Chapter

An Improved Semi-Analytical Approach for Predicting Horizontal and Multilateral Well Performance

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Abstract

Field development and economic evaluation of hydrocarbon demand for an accurate model for predicting horizontal well performance as horizontal and multilateral wells have become far more prominent in the industry than vertical wells. Several approaches for modelling horizontal well performance have been studied and reported in the literature. Analytical approach is the easiest with large inaccuracy in the prediction of the horizontal well performance because of inability to apply it in reservoir-wellbore coupling equation. Numerical approach is more reliable for field application than analytical approach. However, it involves iterative nature that requires longer computational times. Semi-analytical approach is simpler and sufficiently exact for field applications if the governing fundamental flow equation is accurately modelled. This study presents a new semi-analytical model for predicting horizontal and multilateral well performance, which includes friction, acceleration and accumulation induced pressure drop along horizontal well length into the governing fundamental flow equations. The outcomes of the proposed model have been validated by field data gotten from gauge rate of 5660stb/d at steady-state condition. The estimated steady flow rate of 5593.9 stb/day obtained from the new approach shows an error of 1.2% which is seen to be more accurate than steady flow rate values obtained by four previous models that exhibited higher percentage errors when compared to gauge reading.

Keywords: pressure due to accumulation, pressure due to friction, horizontal well, multilateral well, well performance

1. Introduction

As a sequel to advancement in drilling and completion technology, there has been increasing interest in horizontal wells. Production enhancement and economic increment of hydrocarbon recovery have given horizontal wells completion advantages over vertical wells most especially in small and marginal reservoirs [1–5]. However, horizontal well is costlier to drill and complete than vertical well. With current innovation in technology, the petroleum industry has generally moved to horizontal wells, as it is fast becoming the traditional practice [1–10]. Multilateral wells display the same benefits that horizontal wells also do, as well as they can recover hydrocarbon simultaneously from more than one reservoir; this offers significant increments in well planning and economics [7–11].

There have been a few endeavours to predict horizontal well performance; these have led to the development of various models that describe the performance of horizontal and multilateral wells. Previously developed work has been done for the estimation of productivity, and they have all made assumptions that either the well allows for infinite conductivity or the flow along the length of the well is uniform. This assumption leads to the pressure drop along the well to be neglected, and hence it is assumed to be constant throughout the well length. However, it is not a practical assumption as it does not capture the reality of horizontal wells, particularly in long horizontal drain hole where the pressure drop along the length of the well is large and cannot be treated as the reservoir-to-wellbore pressure drop system of the vertical well [3].

Some authors have attempted a coupling model that accounts for wellbore flow, as well as reservoir inflow to estimate the performance of a single phase horizontal well at the point when the pressure drop in the wellbore becomes significant. Dikken [4] was one of the first experts to couple fluid flow in the lateral of the wellbore to the reservoir in-flow using a model; afterward, several models have been reported. The study demonstrated that in most practical circumstances, a wellbore exhibits flow either in the turbulent flow regime or transition flow regime into the wellbore and no laminar flow is present. Landman [5] further proposed enhancements to the model developed by Dikken by varying the productivity index (PI) along the wellbore, and the variations are due to changes in perforation density, permeability and the characteristics of the flow along the well. In the model, a method for evaluating the optimum perforation density results in specific inflow along the well length. Novy [12] generalized the work done by Dikken by developing a model which could be applied to single phase oil flow and gas flow. To handle the gas system, non-Darcy flow term was introduced to the equation by the author. Ozkan and Haciislamoglu [13] examined the impact of pressure drop inside the horizontal section and how a horizontal well responds to it. As such, they presented a general, semi-analytical model which couples reservoir inflow and wellbore flow hydraulics. They defined groups to correlate the response of horizontal well and how these are affected by wellbore hydraulics. Basically, pressure distributions and flux distribution along the lateral of the well were investigated, and they discussed the validity of the assumptions of infinite conductivity. Penmatcha et al. [14] investigated the need to optimise the well length and how it affects the drop in pressure along the horizontal well. They proposed that as the length of the horizontal well increases, there is more accessibility to larger contact with the reservoir; however, this also leads to an increase in resistance to flow, which many times reduces productivity. Ouyang et al. [9] developed a single-phase wellbore-flow model in their research that combined pressure drop due to acceleration, gravity and friction. They developed a model that was very applicable with distinct configurations of perforation at the wellbore and completions; the model developed could be used analytically with any model that describes inflow of fluids into the reservoir or used with reservoir simulations [15].

Chen et al. [16] researched on a model for predicting the performance of multilateral well, and as such, they developed a deliverability model. Firstly, a model that describes the performance of each lateral of the well was developed, coupling a model that describes inflow in a reservoir model with a model that described flow in wellbore to estimate the performance and volume of flow contributed by each lateral. The lateral model that was developed considered pressure drop. Their developed multilateral deliverability model could be used to estimate the performance of each lateral, the whole performance and the total pressure variation in the multilateral well.

