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Optimum horizontal well length considering reservoir properties and drainage area

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ABSTRACT

The length of a horizontal well increases and so does its drainage area. The efficiency of the long horizontal well is no longer proportional to the length of the well, since the rise in the length of horizontal well output segment also tends to causes frictional pressure losses in the well. Nevertheless, there are currently no reliable standards which take into account quantitatively the parameters necessary to determine the optimum well length of horizontal drilling.
A new strategy to the basic productivity index is introduced, taking into account the friction losses under influx conditions in a long manufacturing segment. The consequence of this special productivity index is the constant state flow in an anisotropic structure of a very compressible fluid. This paper presents a technique developed to achieve an optimum length of horizontal pool based on the shift in the overall economics and productivity index (PI) in the long horizontal wellbore with frictional loosing results. In order to achieve optimal overall efficiency in a horizontal well project, an integrated method is proposed for numerical analysis of the parameters that affect profitability using Computer Modelling Group reservoir simulation (CMG).

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1. Introduction

The horizontal wells are the oil or gas wells drilled at an angle of at least eighty degrees to the vertical well. This technique has become increasingly common and efficient typically directional drilling in recent years [6], [9]. It is used by operators to extract oil and natural gas in situations where the reservoir shape is anomalous or difficult to handle. Horizontal wells are an alternative approach for oil and natural gas drilling when vertical wells don't produce enough oil or are not possible. Drilling can hit targets at some non-vertical angle and stimulate reservoirs in aspects that sometimes a vertical well can't. In combination with hydraulic fracturing, previously ineffective rocks can also be used as gas sources. Instances of such types of containers include formations that involve shale gas or gas. The development of horizontal exploration was the most important phase in establishing the ability to extract shale gas from shale [4].
Relatively low permeability shale can produce wide variety of natural gas. To optimize horizontal well output, it is required to govern the optimum direction and the length of horizontal well that enhanced the recovery of the natural gas field at a specific constant flow rate. In the sense of the general technique of directing the horizontal well towards the least significant stress of the rocks, this study considers the geomechanically effects that influence the efficiency of the gas output. In addition, the horizontal well drainage area will be considered for optimum horizontal well direction and length in this analysis. Thus, a new theoretical objective function for Genetic Algorithm (GA) was built on the basis of basic reservoir properties (i.e. permeability, porosity, and saturation of gas) as well as geomechanically properties that included Poisson 's ratio and Young’s modulus [10].

To unit, the determination of the optimum horizontal well path and length has generally been carried out using the traditional test-and-error procedure, when placing the coordinates in a geological or reservoir model and then running with a simulator to retrieve the natural gas; this process involves expertise, considerable time and a fairly high cost . Particularly when dealing with oil or gas fields of relatively large scale, it is faced with the possibility of a surprisingly large number of solutions (well locations) that make traditional approaches impractical and unreliable [7], [8]. Generally, the expended test and error procedures must be carried out in order to achieve an optimal output situation in the prediction of stock reservoir results. It consumes quite a lot of extra time and expense adding several case sensitivities to the improving scenario with the process of trial and error. Essentially, a longer horizontal well part would lead to a higher extraction of natural gas [11], [13].

However, after some duration, optimizing the horizontal well depth causes the peak time and the recovery factor (RF) of the reservoir will drop. The most outstanding aspect is that abandoned fields and old fields can be revived to drill the remaining oil in the reservoir and restore the old oil field production. In the meanwhile, this could take advantage of the initial field, the initial upper well and the original oil and natural gas pipeline, which will save substantial investment [15].

