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Multiphase Flow Behavior Prediction and Optimal Correlation Selection for Vertical Lift Performance in Faihaa Oil Field, Iraq

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Abstract

In the petroleum industry, multiphase flow dynamics within the tubing string have gained significant attention due to associated challenges. Accurately predicting pressure drops and wellbore pressures is crucial for the effective modeling of vertical lift performance (VLP). This study focuses on predicting the multiphase flow behavior in four wells located in the Faihaa oil field in southern Iraq, utilizing PIPESIM software. The process of selecting the most appropriate multiphase correlation was performed by utilizing production test data to construct a comprehensive survey data catalog. Subsequently, the results were compared with the correlations available within the PIPESIM software. The outcomes reveal that the Hagedorn and Brown (HB) correlation provides the most accurate correlation for calculating pressure in FH-1 and FH-3 while the Beggs and Brill original (BBO) correlation proves to be the optimal fit for wells FH-2 and Gomez mechanistic model for FH-4. These correlations show the lowest root mean square (RMS) values of 11.5, 7.56, 8.889, and 6.622 for the four wells, respectively, accompanied by the lowest error ratios of 0.00692%, 0.00033%, 0.00787%, and 0.0011%, respectively. Conversely, Beggs and Brill original (BBO) correlation yields less accurate results in predicting pressure drop for FH-1 compared with other correlations. Similarly, correlations, such as Orkiszewski for FH-2, Duns and Ros for FH-3, and ANSARI for FH-4, also display less accuracy level. Notably, the study also identifies that single-phase flow dominates within the tubing string until a depth of 6000 feet in most wells, beyond which slug flow emerges, introducing significant production challenges. As a result, the study recommends carefully selecting optimal operational conditions encompassing variables such as wellhead pressure, tubing dimensions, and other pertinent parameters. This approach is crucial to prevent the onset of slug flow regime and thus mitigate associated production challenges.

Keywords: multi-phase flow correlation, Vertical lift performance, Pipesim software, tubing string hydraulic, Faihaa oil field.

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1- Introduction

Multiphase flow can be defined as the simultaneous flow of more than one phase (gas, solid, or liquid) together in one common conduit [1, 2]. The movement of the produced fluid from the reservoir to the production string will be always accomplished by pressure drop. This pressure drop increases as the fluid rises higher in the production string, causing more dissolved gas to come out of the solution and this phenomenon is known as multiphase flow [3- 6]. In the tubing string, the liquid and gas phases exhibit varying velocities due to the gas having lower density and viscosity compared to oil. This results in a faster upward flow for the gas, while the liquid flows faster than the gas when moving downward, due to gravity and density disparities. This behavior introduces complexity to multiphase flow, as it encompasses multiple flow variables. Even in the case of straightforward pipeline geometry, the calculations involved in multiphase flow remain intricate and challenging [7, 8]. Multiphase flow through tubing strings is a well-known concept in the oil and gas industry. However, it remains a focal point of extensive interest in the upstream petroleum sector. Proper selection of the most accurate multiphase flow correlations for any flow conditions and fluid properties is essential for petroleum engineers to optimize well deliverability and overall production performance [9]. The complexity in two-phase flow in pipes arises from the interface between the two phases. The existence of this interface is influenced by various factors, including flow rates, pipe geometry, and physical properties of the phases. The interface can take a wide variety of forms, known as flow patterns or flow regimes [10 - 13]. The most common flow regimes for two-phase flow can vary depending on the orientation of the flow. In horizontal flow, the common flow regimes are Bubble, Slug, Plug, Annular, Stratified, Dispersed, and Wavy [14, 15]. In vertical flow, the common flow regimes are Bubble, Slug, Churn, and Annular [16, 17]. In addition, predicting multiphase flow behavior in oil and gas production system has another challenge due to the presence of various phenomena, including heat and mass transfer. As fluids flow through the piping system, heat