Guo et al. [10] stated that although it has become common in the industry to drain a reservoir with a horizontal well and multilateral wells, it was observed that most of these wells do not produce at their expected production rate. This is because it is difficult to estimate the exact 'expected production rate' due to the fact that the production rate is estimated by models which stem from the assumption that the well was an infinite-conductive drain hole by considering the frictional effect of the long horizontal portion of the flow.

A semi-analytical model is reported by Tabatabaei and Ghalambor [8] for predicting the horizontal oil well performance. The model couples flow from a box-shaped drainage volume to flow in the wellbore. The horizontal wellbore flow description presented considers pressure drop due to friction, acceleration and fluid in flow effect. Their model easily adapted to predict productivity of multilateral wells by coupling the inflow performance of individual laterals with build-up section and the main vertical. The outcome of their study was more accurate than other previous experts as it shows the least percentage error derivation of 5% from the actual result obtained from gauge measurement. The recent study by Fadairo et al. reveals that all possible pressure restriction terms should be considered to combat the inaccuracy in results obtained using existing models in the literature [1–3, 17–19]. This chapter is an advancement on the Tabatabaei and Ghalambor model [8] by inclusion of pressure restriction due to accumulation in the governing flow equation for horizontal well. The output of this research shows that the disparity between the measured gauge value and previous work done is due to their failure to consider all possible pressure drops in long horizontal drain hole including pressure drop due to accumulation as the present study gives less than 1.2% error deviation from the actual value.

2. Theory

The numerical approach is more reliable for field application than the analytical approach. However, the numerical approach involves a systematic procedure and iterative nature which require longer computational times. It is more difficult to compute and access for day-to-day application in the industry. A basic and thorough semi-analytical approach has capacity to accurately predict the performance of a horizontal well. It is attractive and simpler to use as well as extensive and sufficiently exact for field applications if the governing fundamental flow equation is accurately modelled.

Generally, the existing models describing the performance of horizontal wells are divided into three classifications:

1. Analytical solutions.

2. Semi-analytical models.

3. Numerical models.

Semi-analytical coupling model gives an exhaustive and comprehensive estimate of productivity; this model is applicable do different reservoirs of varying conditions. Similarly, this model can be easily modified to predict the productivity of multilateral wells by coupling the inflow from all the different laterals with the total hydraulic build-up in the wellbore [8].

3. Model description

The horizontal and multilateral inflow model derived from the coupling of porous media inflow and horizontal drain hole inflow models have been reported by several experts in the literature. One of the earliest coupling models was developed by Dikken [4], and afterward, several others have been reported. The results obtained from previous models show large disparity between the actual and the calculated result for failure to consider all accessible pressure drop in the horizontal drain portion.

Consider fluid flow from the reservoir into the horizontal drain hole as shown in **Figure 1**. Assuming that the reservoir is assumed to be a constant pressure reservoir with the outer boundary responsible for keeping the pressure constant, and as such, the reservoir pressure is assumed to be the outer boundary pressure P_e. Flowing pressure along the horizontal well is not constant and hence does not only depend on pressure drop due to friction and acceleration as opined by Tabatabaei and Ghalambor [8] but also based on restriction due to accumulation. The general coupling inflow equation for the horizontal well system is expressed as

$$q_s(x) = J_s(x)[P_e - P_w(x)] \tag{1}$$

In this paper, the reservoir productivity index J_s can be obtained using the Furui et al. [21] model while the flowing horizontal wellbore pressure can be obtained from the fundamental energy equation of flow in pipe as a function of space and time.

The overall flow rate of the horizontal well is gotten by the integration of Eq. (1) along the entire length of wellbore

$$Q = \int_0^L q_s(x)dx = \int_0^L J_s(x)[P_e - P_w(x)]dx \tag{2}$$

In solving Eq. (2), an analytical solution is more cumbersome because the pressure along the wellbore $P_w(x)$ and the specific productivity index $J_s(x)$ vary with the length of the well and several pressure dependent variables as function of time and space are involved, and hence, the coupling model is solved numerically.

To resolve Eq. (2), the lateral portion of the well is divided into a small number of segments; these segments are numbered from the toe to the heel as demonstrated in **Figure 2**. Therefore, the overall flow rate is an addition of the flow rates from the different segments.

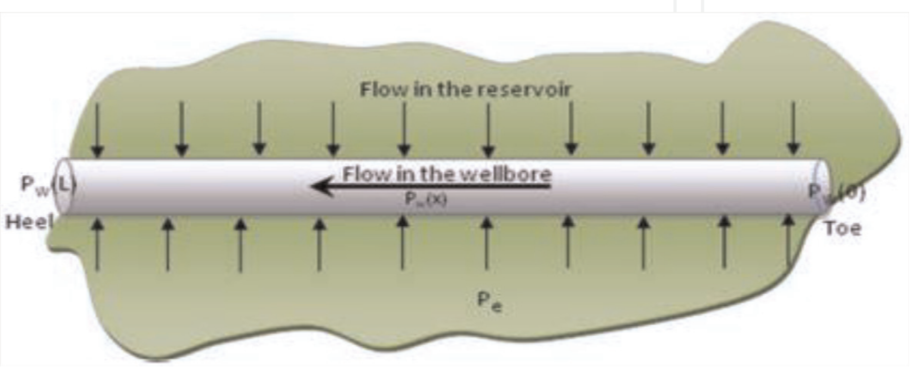

Figure 1.
Coupled wellbore-flow and reservoir in-flow [20].