There is a significant pressure drop below the wellbore on a vertical well. This wide decrease in pressure triggers coning. Consequently, the coning can be avoided or reduced by reducing the pressure drop in the immediate area of the well. Nonetheless, a decrease in the pressure level cannot be accomplished without a corresponding decrease in a production rate, that in many cases is not valid economically. Horizontal wells have a way of reducing pressure reduction while preserving oil output levels. In general, the horizontal well is one that is drilled parallel to the bedding plane, as opposed to the vertical well that intersects the layer plane at 90°. A horizontal well in this article refers to any form of wells that have deviated from the vertical well and extends significantly into the reservoir. They are builded to take advantage of the different benefits over traditional vertical wells. One such advantage, as described earlier, is to decrease coning patterns of horizontal wells [12].

In conclusion, horizontal wells have been widely used to reduce water / gas coning issues. Usage of horizontal well techniques has been widely utilized around the world to boost the recovery of hydrocarbon. At a low outflow, a horizontal well could have a greater oil and gas production potential compared to a vertical well. The critical rate can therefore be high in horizontal wells compared to vertical wells. they can also be used to minimized the rate of coning of gas in gas-cape-driven wells.

In 1990, Joshi [1] proposed a method for measuring the horizontal well drainage area, which clarified the relationship between the drainage area of vertical well and horizontal well. This due to estimating the vertical well drainage area in order to evaluate the drainage area of horizontal well assuming the cylindrical drainage area along the open hole and the half ball at the edge of each end, such as the healing and foot. By fact, however, hydrocarbon production has shown that much of the oil is extracted from healing, which shows the different shape of the drainage area.

Belhaj et all [2] have been implemented a method of estimating the horizontal well drainage area, which is relied on the material balance equation and the decline curve analysis in a single-phase flow, providing a variable of the recovery factor which is not always available for the early phase in the well-being of the reservoir.

During these days, The major purpose of drilling horizontal wells are to rise and maximize hydrocarbon production rate which conclude the ultimate recovery for more oil underground ,and the concept behind this is horizontal well gets more exposure than vertical well in term of drainage area which increase the productivity index(PI) (1) versus horizontal section length. However, In year 2004, Saudi ARAMCO in kingdom of Saudi Arabia replaced all of their vertical wells to horizontal wells with maintaining the same production rate in Ghawwar Field which this teqnique reduce the effect of water coning .However, well spacing will be affected specially in the horizontal well area development, the main issue being how to define the effective horizontal length (EHL) and effective drainage area (EDA) (2) from effective drainage volume (EDV) [17].

$$PI = \frac{Q_p}{P_d - P_{wf}} \quad (1)$$

Where, PI, Productivity Index.

Q_p, is the production rate of the chosen phase.

$P_{d,}$ is the pressure at the drainage radius.

$P_{wf,}$ is the bottom hole flowing pressure.

$$A_h = \frac{\pi\left(\frac{L}{2} + R_{ev}\right)(R_{ev})}{43560} \quad (2)$$

$A_{h,}$ Effective horizontal drainage area

L, Horizontal well length.

R_{ev}, Effective drainage radius.

In 1990, Dikken [3] addressed the consequences of pressure losses due to the highest flow rate in the long horizontal well. He defined the flow rate (3) in the reservoir with a precise productivity index (PI), that was the constant within the length of the unit. A volume balance around the well boundary eventually led to the differential equation that can be resolved for the flow rate profile along the well. It has been solved this issue logically for the infinite length of the horizontal well and statistically for the finite length of the horizontal well. Most of the investigative forecast model for horizontal well is indefinitely conductive, or the flow is consistent over the total well range.

$$q_w(x) = \frac{2\,J_s\,(x)\,\Delta P\,(L - x)}{\exp\,(L\sqrt{J_r\,(X)}\,R_s)} \quad (3)$$

q_w (x), Flow rate in the wellbore.

Js(x), Productivity index per unit length.

Jr, Areal productivity Index (PI).

L, Horizontal well length.

x, Distance along the well coordinator.

ΔP, Drawdown at the heel of the well.

R_S, Flow resistance of the well.

