

Enhancing Oil Production Rate by Well Type Conversion in an Iraqi Field

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Abstract

Horizontal wells have been drilled worldwide for the past decades, mainly to increase well's deliverability. Many vertical wells have been converted to horizontal wells. Only some of them were successful in increasing the oil production rate as expected. In this study, a vertical well (V1) in Kirkuk field was studied and converted to a designed horizontal well (H1) to increase the productivity. PROSPER software was used to model both wells. H1 was designed with well horizontal lengths of 152, 305, 457, and 610 m, and permeability ratios of 0.1, 0.2, 0.4, 0.7 and 1.0. A developed correlation for calculating well construction cost, along with Questor software, were used to perform the economic analysis. It was found that the highest productivity index and production rate ratios were 5.2 and 2.41, respectively. Reservoir pay thickness and permeability ratio are the main parameters in determining the minimum feasible horizontal well length. Reservoir pressure and water cut were found to be the most sensitive parameters in both wells. The net profit generated by a horizontal well with length of 610 m and permeability ratio of 0.2 is 1.9 folds the net profit generated by a vertical well, in three years.

Keywords: Horizontal wells; Productivity index; Oil production; Permeability ratio; Pay thickness; Well construction cost; Iraq.

1. Introduction

A horizontal well is the one drilled with a deviation -from the vertical axis- of more than 80° (Lacy et al., 1992). It was noticed since the nineties of the past century that there is a growth in the use of horizontal wells for their advantages; including increasing the well's productivity, increasing oil recovery, their usefulness in reviving noncommercial reservoirs (El-Sayed, 1991; Wang et al., 1993; Al-Obaidi and Ahmed, 2023), and their role in reducing coning risks in addition to delay water breakthrough (Altaher et al., 2023). For these reasons, researchers tend to keep in their minds horizontal well utilizing when conducting various studies, as noticed in Kareem and Almahdawi's recent study (2023).

Productivity index (J) is an indication of the well productive capacity during the pseudo-steady state which is reached after a sufficient production period of time (Jahanbani and Shadizadeh, 2009). Estimating (J) when a new field is developed is of great importance to determine the production potential of the well and predict its deliverability (Al-Otaibi et al., 2012). Hence a productivity index ratio (J_h/J_v) determination is essential to compare between the productivities of the two types of well. Overview of

several (J_h/J_v) gathered from different studies made over the years, clarifies the enhancement in productivity when using horizontal wells compared to vertical wells, as shown in (Table 1).

Table 1. Productivity Index Ratios Reported in Literature

J_h/J_v	Comment	Reference
2 - 6	In 100 ft thick reservoirs, when vertical wells are not stimulated	(El-Sayed, 1991)
2.5 - 7	In a field in North America	(Lacy et al., 1992)
10	Average for 7 horizontal wells in a field in the Middle East	(Chen, 1993)
3 - 6	Where “3” is in thin reservoirs with gas cap and aquifer	(Wang et al., 1993)
3	In a field in the Middle East	(Ishak et al., 1996)
1.8 - 2.3	The value changes depending on well location	(Al-Otaibi et al., 2012)
1.5 - 5	Approximation. In a field in Iraq	(Alsodani et al., 2013)

The productivity enhancement observed when using horizontal wells, compared to vertical wells, is due to the larger contact area between the wellbore and the reservoir (Permadi, 1995). With the larger contact area, drainage area increases and the sweep efficiency may improve (Thomas et al., 1996), in addition to lowering the drawdown pressure required to produce a certain amount of hydrocarbon, which ultimately enhances the oil production rate (Q_o) and recovery (Novy, 1995; Lu et al., 2013).

Various reservoir, fluid, and well parameters, affect the productivity and deliverability of the horizontal well, including reservoir pay thickness, vertical permeability, the reservoir fluids properties, horizontal well length and well diameter (Shedid and Zekri, 2001; Vicente et al., 2003).

Thin oil columns usually have low permeability-thickness value, which results in very low production rates, hence hydraulic fracturing was long used to stimulate such reservoirs and increase the oil production, but managing the height of fractures accurately might be a problem itself in some cases, resulting in failure to achieve a sufficient oil production, but horizontal wells are able to achieve the targeted production if the formation thickness is enough for them to be drilled (Garroucha et al., 2004). With the increment in reservoir vertical permeability, horizontal well productivity increases (Lacy et al., 1992; Ling et al., 2012).

The horizontal well productivity is highly dependent on well length, as it increases proportionally to the length of the lateral section (Lacy et al., 1992; Menouar and Huang, 1993; Wang et al., 1993). Also, increasing the wellbore and tubing diameters increases (Q_o) (Tian et al., 2002; Ling et al., 2012); as larger well diameters reduce the frictional pressure drops, hence increasing (Q_o), but the high cost of tubing presents a limit to be considered when selecting the optimum tubing diameter (Tian et al., 2002).

Vertical lift performance (VLP) represents the flow capability of a well to deliver liquid from the bottomhole to the surface, and it is essential, alongside the inflow performance relationship indicated by J , to predict the optimum well (Q_o) (Jabbar and Alnuaim, 2013). Some parameters affecting the VLP through the tubing geometry are: tubing diameter, tubing roughness, and tubing length; which is related to reservoir depth in both: vertical wells and openhole horizontal wells (Aziz et al., 1999).

(Q_o) is reduced when the pressure drop inside the wellbore is increased. The pressure drop is composed of three terms: frictional term, flow acceleration term, and gravity term (Saavedra and Reyes, 2001). Most attention is given to the frictional term as it is the pressure loss that can be decreased by optimizing the well parameters (Adesina et al., 2016), despite the fact that the gravity term has the highest contribution to the total pressure drop compared to friction and other wellbore hydraulics (Yildiz and Ozkan, 1998).

Although a success rate as high as (95%) in increasing the (J) in any reservoir is achieved by using horizontal wells (Adesina et al., 2016), the horizontal wells usually cost more than vertical wells, indicating that economic success is not as high. In fact, at the turn of the new century, only (54%) of horizontal well projects were economically successful (Cho, 2001), but this percentage increased to (65%), at least in the United States, after around (15) years (Temizel et al., 2015). To increase this

percentage, well costs must be studied carefully and high production rates for long periods of time must be achieved when using horizontal wells (Osisanya, 1997).

Economic evaluation of drilling a new oil well, should include studying the following parameters: revenue depending on (Q_o) and oil price, capital costs (CAPEX) or initial investment for well drilling and completion, and operating costs (OPEX) or money spent during the project. All of these components should account for the time value of money (TVM), and all of them, except the CAPEX, should account for the period of oil production to calculate the total revenue and expenditures, and determine the net profit (Orodu et al., 2012).

(CAPEX) represents the costs of drilling the well to the point of completion (Well Construction Cost), tubing, producing equipment, and separators (Ikwan et al., 2016). (OPEX), which includes the facility handling charges -for example-, is about the same for both vertical and horizontal wells, although the cost per barrel is generally lower in horizontal wells since their (Q_o) is generally higher (Joshi, 2003).

(Q_o) ratio should be compared with the well cost ratio of horizontal well to the vertical well, in order to determine the economic feasibility of using a horizontal well instead of a vertical well. Examples of the cost ratio reported in the literature are presented in (Table 2).

