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Maximizing Productivity of Horizontal Wells by Optimizing the Lateral Length

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Abstract

Compared to vertical wells, horizontal wells offer higher productivity and recovery, while lowering cost and environmental footprint per unit hydrocarbon recovery. The incremental value of a horizontal well increases with its lateral length, but drilling and completion constraints as well as flow-induced frictional pressure losses limit the lengths in the well construction and production phases, respectively. With the objective of maximizing productivity in the operating phase of a horizontal well, this paper couples Borisov's steady-state inflow model and an analytic wellbore hydraulic (outflow) model to develop algebraic equations of total reservoir and wellbore pressure drop as a function of lateral length. An appropriate friction-factor function that characterizes turbulent fluid flow in both smooth and rough drain holes is employed. First-order derivatives of these algebraic equations were used to establish stationary points that yield closed-form mathematical expression for estimating optimum well length as a function of reservoir and well properties. Sensitivity tests performed on a range of reservoir and well data provide useful insights into the interplay of reservoir drawdown and wellbore frictional losses on the overall pressure drop, and hence optimum well length. Although Borisov's model applies to an isotropic reservoir, findings from this work should be relevant for practical applications, which include anisotropic systems.

Keywords: *Horizontal wells, Optimum lateral length, Steady-state inflow, Wellbore frictional losses, Drain hole*

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1. Introduction

Horizontal wells have become an integral part of the oil and gas industry due to their numerous benefits over vertical wells (Alharbi and Alarifi, 2023; Eyitayo et al., 2023; AJOT, 2022; Gao, 2019; Thakur, 1999; Permadi, 1995; Joshi, 1991). The comparative advantages include higher productivity and recovery efficiency, as well as lower risks of coning and sand production due to reduced fluid velocities in the near wellbore area. Additionally, horizontal wells yield lower unit development cost and environmental footprint. The main principle underlying these benefits is the larger reservoir exposure (drainage area) provided by horizontal wells, which facilitates more efficient extraction of hydrocarbons (Houben et al., 2022; Stark, 2003). Horizontal wells are generally characterized by an inclination of at least 85^o (Azar, 2004).

Horizontal drilling has revolutionized the petroleum industry, offering a more efficient approach to reservoir exploitation compared to vertical wells. From the mid-1980s, the exploration and production industry experienced a consistent surge in the number of horizontal wells being drilled (Eyitayo et al., 2023; Ishak et al., 1995; Fisher and French, 1992; Burgess and van de Slijke, 1990). Today, the technology and experience in delivering such wells have evolved such that horizontal wells are considered the standard and often regarded as the default well profile for most field development projects. The net increase in productivity and recovery per well recorded in several basins over the last three decades can largely be attributed to the utilization of horizontal wells (AJOT, 2022; Thakur, 1999). To underscore the proliferation of its applications, there is evidence of a sharp increase in the number of freshly commissioned horizontal wells for both conventional and unconventional resources within the Permian Basin between 2020 and 2021 (Eyitayo et al., 2023; AJOT, 2022). The competitive advantage offered by horizontal wells in abating the volume of water produced per unit hydrocarbon recovery in conventional and unconventional reservoirs is profound (Eyitayo et al., 2023).

The positive influence of the lateral length of a horizontal well on its drainage area and productivity has been recognized (Alharbi and Alarifi, 2023; Elgaghah et al., 1996). Long lateral sections are attracting considerable interest from several operators in pursuing their business objectives to maximize productivity, injectivity, and overall performance of horizontal wells (Rassenfoss, 2022). As an example, operators in the Permian Basin increased the average lateral length of horizontal wells from less than 4,000 ft in 2010 to more than 10,000 ft in the year 2022 (AJOT, 2022). For clarity, the average lateral lengths of horizontal wells drilled in different counties within the Permian Basin in the years 2016 and 2017 are displayed in Figure 1. Empirical data in Figure 1 shows that the emerging trend in drilling horizontal wells is towards very long lateral (drain-hole) sections. Large drainage areas of long horizontal wells are leveraged in conventional reservoirs to reduce the number of development wells to improve project economics by minimizing unit development cost and maximizing recovery (AJOT, 2022; Thakur, 1999). Nevertheless, it must be said that most of these long laterals are for exploiting hydrocarbon resources in tight (low permeability and mobility) formations (Gao, 2019).

Despite the numerous advantages, the lateral length of a horizontal well is constrained by several challenges associated with drilling, completion, and production. These factors influence the optimum value of the lateral length that can be accomplished. The main drawbacks against long laterals in the well-construction phase include increased drilling and completion costs as well as higher risk of stuck pipes due to higher torque and drag. The production phase is plagued with more complicated surveillance and flow-assurance challenges as well as higher frictional pressure losses and the concern of balancing flow contributions of the heel and toe sections of the well (Smith, 2015; Caglayan, 2014; Tabatabaei and Ghalambor, 2011; Penmatcha et al., 1999; Folefac et al., 1991). It is encouraging that advancements in technology, alongside contemporary drilling and completion equipment and techniques, are progressively mitigating some of the challenges associated with extended-reach horizontal wells (Rassenfoss, 2022).

Given the interplay of frictional pressure losses and lateral length, researchers and operators seek the optimum lateral length that strikes a balance between the benefits of an enlarged drainage area and the drawback of higher frictional losses. This problem has been studied with analytical and numerical-simulation models, but with scope for improvement (Penmatcha et al., 1999; Al-Bayati et al., 2020; Ohaegbulam et al., 2017; Fadairo et al., 2011; Cho and Shah, 2000).

Novy (1995) developed generic graphs and guidelines for evaluating optimum well length as a function of flow rate and well diameter for specific ranges of wellbore and reservoir characteristics as well as drawdown. These graphs and guidelines have the following limitations (i) they do not explicitly account for dependency of optimum well length on the reservoir, fluid and wellbore properties. In practice, all these properties vary widely, hence inferences from the graphs and guidelines are not always unique; and (ii) lack of a closed-form mathematical expression for estimating optimum well length, especially in wellbores characterized by turbulent flow, which is the more realistic flow regime in most wells.