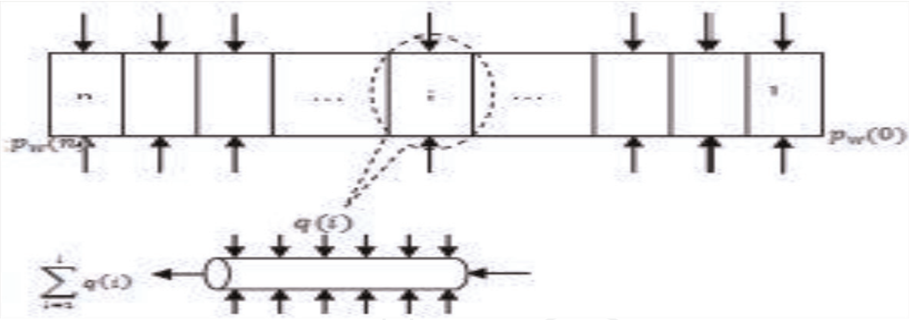

Figure 2.
A diagram of a segmented lateral of the wellbore [8].

$$= \sum_{i=1}^{i=n} q(i) \tag{3}$$

Accordingly, to determine the flow rate of every segment $q(i)$, the wellbore flow at a segment is coupled with the reservoir inflow throughout that segment

$$q(i) = J_s(i)\Delta x\left[P_e - \overline{P_w}(i)\right] \tag{4}$$

It is assumed that the length of the segment, Δx, is very small, and as such, the specific productivity index of the segment $J_s(i)$ does not vary along the segment, as such it is computed at the centre of every segment by using the model developed by Furui et al. [21]:

$$J_s(i) = \frac{7.08 \times 10^{-3}k}{\mu B\left[In\left(\frac{hl_{ani}}{r_w(l_{ani}+1)}\right) + \frac{\pi w}{2hl_{ani}} - 0.785 + S(i) + S_R\right]} \tag{5}$$

The partial-penetration skin factor S_R is computed using the model created by Babu and Odeh [22]. Similarly, the reservoir anisotropy and the exposure time to drilling fluid (especially drilling mud) are assumed. Also, the elliptical-cone-shaped model is assumed for the distribution of formation damage factor $S(i)$ along the lateral of the well suggested by Frick and Economides [23].

$$S(i) = \left(\frac{k}{k_s} - 1\right)In\left[\left(\left[\frac{2a_{max}}{r_w[I_{ani}+1]} - 1\right]\frac{x(i)}{L} + 1\right)\right] \tag{6}$$

To calculate the average pressure in the horizontal wellbore throughout the segment $\overline{P_w}(i)$, the following equation is used:

$$\overline{P_w}(i) = \frac{1}{2}[P_w - P_w(i-1)] \tag{7}$$

where

$$P_w(i) = P_w(i-1) - \Delta P_{fric}(i) - \Delta P_{acc}(i) - \Delta P_{acm}(i) \tag{8}$$

The two above equations are combined to give Eq. (9)

$$\overline{P_w}(i) = P_w(i-1) - \frac{1}{2}\left[\Delta P_{fric}(i) + \Delta P_{acc}(i) + \Delta P_{acm}(i)\right] \tag{9}$$

The pressure drop due to acceleration and friction along the wellbore was obtained using a flow model developed by Ouyang et al. [9] while the pressure drop due to accumulation was obtained using the concept reported by Fadairo et al. [1].

The pressure drop due to friction throughout every segment for both laminar flow regime and turbulent flow regime in oilfield units is determined by the equation as follows:

Pressure drop due to friction in the laminar flow regime:

$$\Delta P_{fric}(i) = C_1[q_t + q(i)]\left(1 + C_2[q_t + q(i)]^{0.6142}\right) \tag{10}$$

where

$$C_1 = \frac{8 \times 10^{-6}\mu\Delta x}{d^4} \tag{11}$$

$$C_2 = 5.08 \times 10^{-3}\left[\frac{\rho}{\mu x(i)}\right]^{0.6142} \tag{12}$$

and the q_t is the axial-flow rate going into the segment, and this is shown as:

$$q_t = \sum_{i=1}^{i-1} q(i) \tag{13}$$

Pressure drop due to friction in the turbulent-flow regime:

$$P_{fric}(i) = \frac{C_3\left([q_t + q(i)]^2 - \left(C_4[q_t + q(i)]^{2.3978}\right)\right)}{\left[-4\log\left(C_5 - \frac{C_6}{[q_t+q(i)]} \times \log\left(C_7 + \frac{C_8}{[q_t+q(i)]^{0.8981}}\right)\right)\right]^2} \tag{14}$$

where

$$C_3 = \frac{7.46 \times 10^{-7}\mu\Delta x}{d^5} \tag{15}$$

$$C_4 = 3.83 \times 10^{-3}\left[\frac{\rho}{\mu x(i)}\right]^{0.3978} \tag{16}$$

$$C_5 = \frac{\varepsilon}{3.7065} \tag{17}$$

$$C_6 = \frac{3.385\mu d}{\rho} \tag{18}$$

$$C_7 = \frac{\varepsilon^{1.1098}}{2.8257} \tag{19}$$

$$C_8 = 4.09\left(\frac{\mu d}{\rho}\right)^{0.8981} \tag{20}$$

Pressure drop in acceleration throughout every segment is determined by:

$$\Delta P_{acc}(i) = \frac{7 \times 10^{-9}\rho}{g_c d^4}\left[q^2(i) + 2q_t q(i)\right] \tag{21}$$