Novy [16] expanded Dikken 's research through establishing equations that included all single-phase oil and gas flows. Throughout the gas flow case, the non-Darcy flow term shall be included in the review. The basic flow models were adopted as a boundary-value equation. It has been resolved due to assuming steady-state condition and single-phase flow. In addition, improving Dikken's model applying the index of productivity by Landman [5] that can be altered over the wellbore. The index of productivity varies along the wellbore length through variation in density of perforation, fluid flow features and permeability of the rock. Estimating the optimums density of perforation, a long a horizontal well that provides constant specific inflow through the well has advanced novel methodology. As a result, reservoir properties and drainage area have considered a key role to improving productivity of hydrocarbon in a horizontal well.

2. Material and method

Water / or gas coning issues is mainly due to the movement of reservoir fluids towards a lower resistance, which is balanced by the fluids' tendency to maintain stability of gravity. Analysis of either gas or water can be flow. The production through the well will generate pressure gradients that reduce the gas/oil contact as well as increase the contact between water and oil in the immediate closed to the wellbore. The tendency of the oil zone to stay above the hydrocarbon field because of its lower density. The water due to its higher density will stay below the oil zone that is counteractive to these flow gradients. Such counterbalancing forces appear to bend gas-oil and water-oil contacts into a bell form, since there are basically three forces that can influence on flow distributions across a wellbore. These forces are: Gravity force, viscous force, capillary force.

Gravity forces are directed in a perpendicular direction, resulting from differences in fluid density. Thus, at any given time and point, there is an equilibrium among viscous and gravitational forces at points on and off the well completion interval. If the dynamic (viscous) forces close the wellbore increase the gravitational forces, the fluid would eventually break into a well which is named breakthrough time. Capillary forces typically have a marginal impact on coning and would be ignored.

Furthermore, it has been used Computer Modelling Group reservoir simulation (CMG) to identify the optimum horizontal well length due to alter perforation location in horizontal section. This has also taken in consideration effective of three forces on fluid flow in drainage area.

Table 1. Basic reservoir information

Geometry		
Radial extent	2,050 ft	
Radius of wellbore	0.25 ft	
Radial position of first block center	0.84 ft	
Number of radial	10 blocks	
Radial block boundaries, ft	0.25, 2, 4.32, 9.32, 20.17, 43.56, 94.11, 203.32, 439.24, 948.92 and 2050	
No. of layers	15	
Dip angle	0°	
Depth of top formation	9000ft	
Fluid & Rock properties		
Compressibility of pore space	4e10-6 psi^{-1}	
Compressibility of water	3e10-6 psi^{-1}	
Oil compressibility for under saturated oil	1x10-5 psi^{-1}	
Oil viscosity compressibility for under saturated oil	0 psi^{-1}	
Oil density in stock tank	45 Ibm /cu ft	
Water density in Stock tank	63 Ibm/ cu ft	
Gas density at standard-condition	0.0702 Ibm/ cu ft	
Initial conditions		
Gas/Oil contact depth	9035 ft	
At Gas/Oil contact, oil pressure	3600 psi	
At Gas/Oil contact, capillary pressure	0 psi	
Water contact depth	9209 ft	
At Water/Oil contact, capillary pressure	0 psi	
Well data		
Well completion in blocks	(1, 7)	(1, 8)
Permeability/thickness, md -ft	6200	480
Skin factor (S)	0	0
Lowest BHFP	3000psi	
Depth of pump	9110ft	
Production schedule		
Period (days)	Oil production rate (STB/d)	
1 to 10	1000	
10 to 50	100	
50 to 720	1000	
720 to 900	100	

Table 2. Rock properties

No. Layer	Thickness (ft)	K_x (md)	K_z (md)	ϕ
1	20	35	3.5	0.087
2	15	47.5	4.75	0.097
3	26	148	14.8	0.111
4	15	202	20.2	0.16
5	16	90	9	0.13
6	14	418.5	41.85	0.17
7	8	775	77.5	0.17
8	8	60	6	0.08
9	18	682	68.2	0.14
10	12	472	47.2	0.13
11	19	125	12.5	0.12
12	18	300	30	0.105
13	20	137	13.75	0.12
14	50	191	19.1	0.116
15	100	350	35	0.157

*Porosity is at reference pressure (3600 psi).

