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ORIGINAL PAPER - PRODUCTION ENGINEERING

# Sensitivity study of horizontal length, offset from water oil contact and withdrawal rate of horizontal well in bottom water drive reservoir

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**Abstract** Estimation of critical rate is required for maximizing oil production from horizontal well before water breakthrough. Post-breakthrough recovery is dependent on parameters viz: Horizontal length (L), withdrawal rate (Q) and offset from WOC (h). Critical rate has been determined using various analytical methods whereas EUR from horizontal well has been calculated for forty-eight cases (L-4 no's, Q-3 no's, h-4 no's) using commercial black oil simulator. Result of the study shows that maximum impact on cumulative oil production is given by offset from WOC followed by withdrawal rate and lastly on horizontal well length.

**Keywords** Coning · Offset · Horizontal completion · Water-free production · Sensitivity

## Introduction

Excessive water production from hydrocarbon reservoirs is one of the most serious problems in matured oil fields. Besides the down fall of oil production rate and wastes of reservoir energy, operating cost of in the surface production operations also increases due to handling, treatment, and disposal of large quantities of produced water (Sharma et al. 2009; Al Hasani et al. 2008). Horizontal wells have been used to produce thin zones, fractured reservoirs, formations with water and gas coning problems, waterflooding, heavy oil reservoirs, gas reservoirs, and in EOR methods such as thermal and $CO_2$ flooding (Joshi 2003).

The maximum water-free production rate, referred to as the critical fluid production rate (CFPR), is a function of the thickness of the oil zone, the length of the completion interval, the distance between the completion interval and the water zone, the density of the oil and water, the viscosity of the oil and the formation permeability (Piper and Gonzalez 1987).

Recovery maximization from horizontal well completion is a challenge in the oil industry, which is dependent on variants viz: critical rate, length of horizontal section, offset from water oil contact (WOC), withdrawal rate.

Dikken (1990) first presented and modeled the pressure drop in horizontal well and its effect on the performance of horizontal well, Hyun studied for integrated optimization on long horizontal well length, and Zifei et al. (1997) developed a model for optimal horizontal well length using an coupled model of reservoir and wellbore hydraulics, whereas Hu et al. (2000) presented that of model using net present value (NPV) method.

Efros (1963) proposed a critical flow rate correlation that is based on the assumption that the critical rate is nearly independent of drainage radius. The correlation does not account for the effect of the vertical permeability (Ahmed Tarik 2010). Karcher (1986) proposed a correlation that produces a critical oil flow rate value similar to that of Efros' equation. Again, the correlation does not account for the vertical permeability (Ahmed Tarik 2010). Joshi (1988) determined the critical oil flow rate in horizontal wells by defining the following parameters: horizontal well drainage radius, half the major axis of drainage ellipse, effective wellbore radius (Ahmed Tarik 2010).

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## Problem description

Horizontal Well-49 is located in the southwestern part of the field (Fig. 1). It was drilled and completed in the year 2007. Open-hole logs indicated that the original WOC was at a depth of 2551 m TVDSS. The landing point was kept at 2540 m true vertical depth below sea level (TVDSS). The well started production from April 2007 to August 2011 at 140 $m^3$/d. Initially, the production rate was kept at 140 $m^3$/d (7 mm bean), which was increased further to 170 $m^3$/d (8 mm bean). It can be seen from Fig. 2 that water started coming after increasing the production rate by increasing the drawdown by increasing the bean size. Well water cut started thereafter, reached a level of 60%, and finally watered out. A diagnostic plot for the verification of the cone has been prepared and presented as shown in Fig. 3. In order to mitigate water production and maximize production determination of critical rate (pre-breakthrough performance) and production profile generation using commercial reservoir simulator (post-breakthrough performance) needs to be carried out by doing sensitivity analysis on horizontal length, withdrawal rate and offset from WOC.

## Proposed methodology

In this paper, following methodology has been adopted for determination of optimum horizontal completion parameters.

A. Initial estimation of CFPR using various analytical methods
B. Numerical simulation modeling
C. Model validation using history matching
D. Sensitivity Analysis
   a. Withdrawal rates
   b. Offset from WOC
   c. Horizontal length
E. Results and discussion
F. Conclusion and recommendations

### Initial estimation of CFPR using various methods

Methods for calculating critical rate using Efros, Krachers, and Joshi's method were used to calculate the CFPR (Ahmed Tarik 2010). All the calculations will be performed using the actual reservoir fluid and rock properties reported in Table 1.

