and _wspa3 FWPT curves were substantially relatively apart in an advanced water flood time (around the 5000th day) where _wspa2 FWPT (the 4 times the initial spacing ratio) becoming the lowest.

The next formula is the diffusivity equation of any flow through a rock media:

$$1.127\times10^{-3}\frac{k}{\mu}\frac{\partial^2 p}{\partial x^2}-\frac{q_{sc}(x,t)B}{V_b}=\frac{\phi c_t}{5.615}\frac{\partial p}{\partial t}, 0<x<L, t>0$$

where, transmissibility noted by T is defined as such:

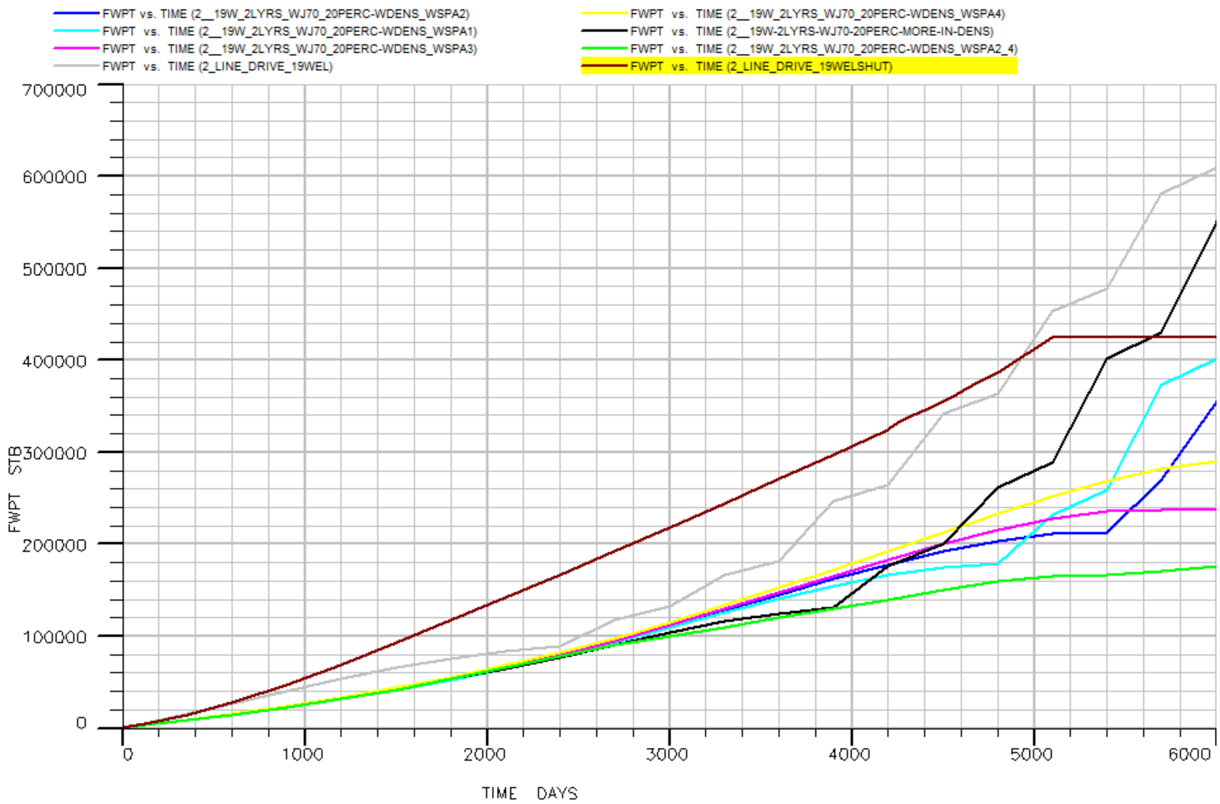
$$T=1.127\times10^{-3}\frac{kwh}{\mu\Delta x} \qquad \tilde{V}=\frac{\phi c_t wh\Delta x}{5.615\Delta t}$$