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transfer occurs, further complicating the overall dynamics. Additionally, mass transfer among hydrocarbon fluids takes place as pressure and temperature change, adding another layer of complexity to the prediction process [18, 19]. Due these complexities, predicting the behavior of multiphase flow in pipelines remains a complex challenge. Researchers have proposed various methods based on theoretical, experimental, and field observations to accurately predict multiphase flow behavior. These methods can be categorized into two main approaches: empirical and mechanistic. The empirical approach empirically connects pressure losses with all essential factors without explaining the source of the event, whereas the mechanistic approach uses physics to analyze and explain the phenomenon [20]. The empirical correlations commonly used to model multiphase flow are typically developed based on specific ranges of variables and conditions employed during experimental processes. However, none of these correlations have been definitively proven to be universally applicable or provide satisfactory results for all field conditions and parameters. Since multiphase flow behavior can vary significantly across different oil fields and operational scenarios, it poses challenges in finding a single correlation that accurately captures the complexities of the entire field [21-25]. The primary purpose of multiphase flow correlations is to predict the liquid holdup and the frictional pressure gradient [26]. The most commonly used empirical correlations to calculate the pressure loss are Dukler et al. (1964) [27] and Beggs and Brill (1973) [28], Duns and Ros (1963) [29], Hagedorn and Brown (1965) [30], Orkiszewski (1967) [31], Aziz et al. (1972) [32], and Gray (1978) [33]. The basic energy balance equation was used to derive the general equation of pressure gradient, which is applicable to any fluid flowing in vertical or deviated wells. This equation was developed for two-phase flow by assuming that their flow regimes and properties are homogenous in a fixed volume of pipe. The total pressure gradient Eq. 1 comprises three components: hydrostatic or elevation changes, friction, and acceleration. [7].

$$\left(-\frac{dp}{dl}\right) total = \left(\frac{dp}{dl}\right) hydrostatic + \left(\frac{dp}{dl}\right) friction + \left(\frac{dp}{dl}\right) acceleration \qquad (1)$$

Where: dp/dL = pressure gradient.

The main goal of this study is to determine the most appropriate multiphase flow correlation from the 8 selected correlations available in PIPSIM software for four wells located in the Faihaa oil field in southern Iraq. This will help suggest a proper vertical lift model that can be utilized in analyzing wells performance at different flow conditions in the Faihaa oil field.

2- Methodology

In this study, the flow behavior in the wells under investigation was carried out using PIPESIM software which is one of the most powerful tools that can predict the well performance and production capability. It is a well design and optimization software owned by Schlumberger company, contains various multiphase flow correlations that are used to calculate the pressure gradient for the four wells in our case study. The modeling process was performed by selecting the appropriate system model and inputting various data, including Pressure- Volume- Temperature (PVT) data, reservoir information, equipment specifications, well test results, and production data as shown in Table 1 and Table 2. To determine the most suitable multiphase flow correlation, production test data was utilized to create a survey data catalog. Subsequently, a data-matching task was conducted to compare the used multiphase flow correlation available in the PIPESIM software that listed in Table 3. The measured pressures from each well were compared to the calculated pressures obtained from the PIPESIM software to identify the multiphase flow correlation that provides the best match between the measured and calculated pressures. The correlation that yields the closest match between the measured and calculated pressures was selected as the most appropriate for predicting the pressure drop within the wells. The selection of the optimal correlation will be based on two criteria: the lowest value of Root Mean Square (RMS) for the calculated parameter and the lowest error ratio for the measured parameter. The absolute error ratio will be determined using Eq. 2, which allows for a quantitative assessment of the correlation's accuracy in relation to the measured parameter. It is necessary to mention that this study is limited to Faihaa Oil Field and the production data available for the studied four wells, as shown in Table 2. Thus, full survey data (full pressure profile (flowing or static survey versus depth)) are not available and just two pressure points (wellhead and bottom hole) are used. By following the summarized methodology in Fig. 1 below, the aim of identifying the correlation that provides the best fit for the observed data, and ensuring accurate predictions of pressure drop within the wells under investigation will be easily reached.

$$Absolute\ error\ ratio = /\frac{test\ outlet\ pressure - calculated\ outlet\ preesure}{test\ outlet\ preesure}/ * 100\% \qquad (2)$$

Table 1. Range of Reservoir, Test, and PVT Data for the Four Wells in the Faihaa Oil Field