Table 2. Horizontal to vertical wells cost ratios

Cost Ratio (Horizontal Well \$/Vertical Well \$)	Comment	Reference
1.5 - 3	Onshore	(Lacy et al., 1992)
1.2 - 1.8	In the Middle East	(Ishak et al., 1996)
1.5	On average	(Osisanya, 1997)
1.4 - 3		(Cho, 2001)
1.5 - 2.5		(Joshi, 2003)
1.5 - 3		(Ling et al., 2012)
1.5 - 2.5	In the USA	(Temizel et al., 2015)

Kirkuk oil field, located in north-eastern Iraq, is selected as the area of the current study. It is composed of carbonate rock formed during the Late Paleocene to Early Eocene epoch (Assad et al., 2022), and consists of several formations including Khurmala Formation, which is first described by (Bellen et al., 1959), (Karim et al., 2018).

Since a relatively low (Q_o) of a vertical well (V1) in Khurmala is observed; due to several reservoir-related factors including low reservoir pressure, a horizontal well is designed with different well lengths simulated at different permeability ratios (k_v/k_h), to evaluate its effect on productivity and deliverability. Economic evaluation of the proposed horizontal well designs, in comparison with the drilled vertical well, is studied to determine the feasibility of the horizontal well length limit with different (k_v/k_h).

Another main objective of this work is to study the various reservoir, fluid, and well parameters for evaluating their effect on the deliverability of both the vertical and horizontal wells, in order to determine the importance of each, with different oil production rates. In addition to finding the minimum reservoir pay thickness at which a horizontal well becomes more feasible than the vertical well, with different lateral well lengths and (k_v/k_h).

2. Materials and Methods

The vertical well and the four cases of the horizontal well are modeled using the reservoir and fluid data provided in Table 3.

Table 3. Reservoir and Fluid Properties

Parameter	Value	Unit
Reservoir pressure	8.5	MPa
Reservoir temperature	322	°K
Bubble point pressure	8.4	MPa
Reservoir permeability	38.5	mD
Reservoir pay thickness	95	m
Reservoir area	0.2496	Km ²
Reservoir porosity	25	%
Oil gravity	35	API
Gas specific gravity	0.878	Dimensionless
Water cut	0	%
Rs	70	sm ³ /sm ³
Total GOR	70	sm ³ /sm ³

2.1. Software and Models

The drilled vertical well (V1) is simulated using Darcy and Vogel models in IPM-PROSPER software. Actual production data is used to select the most representative model. The same software is used to simulate the designed horizontal well (H1) with (dP) Friction Loss in Wellbore model, while No Flow Boundaries model is used to obtain (J) values, since it generates similar inflow performance relationship curve and (Q_o) results to those generated by (dP) Friction Loss in Well model.

2.2. Horizontal Well Design

H1 is designed to be placed in the middle of the reservoir with four different lateral lengths: 152, 305, 457, and 610 m. Each length is simulated in five different (k_v/k_h): 0.1, 0.2, 0.4, 0.7, and 1.0. Drainage area is calculated for each H1 as an average of the two equations 1 and 2.

$$A_D = \pi ab \quad (1)$$

$$A_D = 2Lb + \pi b^2 \quad (2)$$

Where (A_D) is drainage area (m²), (a) is half the major axis of the ellipsoidal drainage area (m), (b) is the drainage radius of the vertical well (m), and (L) is the lateral well length (m). (Table 4) shows the depths of the different sections of (H1).

Table 4. Horizontal well Design

Measured Depth (m)	Total Vertical Depth (m)
0	0
780	780
919	899
1011	952
1100	978
1100+L	978

2.3. Productivity Index and Production Rate Ratios

The J of V1 is calculated by PROSPER using equation 3, while equation 4 is developed by Goode and Kuchuk (1991) to calculate J in both dP Friction Loss in Wellbore and No Flow Boundaries models

of the horizontal well (Petroleum Experts Limited, 2010: p. 179). (J_h/J_v) is calculated for each case of well length and (k_v/k_h).

$$J = \frac{Q_o}{P_r - P_{wf}} \quad (3)$$

$$J = 7.08 * 10^{-3} \sqrt{k_x k_y} h / \mu B_o (P_{wD} + S_m^*) \quad (4)$$

Where Q_o is oil production rate (STB/day), P_r is reservoir pressure (P_{sig}), P_{wf} is flowing bottomhole pressure (P_{sig}), K_x is horizontal permeability in x-direction (mD), K_y is horizontal permeability in y-direction (mD), h is reservoir thickness (ft), μ is viscosity (cP), B_o is formation volume factor (bbl/STB), P_{wD} is dimensionless pseudo-steady state pressure, and S_m^* is Goode and Kuchuk skin factor.

Petroleum Experts 2 (PE-2), which was developed to combine the best features of other methods, avoiding some of their limitations (Pet. Experts Limited, 2010), is selected in PROSPER to generate the VLP curve. The optimum (Q_o) is determined for the vertical and different H1 cases, then the horizontal to vertical well (Q_o) ratio is calculated.

2.4. Parameters' Sensitivity Analysis

Studying the effects of different parameters on the well's deliverability is important as some of them can be changed by the well designer or altered with production time. The effect of six parameters on the well's deliverability is studied for V1 and three selected cases of the H1. These cases are 152 m, 305 m, and 610 m horizontal wells, in a reservoir with vertical to horizontal permeability ratio simulated as 0.2. Sensitivity analysis will be performed on the following parameters:

- Reservoir pressure: the original value is 8.5 MPa. It decreases naturally with production time, if no pressure maintenance means is used. New pressure values will be lower than the original reservoir pressure by: 1%, 5%, 10%, 20%, 30%, and 40%.
- Reservoir permeability: the original value is 38.5 mD. It can be increased through stimulation. New average horizontal reservoir permeability values will be higher than the original value by: 10%, 25%, and 50%.
- Water cut: the original value is 0%. It may increase with more oil production. New water cut values will be: 1%, 5%, 10%, 20%, 30%, and 40%.
- Total gas-oil ratio (GOR): the original value is 70 sm^3/sm^3 . In case of gas coning, for example, the total GOR will increase. New total GOR values will be increased by: 5%, 10%, 20%, and 50%.
- Tubing diameter: the original value is 2.992 in (76 mm). It is a part of the well design, changing it will provide an idea about its effect of the well's deliverability. The new values, which are used in different wells in Kirkuk field, will be: 2.44 in (62.0 mm), 3.958 in (100.5 mm), and 5 in (127.0 mm).
- Tubing roughness: the original value is 0.0006 in (0.015 mm). It changes with time, i.e., the age of the tubing. New values, compared to the original, will be: +10%, +50%, and +80%.

In addition to these six parameters, the importance of reservoir pay thickness is studied also, in terms of its effect of J and Q_o ratios.

2.5. Economic Evaluation

Economic evaluation is aimed for calculating the cost ratio of horizontal to vertical wells and compares it to the revenue ratio calculated from (Q_o) ratio. It considers different scenarios of well length and (k_v/k_h) for horizontal wells.

A well construction cost correlation is developed based on the data provided by (Lukawski et al., 2014) for onshore USA oil wells' average construction cost per foot against depth, which are listed in

Table 5. When plotted, and converted to meters, Fig. 1 is produced and equations 5 and 6 with a correlation coefficient (R^2) of 0.987 are constructed.