The (ṽ) is flow accumulation between the grid blocks (i & i+1), Thus, if the distance Δx between blocks increase, the transmissibility decreases. In return, Δt in ṽ equation must increase proportionally for the flow cumulative to be the same as before. In other words, the flow is slowed down when Δx is increased (or well spacing ratio increased). From Fig. 8, B well spacing ratio effect shows that FWPTs decreases but unsteadily comparing to the directional permeability effect. In Fig. 8B the higher the spacing ratio (d/a) the latter is the FWPT sharp upward surge. The comparison between both effects above can be analyzed from the Transmissibility (T) along a specific direction and the cumulative term (ṽ) equation. K change affects linearly T as can be seen from T equation. But, in our case since the well spacing ratio is a ratio (d/a) was done such as d increases and a decreases at same time and because d/a is a fraction of Δx/w, an increase of Δx in ṽ equation is compensated by a decrease of w which perturbates the flow accumulation and lead to the instability seen in Fig. 8B.

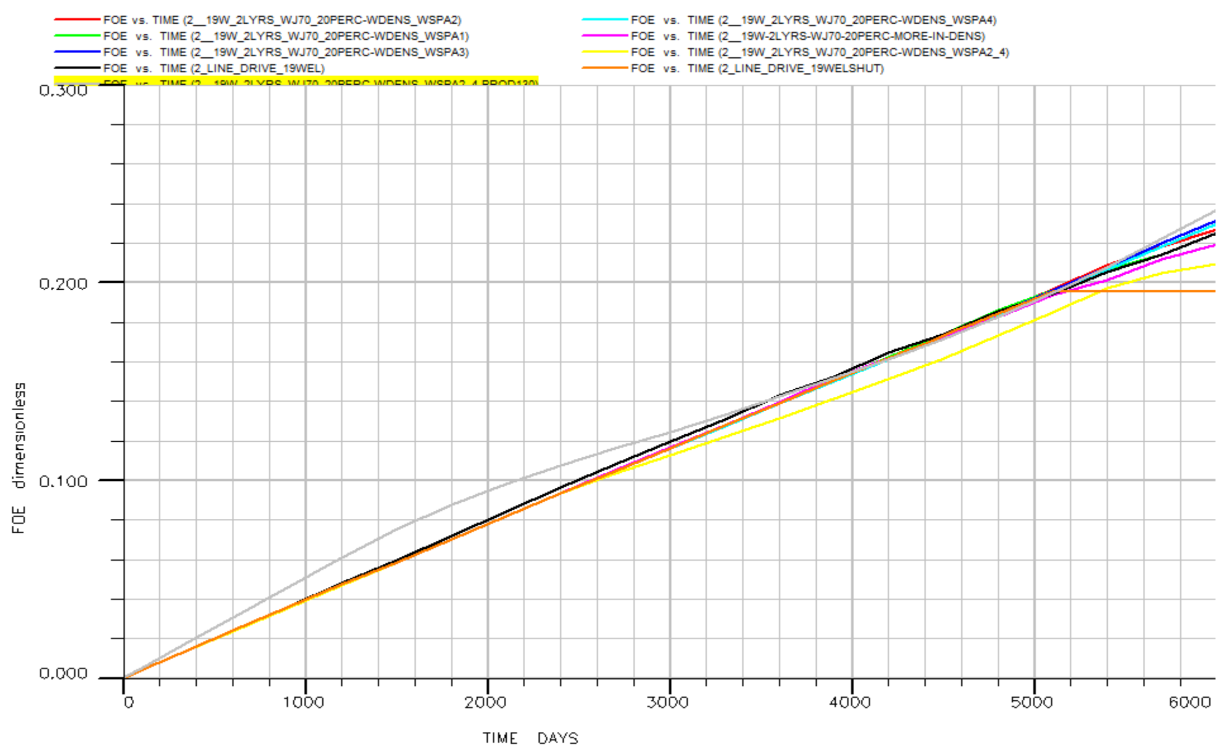
Effect of water-cut control: The _wspa2 curve in the previous run selected as best was subject to water-cut control at the 5400th day to lessen the water production sudden increase at that day (blue curve). The result is shown by Fig. 9A. At day 5400th the water-cut (q_w/ (q_o + q_w)) calculated was found equal 0.043. An Eclipse 100 keyword was used so that the current injection rate (70 stb/day) is multiplied by 0.857 when the water-cut at day 5400th is reached to bring it down to (60 stb/day). The resulting FWPT curve (green curve) shown in Fig. 10 shows that water production decreased (from the blue to the green curve) and even become steadier (with n sudden fluctuation up at day 5400th). The decrease in FWPT is also substantial (180,000 stb) day 6000th.