Cho and Shah (2000) employed economic modelling to determine the optimum drain-hole length of horizontal wells. Specifically, their method entails coupling an economic model that considers well-delivery (drilling and completion) costs alongside a revenue profile to a producitivity index model that accounts for wellbore (lateral section) hydraulics and reservoir inflow losses. Syed (2014) extended the same approach to include operating costs, tax, royalty and some other cost centres. Fundamentally, this method is characterized by an objective function that seeks to estimate the well length that maximizes the net present value. Shortcomings of this approach include (i) relatively high complexity to apply in practice, precluding quick analysis and decision-making, as well as (ii) the use of empirical cost functions from limited dataset limits its wide applicability. Furthermore, most of the previous methods do not consider the effect of skin factor on optimum lateral length (Cho and Shah, 2000; Novy, 1995; Syed, 2014).

Several steady- and pseudo-steady state horizontal-well inflow models are available in the literature. These models, which vary in their underlying premises and complexity, describe the relationship between productivity index and lateral length (Joshi, 1991; Lu, 2001; Goode and Kuchuk, 1991; Renard and Dupuy, 1990; Babu and Odeh, 1989). Some researchers, such as Borisov (1964) and Giger et al (1984), assumed isotropic reservoirs in a steady-state regime in circular and elliptical geometry, respectively. While the Borisov (1964) model appears simplistic in assuming a circular flow pattern for horizontal wells, the model has performed satisfactorily against more complex inflow models (Alharbi and Alarifi, 2023; Escobar et al., 2004). Indeed, as an alternative to the traditional physics-driven inflow models, the emerging trend of model simplicity is driving interests in data-driven hybrid models predicated on artificial intelligence (Alharbi and Alarifi, 2023; Buhulaigah et al., 2017; Alarifi et al., 2015).

Anisotropy has been introduced into the inflow models of horizontal wells. For instance, Joshi (1988) accounted for reservoir anisotropy and well eccentricity. Economides et al. (1991) provided simulation results that show excellent agreement with analytical or semi-analytical approximations for both infinite and finite conductivities. However, Renard and Dupuy (1990) showed that horizontal wells are less affected by permeability reduction around the wellbore.

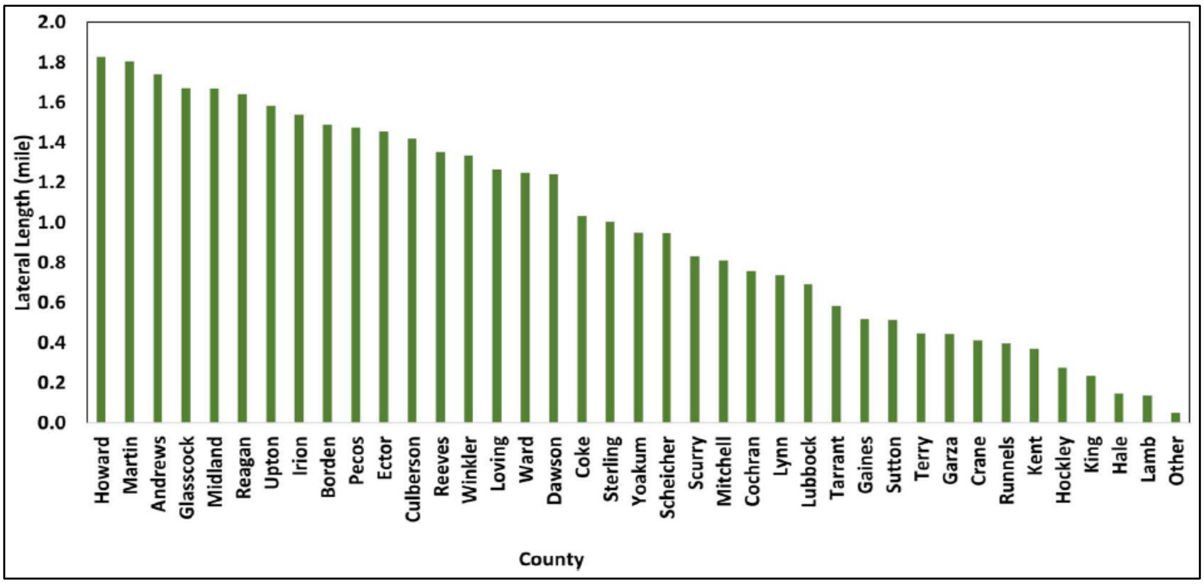


Fig. 1: Lateral lengths of some horizontal wells in different Texas counties between 2016 and 2017 ([Eyitayo et al., 2023).

Based on pseudo-steady state assumptions, Babu and Odeh (1989) formulated a complex general solution that considered a geometric factor that accounts for permeability anisotropy, well location, and drainage volume dimensions, alongside the skin caused by restricted entry due to well length. The model suggests that well length and penetration ratio have the strongest influence on the productivity of horizontal wells. However, the main challenges with this class of model (Goode and Kuchuk, 1991) are their complexity and the computational costs of several numerical simulation runs to determine the optimum lateral length of a horizontal well.

Borisov (1964) model is the simplest of all the analytical models available in literature. However, the Joshi model appears to be the most popular for analytical characterization of horizontal-well inflow performance. Many previous works on this subject deferred to Joshi (1991) as the preferred inflow model (Ohaegbulam et al., 2017; Fadairo et al., 2011; Cho and Shah, 2000). However, to the best of our knowledge, the applicability of Borisov (1964) model remains to be examined in the context of optimizing lateral length. Although its formulation does not account for the influence of reservoir anisotropy explicitly, the suitability of the Borisov (1964) model to several practical problems, including some anisotropic cases, has been documented (Alharbi and Alarifi, 2023; Economides et al., 1991; Almuraikhi, 2017). Attracted by its relative simplicity, this paper employs the Borisov (1964) model to investigate the optimum lateral length of horizontal wells in which pressure drops due to both inflow and outflow (lateral section) are considered. This study aims to provide a relatively simple, yet robust, analytical model for evaluating the optimum lateral length that maximizes the productivity of horizontal wells. In principle, the optimum length will also reduce operational challenges of horizontal wells. This paper is a contribution towards more efficient and cost-effective exploitation of hydrocarbon reservoirs through horizontal wells. The developed model provides valuable insights into the interplay of reservoir drawdown and wellbore frictional losses, providing guidance for operators in real-world applications.