Variables	Data range
Reservoir data	
Reservoir pressure (psi)	7713-8190.05
Water cut (%)	0
Productivity index (STB/day/psi)	1.58-18.38
Reservoir temperature (°F)	267.8-276
Test data	
Liquid rate (STB)	1978.21-8550
Tubing size (in)	3.5
Well-head pressure (psi)	2074.7-3175.7
PVT data	
Bubble point pressure (psi)	4016-4500
Solution gas oil ratio (scf/STB)	1072.23-1406.36
Oil density (API)	35-36.75

Table 2. Production Test Data for FH-1, FH-2, FH-3, FH-4 Wells

Well	Test point	Depth (m)	Pressure (psi)	Flow rate (STB/D)
FH-1	1	0	2310.7	3415
	2	4000.85	6910	3415
FH-2	1	0	3004.7	4072
	2	3983.08	7171	4072
FH-3	1	0	3175.7	2006
	2	3971.95	6941.15	2006
FH-4	1	0	2074.7	8550
	2	3985.33	7590	8550

Table 3. The Used Multiphase Flow Correlations Available in the PIPESIM Software

Correlation	Conditions	Category
Aziz Govier Fogarasi	Slip and flow regime	Empirical
Ansari	Slip and flow regime	Mechanistic model
Beggs &Brill original (BBO)	Slip and flow regime	Empirical
Beggs &Brill reversed (BBR)	Slip and flow regime	Empirical
Gomez1	Slip and flow regime	Mechanistic model
Gray Original		
Duns &Ros original (DRO)	Slip and flow regime	Empirical
Hagedorn &Brown(HB)	Slip but no flow regime	Empirical
Orkiszewski (OKS)	Slip and flow regime	Empirical

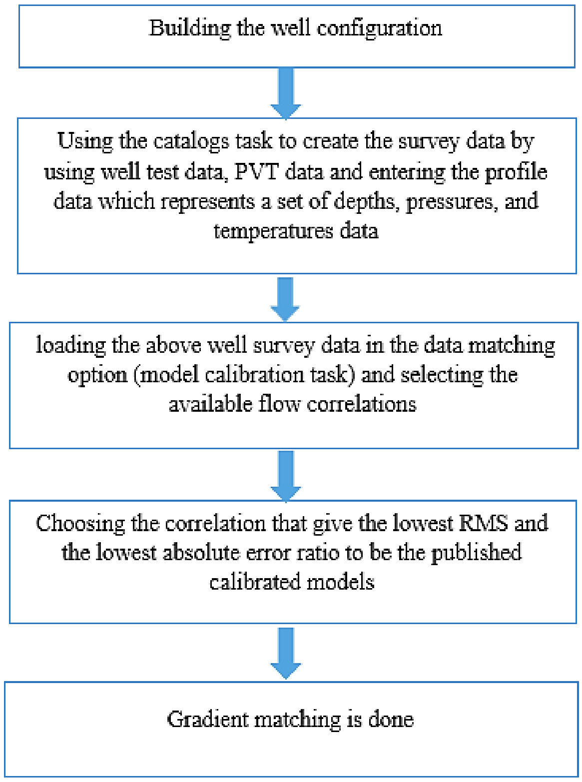

Fig. 1. Flowchart Diagram Illustrates the Steps to Multiphase Flow Correlations Selection and Gradient Matching

3- Results and Discussions

3.1. Vertical Flow Correlation Matching for Well FH-1

Using the production test data for well FH-1 introduced in Table 2, the study conducted a data-matching task to compare various multiphase flow correlations listed in Table 3. The result of vertical flow correlation matching is shown in Fig. 2 and Table 4.