Figure 9B shows the effect of the water-cut control on FOE. It can be seen that FOE has decreased to around 0.025 (yellow curve) as maximum increment down at the end. Although FWPT has decreased of about 180,000 stb at day 6000th (Fig. 9A) from blue to light green curve with the green curve constantly below the blue curve) the FOE has not improved as expected (it went from red to yellow curve). Thus, we decided to allow more production (production rate was increased from 100 to 130 stb/day). When production rate was raised up along with water-cut control, FOE increased smoothly (gray curve, Fig. 9B) to a maximum increment of 0.013 at day 1800th. Then, the FOE decreased in a later time to about the same level as _wspa2's curve without water-cut control. This brings to mind if not the decrease of FOE after it increased (gray curve) is not because of the restriction of a certain amount of water-cut at a certain day. In Fig. 9, 10 and 2, the water-cut control is removed while keeping the production upgrade to compare the FOE versus FWPT with and without the water cut control.

It is seen from Fig. 10A that indeed the water-control was the cause of the decrease after increase (blue curve) of the FOE after shifting Production Rate (PR) to 130 stb/day as FOE increases steadily and substantially (aqua curve). Also, the increase of production rate along with water cut control (blue curve) yielded 0.12 FOE increment (0.03/0.24 = 12.5%) from base case (without water-cut control and production increase) while without water cut control it yielded 0.08/0.3 (or 26%). But this is not enough to conclude that dismissing water-cut is better than the previous case until FWPT is investigated. The result is shown by Fig. 10B.