Table 3. Saturation functions

Water/Oil functions			
S_w	K_{rw}	K_{row}	P_{cow}
0.22	0	1	7
0.3	0.07	0.4	4
0.4	0.15	0.125	3
0.5	0.24	0.0649	2.5
0.7	0.33	0.0048	2
0.8	0.65	0	1
0.9	0.83	0	0.5
1	1	0	0
Gas / Oil functions			
S_g	K_{rg}	K_{rog}	P_{cgo}
0	0	1	0
0.04	0	0.6	0.2
0.1	0.022	0.33	0.5
0.2	0.1	0.1	1
0.3	0.24	0.02	1.5
0.4	0.34	0	2
0.5	0.42	0	2.5
0.6	0.5	0	3
0.7	0.8125	0	3.5
0.78	1	0	3.9

Table 4. PVT properties of fluid flow at specific pressure.

Saturated oil					Water			gas		
Pressure (Psia)	**BO** (RB/STB)	**ρ_O** (Ibm/cu ft)	**μ_O** (cp)	**R_sGOR** (scf/STB)	**B_W** (RBLSTB)	**ρ_w** (Ibm/cu ft)	**μ_w** (cp)	**B_g** (Mscf/STB)	**ρ_g** (Ibm/cu ft)	**μ_g** (cp)
400	1.012	46.497	1.17	165	1.01303	62.212	0.96	5.9	2.119	0.013
800	1.0255	48.1	1.14	335	1.01182	62.286	0.96	2.95	4.238	0.0135
1200	1.038	49.327	1.11	500	1.01061	62.360	0.96	1.96	6.397	0.014
1600	1.051	50.726	1.08	665	1.00940	62.436	0.96	1.47	8.506	0.0145
2000	1.063	52.072	1.06	828	1.00820	62.510	0.96	1.18	10.596	0.015
2400	1.075	53.318	1.03	985	1.007	62.585	0.96	0.98	12.758	0.0155
2800	1.087	54.399	1	1130	1.0058	62.659	0.96	0.84	14.885	0.0160
3200	1.0985	55.424	0.98	1270	1.0046	62.734	0.96	0.74	16.896	0.0165
3600	1.11	56.203	0.95	1390	1.00341	62.808	0.96	0.65	19.236	0.0170
4000	1.12	56.930	0.94	1500	1.00222	62.883	0.96	0.59	21.192	0.0175
4400	1.13	57.534	0.92	1600	1.00103	62.958	0.96	0.54	23.154	0.0180
4800	1.14	57.864	0.91	1676	0.99985	63.032	0.96	0.49	25.517	0.0185
5200	1.148	58.267	0.9	1750	0.99866	63.107	0.96	0.45	27.785	0.0190
5600	1.155	58.564	0.89	1810	0.99749	63.181	0.96	0.42	29.769	0.0195

The mesh in horizontal direction (r) provided as distance from the origin (ft), is
0.25 (r_w), 2, 4.32, 9.33, 20.1.7, 43.56, 94.11, 203.32, 439.24, 948.92, and 2,050.00.

The mesh in vertical direction (z), provided as depth from the top (ft), is
9012.50, 9027.50, 9042.50. 9055.50, 9066.50, 9085.50, 9098.50, 9113.50, 9114.50, 9129.50, 9150.50, 9153.50, 9188 .50, 9189.50, 9228.50, and 9289.50.

Furthermore, two additional points were added in the vertical direction (z) at depths of 8,987.50 and 9,428.50 ft. Fully sealing faults were set at 9000.0 and 9359.0 ft.