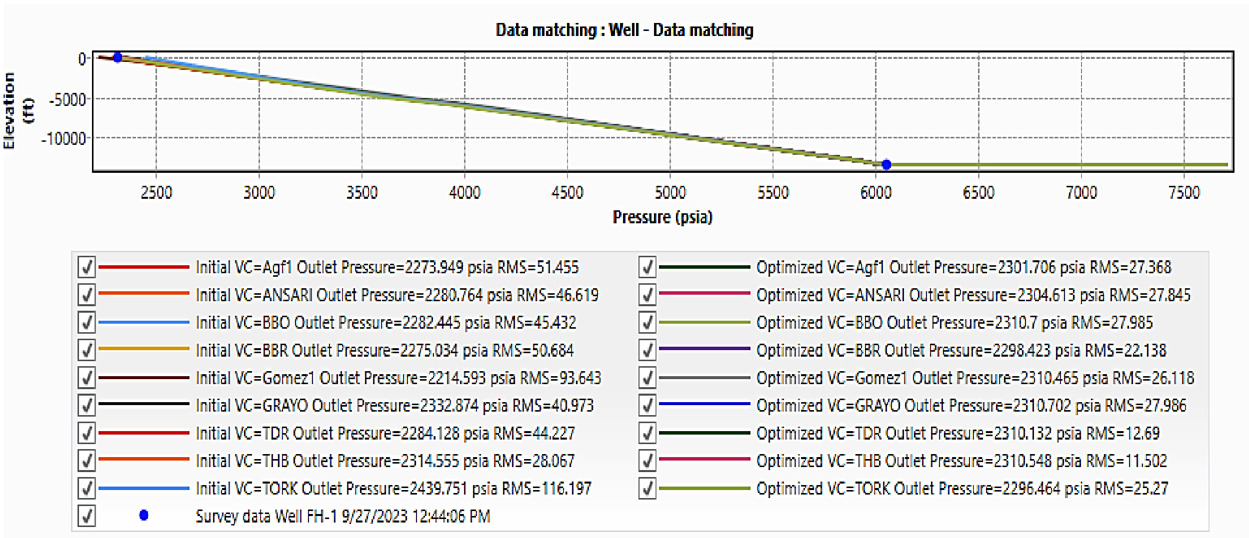

Fig. 2. Gradient Matching for FH-1 Using Different Multiphase Flow Correlations

Table 4. Outlet Pressure Correlation Comparison for FH-1

Correlation	Test outlet pressure, psi	Calculated outlet pressure (WHP), psi	Absolute error %	RMS
Aziz Govier Fogarasi	2310.7	2301.70	0.38	27.368
Ansari	2310.7	2304.61	0.26	27.845
Beggs and Brill original	2310.7	2310.7	0	27.98
Beggs and Brill revised	2310.7	2298.42	0.53	22.13
Gomez 1	2310.7	2310.465	0.0101	26.118
Gray original	2310.7	2310.70	0	27.98
Duns and Ros	2310.7	2310.89	0.00822	11.54
Hagedorn and Brown Original Tulsa	2310.7	2310.54	0.00692	11.50
Orkiszewski	2310.7	2296.46	0.61626	25.27

Table 4 displays that the Hagedorn and Brown Original correlation provides the most accurate results with the smallest absolute error of 0.00692% and the lowest root mean square value of 11.50. Therefore, this correlation is selected to construct the Vertical Lift Performance (VLP) curve in the FH-1 well due to its superior matching between the test and calculated outlet pressure. The pressure, temperature, pressure gradient, hold-up, and regime distribution along the flow path for this well are illustrated in Table 5.

Table 5 shows that the total pressure drop across the system will be 5403.1 psi, 1659.8 psi from the reservoir across the completion to the bottom hole, 71.2 psi from the bottom hole to the lower end of the tubing, and 3672.1 psi across the tubing as shown in Fig. 3 below. Also, the temperature starts from 207.55 °F at the wellhead and increases with depth until reaching 267.8 °F in the mid of completion as shown in Fig. 4 below. The liquid hold-up was 100 % from reservoir depth up to 7000 ft elevation and started to decrease as the liquid moved up in the tubing reaching 68.6 % at the wellhead (0 ft elevation) as in Fig. 5. The flow pattern is liquid phase from the lower end of the tubing up to 7000 ft elevation and bubble regime from 6000 ft to 5000 ft elevation and slug flow from 4000 ft elevation up to the wellhead as shown in Fig. 5. gas start to appear in the well from 6000 ft elevation up to the wellhead to be 1.968 mmscf/d flowing gas flowrate as in Fig. 6 below.