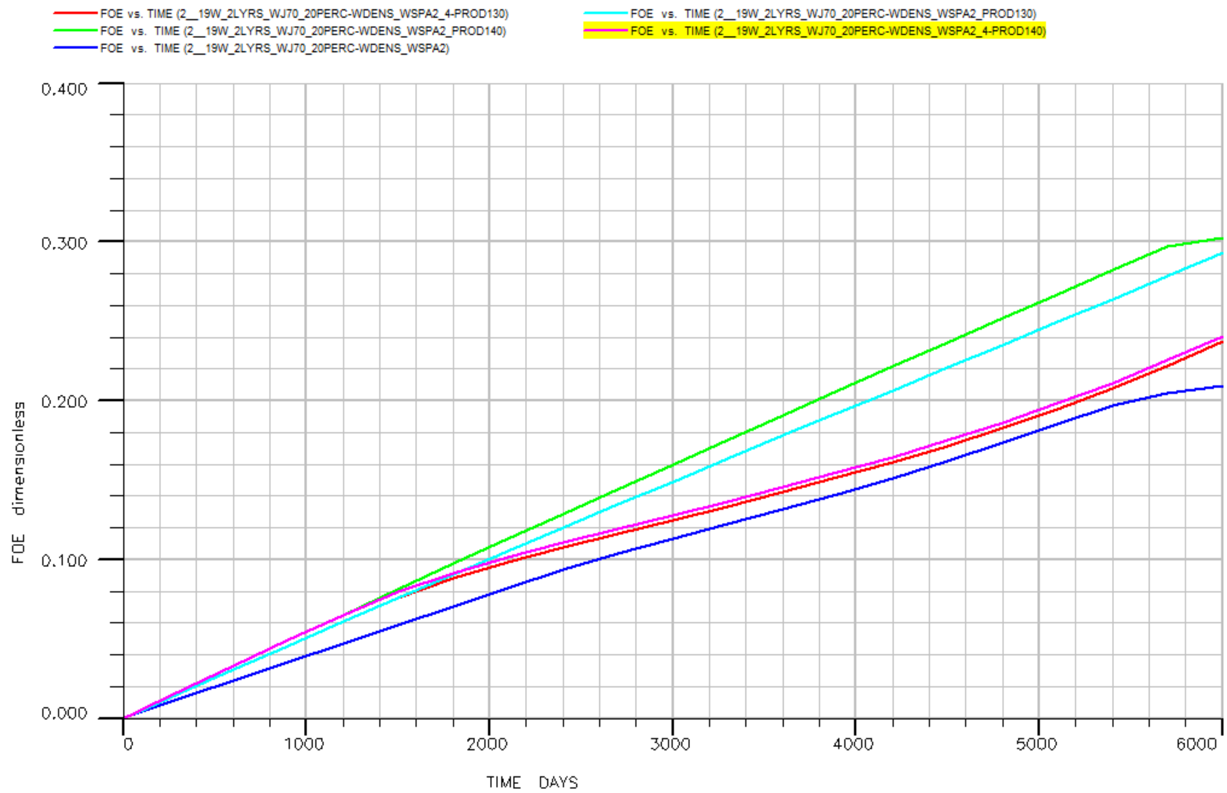


(A) FWPT, line drive 19 w-effect of water-cut control at an advanced time

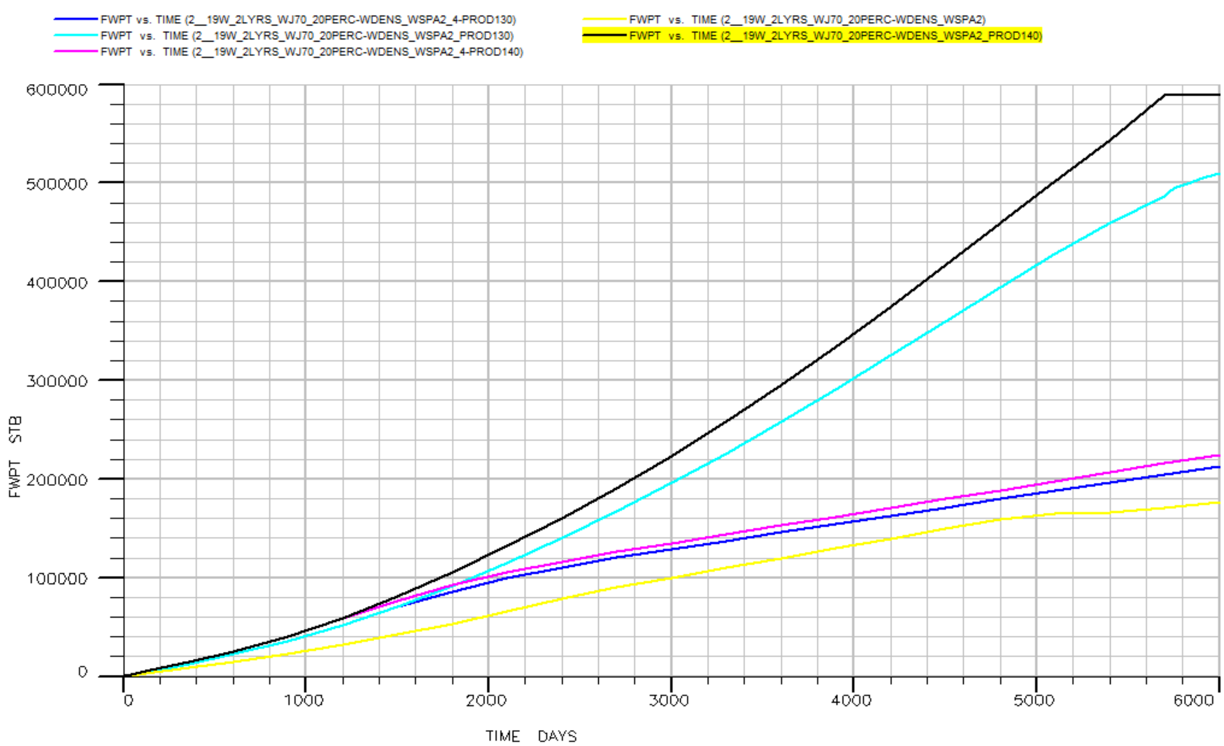


(B) FOE, line drive 19 w-effect of water-cut control at an advanced time

Fig. 9: Base case (black curve): 19 wells line drive U 2nd layer injection at 70 stb/day U 20% water density increment