Table 5. Well construction cost data

Measured Depth (ft)	Measured Depth (m)	Cost per Foot (\$/ft)	Cost per Meter (\$/m)
1822	555.3	301	987.5
3102	945.5	249	816.9
4392	1338.7	267	876.0
6365	1940.1	435	1427.2
8673	2643.5	540	1771.7
11027	3361.0	621	2037.4
13602	4145.9	951	3120.1
16111	4910.6	1367	4484.9

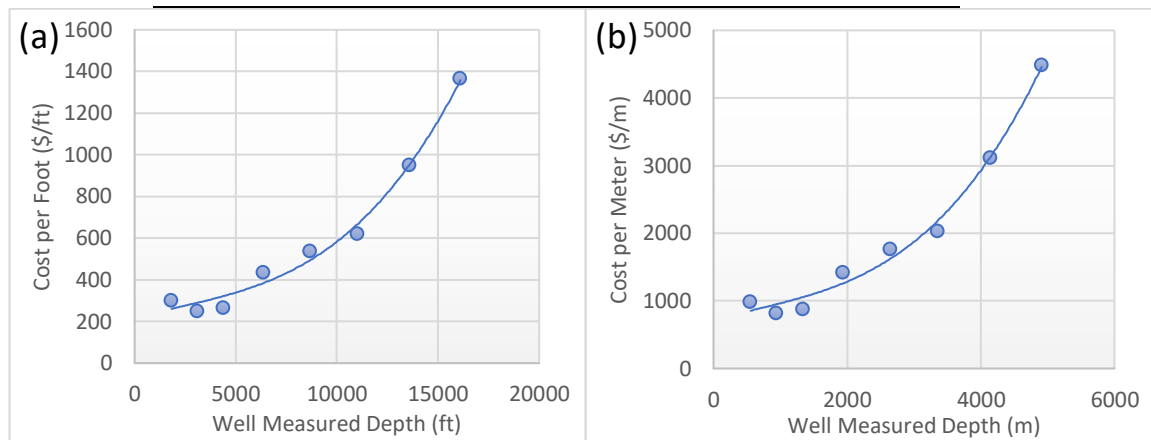


Fig. 1. Wells Constructing Cost vs. Well Measured Depth for Measured Depth in (a) ft, (b) m

$$CCPF = (3 * 10^{-10} MD^3 - 2 * 10^{-6} MD^2 + 0.0264 MD + 217.02) \quad (5)$$

$$CCPM = (3 * 10^{-8} MD^3 - 6 * 10^{-5} MD^2 + 0.2837 MD + 712.02) \quad (6)$$

Where CCPF is a construction cost per foot (\$/ft), (CCPM) is the construction cost per meter (\$/m), and MD is the measured depth.

When equation 6 is checked against the given data, an average relative error of 10.9% is found, as shown in Table 6, which is further reduced to 7.3% with measured depths above 1940 m, and to 4.8% with measured depths above 3361 m. These correlations are valid for depths equal to or less than 16111 ft (4910 m).

Table 6. Well construction cost correlation relative error

Well Measured Depth (m)	Reported CCPM (\$/m)	Calculated CCPM (\$/m)	Relative Error (Reported Cost-Calculated Cost)/Reported Cost
555.3	987.5	856.2	0.133
945.5	816.9	952.0	0.165
1338.7	876.0	1056.3	0.206
1940.1	1427.2	1255.6	0.120
2643.5	1771.7	1596.9	0.099
3361.0	2037.4	2126.8	0.044
4145.9	3120.1	2994.7	0.040
4910.6	4484.9	4210.8	0.061
Average Relative Error:			0.109

The oil well construction cost is calculated by equation 7, which takes into consideration cumulative inflation (24%) and country correction factor (CC).

$$\text{Oil Well Construction Cost} = (CCPM * MD) * 1.24 * CC \quad (7)$$

CC depends on published data for Iraqi fields, and can either be assumed as 1 or adjusted to 0.86 depending on the average of numbers provided by Hussein et al. (2021).

In this research, the well cost is calculated for all studied cases using the following methods:

- Well construction cost using equation 7 with CC=1.
- Well construction cost using equation 7 with CC=0.86.
- Well construction cost using Questor software with considering the (TVM), i.e., a cumulative inflation of (12.24%).
- Total well cost using Questor, which includes used material cost and equipment cost, in addition to well construction cost.

The economic feasibility of the cases of H1 compared to V1 is determined using the ratio of horizontal to vertical well (Q_o) ratio and horizontal to vertical well cost ratio, for each case, i.e., the feasibility ratio. In addition to the feasibility ratio, net profit in US dollars is determined by considering both the revenue and the total well cost which includes all used equipment, material, and moreover the construction cost, i.e., CAPEX, with applying the inflation rate correction. Questor is used to make this calculation, and net profit is calculated for V1 and the 4 cases of the H1.

A range of 60 - 70 \$/bbl (377 – 440 \$/m³) is assumed as the price of Kirkuk field oil unit volume (barrel or cubic meter) minus (OPEX) per unit volume (barrel or cubic meter). This number includes the TVM over the studied period of time, and constant (Q_o) is assumed for the studied period of time, which is 3 years.

3. Results

3.1. Vertical Well Models' Results

(V1) is simulated using two models: Vogel and Darcy. Table 7 shows the error percentage of the two models compared to the actual flow rate (Actual Q_o). Darcy model generates the least error percentage (0.21%) hence it is selected to be used in further calculations related to V1.

Table 7. System Performance Results and Comparison

Model	P_{wf} (MPa)	Q_o (m ³ /s)	Error (%)	Actual Q_o (m ³ /s)	Actual P_{wf} (MPa)
Vogel	5.02	0.00419	1.11	0.00414	5.07
Darcy	5.01	0.00415	0.21		

3.2. Horizontal Well Model's Results

The drainage area and square reservoir side length for each H1 length are calculated, and the results have been tabulated in Table 8.

Table 8. Horizontal well's drainage area and dimensions

Well Length (m)	Side Length of a Square Reservoir (m)	Drainage Area (km ²)
152	572	0.3273
305	635	0.4040
457	693	0.4808
610	747	0.5576

Longer (H1) results in higher productivity indices and (Q_o) with all (k_v/k_h). These results are shown in Fig. 2. This increment is generally higher when the k_v/k_h is lower, as doubling the well length results in increasing J by an average of around 1.86 with $k_v/k_h = 0.1$ and 0.2, compared to an average of 1.83 and an average of 1.82 with $k_v/k_h = 0.7$ and 1.0, respectively. Doubling H1) length results in increasing Q_o by 1.57, 1.50, 1.37, and 1.34 with $K_v/K_h = 0.1, 0.2, 0.7$, and 1.0, respectively.