Table 5. Tubing Correlation Comparison for Hagedorn and Brown Original- Gradient Traverse Calculations Results for Well FH-1

Elevation ft.	Pressure psi	Temperature °F	Hold up	G-L Pattern	Pressure gradient psi/ft.	Elevation pressure gradient psi/ft.	Friction pressure gradient psi/ft.	Acceleration pressure gradient psi/ft.
0	2310	207.55	68.6	Slug	0.252	0.2277	0.0245	6*10^-6
1000	2566.2	216.86	73.4	Slug	0.260	0.2366	0.0237	4*10^-6
2000	2830	225.95	78.1	Slug	0.266	0.2438	0.0230	3*10^-6
3000	3099	234.83	82.5	Slug	0.272	0.2496	0.0224	2*10^-6
4000	3373	243.53	86.9	Slug	0.276	0.2542	0.0220	1.9*10^-6
5000	3654	252.08	92.0	Bubble	0.282	0.2591	0.0232	1.2*10^-6
6000	3937	260.47	96.0	Bubble	0.283	0.2610	0.0221	5.8*10^-7
7000	4220	268.72	99.9	Liquid	0.2835	0.2621	0.0213	5.8*10^-10
8000	4504	272.43	100	Liquid	0.284	0.2630	0.0213	0
9000	4789	275.65	100	Liquid	0.285	0.2638	0.0212	0
10000	5074	278.38	100	Liquid	0.2857	0.2645	0.0212	0
11000	5360	280.58	100	Liquid	0.286	0.2652	0.0212	0
12000	5647	282.25	100	Liquid	0.2871	0.2659	0.0211	0
13000	5935	283.37	100	Liquid	0.2878	0.2666	0.0211	0
13162.7	5982.1	283.5	100	Liquid	0.2879	0.2667	0.0211	0
13162.7	5982.2	283.49	100	Liquid	0.2673	0.2667	0.0005	0
13428.5	6053.3	283.91	100	Liquid	0.2674	0.2669	0.0005	0
13428.5	6053.3	283.91						
13428.5	7713.1	267.8						