2. Materials and methods

We develop a coupled inflow-outflow model that accounts for reservoir drawdown and pressure drop due to frictional losses along the lateral in the wellbore using the workflow as shown in Fig. 2. Borisov's inflow model (1964) is integrated with an analytic wellbore hydraulic (outflow) model. This integration allows formulation of algebraic equations representing the total reservoir and wellbore pressure drops as a function of lateral length and other reservoir and well properties. We utilize a friction-factor function that describes turbulent fluid flow in both smooth and rough drain holes. The first-order derivatives of these algebraic equations are then solved to determine stationary points, resulting in a closed-form mathematical expression of the optimum well length as a function of reservoir and well properties. Results of sensitivity tests reveal valuable insights into how reservoir drawdown and wellbore frictional losses interact to influence the overall pressure drop and productivity, and hence, the optimal well length. While the Borisov model (1964) is intended for isotropic reservoirs, findings from this study are expected to be applicable not only to isotropic formations but also some anisotropic reservoirs.

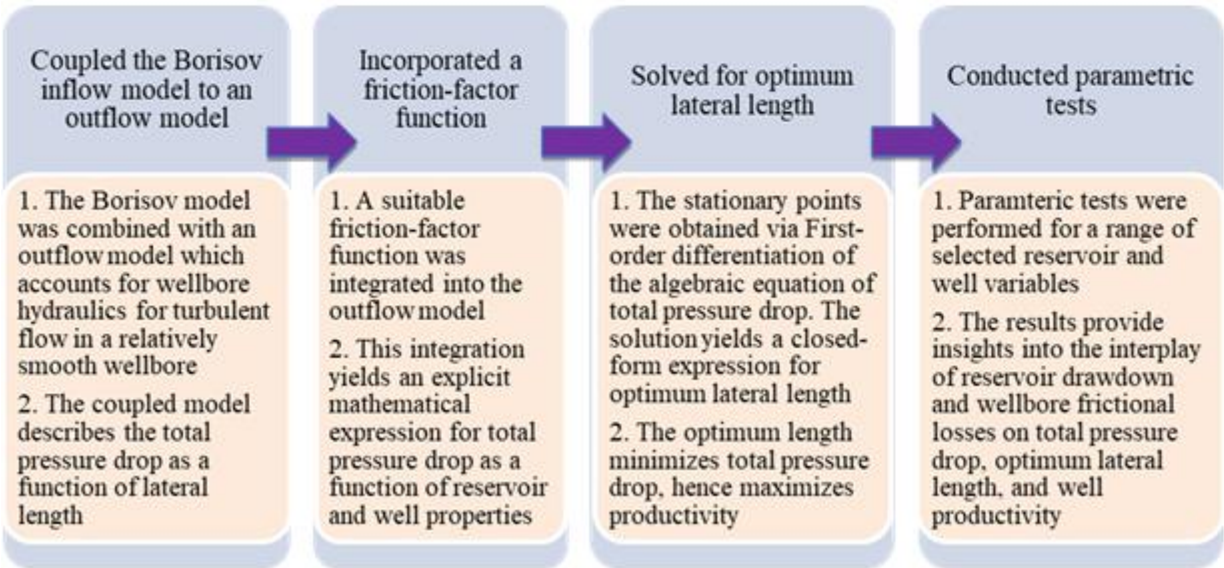


Fig. 2: Methodology

2.1 Model formulation

The main assumptions in the mathematical description of the flow problem and its solution include:

(i) isotropic reservoir,
(ii) steady-state flow of an incompressible single-phase fluid,
(iii) the bulk fluid covers a distance equal to 50% of the lateral length to the well's heel regardless of the inflow point,
(iv) average inflow pressure in the lateral direction is P_1 at the midpoint L/2, while that at the heel (exit point) is P_2, and
(v) fluid molecules produced to the heel always have suffcient energy to overcome any backpressure downstream of the heel to the target delivery point.

Fig. 3 is a conceptual model of the drain-hole section of an arbitrary horizontal well. Inflow and outflow patterns are illustrated. In reality, not all molecules of the inflowing fluid travel the entire drain-hole length L. For example, while fluid molecules entering at the toe (or nearby) would travel at least the entire length L (or more if we consider tortuosity of the flow path), their counterparts entering the wellbore at the heel (or nearby) would travel a distance much less than L to reach the heel which, in this study, is the reference point for the estimation of flowing bottom-hole pressure P_2. The heel is the exit point for fluids that enter the horizontal drainhole. Therefore, the heel is the most suitable reference point for assessing the performance of a lateral. Given large disparity in distances that each inflowing molecule covers before reaching the reference point (heel), we take a simple approach of assuming that all the inflowing fluid molecules travel the same distance equivalent to 50% of lateral length in the outflow path. By aggregating the drawdown in the wellbore, our approach is different and simpler than that taken by previous researchers (Penmatcha et al. 1999, Fadairo et al. 2011, Cho and Shah 2000, Novy 1995, Cho and Shah 2001). For example, unlike previous works that require tracking the drawdown at each position and productivity index (PI) per unit length along the lateral section, this work focuses on the drawdown due to the bulk inflow stream.