3. Result and discussion

The reservoir model, as shown in Figure 1, describes the porosity of all layers (15 layers). This indicates the upper layer porosity graded between (0.08% – 0.1%) as it goes, the lower layer porosity will increase.

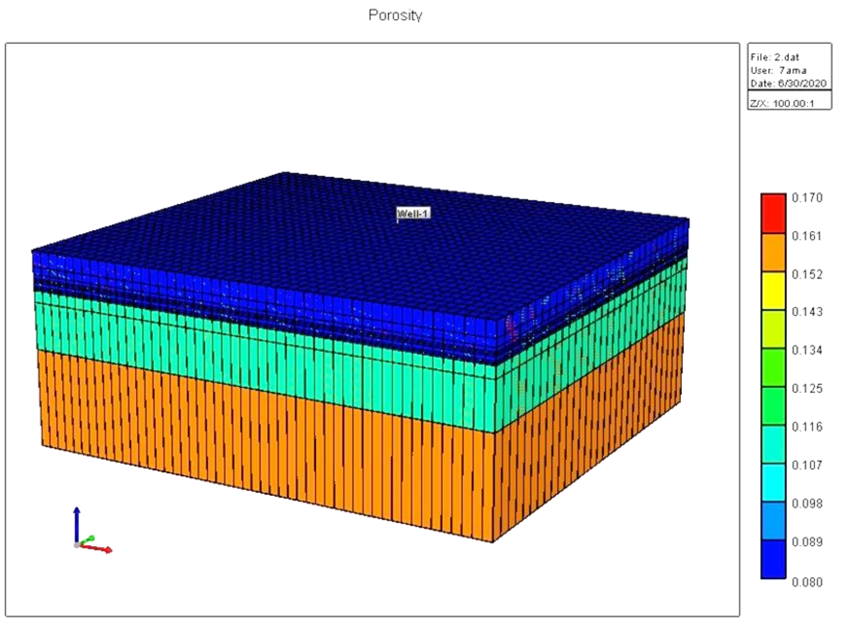

Figure 1. The reservoir model describes the porosity for all layers

Five cases are analyzed for the study of the effect of the pressure, water-cut and gas-oil ratio on the flow rate using computer modeling croup reservoir simulation (CMG):

<u>Case 1</u>: When we perforate the formation at (25-12-1/24-12-1) the flow rate will start from 5250 bbl/day and reduce dramatically to 3250 bbl/day during first 1.5 years, then decrease slightly for the rest time seen figure 2.

This change occurs because of several reasons:

- Pressure decline
- Increase of water cut percentage.
- Increase of Gas-Oil ratio.