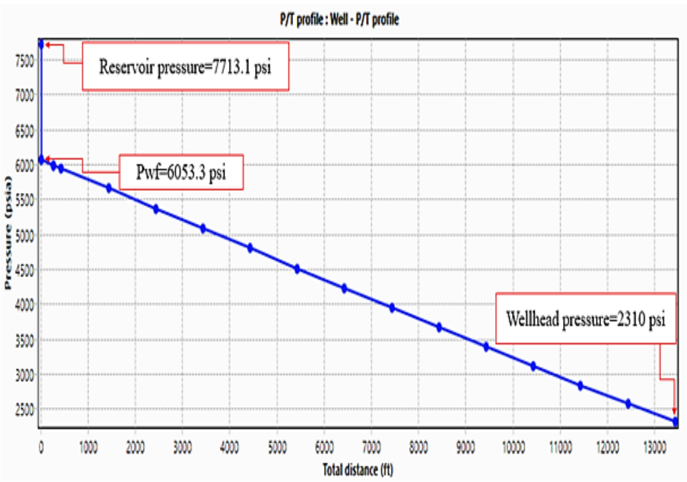

Fig. 3. Pressure Distribution for Well FH-1

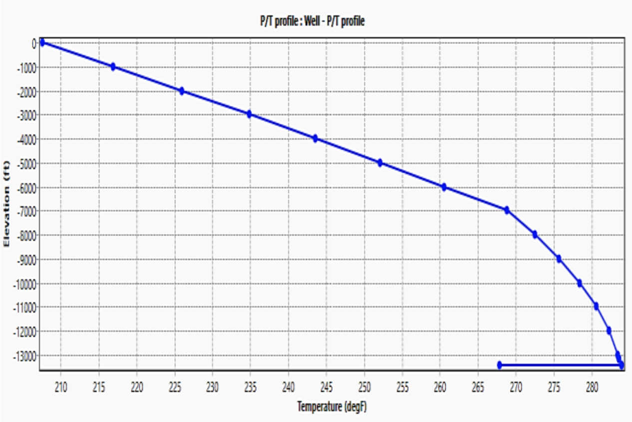

Fig. 4. Elevation vs Temperature for FH-1

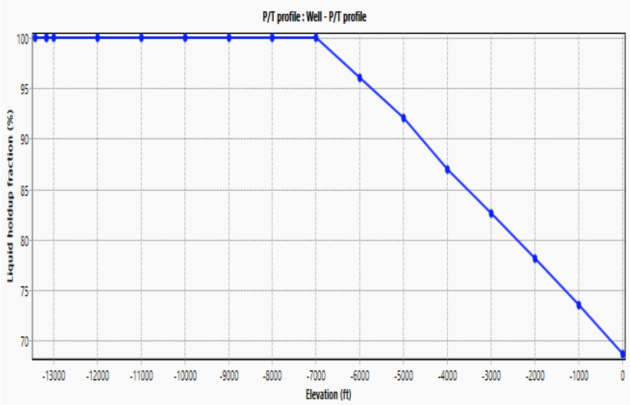

Fig. 5. Liquid Holdup vs Elevation for FH-1

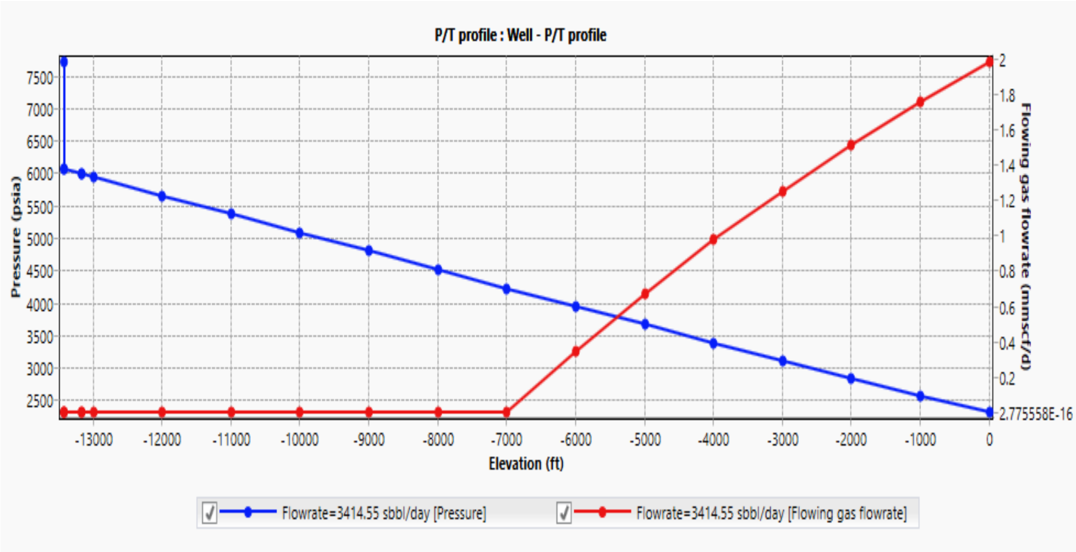

Fig. 6. Effect of Pressure and Elevation Decrease on Flowing Gas Flowrate for FH-1

3.2. Vertical Flow Correlation Matching for Well FH-2

The result of vertical flow correlation matching with the production test data for Well FH 2 is shown in Fig. 7 and listed in Table 6.

The findings indicate that the Beggs and Brill Original correlation demonstrates the lowest absolute error of (0.00033%) and the lowest root mean square of (7.56). Therefore, it has been chosen to construct the VLP curve for the well FH-2. This correlation provides the best matching between the measured and calculated outlet pressure. The pressure, temperature, pressure gradient, hold-up, and the distribution of regimes along the flow path for this well are presented in Table 7.