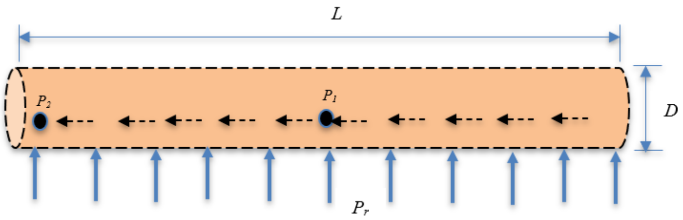


Fig. 3: Inflow and outflow patterns in the lateral section of a horizontal well, supplied by a reservoir at pressure P_r.

By simple energy balance at steady state, the total pressure drop that drives flow from the reservoir to the heel is the sum of the inflow (ΔP_{in}) and outflow (ΔP_{out}) pressure drops.

$$\Delta P = \Delta P_{in} + \Delta P_{out}. \quad (1)$$

The inflow rate Q and associated pressure drop ΔP_{in} are related as follows [33].

$$\Delta P_{in} = P_r - P_1 = \frac{Q\mu B}{2\pi kh}\left\{In\left({}^{4r}/_{L}\right) + \frac{h}{L} In\left({}^{h}/_{\pi D}\right) + s\right\}, \quad (2)$$

If pressure drop along the lateral is strictly due to friction, the following expression relates $\Delta P'_{out}$ and full lateral length L of a horizontal well. In Eq. 3, the quantity B converts flow rate from surface conditions to downhole conditions, hence the product BQ [41-42].

$$\Delta P'_{out} = P_1 - P_2 = \frac{32\rho f_F L B^2 Q^2}{\pi^2 D^5}, \quad (3)$$

Because of our assumption that the bulk stream effectively travels just 50% of the lateral length, the total outflow pressure drop is obtained by setting $L = L/2$ in Eq. 3 to obtain the following expression.

$$\Delta P_{out} = \frac{16\rho f_F L B^2 Q^2}{\pi^2 D^5}. \quad (4)$$

To determine the optimum lateral length, we seek the length L_{opt} that minimizes the total pressure drop ΔP, hence maximizing productivity (defined as the ratio of Q to ΔP). The solution space is bounded by these two extremes: (i) L_{max}, which minimizes the inflow pressure drop ΔP_{in} but maximizes the outflow pressure loss ΔP_{out} associated with rate Q; and (ii) $L = 0$, which minimizes the outflow pressure loss ΔP_{out} but maximizes the inflow pressure drop ΔP_{in} associated with rate Q. However, at the optimum point L_{opt}, the derivative of ΔP with respect to L is zero.

From Eq. 2, we derive the rate of change of inflow pressure drop with lateral length. Likewise, Eq. 4 yields the rate of change of outflow pressure loss with lateral length.

$$\frac{d(\Delta P_{in})}{dL} = \frac{-Q\mu B}{2\pi khL}\left\{1 + \frac{h}{L} In\left({}^{h}/_{\pi D}\right)\right\}. \quad (5)$$

$$\frac{d(\Delta P_{out})}{dL} = \frac{16\rho f_F B^2 Q^2}{\pi^2 D^5}. \quad (6)$$

Empirical correlation by Round (1980) was employed to describe the friction factor of both smooth and rough wellbores. In principle, this correlation is more robust than that of Jain (1976) as the former covers wider ranges of Reynolds number and roughness factor, though the latter is more popular among previous workers (Fadairo et al., 2011; Novy, 1995; Syed, 2014). Additionally, Round (1980) correlation is more appropriate and realistic than the smooth-pipe correlations (Assefa and Kaushal, 2015). The following system of equations is a re-cast of the original function

(Round, 1980) in terms of the Fanning friction factor f_F.

$$f_F = \frac{0.07716}{\left(\log\left(0.135R_r + \frac{6.5}{N_{Re}}\right)\right)^2}, \; 4000 \leq N_{Re} \leq 4\text{x}10^8 \text{ and } 0 \leq R_r \leq 0.05. \quad (7a)$$

$$N_{Re} = \frac{4\rho BQ}{\pi\mu D}. \quad (7b)$$

$$R_r = \frac{\varepsilon}{D}, \quad (7c)$$

where ε is the wellbore roughness (m). N_{Re} and R_r are Reynolds number of the flow and roughness factor of the wellbore, respectively. Both are dimensionless quantities. Again, in Eq. 7b, the product BQ converts Q from surface to downhole conditions. From Eqs. 1, 5 and 6, we obtain the following expression for the change in ΔP caused by a change in L and set same to zero.

$$\frac{d(\Delta P)}{dL} = \frac{16\rho f_F B^2 Q^2}{\pi^2 D^5} - \frac{Q\mu B}{2\pi khL}\left\{1 + \frac{h}{L} In\left(h/_{\pi D}\right)\right\} = 0. \quad (8)$$

Multiplying both sides of Eq. 8 by L^2 and solving the same equation for L yields the following expression (positive root only) for the optimum lateral length from the quadratic function obtained from Eq. 8.

$$L_{opt} = \frac{-\text{b}+\sqrt{b^2-4ac}}{2a} \leq L_{max}, \qquad a \neq 0. \quad (9)$$

in which L_{max} is the allowable upper bound of the lateral length. In practice, L_{max} may be constrained by geological or physical limits in the direction of the well of interest. Such constraints include faults, fluid contacts, poor sand development, lease boundary, pressure interference risks, inter-well spacing regulations, hole-cleaning challenges, concerns of running completion accessories to total depth (toe of the well), limitations posed by future interventions, and well clean-up difficulties.

The quantities a, b and c are given by:

$$a = \frac{16\rho f_F B^2 Q^2}{\pi^2 D^5}. \quad (10)$$

$$b = -\frac{Q\mu B}{2\pi kh}. \quad (11)$$

$$c = -\frac{Q\mu B}{2\pi k} In\left(h/_{\pi D}\right). \quad (12)$$

In essence, the substitution of Eqs. 10-12 and 7 in Eq. 9 would estimate the optimum lateral length of a horizontal well characterized by steady-state inflow from the reservoir into the wellbore and subsequent turbulent flow in either smooth or rough lateral section. For completeness, we define PI (J) of a well as the ratio of flow rate to total pressure drop.

$$J = \frac{Q}{\Delta P_{in} + \Delta P_{out}} = \frac{Q}{\Delta P}. \quad (13)$$

Realizing that L_{opt} yields the global minimum of the total pressure drop, it is straightforward from Eq. 13 that the same L_{opt} will always return the global maximum value of PI obtainable for the reservoir-well system of interest.