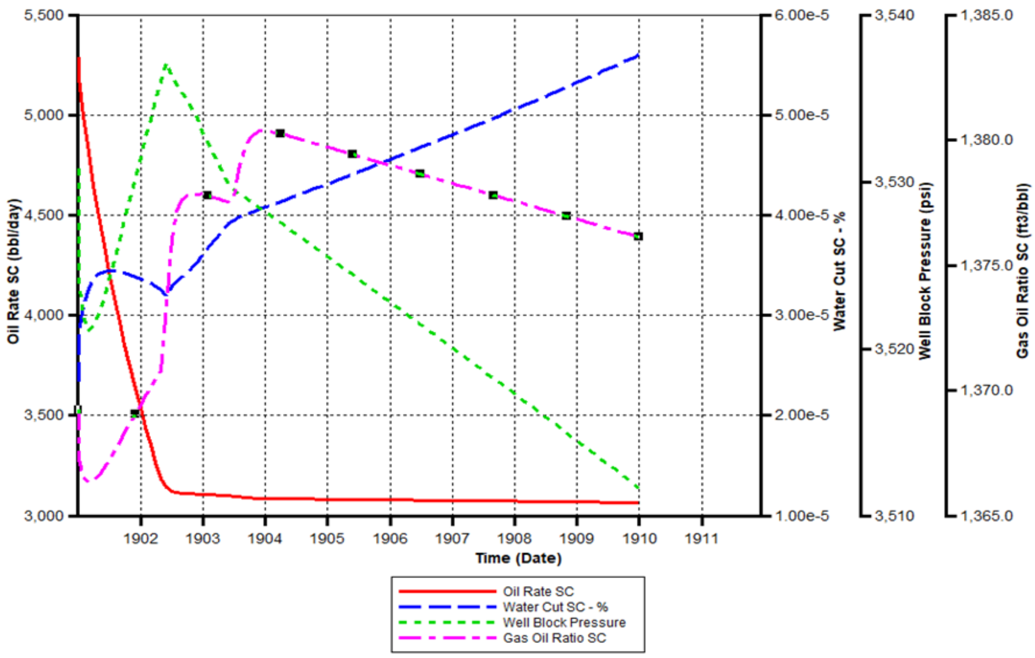

Figure 2. describe the case 1 when perforate the formation at (25-12-1/24-12-1)

Case 2: When we perforate the formation at (25-12-2/24-12-2), the flow rate will start from 5250 bbl/day and reduce dramatically to 3250 bbl/day during first 2 years, then decrease slightly for the rest time as be demonstrated in figure 3.

This change occurs because of several reasons:

- Pressure decline.
- Increase of water cut percentage.
- Increase of Gas-Oil ratio.

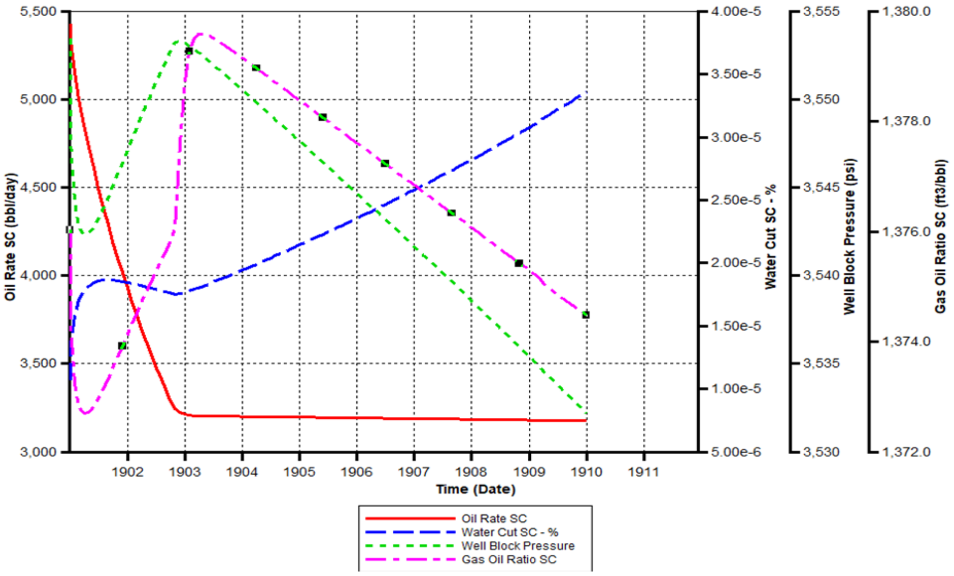

Figure 3. describe the case 2 with perforate the formation at (25-12-2/24-12-2)

Case 3: When we perforate the formation at (25-12-5/24-12-5) the flow rate will start from 11000 bbl/day and reduce dramatically to 6500 bbl/day during first 2 years, then decrease slightly for the rest time seen figure 4.