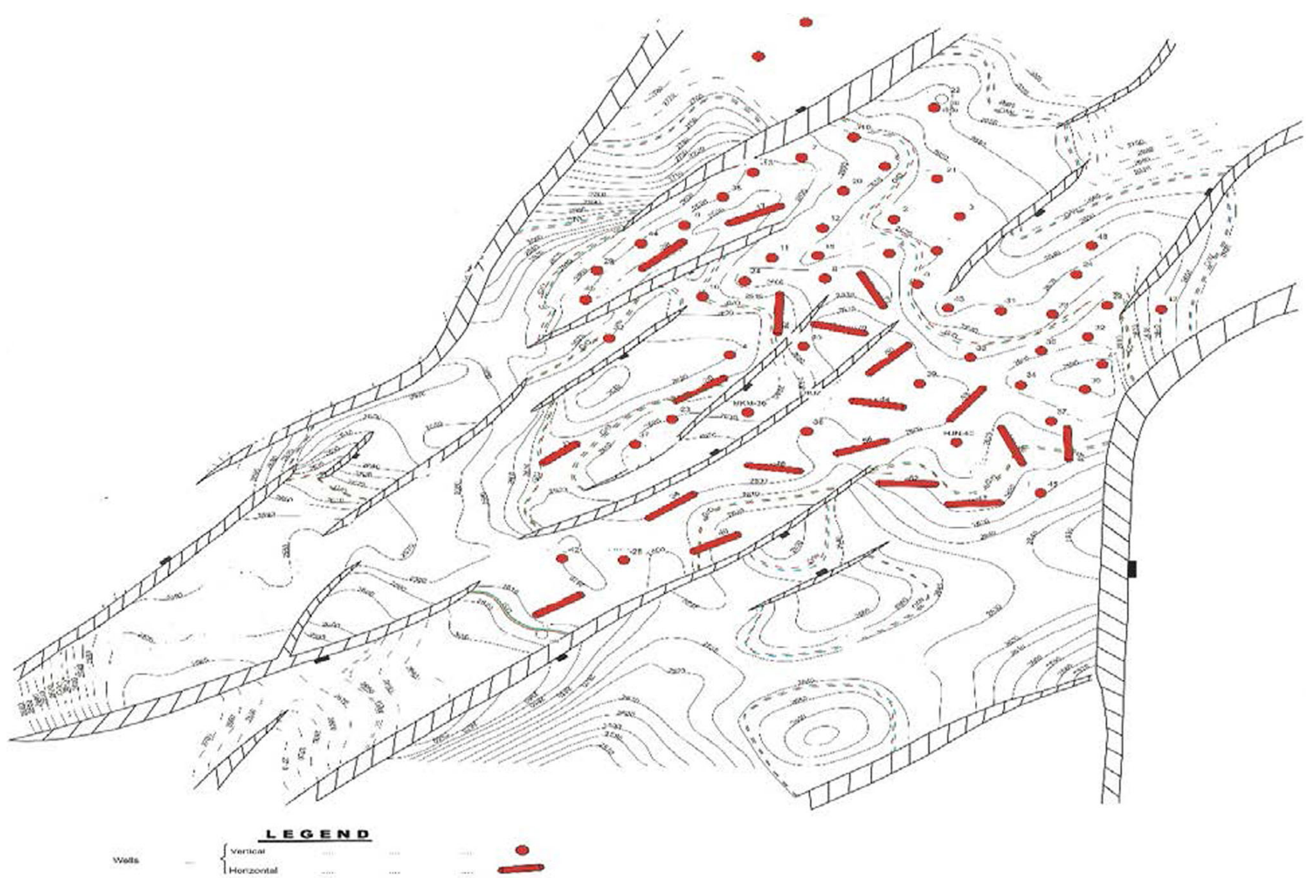


**Fig. 1** Depth contour map on top of Oligocene sand

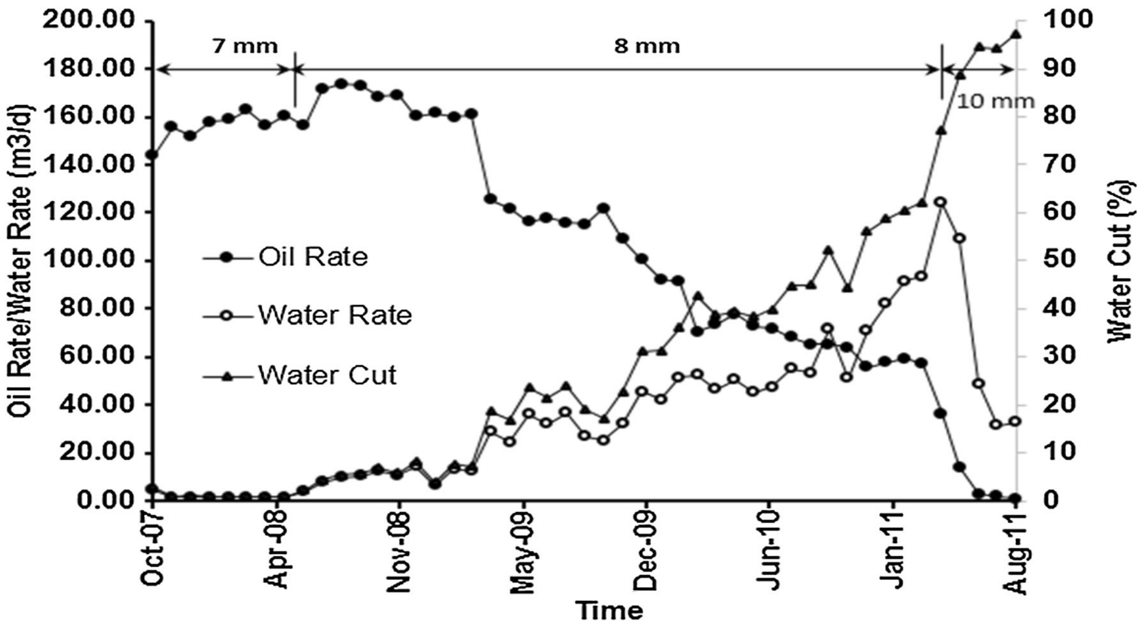


**Fig. 2** Production behavior of well-49

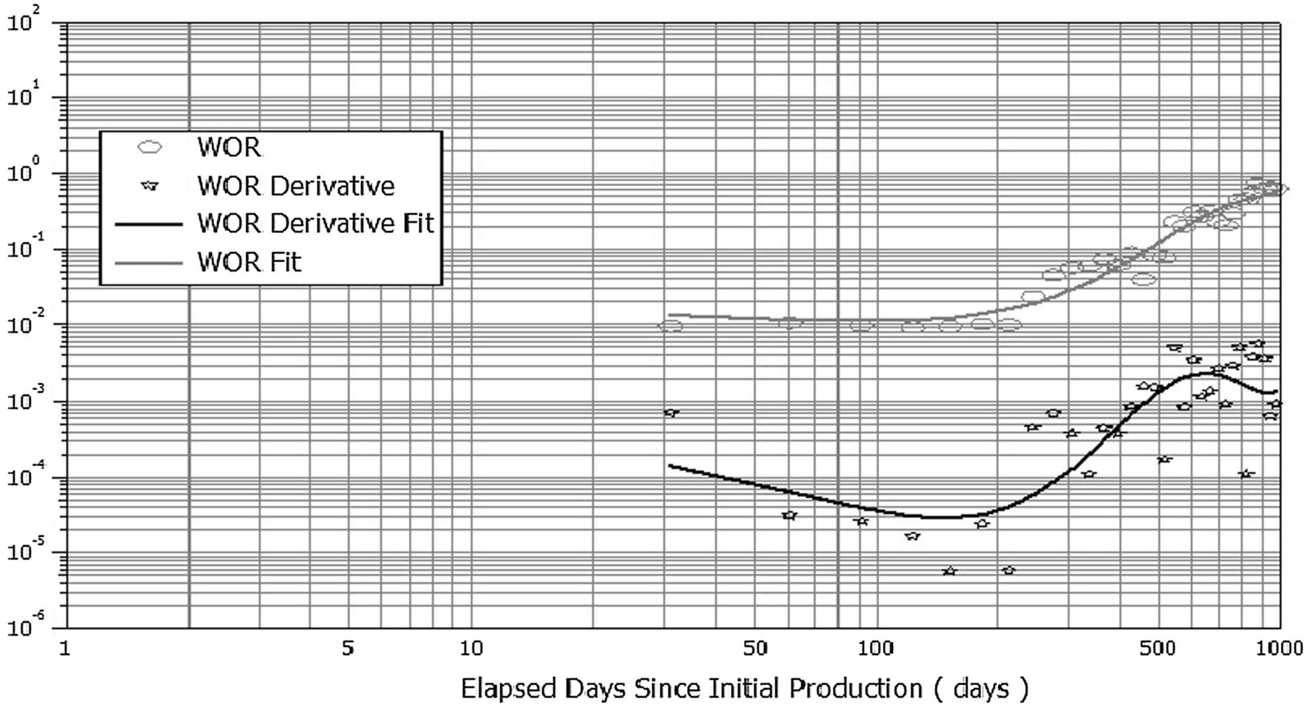


**Fig. 3** Water control diagnostic plot of well-49

## Efros method for critical rate calculation method

$$\mathrm{Qoc} = 0.0783 \times 10^{-4} \left[ \frac{\varrho w - \varrho o}{Y_e + \sqrt{Y_e^2 + \left(\frac{h^2}{3}\right)}} \right] \left( \frac{KhL}{\mu_o B_o} \right) \left( h - (h - D_b)^2 \right) \tag{1}$$

where $K$ is permeability in mD, $h$ is net pay thickness, Ye is half distance between two lines of horizontal well, $L$ is length of horizontal well, and $\varrho$ is density in lb/ft$^3$.