3. Results and discussion

Numerical examples are presented to demonstrate applicability of the new model and gain relevant insights into some factors that control the performance of horizontal wells from the standpoint of minimizing pressure drops, hence maximizing PI. Primary input dataset for the simulation examples is provided in Table 1. We are not unaware of the interactions between lateral length and drainage radius of a horizontal well. In principle, the drainage radius of a horizontal well should change with its lateral length, considering that the lateral length is an indication of reservoir exposure, hence potential drainage area. However, in all cases examined in this work, drainage radius is fixed because our main interest is in the effects of lateral length on pressure drops and productivity. Additionally, it is assumed that all lateral lengths investigated remain on-structure. This implies that reservoir geometry in the direction of the drain-hole section can accommodate all the lateral lengths evaluated in this paper.

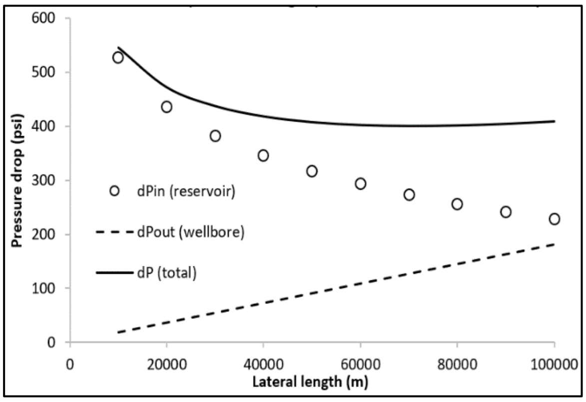
For a fixed set of fluid properties and reservoir geometry, we consider a wide range of permeability and wellbore roughness states to provide good understanding of the effects of permeability and wellbore roughness on the relative contributions of inflow (reservoir drawdown) and outflow (wellbore frictional loss) hydraulics to the overall pressure drop, hence productivity. The R_r value of 0.05 is indicative of the upper bound of wellbore roughness, accounting for the limiting scenario of combined high dogleg severity and tortuosity of the drain hole. Poor wellbore clean-up and subsequent non-uniform beds of fines and other solids deposited along the drain-hole during the operate phase of a horizontal well contribute to wellbore roughness.

Table 1: Input data for simulation

Variable	Value (SI unit)	Value (field unit)
B (dimensionless)	1.2	1.2
D	0.1397 m	5.50 in
H	100 m	328 ft
k	1.0 x 10^{-14} and 1.0 x 10^{-12} m^2	10 and 1000 mD
Q	9.2 x 10^{-3} m^3/s	5000 STB/d
r	1,000 m	3280 ft
s (dimensionless)	5	5
ρ	850 kg/m^3	53.0 lb/ft^3
μ	5.0 x 10^{-4} Ns/m^2	0.5 cP
R_r (dimensionless)	0 and 0.05	0 and 0.05

Fig. 4a illustrates how each contributor and the total pressure drop vary with the lateral length for an example formation characterized by 10 mD permeability. The well has a target production rate of 5,000 STB/d and characterized by a perfectly smooth wellbore (R_r = 0). The results indicate that for a given production rate, pressure drop due to outflow increases with lateral length, while reservoir drawdown diminishes with lateral length. In this case, reservoir drawdown dominates the total pressure drop. For the same 10-mD reservoir and 5,000 STB/d throughput, the corresponding simulation results for a very rough wellbore (R_r = 0.05) are shown in Fig. 4b. At a given lateral length, Fig. 5a and 5b indicate that total pressure drop is proportional to wellbore roughness, while the reservoir drawdown is independent of the wellbore roughness but varies inversely (though non-linearly) with well length.

Based on the results in Figures 4a and 4b, we can deduce that in low-permeability reservoirs, the gain in productivity obtainable from increased reservoir exposure offered by longer lateral is more important than the negative impacts of the incremental frictional losses that would be recorded as the bulk stream flows through either a smooth or rough drain-hole section. This finding explains the emerging drive for long laterals in horizontal wells to exploit relatively tight formations such as in the Permian Basin (Eyitayo et al., 2023; AJOT, 2022; Rassenfoss, 2022).



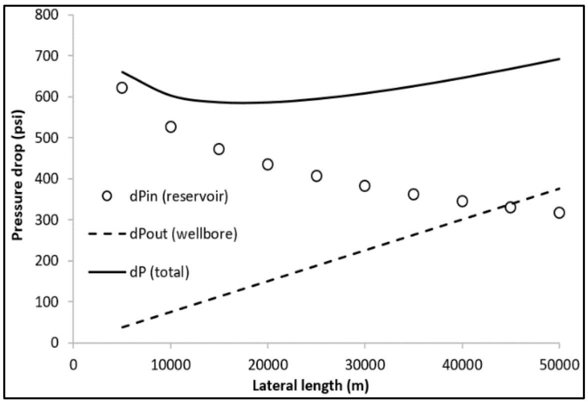


Fig. 4: Reservoir, wellbore and total pressure drops vs. lateral length for which *k* = 10 mD and *Q* = 5,000 STB/d (a) *Rr* = 0 (b) *Rr* = 0.05.

Fig. 5a and 5b are the simulation results for the same example problem, but with permeability set at 1,000 mD. Despite the relatively high permeability, reservoir drawdown still dominates the total pressure drop required to accomplish the target production rate of 5,000 STB/d up to lateral lengths of ca. 3,400 m and 1,200 m in the smooth and rough wellbores, respectively. Beyond these transition lateral lengths in this example, pressure drop due to outflow becomes increasingly dominant. Comparing the relevant plots in Figures 4 and 5, it can be deduced that for the same set of lateral length, fluid viscosity and production rate, the low-permeability case yields a much higher total pressure drop than its high-permeability counterpart regardless of the underlying wellbore roughness. From the standpoint of minimizing the total pressure drop for the same offtake rate, these results suggest a greater opportunity to utilize relatively short lateral lengths to exploit high-permeability reservoirs than obtainable in developing low-permeability reservoirs. Additionally, for the same permeability, relatively short laterals are better suited to rough wellbores than their smooth counterparts.