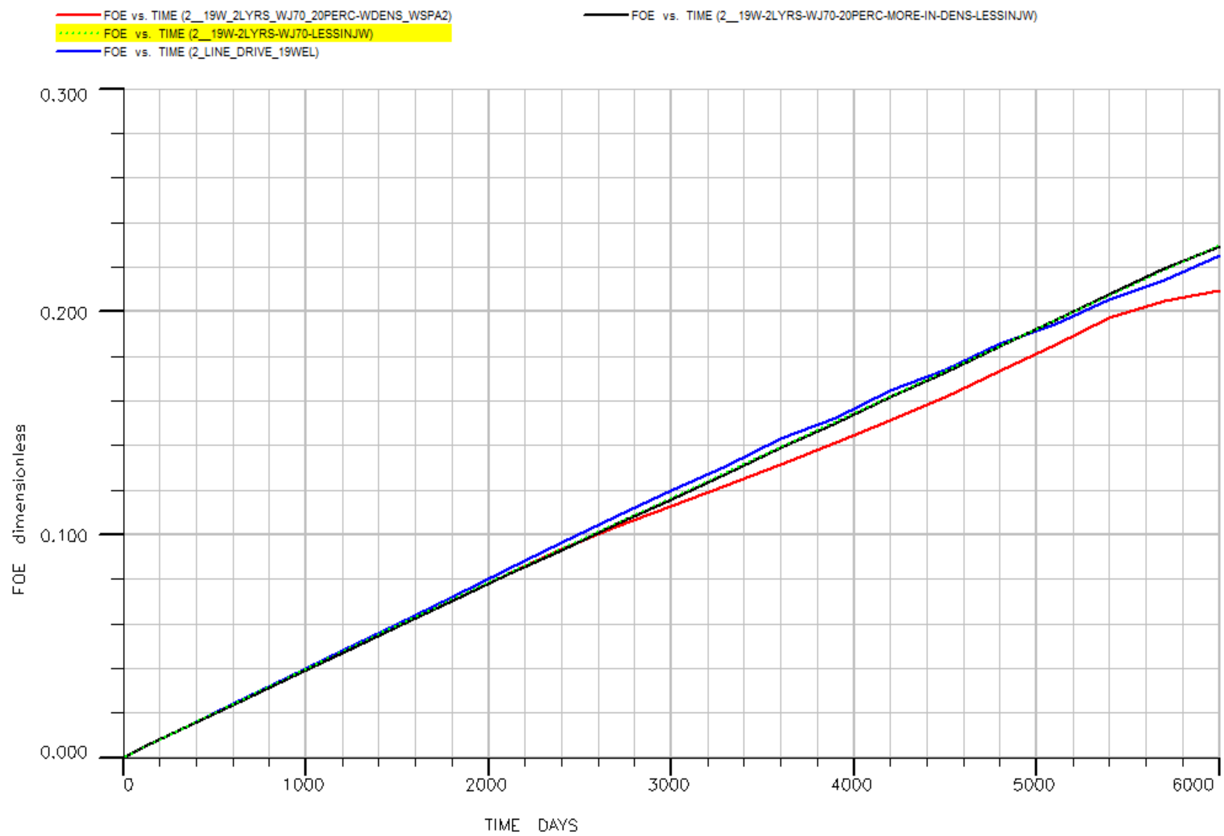


(A) FOE-previous case U production increase and without water-cut control

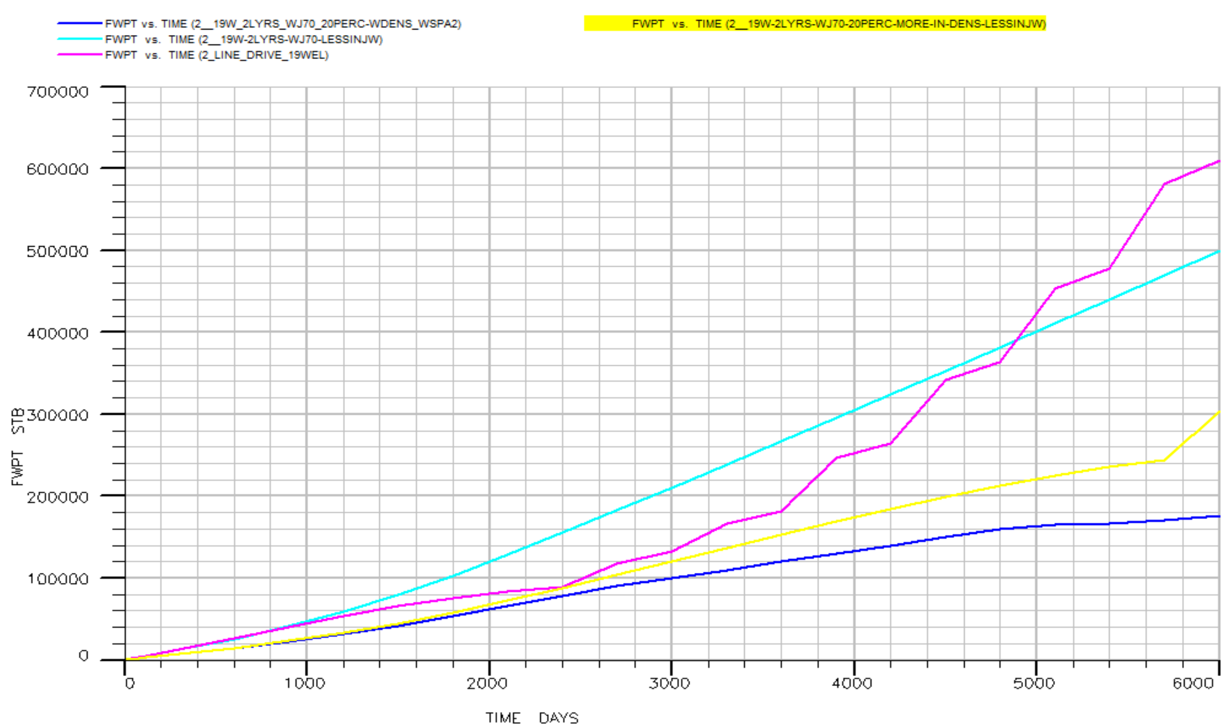


(B) FWPT-previous case U production increase and without water-cut control

Fig. 10: Base case: (FOE: green; FWPT: yellow): 19 wells line drive U injection from the 2nd layer at 70 stb/day U water density increment of 20%