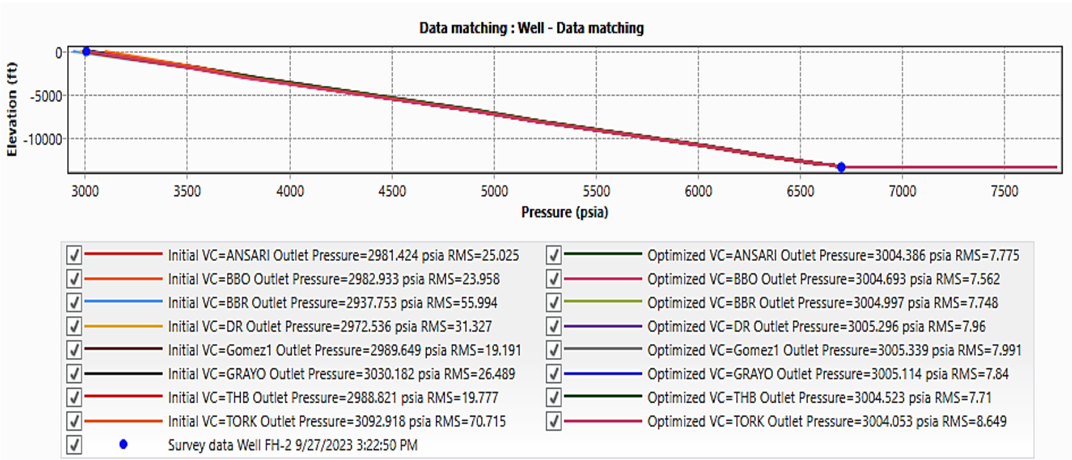

Fig. 7. Outlet Pressure Matching for Well FH-2

Table 6. Outlet Pressure Correlation Comparison for FH-2

Correlation	Test outlet pressure, psi	Calculated outlet pressure, psi	Absolute error %	RMS
Ansari	3004.7	3004.38	0.010	7.77
Beggs and Brill original	3004.7	3004.69	0.00033	7.56
Beggs and Brill revised	3004.7	3004.99	0.0096	7.74
Duns and Ros	3004.7	3005.29	0.0196	7.96
Gomez1	3004.7	3005.339	0.0212	7.991
Gray original	3004.7	3005.11	0.0136	7.84
Hagedorn and Brown Tulsa	3004.7	3004.52	0.00599	7.71
Orkiszewski	3004.7	3004.05	0.0216	8.64

From the table above, the total pressure drop across the system will be 4753 psi, 1053.3 psi from the reservoir across the completion to the bottom hole, 66.3 psi from the bottom hole to the lower end of the tubing, and 3633.4 psi across the tubing as shown in Fig. 8 below. Also, the temperature starts from 197.4 °F at the wellhead and increases with depth until reaching 274 °F in the mid of completion as shown in Fig. 9 below. The liquid holdup was 100 % from reservoir depth up to 6000 ft elevation and started to decrease as the liquid moved up in the tubing reaching 83 % at the wellhead (0 ft elevation) as in Fig. 10. The flow pattern is the liquid phase from the bottom hole up to 6000 ft elevation and distributed regime from 5000 ft elevation up to the wellhead as shown in Fig. 10. Gas starts to appear in the well from 5000 ft elevation up to the wellhead to be 0.012 mmscf/d flowing gas flowrate as in Fig. 11 below.

3.3. Vertical Flow Correlation Matching for Well FH-3

The comparison results for FH-3 are shown below in Fig. 12 and Table 8.

Table 7. Tubing Correlation Comparison for Beggs and Brill Original – Gradient Traverse Calculations Results for Well FH-2

Elevation ft.	Pressure psi	Temperature °F	Hold up	regime	Pressure gradient psi/ft.	Elevation pressure gradient psi/ft.	Friction pressure gradient psi/ft.	Acceleration pressure gradient psi/ft.
0	3004.7	197.4	83	Distributed	0.279	0.250	0.028	7*10^-6
1000	3284.2	208.6	85	Distributed	0.278	0.250	0.027	5*10^-6
2000	3562.4	219.6	88	Distributed	0.277	0.251	0.025	3*10^-6
3000	3839.3	230.4	92	Distributed	0.276	0.251	0.024	2*10^-6
4000	4114.6	241.1	95	Distributed	0.274	0.250	0.023	1*10^-6
5000	4387.8	251.5	97	Distributed	0.272	0.249	0.022	6*10^-7
6000	4660.6	260.8	100	Liquid	0.276	0.248	0.028	0
7000	4937.2	266.1	100	Liquid	0.276	0.248	0.028	0
8000	5214.4	270.8	100	Liquid	0.277	0.249	0.028	0
9000	5492.1	274.9	100	Liquid	0.277	0.249	0.027	0
10000	5770.3	278.3	100	Liquid	0.278	0.250	0.027	0
11000	6049.2	281.0	100	Liquid	0.279	0.251	0.027	0
12000	6328.6	283.0	100	Liquid	0.279	0.251	0.027	0
13000	6608.6	284.1	100	Liquid	0.280	0.252	0.027	0
13105.3	6638.1	284.2	100	Liquid	0.280	0.252	0.027	0
13105.3	6638.3	284.2	100	Liquid	0.253	0.252	0.0006	0
13366.1	6704.4	284.6	100	Liquid	0.253	0.252	0.0006	0
13366.1	6704.4	284.6						
13366.1	7757.7	274						