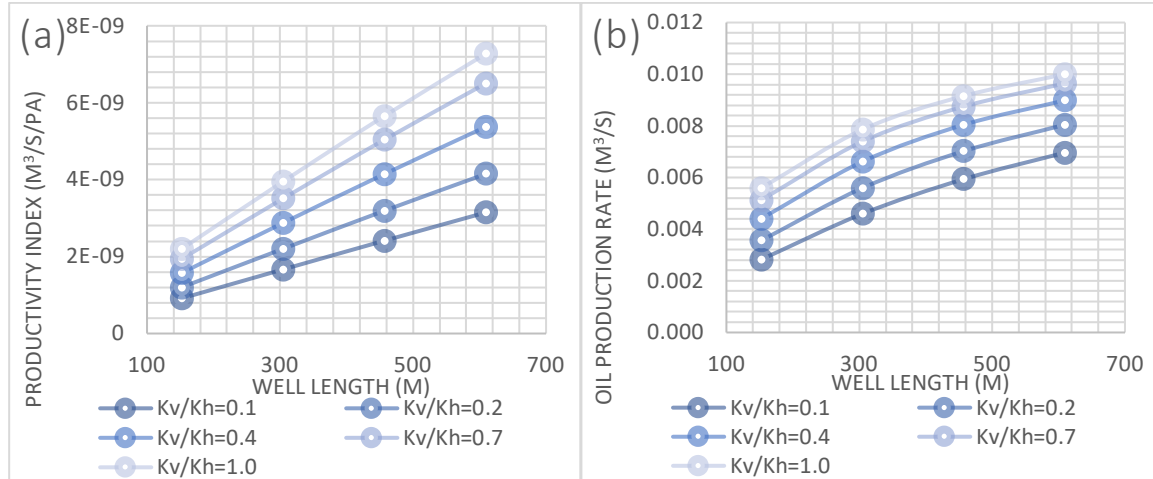


Fig. 2. Effect of Horizontal Well Length on (a) Productivity Index ($m^3/s/Pa$), (b) Production Rate (m^3/s)

3.3. Productivity Index and Production Rate Results Comparison

The effect of each H1 length on J and Q_o compared to those of V1, is shown in Fig. 3, for the different (k_v/k_h) ratios. At a (k_v/k_h) of 0.1, the J_h/J_v is generally low, especially with short H1. In fact, the J ratio is less than 1 when the well length is 152 m, for k_v/k_h of 0.1 and 0.2; hence V1 has a higher J than H1 in these cases. When the well length exceeds 244 m, the J ratio becomes larger than 1 for both cases. With larger well lengths, the J ratio reaches 2.1 to 3.9 for 0.4 k_v/k_h , and up to 5.2 for 1.0 k_v/k_h .

It is shown, also, that the effect of k_v/k_h is more severe when Q_o ratio is studied, compared to studying the J ratio. The Q_o ratio is only 1.7 and 1.9 compared to 2.3 and 3.0 J ratio, for 610 m (H1) length with 0.1 and 0.2 k_v/k_h , respectively. Also, the highest (Q_o) ratio is only 2.4, compared to the corresponding (5.2 J) ratio.

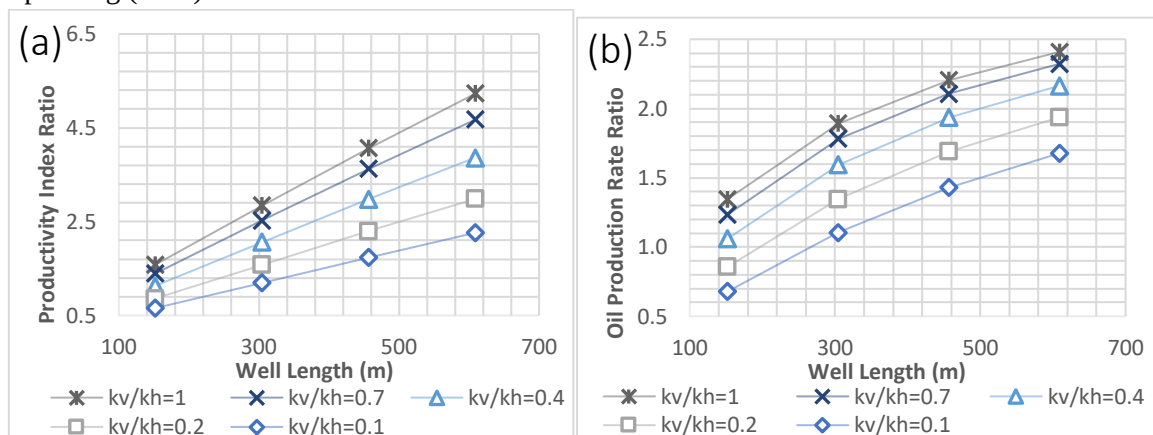


Fig. 3. Effect of horizontal well length on (a) Productivity Index Ratio, (b) Production Rate Ratio

The increased production rates, using H1, are accomplished with lower drawdown pressures, as shown in Fig. 4. A 610 m well drilled in a reservoir with ($k_v/k_h = 1$) will require 0.41 the drawdown pressure required by V1, to produce 2.41 folds what V1 produces. A well with moderate length drilled

in a moderate permeability ratio reservoir, e.g., 305 m drilled in 0.4 k_v/k_h , requires 0.72 of V1's drawdown pressure to produce 1.59 Q_o of the latter.

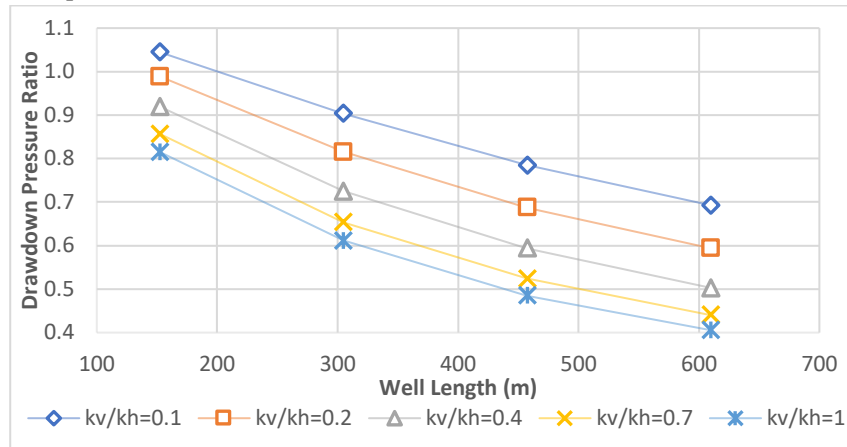


Fig. 4. Effect of horizontal well length on drawdown pressure ratio

3.4. Effect of Reservoir Pay Thickness on J and Q_o Ratios

The effect of reservoir pay thickness is one of the main parameters related to productivity enhancement achieved by H1, compared to V1.

Fig. 5 shows that the J_h/J_v is above 1, for all the studied cases, at a reservoir pay thickness less than or equal to 59 m, leading to the conclusion that horizontal wells are more feasible in thin reservoirs. However, in the studied cases, a horizontal well length of 305 m or more is feasible in any reservoir pay thickness up to 95 m and k_v/k_h equals or greater than 0.1. The J ratio increases with both: (H1) length and (k_v/k_h).

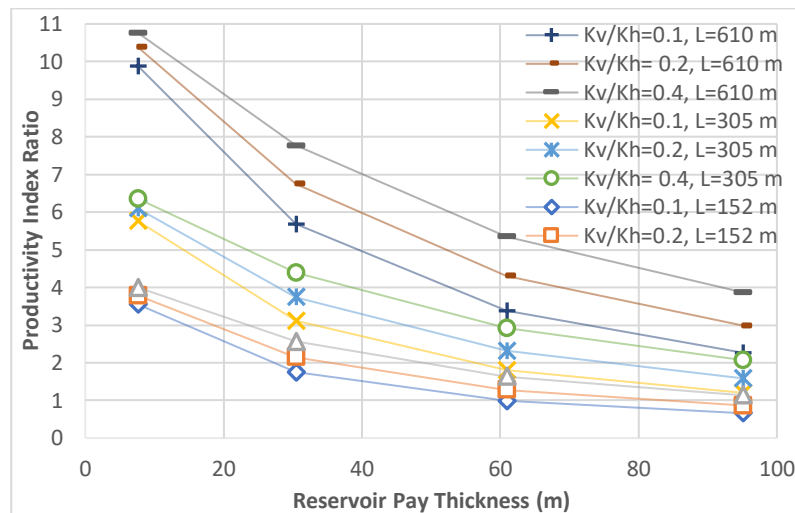


Fig. 5. Effect of Reservoir Pay Thickness on Productivity Index Ratio

Fig. 6 shows that Q_o ratio, similarly to the J_h/J_v , has an inversely proportional relationship with reservoir pay thickness, and a directly proportional relationship with H1 length and k_v/k_h .