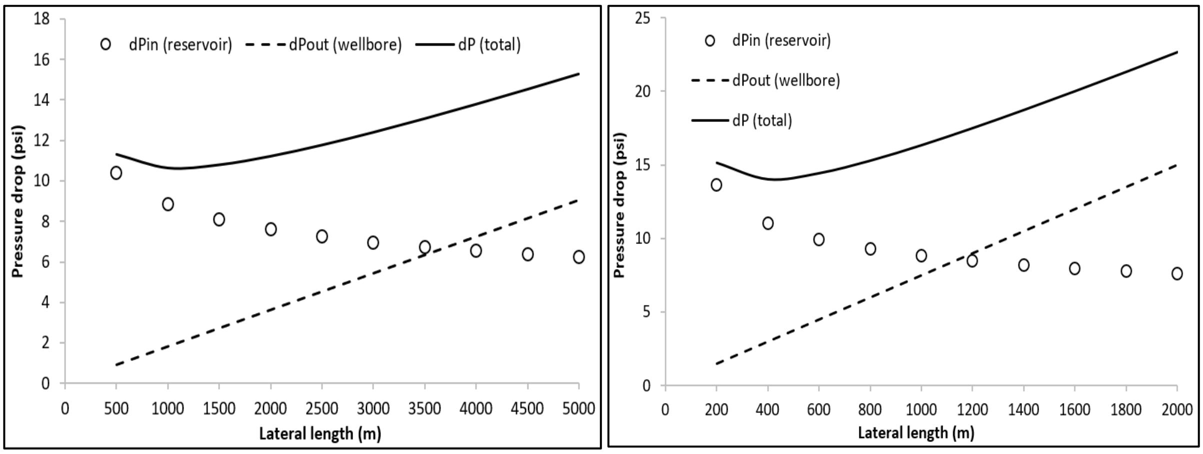


Fig. 5: Reservoir, wellbore and total pressure drops vs. lateral length for which k = 1,000 mD, Q = 5,000 STB/d, (a) Rr = 0 (b) Rr = 0.05.

A cursory look at Fig. 5a and 5b may be counter intuitive as one could initially conclude that the smooth wellbore case is characterized by higher total pressure drop than the corresponding rough wellbore case. However, a closer examination for a specific lateral length clearly shows that lower total pressure drop is consistently estimated for the smooth wellbore case. As an example, given a lateral length of 1,000 m, the associated total pressure drops in the smooth and rough wellbore cases are approximately 11 psi (Fig. 5a) and 17 psi (Fig. 5b), respectively.

Taking advantage of Eqs. 7 and 9-12, the variation of optimum lateral length was evaluated as a function of permeability for the example case of 5,000 STB/d production target (Fig. 6). The optimum lateral lengths for the reference cases of 10 and 1,000 mD are about 71,000 m and 1,100 m, respectively in the case of a smooth wellbore. The corresponding results in the case of a rough wellbore are ca. 17,500 m and 400 m, respectively. For greater clarity, Figures 7a and 7b display the variation of PI vs. lateral length vs. wellbore roughness for the example cases of 10 mD and 1,000 mD, respectively.

In Fig. 7a and 7b, it is noteworthy that the maximum PI is approached asymptotically in the vicinity of L_{opt}. While the results in Figure 7a show the global maximum PI corresponds to L_{opt} ~ 17,500 m for a rough wellbore draining a low-permeability rock, a lateral length of 5,500 m yields a PI that is within 10% of the global maximum (i.e., 7.7 vs. 8.5 STB/d/psi). Therefore, for practical applications on the assumption of 100% contribution along the entire section of the completed drain hole, one could justifiably settle for a 5,500-m lateral length as against the theoretical optimum 17,500-m lateral in this example. Other factors remaining the same, such an informed decision would save some 68% of the lateral length (and associated well costs), while potentially regretting just ~10% of the maximum PI in relation to the theoretical optimum lateral length. Similar analysis for the case of developing the high-permeability reservoir example with a rough wellbore suggests that one could potentially deploy a drain-hole section of ~ 180 m, as against the theoretical optimum lateral length of ca. 400 m. This informed trade-off would potentially save about 55% of the lateral length at the expense of regretting ca. 10% (322 vs. 356 STB/d/psi) of the theoretical maximum PI of the system.

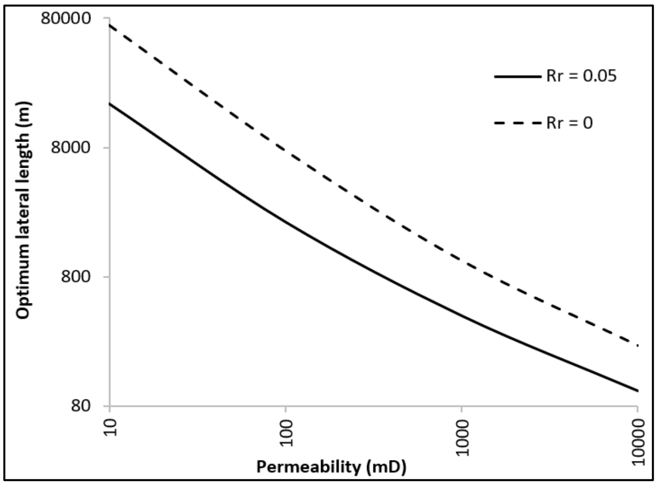


Fig. 6: Optimum length vs. permeability and wellbore roughness for a target Q = 5,000 STB/d

Against the backdrop that reservoir drawdown influences the total pressure drop, it is straightforward to realize that L_{opt} decreases with permeability for the same wellbore roughness (Figure 6). However, these results suggest that the inverse relationship between L_{opt} and permeability is non-linear, but approximately logarithmic (as evident in the underlying Borisov inflow model in Eq. 2). Again, these results underscore the attractiveness of long laterals in low-permeability reservoirs, where larger drainage (contact) areas can be exploited to maximize productivity, sweep efficiency and recovery. In principle, the simulation results indicate that reservoir permeability and lateral length are mutually compensating to maximize productivity. That is, permeable formations could warrant utilizing short lateral wells while tight reservoirs are candidates for long lateral wells to maximize productivity.