Pressure drop due to accumulation is to be determined by:

$$\Delta P_{acm}(i) = \frac{4.1667 \times 10^{-5}}{g_c d^2 t} [q(i) + q_t] \tag{22}$$

An iterative method is used to solve Eq. (4) as the pressure drop is associated with the production rate. The procedure for calculating the production rate of each segment $q(i)$ and the overall cumulative production rate Q is as follows:

1. A pressure for the wellbore at the toe is assumed, $P_w(0)$.

2. The portrayed reservoir/wellbore-coupling model is used to determine flow rate, (1), and pressure drop over Segment 1. $[\Delta P_{fric}(i) + \Delta P_{acc}(i) + \Delta P_{acm}(i)]$.

3. Equation (8) is used to compute the pressure at the end of segment 1, $P_w(1)$, Eq. (8):

$$P_w(i) = P_w(i-1) - \Delta P_{fric}(i) - \Delta P_{acc}(i) - \Delta P_{acm}(i)$$

4. Steps 2 and 3 will be repeated, advancing in the direction of the heel to ascertain the flow rate in every segment, $q(i)$, and then the pressure at the end of every segment, $P_w(i)$, can be calculated.

5. The flowing bottom hole pressure, P_{wf}, and the pressure that has been calculated at the heel, $P_w(n)$, with Eq. (8) are compared and the pressure at the end of each segment can be calculated; as such, the flow rate in each segment can be determined with Eq. (3). Thereafter, the flow rate from each section will be summed up to give the total flow rate.

If the condition in Eq. (23) is not true, then another value is assumed for the pressure at the toe and the procedure from step 2 to step 5 is repeated until the condition in Eq. (23) is true

$$|P_{wf} - P_w(n)| \leq e \tag{23}$$

Here, the estimation of e relies upon the degree of accuracy required in expectation of well efficiency.

4. Multilateral-well deliverability model

The concept in the currently developed model for horizontal productivity can be adapted to evaluate flow in a multilateral well by commingling flow from different lateral or horizontal portions into a main wellbore. **Figure 3** shows a multilateral well with three lateral wells. The pressure that is known at the beginning is the wellhead pressure, and every other component of pressure in the well system are and must be resolved. The following process is to predict the pressure drop behaviour along each lateral, and also the pressure drop behaviour in the main borehole with the corresponding production performance of each lateral and overall production rate can also be predicted. A pressure for the wellbore at the toe for the first lateral is assumed, $P_w(0,1)$. The coupling equation from the previous section is used

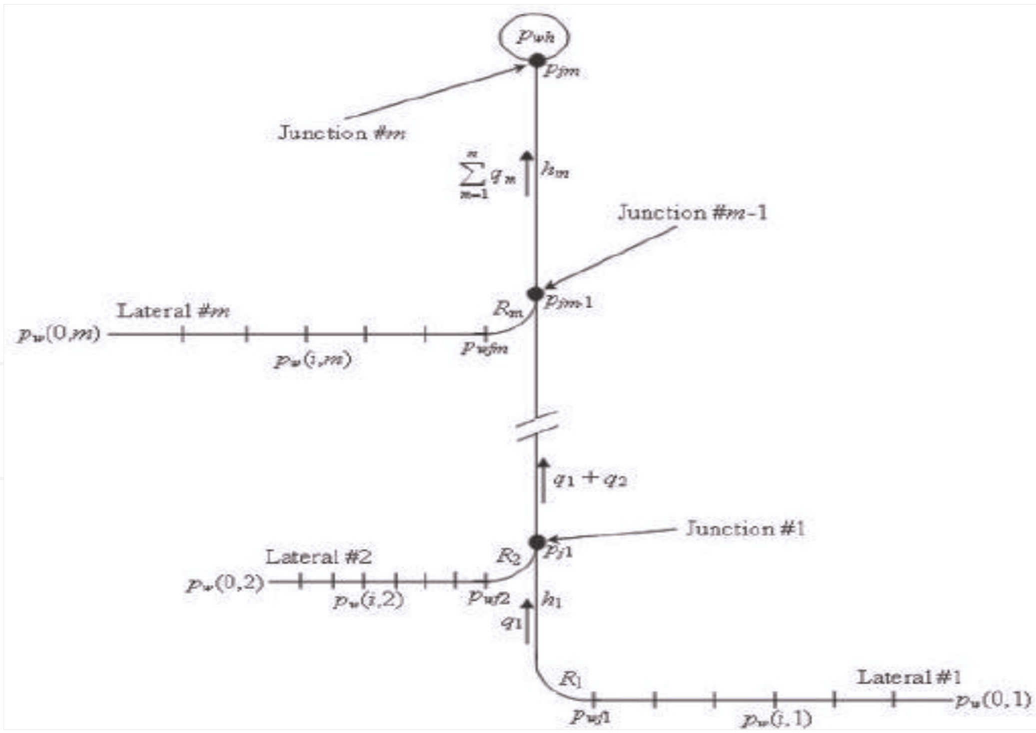

Figure 3.
A diagram of a multilateral well [8].

to determine the productivity of lateral 1 and the pressure performance along the first lateral to ascertain the pressure of the heel of lateral 1 P_{wf1}.