Krachers method for critical rate calculation method:

**Table 1** Reservoir and fluid properties

| Reservoir properties | |
|---|---|
| Drainage radius, Re(Feet) | 1320.00 |
| Horizontal permeability(md) | 100.00 |
| Vertical permeability (md) | 5.00 |
| Pay zone thickness (Feet) | 98.43 |
| Standoff from WOC, Dt(Feet) | 65.62 |
| Completed interval, hp(Feet) | 60.00 |
| Average reservoir pressure, P(Psi) | 3769 |
| Formation porosity, ϕ (%) | 22 |
| Wellbore radius, Rw(Feet) | 0.23 |
| Length of horizontal well, L (Feet) | 2625 |
| Half drainage length, Ye (Feet) | 656 |
| Fluid properties | |
| Density of water, ϱw(lb/ft3) | 62.40 |
| Oil API | 22.00 |
| Density of oil, ϱo(lb/ft3) | 57.52 |
| Oil viscosity, μo(cp) | 0.60 |
| Oil formation volume factor, Bo | 1.10 |
| Oil Saturation pressure, Pb(Psi) | 3769 |

$$Qoc = 0.0783 \times 10^{-4}\left[\frac{(\varrho w - \varrho o)LD_b^2K_h}{\mu_o B_o(2Y_e)}\right]\left[1 - \frac{D_b^2}{Y_e^2}\right]\left(\frac{1}{24}\right) \tag{2}$$

where $B = h -$ Db and Db is distance between WOC and horizontal well, feet.

Joshi's method for critical rate calculation method:

$$Qoc = 0.0246 \times 10^{-4}\left[\frac{(\varrho w - \varrho o)\left(h^2 - (h - D_b)^2\right)K_h}{\mu_o B_o \ln\left(\frac{r_{eh}}{r_w}\right)}\right] \tag{3}$$

where $\varrho$ is density in lb/ft$^{3,}$ Kh is horizontal permeability, mD, Db is distance between WOC and horizontal well in feet, Dt is distance between horizontal well and GOC in feet, and rw is wellbore radius in feet.

CFPR calculation results from the various analytical methods are presented in Table 2.

## Numerical simulation model

The 50 m by 50 m gridding of the original model was upscaled to 100 m by 100 m. The vertical resolution was reduced approximately by a factor of two, increasing average cell height from 0.5 to 1 m. The geomodel was resampled into upscaled grid to capture rock types, porosity, and permeability and saturation distribution. The porosity was resampled arithmetically with weighing by pore volume. The resultant upscaled simulation grid has 120 × 72 × 86 (7,43,040 cells) having 3,08,326 active cells, and upscaled model was migrated into the Eclipse Simulator. Further reduction on active blocks was carried out by reducing the number of grid blocks in aquifer region and conducting re-dimensions to the pore volume of the aquifer grid cell.

**Table 2** CFPR calculation results from the various analytical methods

| Method | CFPR (STB/D) |
|---|---|
| Efros | 24 |
| Krachers method | 24 |
| Joshi's method | 39 |

**Table 3** Statistics for different rock type

| Rock type | % Fraction | So % | K (md) | Phi % |
|---|---|---|---|---|
| 1 | 14.5 | 60.44 | 1157 | 22.25 |
| 2 | 28.5 | 51.64 | 502 | 20.73 |
| 3 | 33.1 | 37.66 | 220 | 18.29 |
| 4 | 8.1 | 7.11 | 180 | 15.44 |
| 5 | 15.8 | 1.35 | 157 | 10.96 |

There were five rock types introduced in the model (rock type 1 to rock type 5). Rock type 1 is considered to be the best rock type, whereas rock type 5 is worst rock type considered for the study. Statistics of rock type distribution in terms of oil saturation, permeability, and porosity is given in Table 3. Porosity, permeability, and rock types distribution of the geomodel with well location are shown in Figs. 4, 5, 6, respectively.

## History matching

Actual history rates and cumulative on oil, water, and gas for a total of 35 wells for a period of 10 years were simulated with a commercial black oil simulator. Results of the history match on reservoir scale are illustrated in Fig. 7. Well-wise gas oil ratio (GOR), water cut, and the flowing/static pressure data were used as history matching parameters. It can be seen that rates (oil rate, water rate), GOR, and pressure have been matched quite well with the actual history by the simulator at field level.

Well-49 coning behavior was also captured by the simulated model which is illustrated in Fig. 8. All figures show good match between simulated and actual production.

It is evident from Figs. 7 and 8 that dynamic model is capable of predicting historical production at field level as well as well level. This model can be used for doing