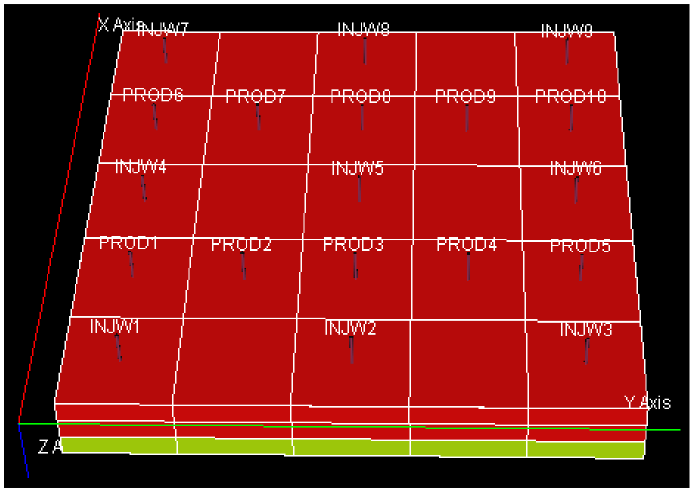


(A) FOE-effect of reduction of injectors on the “faster water”

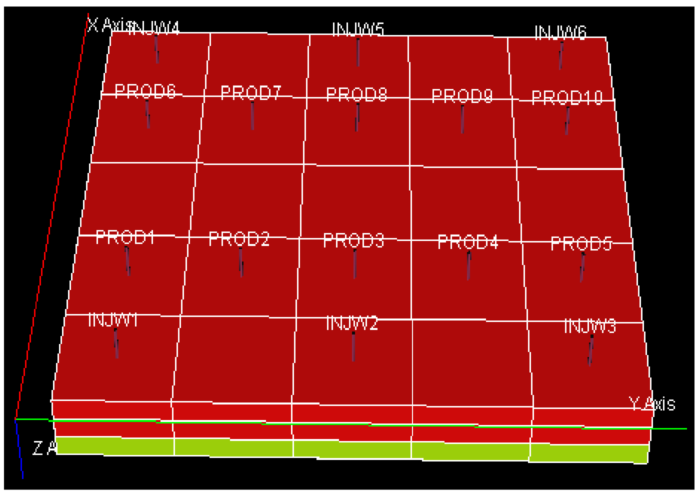


(B) FWPT-effect of reduction of injectors on the “faster water”

Fig. 11: Effect of reduction of injectors on the “faster water”



(A) Line drive-initial (19 wells)



(B) Line drive-less well injection

Fig. 12: Line drives

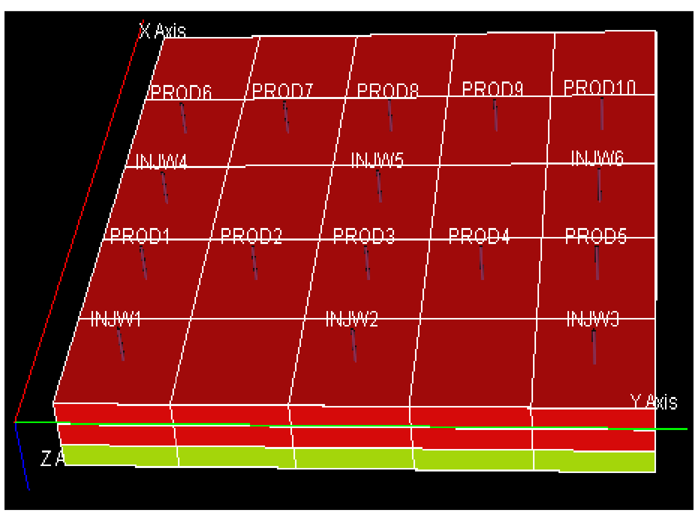


Fig. 13: Line drives-less injection wells-different position

The successive shift upward from blue to pink and from aqua to black curve indicate the importance of water cut control to shift down substantial amount of water production when PR is upgraded. At the end, by deduction and comparison, water density increase and injection rate decrease according to the Fig. 10B, the yellow curve is base case (2^{nd} layer injection, 20% water density increment and 2 times initial well spacing ration) taken before PR upgrade and without water-cut control. By comparison and deduction from all water flood parameters previously used, would a reduction of injection wells suffice instead of water density increase and injection rate decreased? The next shows that even when the 2 times well spacing ratio was brought to the initial (d/a = 1) and the injection wells reduce we still get high FOE and lower FWPT while reducing high amount of well costs.