The foregoing simulation results underscore the need to fully understand the interplay of reservoir drawdown and frictional losses in the horizontal section before concluding on the optimum lateral length that would maximize productivity of a horizontal well. The mathematical models and outcome of selected parametric tests presented in this work provide useful insights to optimize the lateral length for competitive technical well performance (PI) and economic returns at minimal well-construction costs. This notwithstanding, the final decision on well design should be on a case-by-case basis while considering other factors such as drillability, completability, well clean-up, flow assurance, reservoir geometry, surveillance, local regulations, field management, economics, and environmental impact (e.g., disposal of cuttings and other drilling wastes).

In practice, to facilitate effective well and reservoir management, engineers seek a production rate that defines the upper bound of the operating envelop of a well. Accordingly, we examine the influence of target flow rate on the lateral length. For the example case of a smooth wellbore, Fig. 8a displays the relationships between L_{opt} and flow rate for low and high permeability rocks. Corresponding results for a rough wellbore are provided in Figure 8b.

Fig. 8a and 8b present the sensitivity of L_{opt} to flow rate and permeability for smooth and rough wellbores, respectively. Although his work was premised on a different approach, a similar functional relationship between L_{opt} and flow rate was reported by Novy (1995). Though the trends are generally comparable, the quantitative values of the L_{opt} vs. flow rate curves in Figure 8 are not quite the same as those of Novy (1995). Among other factors, we attribute variances in quantitative values to differences in mathematical models and input dataset between this study and that of Novy (1995). The variances notwithstanding, useful deductions can be drawn from Figs. 8a and 8b to aid the design and management of horizontal wells.

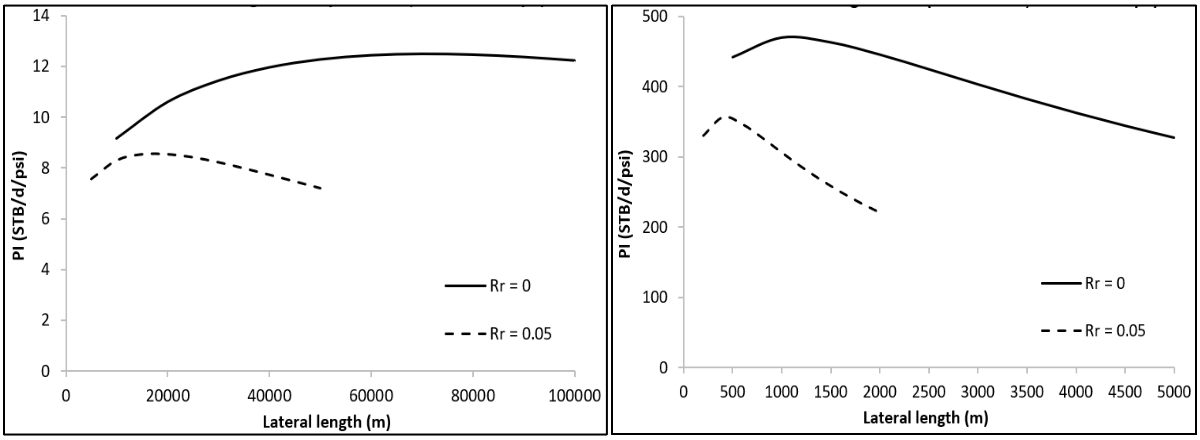


Fig. 7: PI vs. lateral length and wellbore roughness (Q = 5,000 STB/d) (a) k = 10 mD (b) k = 1,000 mD.

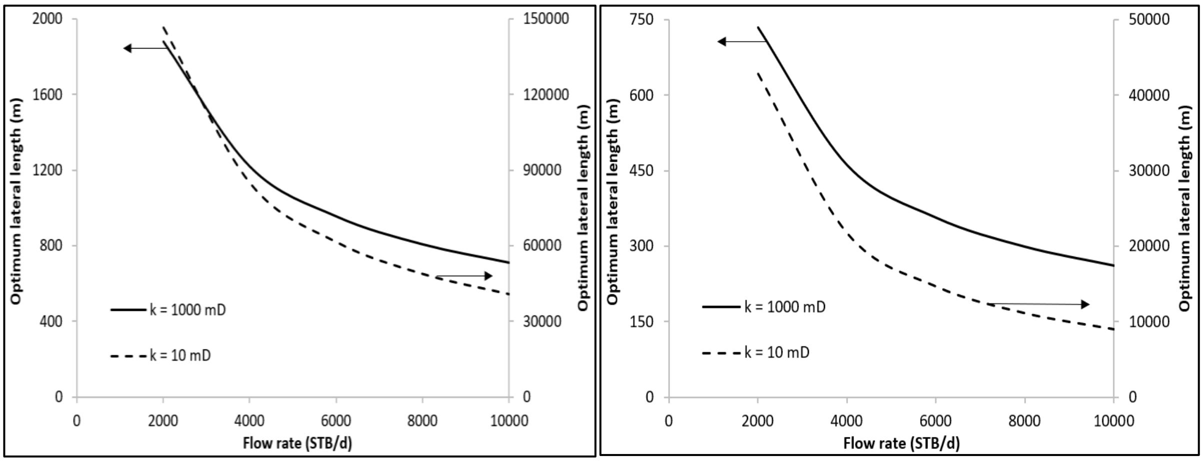


Fig. 8: L_{opt} vs. flow rate and permeability (a) Rr = 0 (b) Rr = 0.05

A key deduction from example plots in Fig. 8 is that, while other factors remain constant, optimum lateral length reduces (asymptotically) with target flow rate to maximize the productivity of a horizontal well. For each flow rate in Figures 8a and 8b, the vertical intersection with the appropriate curve is the drain-hole length above which it may not be efficient to operate the well. Alternatively, for a given L_{opt}, the horizontal intersection with the curve provides maximum allowable flow rate that guarantees efficient production of the well such that the total pressure drop is minimized. These are important insights for optimization during the construction and production phases of wells.