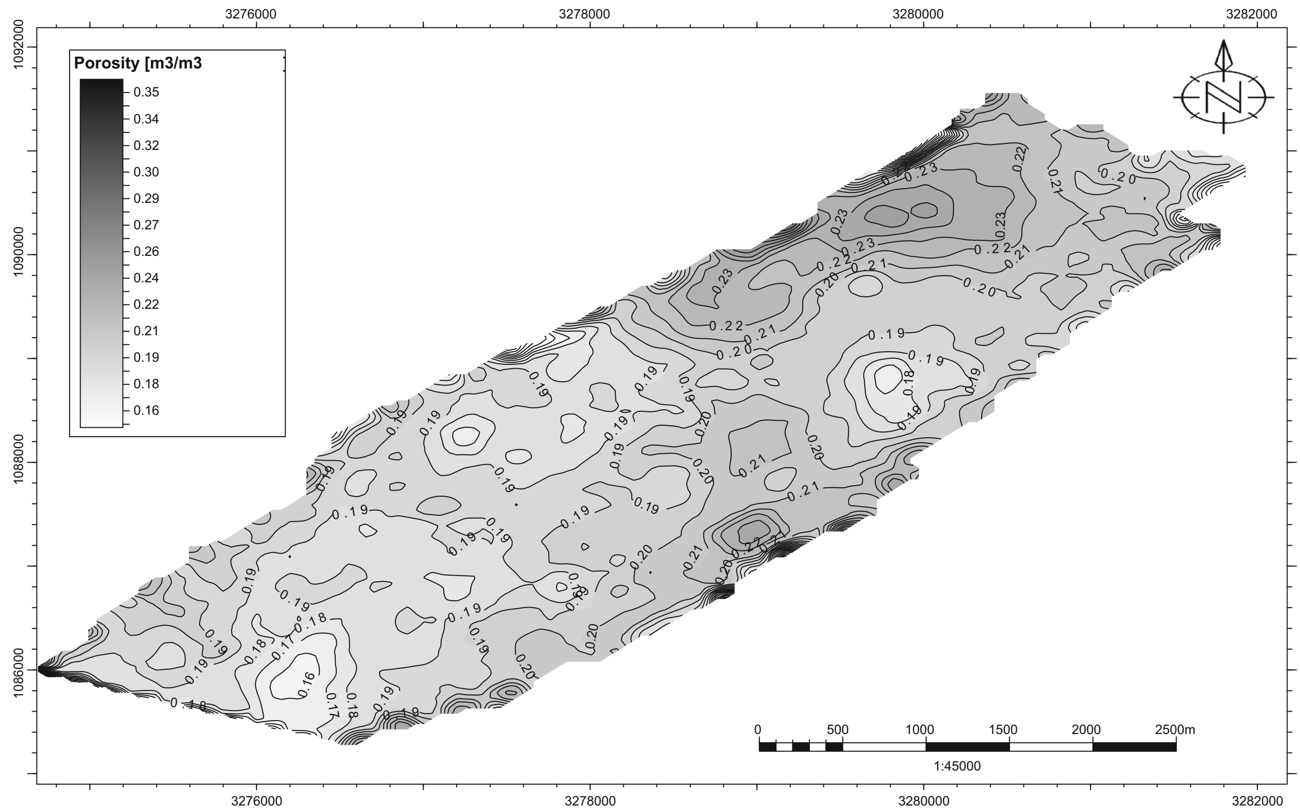


**Fig. 4** Porosity distribution of the geomodel

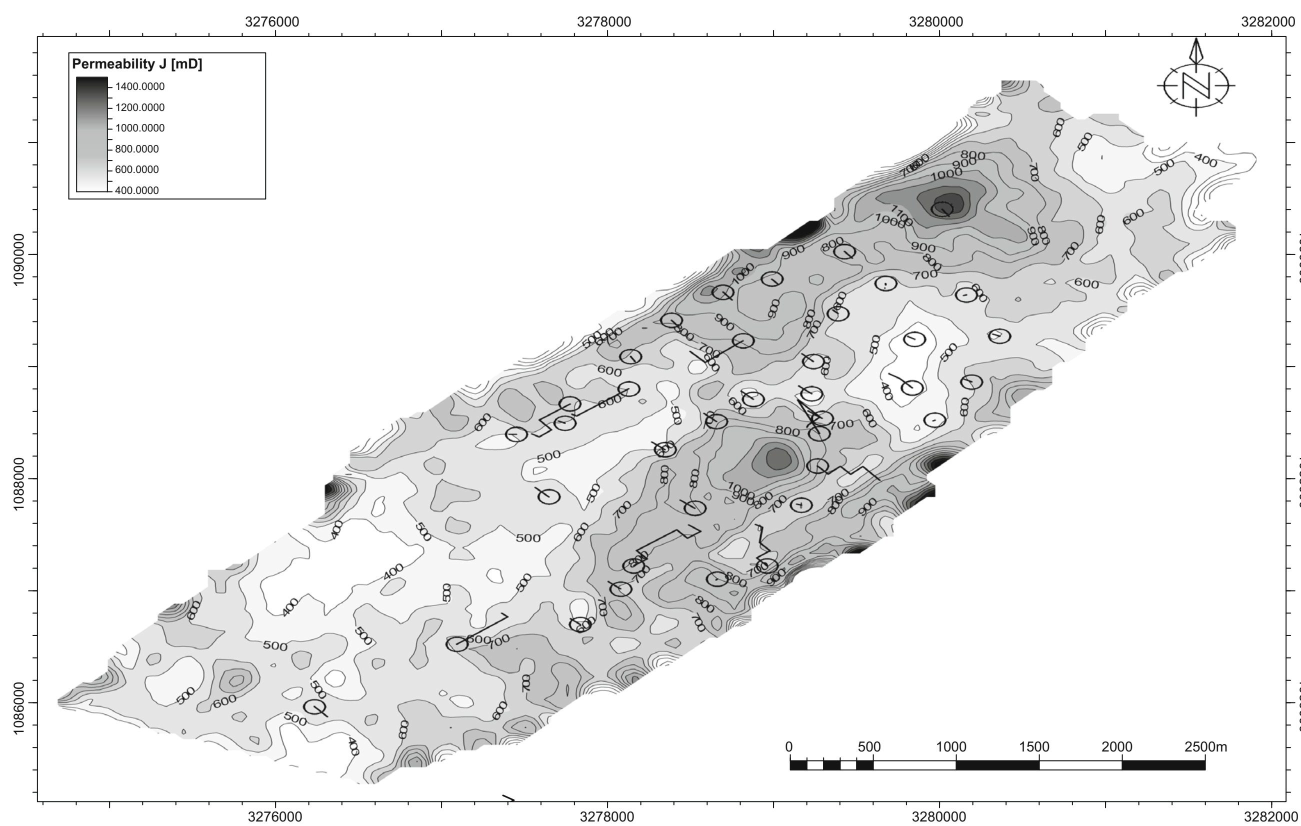


**Fig. 5** Permeability distribution of the geomodel

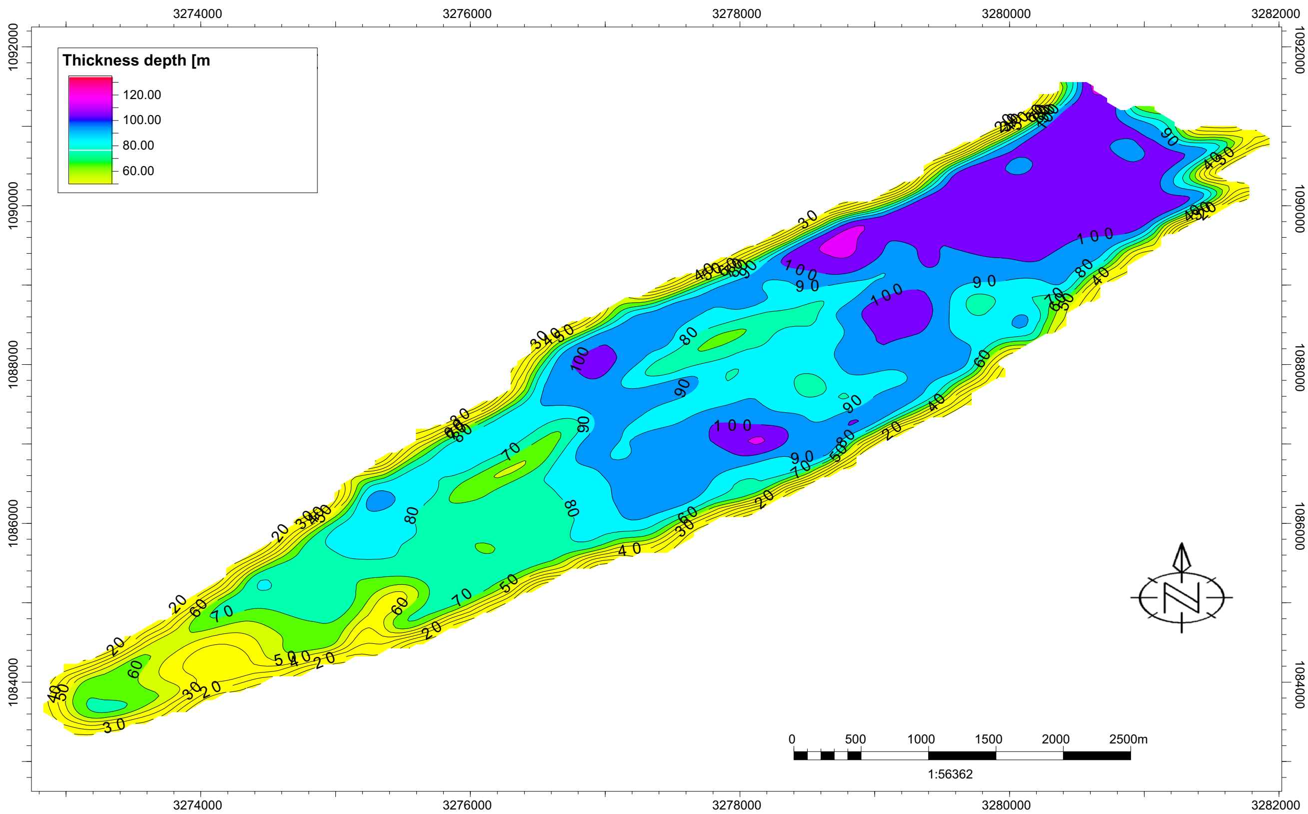


**Fig. 6** Reservoir Thickness distribution of the geomodel

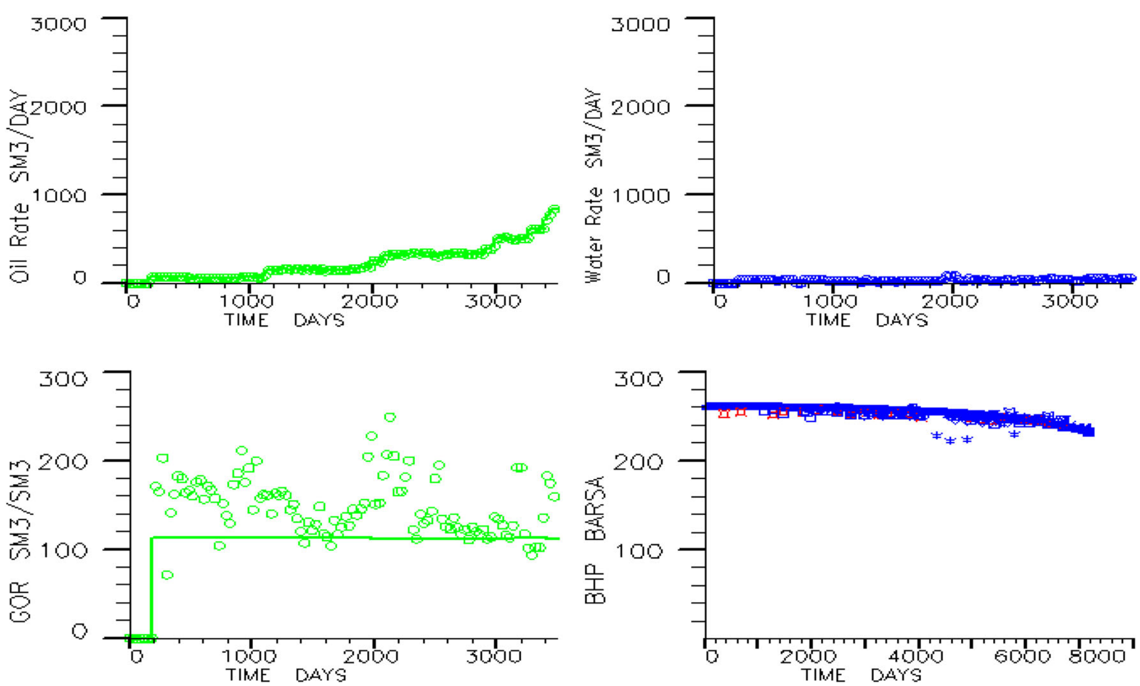


**Fig. 7** History match results at field level

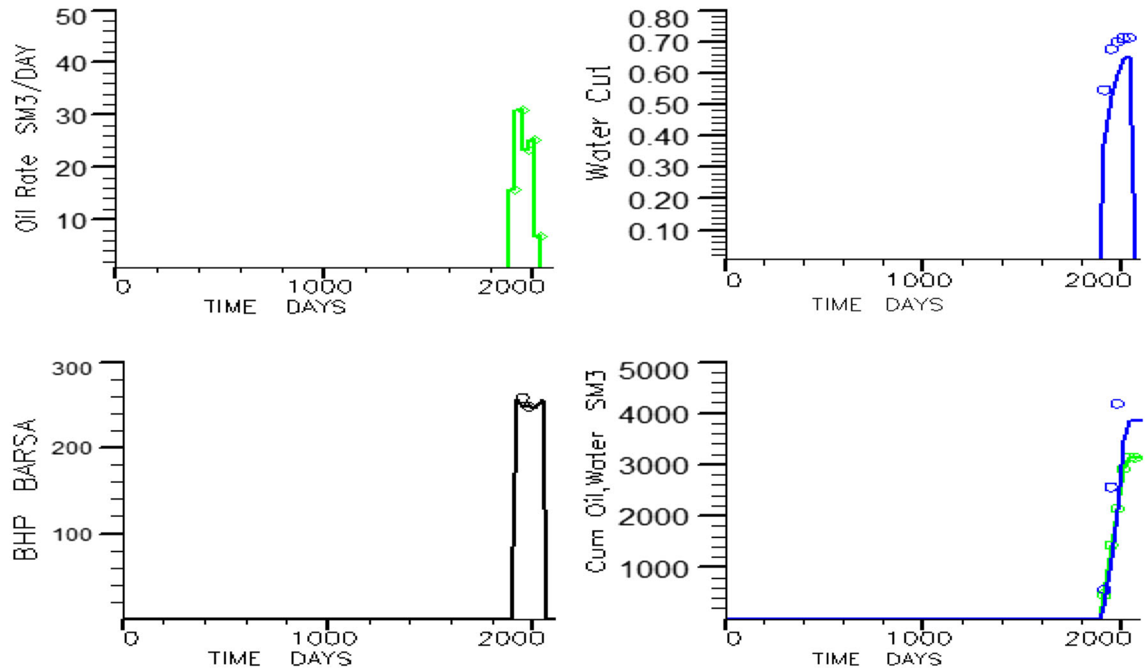


**Fig. 8** History match results at well level for Well-49

sensitivity analysis for predicting hydrocarbon recovery with different variants such as liquid rate, offset from WOC.

## Sensitivity analysis

This model was used to perform sensitivity analysis on rate and offset from WOC. All variants are mentioned in Table 4. From the above combination, fifteen (15) cases were constructed.

The prediction cases for reservoir were run using well production rate control. The well was given the production constraint as per the surface handling capacities. The wells were subjected to certain other constraints as shown in Table 5. From these 48 cases, four groups were constituted as per offset (Table 4).

Forty-eight (48) cases were simulated where twelve (12) cases were simulated for each offset from WOC. Outcome of the simulation runs have been presented from Figs. 9, 10, 11, 12. Each figure has four plots, description of which is given below.