Effect of reducing well injectors: From Fig. 11A and B, both the removing and keeping of water density decrement a long with reduction of injection wells (From Fig. 12A and B pattern). Actually even with the removing of water density decrement, the FOE curve remained almost intact when injection wells were reduced (as shown by the black curve). On the other hand, the addition of water density seems to be necessary with the injection wells reduction to bring down the FWPT curve from the aqua curve to the yellow curve. In order to see if the well positioning in Fig. 12B is optimal, a pattern of same configuration and well numbers but different positioning was simulated (Fig. 13).

In Fig. 12B, the two five parallel producers' lines were swept oppositely from two sides towards each other while in Fig. 13 only one producer line was swept from two sides. Considering that the flow from wells is radial, oil is produced with high water injection from P1, 2, 3, 4 and 5, respectively in Fig. 12B thus resulting in higher water cut than Fig. 13 case. From P6, 7, 8, 9 and 10, respectively oil production is produced slowly as longer space to seep (due to the space left after injection wells reduction). This results in higher FWPT and lower FOE for the Fig. 12B pattern comparatively with the Fig. 2 pattern. Thus Fig. 12B pattern is the best.

CONCLUSION

- Good sweep efficiency can be achieved with a regular pattern with an optimal well position.
- If same the rate is used for injection & production wells, symmetry in well pattern is necessary for better oil recovery. Also, preferably production is converged by surrounding injectors.
- Increasing water production yields high oil recover but with high water production.
- Water cut is controlled to bring any surge or sharp increase of water cumulative production at later time.
- It is better to keep water-cut control when the production rate is able upgraded by well completion or giving that it will increase during the water flood process as reservoir pressure back up higher.
- Increasing water production for the fast water case (M>1) yields further water production unless water cut is controlled to bring any surge or sharp increase of water cumulative production at a later time.
- Water density decrease has more effect in terms of FOE on the slow water case than injection rate and the effect is bigger than water increase effect on the fast water case. In fact, the water density increase has practically negligible effect on the FOE of the fast water case whence the need of more water flood parameter to slow down (to encounter by-passing). There must be noted the benefiting decrease of water density for the slow water case is limited (up to (10-15%) range) for a 631 b/ft^3 water density (at 21C and 4500 psi).
- Although water density has negligible effect on FOE for the fast water case (or M>1) it is the most influential water flood parameters in terms of FWPT lowering.
- Water production trend is smoother and semi-steady increase when water is slowed down to a certain limit. This increases FOE and decreases FWPT up to a certain limit where production rate increase should be allowed though it increases FWPT but it is only a little. This confirms the improvement of sweep efficiency by less water by-passing.
- Using the water flood parameters (decrease of injection rate, increase of water density, inducing an up-dip flow displacement-injecting from an upper layer, increasing well spacing ratio, etc.) can be used to decrease the water cumulative (FWPT) and increase oil recover (FOE) by reducing water by-passing. But, the use of these parameters is only to a certain degree, after that, not only FWPT will decrease but FOE as well as water will slow till no sufficient energy to move up oil.

REFERENCES

Ahmed, T.H., 2006. Reservoir Engineering Handbook. 3rd Edn., Elsevier/Gulf Professional, Burlington, MA.

Callaway, F.H., 1959. Evaluation of water flood prospects. J. Petrol. Technol., 11(10): 11-16.

Singh, S.P. and O.G. Kiel, 1982. Waterflood Design (Pattern, Rate and Timing). Proceeding of the International Petroleum Exhibition and Technical Symposium of the Society of Petroleum Engineers. Beijing, China.