This change occurs because of several reasons:

- Pressure decline
- Increase of water cut percentage
- Increase of Gas-Oil ratio

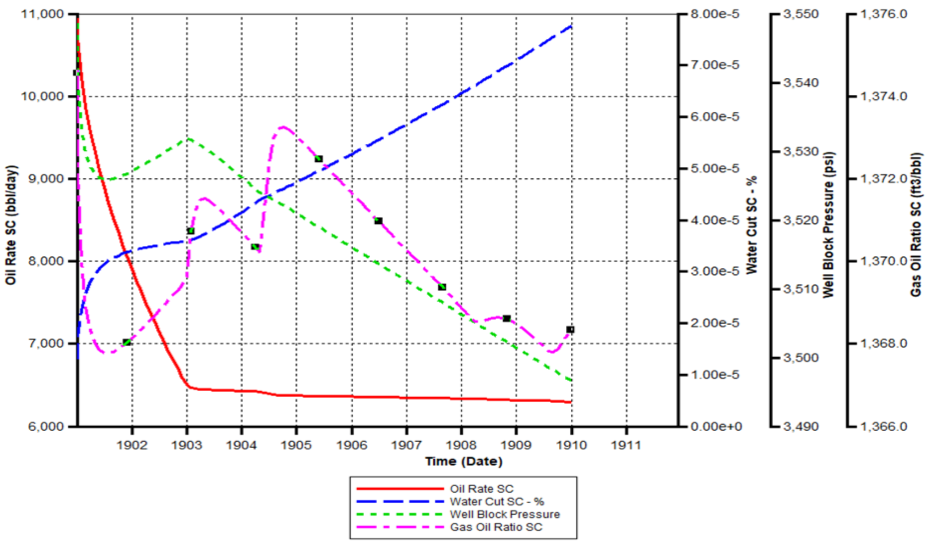

Figure 4. describe case 3 with perforate the formation at (25-12-5/24-12-5)

Case 4: When we perforate the formation at (25-12-8/24-12-8) the flow rate will start from 4000 bbl/day and reduce dramatically to 2250 bbl/day during first 5.5 years, then decrease slightly for the rest time as show in figure 5.

This change occurs because of several reasons:

- Pressure decline.
- Increase of water cut percentage.
- Increase of Gas-Oil ratio.

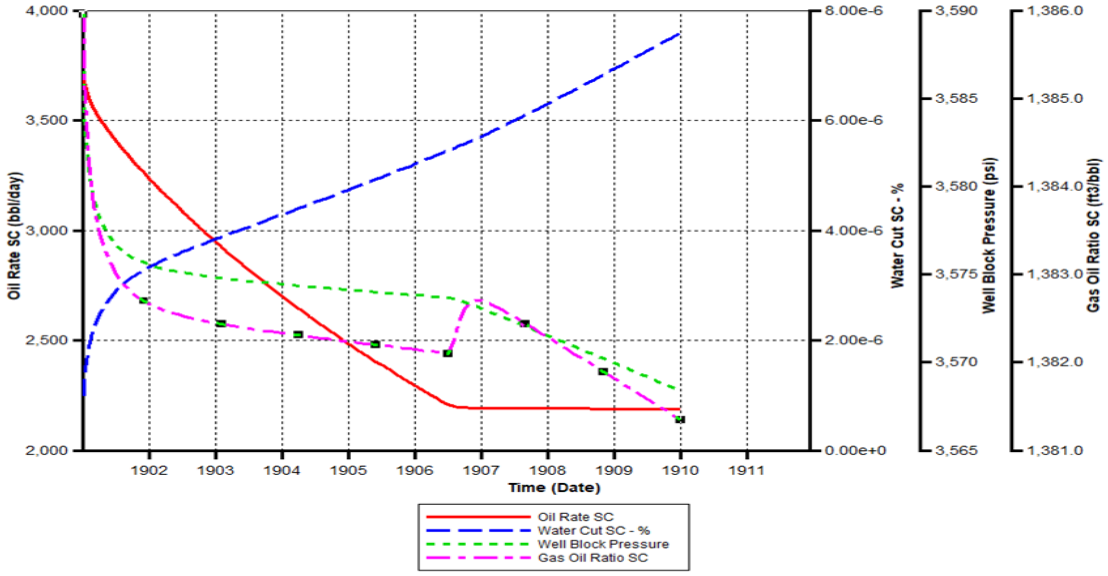

Figure 5. describe case 4 with perforate the formation at (25-12-8/24-12-8)