- Cumulative liquid produced at EOP and pressure drop for various horizontal lengths (A),
- Water cut at EOP and liquid rate for various horizontal lengths (B)
- Cumulative oil production and horizontal length for various liquid rates (C)
- Cumulative oil production and liquid rate for various horizontal lengths (D)

**Table 4** Sensitivity parameters for Group-1 through Group-5

| | | | | |
|---|---|---|---|---|
| Group-1—(5 m offset) | | | | |
| Perforation top | GOC + 2 m | | | |
| Rate ($m^3$/day) | 200 | 250 | 300 | |
| Horizontal Length | 600 | 800 | 1000 | 1200 |
| Group-2 (10 m offset) | | | | |
| Perforation top | GOC + 2 m | | | |
| Rate ($m^3$/day) | 200 | 250 | 300 | |
| Horizontal length | 600 | 800 | 1000 | 1200 |
| Group-3 (15 m offset) | | | | |
| Perforation top | GOC + 2 m | | | |
| Rate ($m^3$/day) | 200 | 250 | 300 | |
| Horizontal length | 600 | 800 | 1000 | 1200 |
| Group-4 (20 m offset) | | | | |
| Perforation top | GOC + 2 m | | | |
| Rate ($m^3$/day) | 200 | 250 | 300 | |
| Horizontal length | 600 | 800 | 1000 | 1200 |

## Results and discussion

Results of the simulation cases have been discussed for all the groups in the subsequent paragraphs.

*Group-1*

- Figure 9a: As rate is increased from 200 to 300 $m^3$/day, pressure drop (final reservoir pressure–initial reservoir pressure) increases for every horizontal length.

**Table 5** Well-level constraints for prediction runs

| Constraints | Value |
|---|---|
| Maximum individual well production rate | Decided based on historical well production rate in the reservoir |
| Completion type | Single completion: bottom-to-top |
| Minimum well bottom-hole pressure | 50–100 bars, depending upon the segment performance |
| Maximum water cut | 95% |
| Minimum economic limit on oil rate | 1 $m^3$/day |
| Maximum GOR constraint | 1500 $m^3/m^3$ |

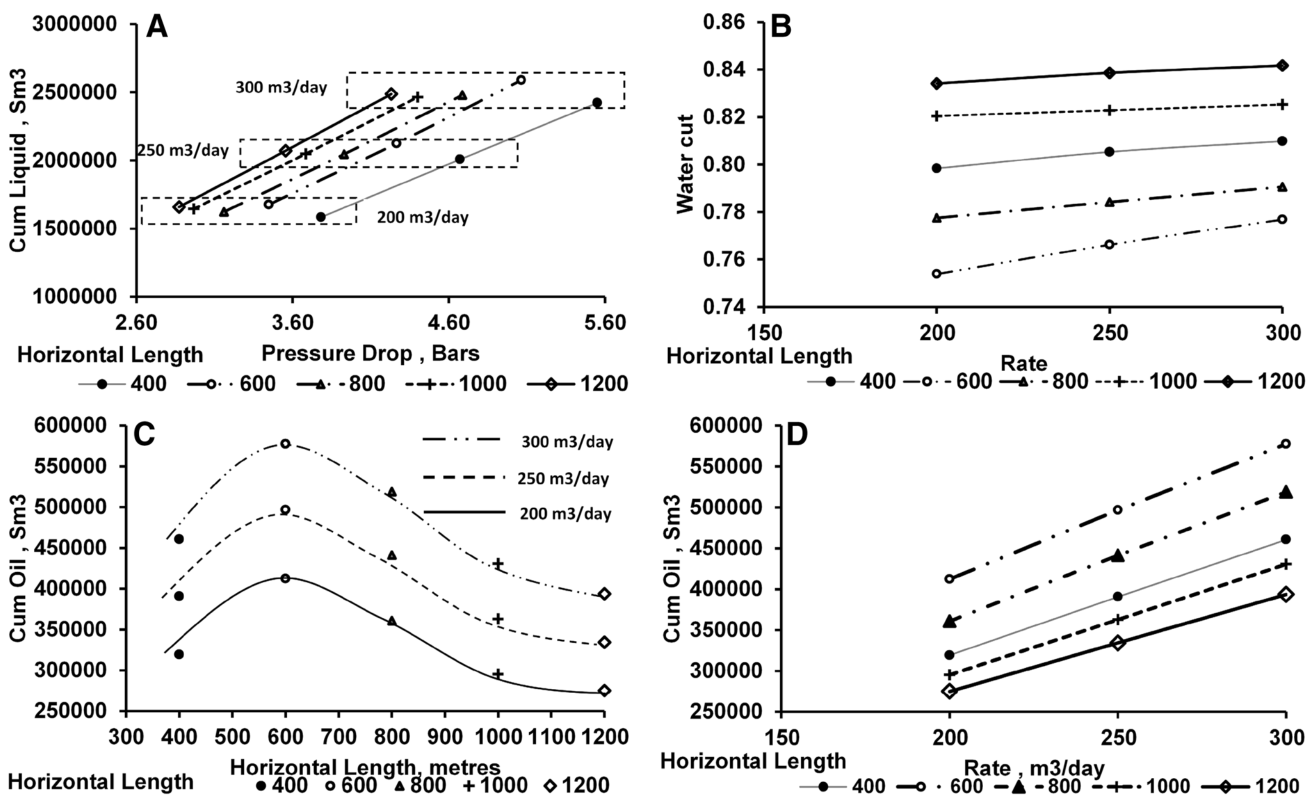


**Fig. 9** Results of Group-1 simulation runs

- Figure 9b: As rate is increased from 200 to 300 $m^3$/day, water cut increases for all horizontal lengths.
- Figure 9c, d: As assigned liquid rate is increased from 200 to 300 $m^3$/day, cumulative oil production increases for all horizontal length sections examined. It can be seen that cumulative oil is maximum in case of 600 m horizontal length, which decreases on increasing horizontal length further.

*Group-2*

- Figure 10a As rate is increased from 200 to 300 $m^3$/day, pressure drop increases for every horizontal length.
- Figure 10b As rate is increased from 200 to 300 $m^3$/day, water cut increases for different horizontal lengths.
- Figure 10c, d As assigned liquid rate is increased from 200 to 300 $m^3$/day, cumulative oil production increases for every horizontal length. It can be seen that cumulative oil is maximum in case of 800 m of either horizontal length, which decreases on increasing or decreasing horizontal length.

*Group-3*

- Figure 11a: As rate is increased from 200 to 300 $m^3$/day, pressure drop increases for every horizontal length.