1. The pressure at junction 1 is obtained with the following equations:

$$P_{j1} = P_{wf1} - \Delta P_{gravity|R1\&h1} - \Delta P_{friction|R1\&h1} \tag{24}$$

where

$$\Delta P_{gravity|R1\&h1} = \frac{\rho_1 (R_1 + h_1)}{144} \tag{25}$$

and

$$\Delta P_{friction|R1\&h1} = \frac{f_f \rho_1 v_{t1}^2 \left(\frac{\pi}{2} R_1 + h_1\right)}{6 g_c d_t} \tag{26}$$

2. A pressure for the wellbore at the toe for the second lateral is assumed, $P_w(0, 2)$. The coupling equation from the previous section is used to determine the productivity of lateral 2 and the pressure performance along the second lateral to ascertain the pressure of the heel of lateral 1 P_{wf2}.

3. A new pressure at junction 1 is P_{j1} and is calculated with Eq. (27):

$$P_{j1} = P_{wf2} - \frac{\rho_2 R_2}{144} - \frac{f_f \rho_2 v_{R2}^2 \pi R_2}{12 g_c d_t} \tag{27}$$

4. Make a comparison of P_{j1} gotten from step 2 to that from step 4, and steps 3 and 4 will be repeated until the two values of $P_{j1}$are similar and as such the production performance from lateral 2 and the pressure performance from lateral 2 are known.

5. Sum the flow rate of lateral 1 and lateral 2 to determine the total production rate between junction 1 and 2.

6. The pressure at the second junction P_{j2} can be calculated using Eq. (28), and similarly, all the subsequent pressures at the different junctions, using the same equation:

$$P_{jm} = P_{jm-i} - \frac{\rho_{avg} h_m}{144} - \frac{f_f \rho_{avg} v_{tm}^2 h_m}{6 g_c d_t} \tag{28}$$

where

$$\rho_{avg} = \frac{\sum_{m=1}^{m} \rho_m q_m}{\sum_{m=1}^{m} q_m} \tag{29}$$

7. Steps 3 and 8 will be repeated, moving upwards on the main wellbore to determine the production performance of the other laterals that might be present, and furthermore, the pressure present at every junction.

8. A comparison is made between the pressure calculated at the junction m, P_{jm}, to the pressure at the wellhead. P_{wh}. The overall flowrate of the well system is gotten from adding up the production rate from each lateral.

$$\left| P_{wh} - P_{jm} \right| \leq e \tag{30}$$

In the event that Eq. (30) does not hold, another pressure value must be assumed at the toe for the wellbore of the first lateral, $P_w(0,1)$, and the entire methodology ought to be repeated.

5. Results and discussion

To validate the current model on the productivity of horizontal and multilateral wells, the field data from a horizontal well in Australia as reported by Tabatabaei and Ghalambor [8] and presented in **Table 1** was employed. Additionally, in this section, interactive plots of the estimated well pressure, production profile and

Parameters	**Value**
Length of the reservoir	2438 ft
Width of the reservoir	600 ft
Height of the reservoir	131.2 ft
Lateral length	2438 ft
Radius of wellbore	0.354
Length from middle to the boundary	1219 ft
Effective wellbore diameter	5.5 in
Roughness of the wellbore	0.1in
Vertical permeability	345md
Horizontal permeability	850md
Formation damage permeability	100md

Parameters	Value
Skin factor due to invasion	2
Skin factors due to other factors	5
Pressure of the reservoir	932.5 psi
Pressure of wellbore at heel	925 psi
Viscosity of oil	0.5cp
Oil formation volume factor	1.058rb/Stb
Density of oil	55.97lbm/ft^2

Table 1.
Field parameters [11].

total pressure using current study compared with other existing models in literature were presented. **Table 2** presents the reservoir and well properties of the multilateral wells that were used as an input for predicting multilateral flow performance. **Table 3** shows the comparison of production rate results obtained from the current model and other existing models in the literature using data in **Table 2** as an input. Performance of dual-lateral well with variation in wellbore pressure at different segments was equally evaluated as shown in **Table 4**. To analyse the time of well's stability, that is, how long it would take for the well to experience stabilised flow, plots of pressure and productivity at the heel and toe of the well were generated.