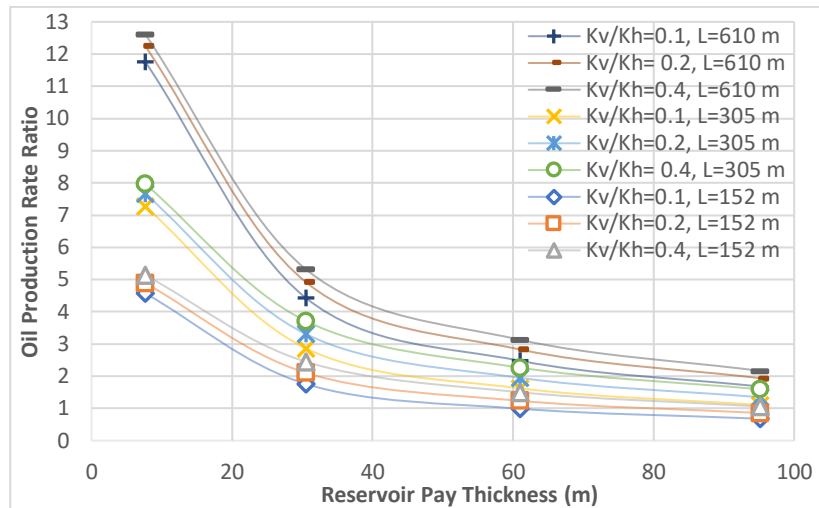


Fig. 6. Effect of Reservoir Pay Thickness on Production Rate Ratio

3.5. Sensitivity Analysis Results and Comparison

Q_o is affected by different reservoir, fluid, and well parameters. The influence of 6 parameters is studied for 4 different cases: vertical well ($Q_o = 0.00415 \text{ m}^3/\text{s}$), 152 m horizontal well ($Q_o = 0.00356 \text{ m}^3/\text{s}$), 305 m horizontal well ($Q_o = 0.00559 \text{ m}^3/\text{s}$), and 610 m horizontal well ($Q_o = 0.00804 \text{ m}^3/\text{s}$). The horizontal wells are simulated with $0.2 k_v/k_h$.

3.5.1. Reservoir pressure sensitivity analysis

As the reservoir pressure reduces with production time, (Q_o) decreases. In low potential systems (V1 and H1 with 152 m length), oil production ceases when the reservoir pressure is reduced by a range of 30% to 40% from the original value. In higher potential systems, (Q_o) will decrease by up to 75.9 to 78%, as shown in Fig. 7. Changing 1% of the original reservoir pressure may result in a change of Q_o that ranges between 1.9 to 2.6%. Lower values correspond to higher system's potentials.

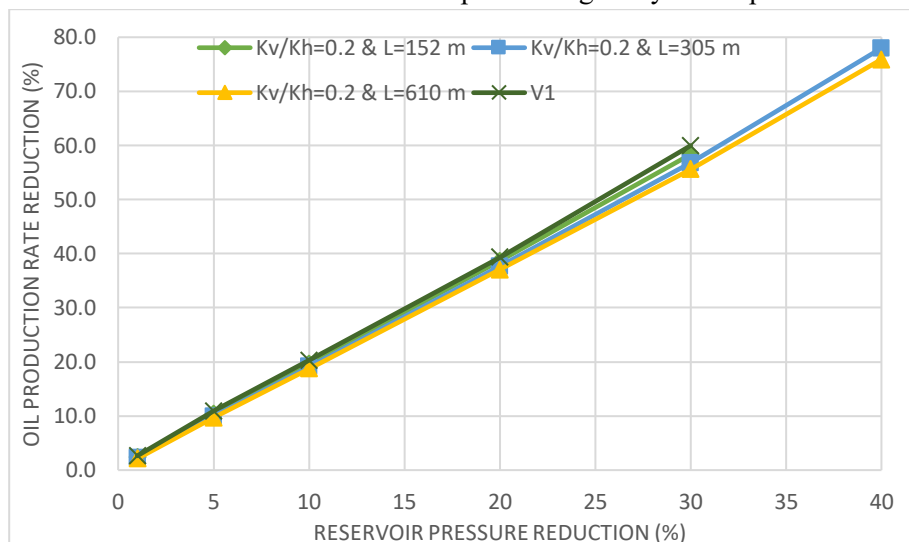


Fig. 7. Reservoir pressure sensitivity analysis

3.5.2. Permeability sensitivity analysis

Fig. 8 shows that increasing permeability increases (Q_o), due to higher rock ability to transmit fluids. (50%) increment in permeability may result in (18 to 38.7%) increment in Q_o . When the

permeability is increased by 1%, the oil (Q_o) increases by a range of 0.4 to 0.9%. The effect of changing the permeability is more critical in V1 and in low flow rate horizontal wells compared to high flow rate horizontal wells, as higher changes in Q_o correspond to lower systems' potential.

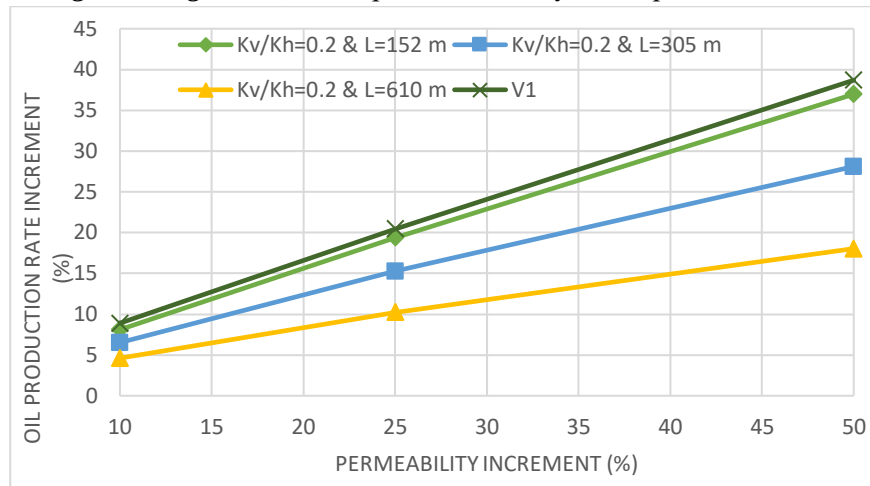


Fig. 8. Permeability sensitivity analysis

3.5.3. Water cut sensitivity analysis

Water cut increments decreases both the liquid rate and the Q_o . Fig. 9 shows that the increment in water cut has a critical effect on Q_o . When the water cut is 1%, (Q_o) is reduced by 1.3, 1.3, 1.4, and 1.6% for the cases of V1 and H1 with $L=152, 305$, and 610 m, respectively, and when the water cut is 40%, the reductions in Q_o for these cases are 55, 58, 56, and 55%. In general, the effect of water cut is more prominent in horizontal wells with higher Q_o , while V1 is more resistant to the increment in water cut.