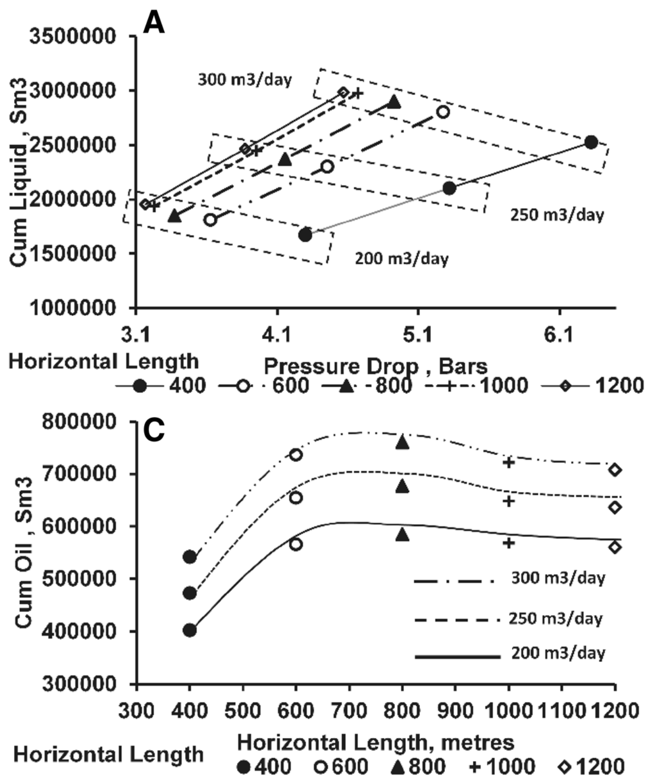


Fig. 10 Results of Group-2 simulation runs

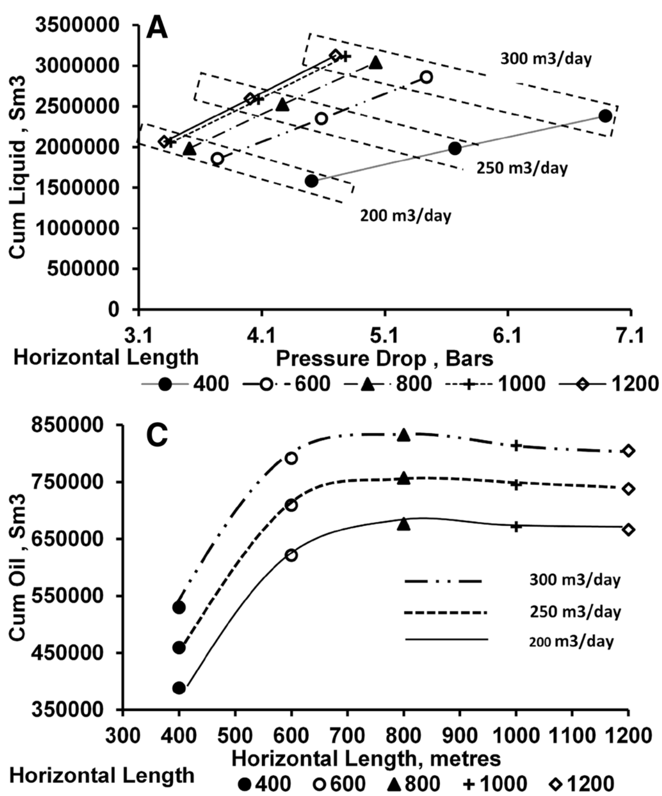


Fig. 11 Results of Group-3 simulation runs

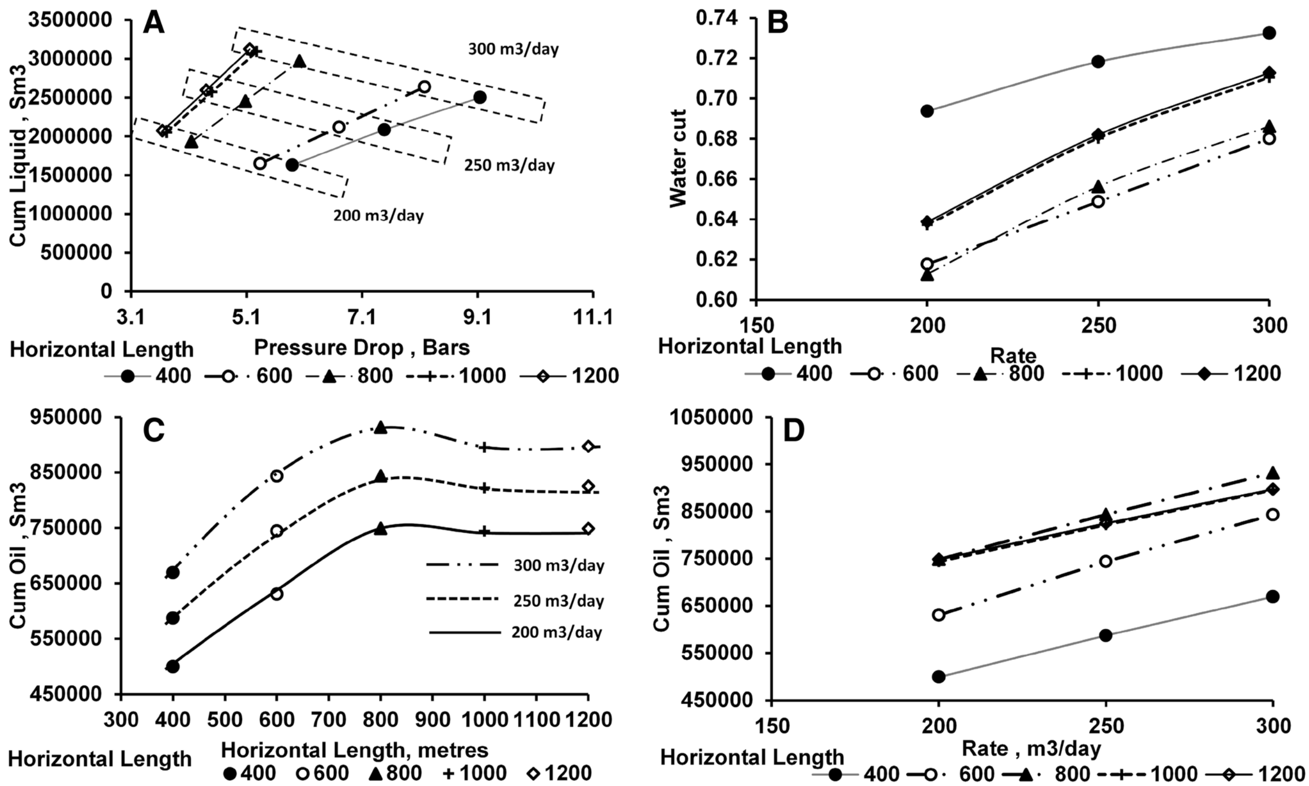


**Fig. 12** Results of Group-4 simulation runs

- Figure 11b As rate is increased from 200 to 300 m$^3$/day, water cut increases for different horizontal lengths.
- Figure 11c, d: As assigned liquid rate is increased, cumulative oil production increases for every horizontal length. It can be seen that cumulative oil is maximum in case of either 800 m horizontal length, which decreases on increasing or decreasing horizontal length.

*Group-4*

- Figure 12a: As rate is increased from 200 to 300 m$^3$/day, pressure drop increases for every horizontal length.
- Figure 12b As rate is increased from 200 to 300 m$^3$/day, water cut increases for different horizontal length.
- Figure 12c, d: As assigned liquid rate is increased cumulative oil, production increases for every horizontal length. It can be seen that cumulative oil is maximum in case of either 800 m horizontal length, which decreases on increasing or decreasing horizontal length.

Additionally, rate sensitivity for lower rates (25, 40, 50, 60 and 70 m$^3$/day) was also carried out in the numerical simulation model. A plot of water cut vs time (Figure 13) for the above cases shows that as rate is increased from 25 to 70 m3/day, water cut breakthrough time decreases gradually. For assigned rate of 25 m$^3$/day, water cut is constant and lowest among all simulation runs. Numerical value of 25 m$^3$/day is close to the analytical solution of critical rate calculated from various methods.