Parameters	Lateral no. 1	Lateral no. 2
Length of the reservoir	2500 ft	2000 ft
Width of the reservoir	750 ft	500 ft
Height of the reservoir	75 ft	50 ft
Lateral length	2400 ft	1500 ft
Radius of wellbore	0.325 ft	0.325
Length from middle to the boundary	1215 ft	900
Effective wellbore diameter	4.5 in.	4.5 in
Roughness of the wellbore	0.0024in	0.0024in
Radius of build-up section	50 ft	30 ft
Distance to upper junction	500 ft	2500 ft
Vertical permeability	25md	50md
Horizontal permeability	100md	150md
Formation damage permeability	10md	25md
Skin factor due to invasion	3	2
Skin factors due to other factors	5	5
Pressure of the reservoir	2250 psi	2000 psi
Viscosity of oil	0.5cp	0.6cp
Oil formation volume factor	1.2rb/stb	1.25rb/stb
Density of oil	56lbm/ft^3	58lbm/ft^3

Table 2.
Reservoir and well properties of each lateral [8].

Model	Production rate (stb/d)	Error (%)
Actual	**5660**	0
Economides et al. [24]	8324	47
Furui et al. [21]	8405	48
Guo et al. [10]	5152	9
Tabatabaei et al. [8]	5939	5
The current model	**5593**	**1.19**

Table 3.
Comparison of the productivity from different models.

Results from each lateral	Current model		Tabatabaei and Ghalambor [8]	
	Lateral 1	Lateral 2	Lateral 1	Lateral 2
Production from each lateral (STD/D	2470.38	14260.47	24,994	14,274
Pressure of wellbore at toe (psi)	1900.8	1646.56	1899	1645
Pressure of wellbore at heel (psi)	1848.7	1634.55	1874	1633
Pressure of wellbore at junction	1620.4	500.2	1620	500

Table 4.
Results of production prediction from each lateral and pressure at each junction.

6. Model validation and comparison

The productivity prediction model for horizontal wells presented in this paper is verified at field scale using the case study presented by Chauvel et al. [11] as discussed in Tabatabaei and Ghalambor [8]. The horizontal well exhibits an 8.5-in open hole completed using a 5.5-in pre-packed screen opened laterally along the well length. The well trajectory is reported almost perfectly horizontal in 131.2 ft oil pay zone thickness and overall vertical depth of less than 6 in.

Production data indicated a liquid flow rate of 5677 BOPD, which corresponds to surface measured production rate with little free gas as the well was producing some psi below the bubble point. As reported in Tabatabaei and Ghalambor [8], some important parameters such as reservoir permeability, skin factor and boundaries were not reported. Therefore, as discussed by Tabatabaei and Ghalambor [8], these parameters were estimated (for the purpose of model validation) by matching the wellbore pressure profile calculated by this current model to measured pressure data.

Figure 4 presents the predicted pressure profile using the current study and the predicted pressure profile using Tabatabaei and Ghalambor [8] along the wellbore adopting the optimum segment number idea of 15. As it can be observed, the inclusion of the accumulation term into the current model as an improvement in Tabatabaei model resulted in a lesser pressure data at the heel and a higher pressure at the toe. The same trend was observed in the plot of specific inflow at each segment within the well as shown in **Figure 5**.

Using the parameters in **Table 1**, the current model can be used to predict productivity of horizontal well, and the results are compared with the actual production rate to ascertain the level of accuracy and precision of the current study as reported in **Figure 6**. **Table 3** illustrates the results of this analysis; the current study that incorporates the accumulation term in the pressure drop equation

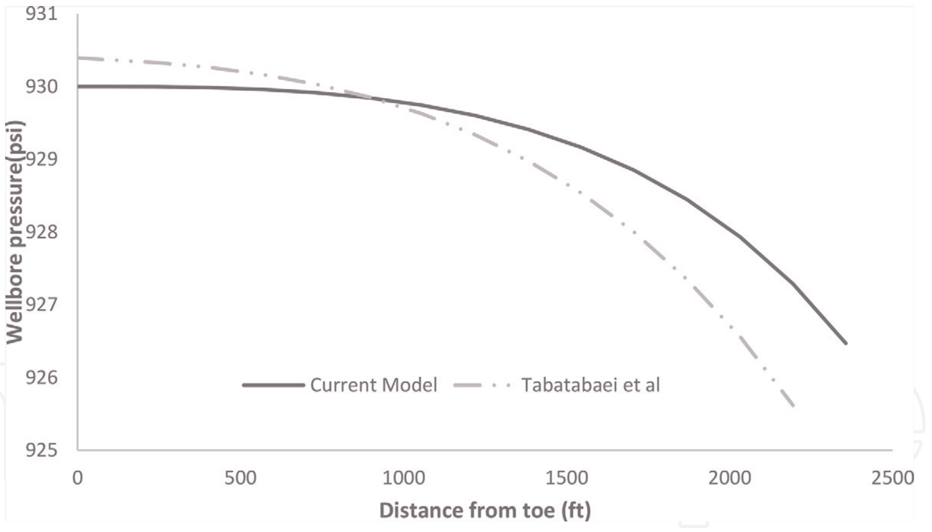

Figure 4.
Pressure performance of the well against distance from the toe.