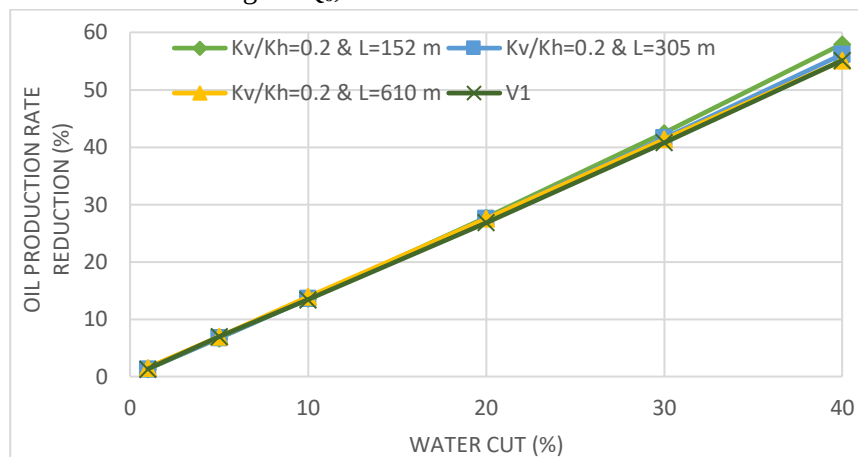


Fig. 9. Water cut sensitivity analysis

3.5.4. Gas-oil ratio sensitivity analysis

The bottomhole pressure decreases with higher GOR values. This causes the Q_o to be increased as shown in Fig. 10. When GOR is increased by 50%, an increment between 11 and 12.4% will occur in the horizontal wells' Q_o . Higher values were corresponded with shorter well lengths. This increment is 12.9% in V1. Increasing GOR by 1% results in an increment in Q_o ranges between 0.2 and 0.4%.

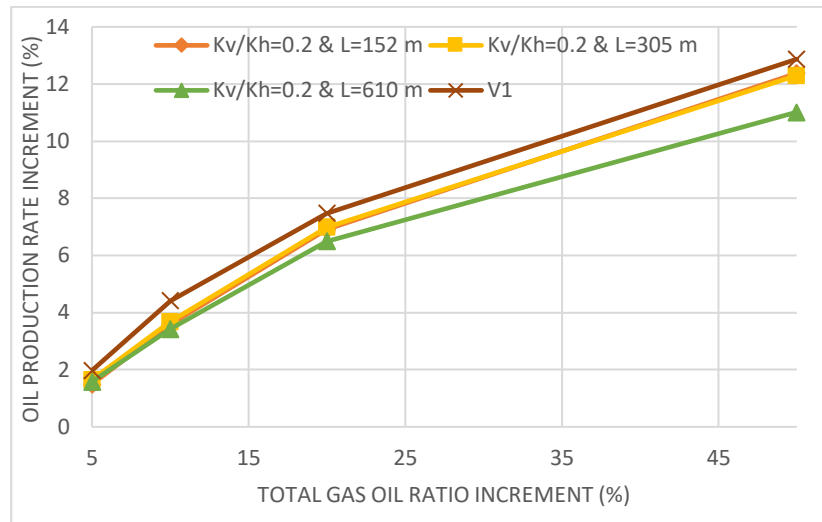


Fig. 10. Total gas oil ratio sensitivity analysis

3.5.5. Tubing size sensitivity analysis

Using new tubing inner diameter, which is smaller than the original diameter, results in a reduced Q_o , and vice versa, as shown in Fig. 11. Increasing the tubing size by 67% results in an increasing Q_o by 19.3, 17.0, 32.9, and 63.5% for V1, H1 with $L=152$, 305, and 610 m, respectively. Changing the tubing size by 1% results in 0.3% to 1.6% change in Q_o .

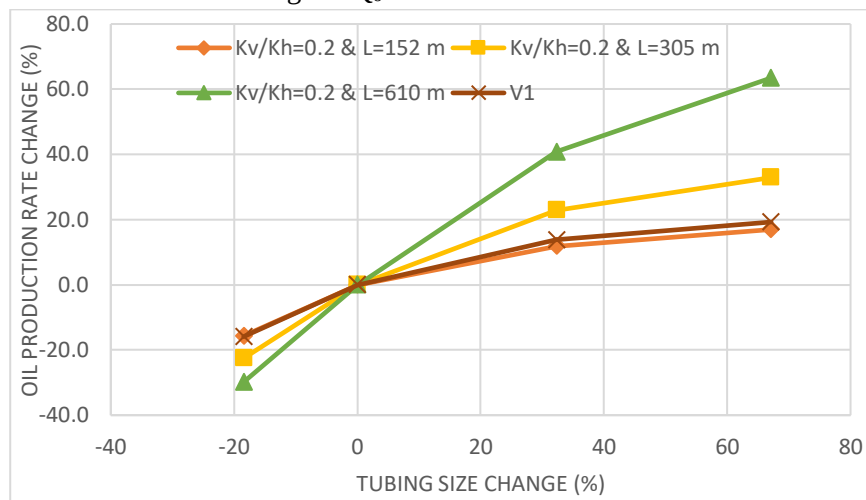


Fig. 11. Tubing size sensitivity analysis

3.5.6. Tubing roughness sensitivity analysis

The relationship between roughness and Q_o is inversely proportional, as shown in Fig. 12. The effect of roughness on Q_o is minimal to the degree that changing 1% of the original roughness value will result in a change in Q_o of only 0.0016% to 0.0141%. Tubing roughness increment results in more frictional pressure drops; hence less Q_o , in all cases, and its effect increases with higher flow rates.

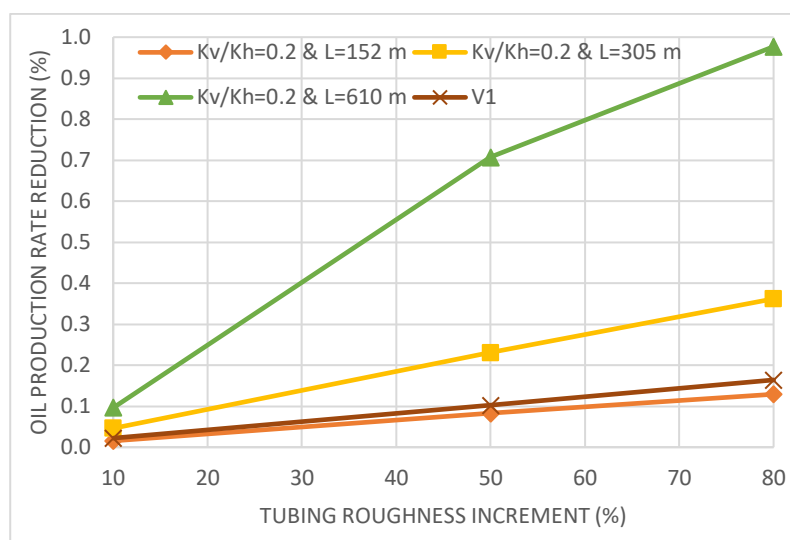


Fig. 12. Tubing roughness sensitivity analysis

3.5.7. Summary of parameters' sensitivity analysis

By comparing Fig. 7 through Fig. 12, it can be shown that when the effect of changing 1% of the parameter's original value on Q_o is studied, the most influential parameters are found to be reservoir pressure, tubing size, permeability, (GOR), and tubing roughness, respectively. Water cut will be the second most influential parameter if the water cut percentage is considered as a percentage of change from the original value.