## Conclusions and recommendations

From the above study, following can be concluded:

- Offset from WOC, horizontal length, and withdrawal rate have an impact on cumulative oil production in case of horizontal well. Maximum impact on cumulative oil production is given by offset from WOC followed by withdrawal rate and lastly on horizontal well length. Maximum recovery of 0.95 MMm$^3$ cumulative oil is obtained using optimum horizontal length of 600–800 m, offset of 20 m and initial withdrawal rate of 300 m$^3$/day. Comparing the result from existing well-49, oil production cumulative of 0.152 MMm$^3$ is obtained throughout the production life with offset of 10 m, horizontal length of 400 m, and initial withdrawal rate of 200 m$^3$/day.
- As offset from WOC increases cumulative oil production increases until 15 m and then remains at almost same level.

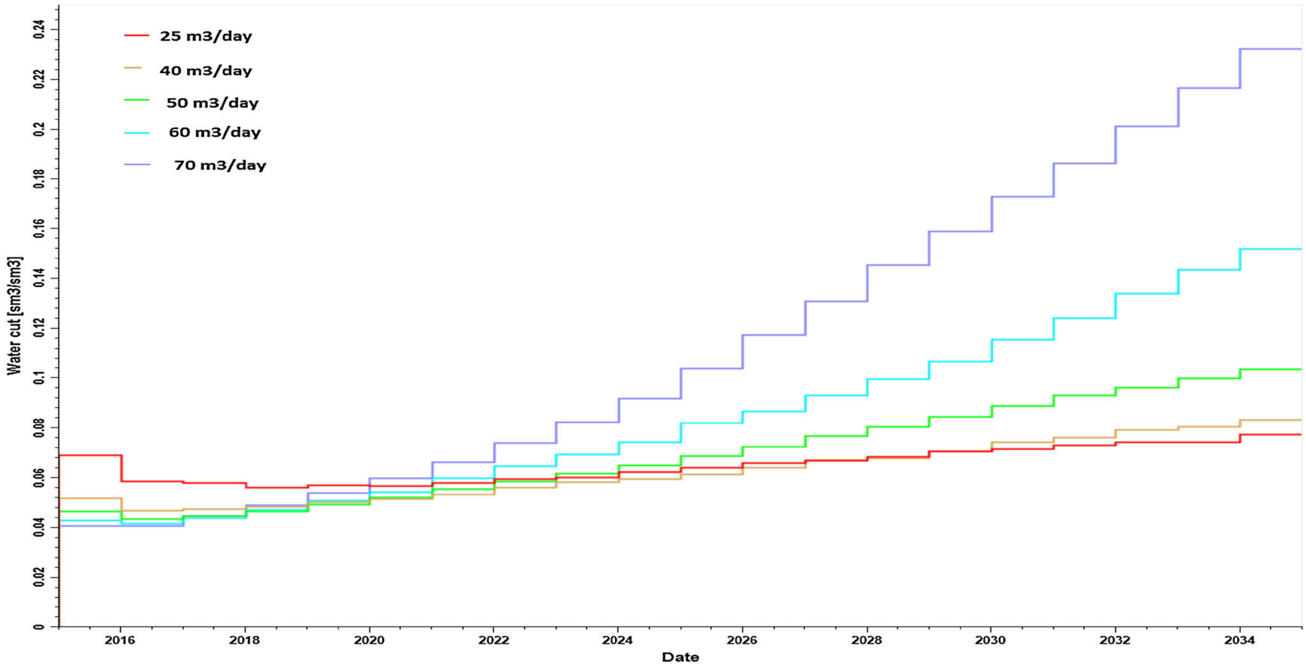


**Fig. 13** Results of Group-4 simulation runs (for lower rates)

- Water cut reduces with increase in horizontal length and increases with higher withdrawal rate.
- For recovery, efficiency to be maximum horizontal length should be between 600 and 800 m; further increase in horizontal length does not increase in cumulative oil production.
- As horizontal length is increased, pressure drop (final reservoir pressure–initial reservoir pressure) reduces.



## Appendix

See Table 6.

**Table 6** Capillary pressure vs water saturation Lab Data

| S No. | Well | PC(Psi)-Res | Sw@Plug-AV |
|---|---|---|---|
| 1 | A-5 | 0.704166667 | 84.67 |
| 2 | A-5 | 2.813055556 | 54.02 |
| 3 | A-5 | 6.333888889 | 45.26 |
| 4 | A-5 | 11.25944444 | 39.79 |
| 5 | A-5 | 17.59333333 | 35.41 |
| 6 | A-5 | 25.33194444 | 33.22 |
| 7 | A-5 | 34.47888889 | 32.12 |

**Table 6** continued

| S No. | Well | PC(Psi)-Res | Sw@Plug-AV |
|---|---|---|---|
| 1 | A-5 | 0.725833333 | 85.23 |
| 2 | A-5 | 2.899722222 | 53.59 |
| 3 | A-5 | 6.525277778 | 44.09 |
| 4 | A-5 | 11.59888889 | 38.82 |
| 5 | A-5 | 18.12055556 | 35.65 |
| 6 | A-5 | 26.09388889 | 33.54 |
| 7 | A-5 | 35.51888889 | 32.49 |
| **S No.** | **Well** | **PC(Psi)-Res** | **Sw@Plug-CV1** |
| 1 | A-5 | 0.693333333 | 100 |
| 2 | A-5 | 2.776944444 | 71.34 |
| 3 | A-5 | 6.243611111 | 60.59 |
| 4 | A-5 | 11.10055556 | 53.43 |
| 5 | A-5 | 17.34416667 | 49.84 |
| 6 | A-5 | 24.97805556 | 46.26 |
| 7 | A-5 | 33.99861111 | 45.07 |
| **S No.** | **Well** | **PC(Psi)-Res** | **Sw@Plug-DV** |
| 1 | A-5 | 0.693333333 | 97.84 |
| 2 | A-5 | 2.776944444 | 67.64 |
| 3 | A-5 | 6.243611111 | 56.85 |
| 4 | A-5 | 11.10055556 | 50.38 |
| 5 | A-5 | 17.34416667 | 46.06 |
| 6 | A-5 | 24.97805556 | 43.91 |
| 7 | A-5 | 33.99861111 | 42.83 |

**Table 6** continued

| S No. | Well | PC(atm)-Res | Sw@Plug2BH |
|---|---|---|---|
| 1 | A-8 | 0 | 100 |
| 2 | A-8 | 0.014168937 | 95 |
| 3 | A-8 | 0.028337875 | 79 |
| 4 | A-8 | 0.042506812 | 55 |
| 5 | A-8 | 0.056675749 | 50 |
| 6 | A-8 | 0.070844687 | 47 |
| 7 | A-8 | 0.085013624 | 45 |
| 8 | A-8 | 0.113351499 | 41 |
| 9 | A-8 | 0.141689373 | 36 |
| 10 | A-8 | 0.283378747 | 32 |
| 11 | A-8 | 0.42506812 | 28 |
| 12 | A-8 | 0.566757493 | 25 |
| 13 | A-8 | 0.708446866 | 23 |
| 14 | A-8 | 1.133514986 | 19 |
| 15 | A-8 | 1.416893733 | 17 |
| 16 | A-8 | 2.125340599 | 15 |
| 17 | A-8 | 2.833787466 | 14 |
| 18 | A-8 | 4.250681199 | 12 |
| 19 | A-8 | 4.959128065 | 11 |
| 20 | A-8 | 5.667574932 | 10.5 |

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