For deeper understanding, we evaluate the skin factor due to flow along the horizontal section. This pseudo-skin effect is attributed to frictional losses along the wellbore upstream of point 2 in Figure 3. This outflow skin factor (s_{out}) along the lateral between the toe and heel of the well is estimated with the following mathematical expression.

$$s_{out} = \frac{2\pi k h \Delta P_{out}}{QB\mu}. \qquad (14)$$

Application of Eq. 14 to the values of ΔP_{out} corresponding to the respective profiles and input data in Figs. 4 and 5 yield the results of equivalent skin factor displayed in Figs. 9a and 9b for the examples of low and high permeability, respectively. As would be expected, these results suggest that skin factor due to frictional loss in the horizontal section generally increases with the length and roughness of the horizontal section of the well. As a practical implication, this pseudo skin is inherent and should always be considered when decomposing the total skin of a horizontal well to forestall erroneous conclusion on well health thereby mitigating potential wrong investment decision on stimulation and other well-intervention activities.

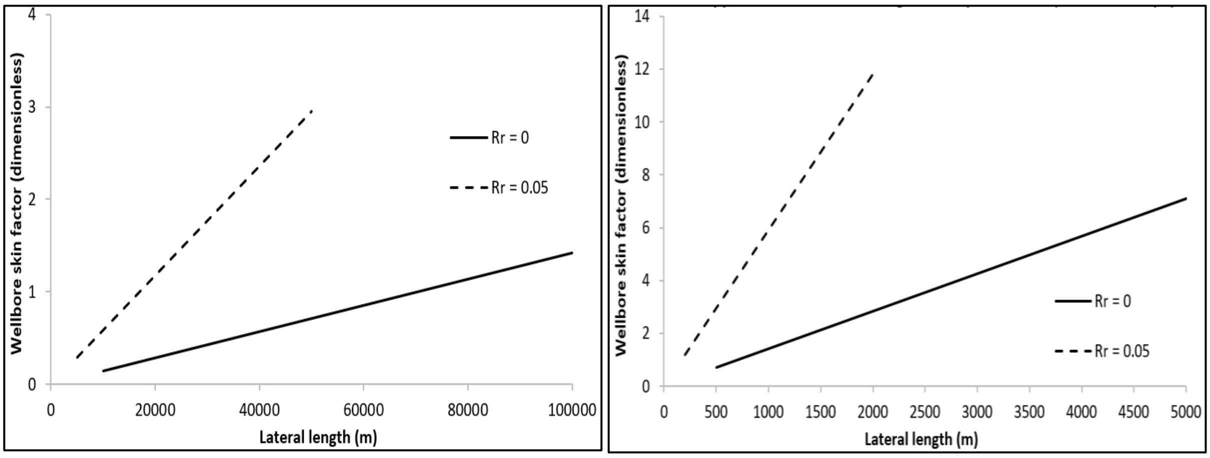


Fig. 9: Skin factor due to frictional losses along well lateral (Q = 5,000 STB/d). (a) k = 10 mD (b) k = 1,000 mD.

4. Conclusion

This research sheds light on optimization of the lateral lengths of horizontal wells in the context of reservoir characteristics and operating conditions. The development of a new analytical model contributes to understanding how to optimize lateral lengths of horizontal wells to achieve both theoretical maximum and realistic productivity. Main concluding remarks include:

a. A new analytical model has been developed for evaluating the effects of lateral length on the performance of horizontal wells characterized by turbulent flow. The model is applicable to both smooth and rough wellbores.
b. Sensitivity tests indicate that relative contributions of reservoir drawdown and wellbore frictional losses to total pressure drop are complex and vary between cases. As a result, the problem of optimum lateral length should be treated on a case-by-case basis.
c. From a production efficiency standpoint, minimizing total pressure drop (within realistic limits), as against minimizing either reservoir drawdown or wellbore pressure loss only, should drive the optimum lateral length to maximize productivity.
d. Simulation results support the emerging trend in which operators are drilling horizontal wells of increasingly longer laterals to exploit low-permeability petroleum reservoirs.
e. For a fixed set of reservoir and well characteristics alongside a specific production rate, optimum lateral length varies inversely with wellbore roughness.

Future efforts on this work should consider the following improvement areas:

a. Extension to anisotropic reservoirs by incorporating horizontal-well steady-state inflow models that account for formation anisotropy.
b. Inclusion of additional near-wellbore pressure losses often occasioned by some lower completion accessories such as inflow control devices and valves (Ahn et al. 2023, Moradi et al. 2022, Nugraha et al. 2022).
c. Accounting for constraints on total drawdown (inflow plus outflow) to complement the guidance on productivity yielded by optimum lateral length. This additional constraint is important to mitigate drawdown-related risks such as failure of sand-exclusion system in the operate phase.

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Nomenclature

B	fluid formation volume factor (dimensionless)
D	wellbore diameter (m)
f_F	fanning friction factor (dimensionless)
h	reservoir thickness (m)
k	permeability (m^2)
L	lateral length (m)

N_{Re}	Reynolds number (dimensionless)
Q	flow rate (m^3/s)
r	drainage radius (m)
R_r	roughness factor (dimensionless)
s	skin factor (dimensionless)
ρ	fluid density (kg/m^3)
ε	wellbore roughness (m)
μ	fluid viscosity (Ns/m^2)

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