Also, it is noticed that V1 is more susceptible than H1 when permeability and GOR are changed. In general, wells with higher system potential are less affected by changes in reservoir pressure, permeability, and GOR, while they are more affected by changes in water cut, tubing size, and tubing roughness.

3.6. Economic Evaluation

The costs and feasibility ratios are calculated for V1 and all cases of H1. Revenues and net profits are calculated for V1 and 4 cases of H1 with k_v/k_h of 0.2.

3.6.1. Well cost

Equation 7 is used for calculating the costs of the well construction cost with two country correction factors, in addition to using Questor software with two approaches. Fig. 13 shows the well costs for the 4 cases using the 4 different approaches, and the horizontal to vertical well cost ratio.

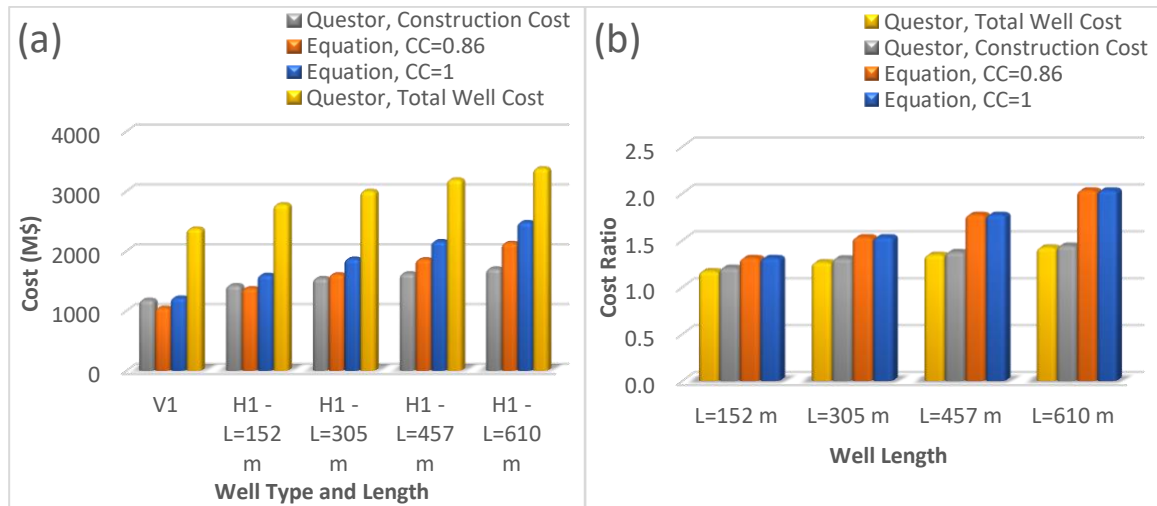


Fig. 13. Well (a) Cost (M\$), (b) Horizontal to vertical cost ratio

It is shown that V1 costs are less than those of the 4 cases of H1, since the measured depth of V1 is less than that of the latters. The well construction cost of V1 ranges between 1.05 MM\$ to 1.22 MM\$, compared to ranges of 1.38 MM\$ to 1.60 MM\$, 1.55 MM\$ to 1.87 MM\$, 1.63 MM\$ to 2.17 MM\$, and 1.71 MM\$ to 2.48 MM\$, for the cases of horizontal wells with $L = 152, 305, 457$, and 610 m, respectively. Total well cost is around (1.49) folds the well construction cost that is calculated by Questor. Comparing the well construction costs calculated by equation 7 with $CC=1$ and those calculated by Questor results in an average difference of (23%), while using $CC=0.86$ reduces that difference to (12%). Equation 7 with $CC=1$ gives higher estimations than those given by Questor for the well construction cost. The horizontal to vertical well cost ratio ranges between (1.31 to 2.03) when equation 7 is used, (1.21 to 1.44) when Questor is used to calculate well construction cost, while 1.17 to 1.42 when Questor is used to calculate total well cost.

3.6.2. Feasibility ratio

It is recommended to drill a horizontal well when the feasibility ratio is above 1, since Q_o increment will be higher than the cost increment compared to V1. Fig. 14 shows the feasibility ratios with different well lengths and k_v/k_h based on the calculations using equation 7 and using Questor. With reservoir (k_v/k_h) of 0.1 and 0.2, V1 is more feasible than H1 for all well lengths, and with k_v/k_h of 1.0, H1 is more feasible than V1 for all well lengths, while the feasibility limits for $k_v/k_h = 0.4$ and 0.7 are 278, and 191 m, respectively, when using the equation.

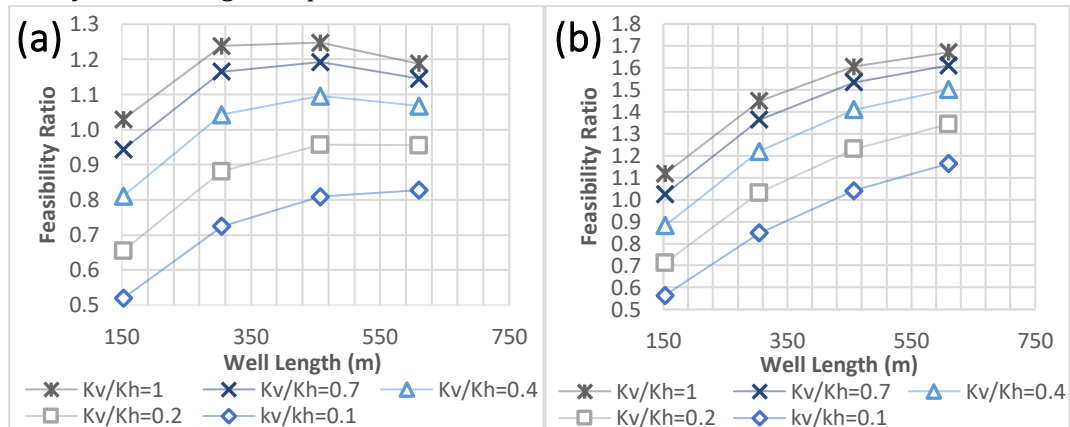


Fig. 14. Feasibility ratio using well construction cost (a) Equation, (b) According to Questor

When calculating the well construction cost using Questor, a feasibility ratio of more than 1.6 is achieved, as shown in Fig. 14 above, with using the horizontal length of 610 m drilled in reservoir with $k_v/k_h = 0.7$ and 1. The feasibility limits are 427, 290, and 207 m for $(k_v/k_h) = 0.1, 0.2$, and 0.4 respectively.

Fig. 15, on the other hand, shows the feasibility ratio vs. well length for different reservoir permeability ratios, but it calculates the cost as total well cost. This method's results are probably more realistic, but are certainly more optimistic compared to the other methods. Fig. 15 shows close resulting curves to those shown in Fig. 14.b; as they are both plotted using Questor, instead of equation 7. However, the feasibility limits observed from Fig. 14.b are slightly less than those observed in Fig. 15.