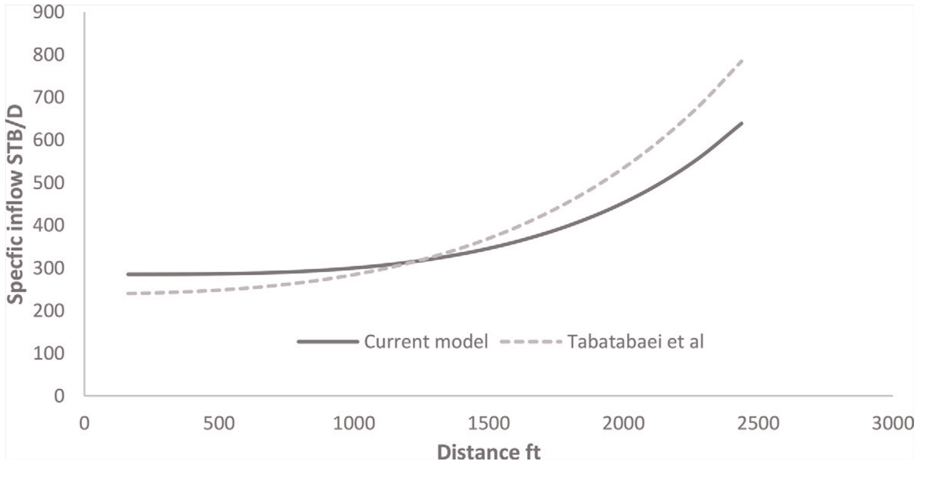

Figure 5.
Specific inflow at each point in the well.

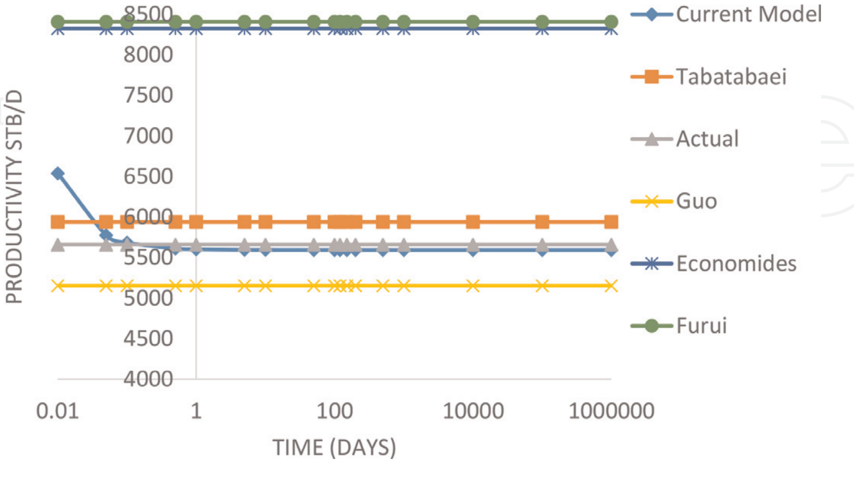

Figure 6.
Productivity over time.

predicted a production rate of 5593 STB/D compared to an actual production rate of 5660 STB/D reported by Chauvel et al. The close results validate the inclusion of the accumulation term in the coupling model and hence show why the model prediction gave the lowest percentage error 1.19%. Other models used for comparison were Economides et al. [24], Furui et al. [21], Guo et al. [7, 10] and Tabatabaei and

Ghalambor [8], as reported by Tabatabaei and Ghalambor [8], Economides and Furui assumed infinite-conductivity-drain hole, Guo included pressure drop along the wellbore in his development, while Tabatabaei and Ghalambor incorporated the acceleration term into the pressure drop equation. Using the same parameters as in **Table 1**, Economides et al. [24] and Furui et al. [21] overestimated the production rate (8324 STB/D and 8405 STB/D respectively) compared to the actual production rate which is evident in the recorded high percentage error. This was explained to be due to the omission of pressure drop along the wellbore in their model development. Guo et al. [7, 10] and Tabatabaei and Ghalambor [8] predictions are close to the actual production rate but not as accurate as the current study. Guo et al. model underestimated the well's productivity by around 9% because flow restriction is not only due to friction but all other pressure drops in horizontal wellbore such as pressure drop due to accumulation and in flow effect. The comparison also shows that the model by Tabatabaei and Ghalambor overestimated the well's productivity by approximately 5% for their failure to consider possible pressure drop due to accumulation in the wellbore. Therefore, the current study justified the inclusion of the accumulation term in the governing inflow equation for coupling model of reservoir-horizontal wellbore development.

The productivity of horizontal well depends on the difference between the reservoir pressure and the wellbore pressure at any point along the wellbore. Estimating the lateral productivity of horizontal well necessitates predicting the pressure profile and distribution along the wellbore. **Figures 6** and **7** respectively illustrate the well pressure and productivity distribution with time using the current model and Tabatabaei model. The current model exhibits both early time unstabilised flow and later time stabilised flow characteristics. The stabilised flow period accurately matched the actual productivity recorded on field; this analysis further justifies the introduction of the accumulation term in the current study and validates the accurate predictive power of the current model in terms of horizontal well's productivity prediction. Using the current model, stabilised flow period started at around 120 days and productivity of the well peaked at about 5592.8 STB/D.