Case 5: When we perforate the formation at (25-12-11/24-12-11) the flow rate will start from 15000 bbl/day and reduce dramatically to (10500 then to 9750 bbl/day) during first year, then decrease slightly for the rest time as show in figure 6.

This change occurs because of several reasons:

- Pressure decline
- Increase of water cut percentage
- Increase of Gas-Oil ratio

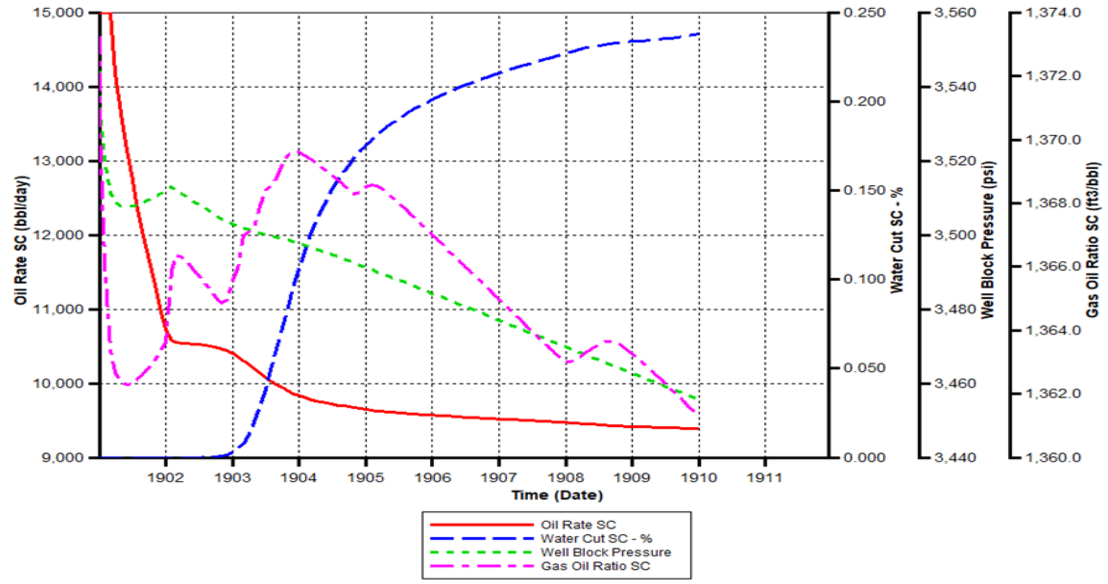

Figure 6. describe case 5 with perforate the formation at (25-12-11/24-12-11)

4. Conclusions

The following conclusions have been drawn from the study with a view to optimizing the length of horizontal well:

Pressure losses can have a major impact on productivity of horizontal well, in particular for longer wellbores and highest production rates. Failure to consider frictional pressure loss effects in horizontal wells can lead to over prediction of well performance. Without accounting for frictional pressure, productivity will increase unrealistically with longer well lengths.

Oil viscosity, well diameter and horizontal permeability have a significant impact on productivity of horizontal well. Such criteria must be taken into account for optimizing the length of the horizontal well.

Frictional pressure losses in high permeability formations containing relatively low viscous oil have a substantial effect on the efficiency of small diameter wellbores.

Incorporating the effect of perforations in horizontal wells increases the frictional pressure loss, which has an effect on well length and productivity. For the range of parameters used in this work, there was a slight reduction in the productivity index.

The Gas-Oil ratio and water-cut will increase, if the flow rate decrease.

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