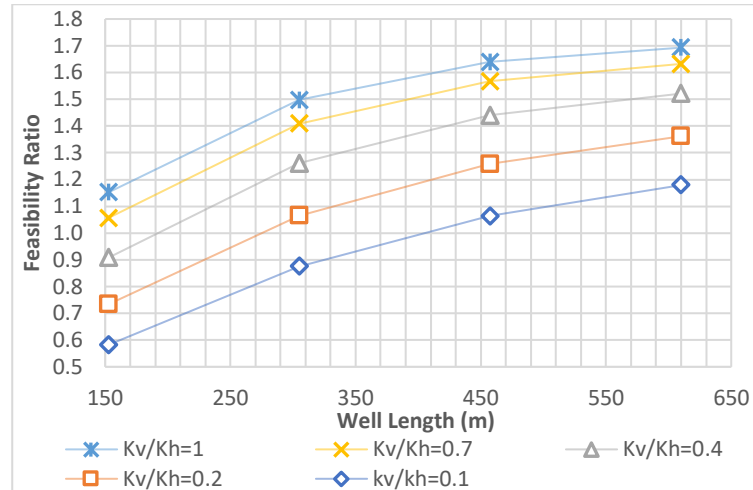


Fig. 15. Feasibility ratio using total well cost by questor

Feasibility ratio results show that the economic feasibility of horizontal wells is directly proportional to both well horizontal length and reservoir (k_v/k_h) , for a given reservoir pay thickness.

3.6.3. Net profit

Fig. 16 shows the net profit that is generated by V1 and 4 cases of H1. The maximum net profit is generated when 610 m long well is used, although considerably high profits are generated from 305 and 457 m long wells, as well. (H1) with length given between 152 and 305 m will generate more profit than that generated by (V1), when the (k_v/k_h) is 0.2. The high costs of relatively long horizontal wells drilled in relatively low (k_v/k_h) reservoirs, are fairly justified by the profit numbers provided; as they range between 283.8 million US\$ and 331.7 million US\$, depending on the price of oil, in only three years. This profit is 1.9 folds the profit generated by V1 in the same period.

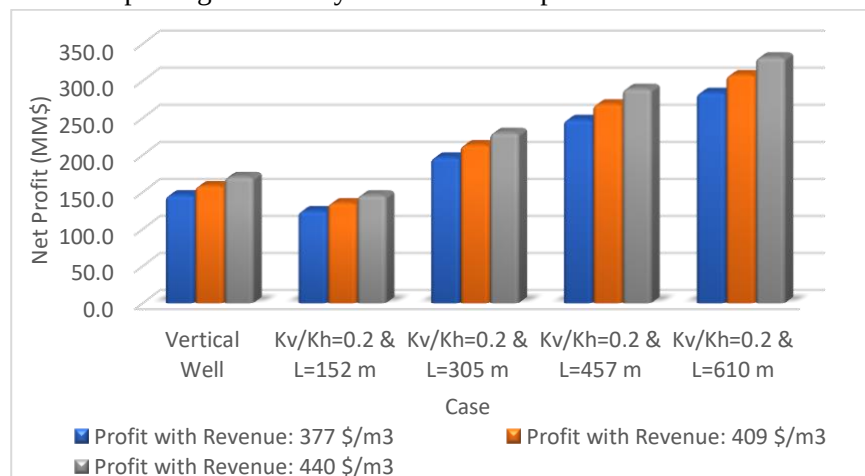


Fig. 16. Net profit

4. Discussion

Relating H1 length with k_v/k_h shows that when one of them has a higher value, the effect of the other on J and Q_o will be less; because both the H1 length and the k_v/k_h contribute to the production system's potential. When both parameters are low, the J ratio is less than 1; hence V1 has a higher J than H1 in these cases. The reason behind that is the fact that the (H1) productivity depends highly on the vertical permeability, due to its geometry, while V1's productivity depends more on the vertical permeability.

The highest (Q_o) ratio is found to be only (2.4), compared to the corresponding 5.2 (J) ratio. This lower ratio is due to the fact that (H1) is longer than (V1), even without its lateral section, that is because of its extended deviated length, hence it is affected by higher pressure drops. Still, higher (Q_o) is achieved using (H1) even with lower drawdown pressure, compared to (V1). Lower drawdown pressure is preferable as it results in delayed water and/or gas coning (Menouar and Hakim, 1995; Altaher et al., 2023).

When the effect of the pay zone thickness is studied, it was found that horizontal wells are more feasible in thin reservoirs, as V1's potential is reduced with less thickness, while the horizontal length compensates for this reduction in horizontal wells.

In low potential systems, it can be seen that the oil production terminates when the reservoir pressure is reduced by a range of 30% to 40% from the original value, and that is because the drawdown pressure will not be enough to produce oil from the well, while higher potential systems of longer horizontal wells withstand this reduction.

As the water cut increases, the Q_o is reduced due to lower liquid production rate and higher percentage of water in the fluid's mixture, while liquid production rate is reduced due to higher bottomhole pressure; because of the increasing amounts of water (heavier than oil) in the fluid's mixture in the well resulting in higher gravity pressure drop. Higher GOR ratio has the opposite effect, since it causes the bottomhole pressure to decrease due to less fluid column weight in the wellbore because of less fluid density.

The effect of changing the tubing size is directly proportional to the magnitude of the original (Q_o), as larger diameters will reduce the frictional pressure losses significantly, and more effectively when the flow rate is higher. The same effect is noticed with tubing roughness, as the relationship between tubing roughness and friction pressure loss is directly proportional as well and hence the relationship between roughness and Q_o is inversely proportional.

From an economic perspective, it can be noticed that the horizontal wells cost is found to be more than the vertical wells, but they generate higher revenue. Higher profits reaching up to (1.9) folds, result from relatively long horizontal wells drilled in relatively low (k_v/k_h) reservoirs, compared to the vertical wells.

5. Conclusions

Horizontal oil wells have been successful in increasing the productivity in many cases, depending on a combination of factors, but their cost, compared to the cost of vertical wells, limit their economic success. In this paper, a producing vertical well is simulated using PROSPER software alongside a designed horizontal well with four different well lengths simulated in five different (k_v/k_h), to study the feasibility of horizontal wells in terms of productivity and economics.

Three major parameters should be considered when proposing the horizontal well; reservoir thickness, k_v/k_h , and well length. Increasing both the H1 length and k_v/k_h was found to be extremely influential in increasing the J of the well and its Q_o . V1 has a higher J than H1 when the k_v/k_h is 0.1 and the well length is less than 244 m in a reservoir pay thickness of 95 m, and the J_h/J_v will not be higher than 1 unless the reservoir thickness is less than 59 m. With longer wells and higher k_v/k_h , the J and Q_o

ratios reached 5.2 and 2.4 respectively. The latter is achieved with a drawdown pressure ratio of only 0.41, delaying coning. The most influential parameters affecting (Q_o) were reservoir pressure, tubing size, permeability, GOR, and tubing roughness, respectively. Water cut might be the second most influential parameter in some calculation methods. Also, horizontal wells with length of 305 m and more were found to be less affected by changes in reservoir pressure, permeability, and GOR, compared to V1, and shorter horizontal wells. To achieve economic success, both the productivity of the well and its cost should be calculated. This paper used a developed correlation and Questor software to calculate the well cost. Feasibility ratio is calculated for all proposed cases of H1 with four different approaches and it was found that the developed correlation provides the most pessimistic numbers, hence it can be used to estimate the worst-case scenario results, while total well cost using Questor provides more probable results. Well cost ratio ranged between 1.17 to 2.03, and when compared with the Q_o ratio through the feasibility ratio, it was found that a feasibility limit of a minimum horizontal well length is necessary to be calculated for a given k_v/k_h and reservoir pay thickness, in order to achieve economic success. The net profit generated by a horizontal well with length of 610 m simulated in 0.2 k_v/k_h reservoir is 1.9 folds the net profit generated by a vertical well, in three years, indicating the high feasibility of using horizontal wells over vertical wells, when essential factors are taken into consideration.

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