Generally, the productivity of horizontal wells as a function of the wellbore length depends on the reservoir and wellbore properties. **Figure 8** presents the effect of horizontal well length on pressure drop and in turn productivity for predictions of both the current study and that of Tabatabaei [8]. It can be observed from the plot that productivity increases as the well length increases. Using the reservoir parameters and well completion information presented by Tabatabaei and Ghalambor [8] as an input in the current model and the existing model in the literature [8]. Multi-lateral well performance prediction by this model is illustrated

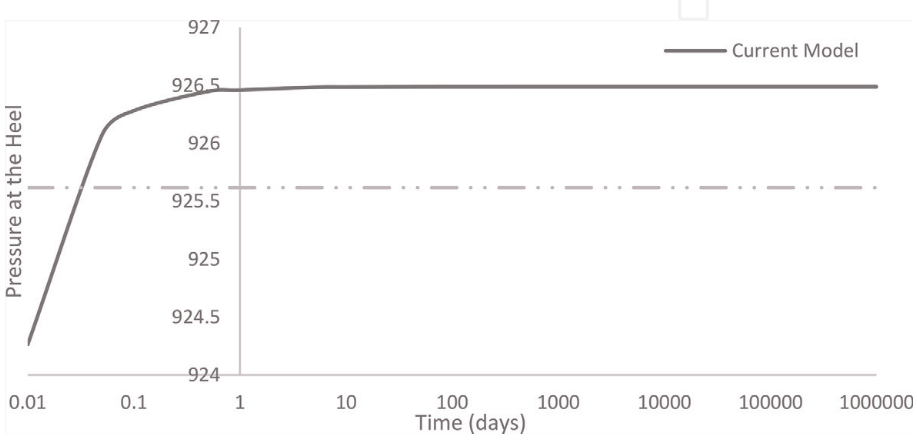

Figure 7.
Pressure variation at the heel with time.

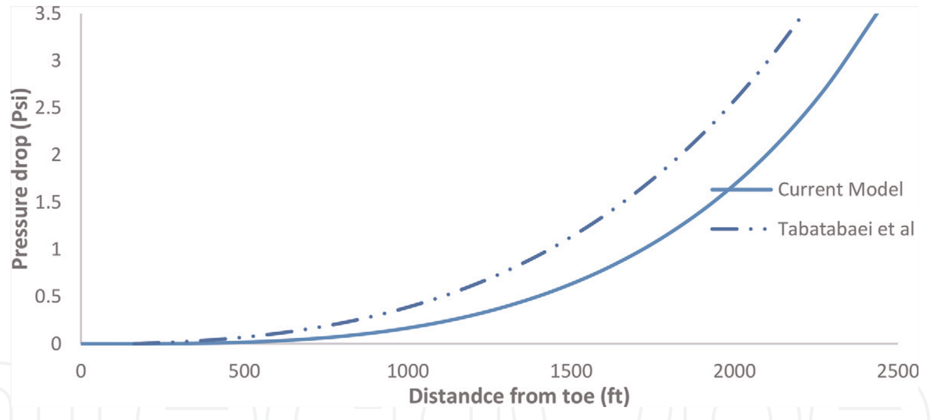

Figure 8.
Effect of horizontal well length on productivity.

and the outcomes are compared with those of Tabatabaei and Ghalambor [8] in **Table 4**. Total production and production from each lateral were calculated using the current model at different wellhead pressures. The result shows a non-linear increase in productivity as wellhead pressure increases.

7. Conclusion

The modified semi-analytical model was developed to predict the production performance of horizontal wells. A coupling of the inflow in the reservoir and flow in the wellbore was used for the development of the model.

Conclusions made from this study are as follows:

1. Disregarding the pressure drop in the wellbore will lead to an overestimation of the production rate of the well. Also, we see that not considering the inflow effect of the fluid will result in an underestimation of the production from the well.

2. Using the information gotten from field, it was shown that this model is more precise on the account that it gives a more practical representation of the flow in the wellbore and inflow to the reservoir, as this model is compared with the pre-existing models.

3. The model is simplified to be user-friendly as well as very efficient and sufficiently accurate for field applications. It can be used in reservoirs of varying conditions. We also see that the model is applicable for predicting the productivity of a well in a heterogeneous reservoir.

4. It can also be easily adapted to predict the productivity of multilateral well by incorporating the production performance of each lateral individually, with the well hydraulics of each of the build-up sections between the laterals and also the well hydraulics in the main wellbore.

5. Effects of friction, acceleration and accumulation, which lead to the pressure drop with increasing well lengths, should take into account avoiding an overestimation of the well's productivity.

Nomenclature

$q_s(x)$	in flow in the well per unit length of the wellbore
$J_s(x)$	specific productivity index
$J_s(i)$	specific productivity index of segment number i
$\overline{P_w}(i)$	average wellbore pressure at this segment
Δx	length of the segment
S_R	partial-penetration skin factor
$S(i)$	formation damage skin factor
k	effective permeability of reservoir
$x(i)$	distance between the centre of the segment I and the toe
m	number of junctions

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