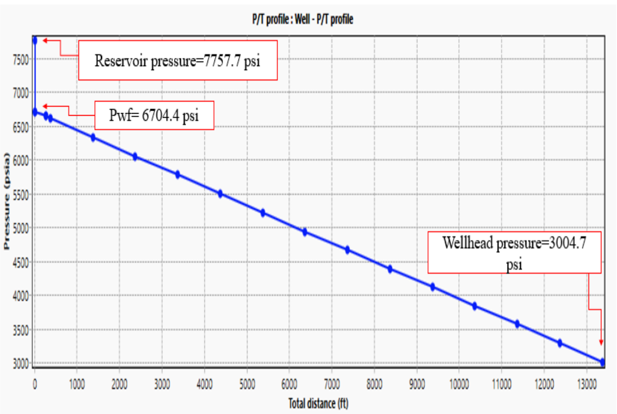

Fig. 8. Pressure Distribution for Well FH-2

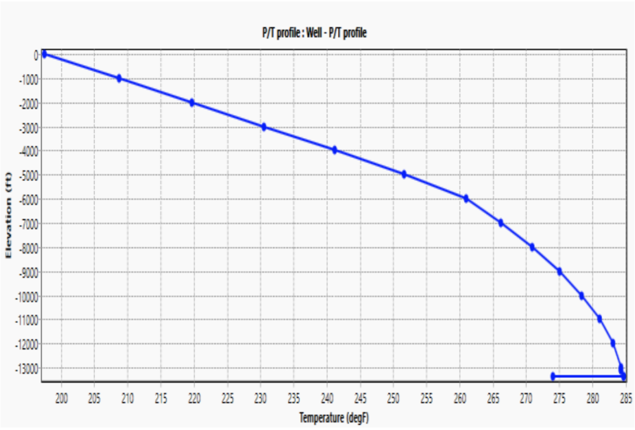

Fig. 9. Elevation vs Temperature for FH-2

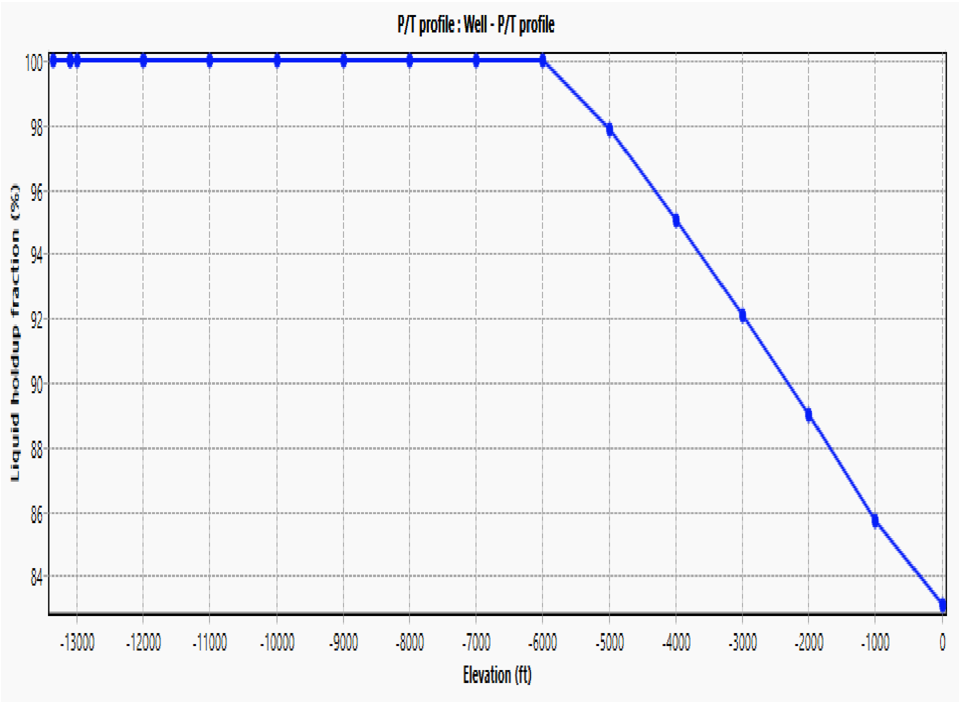

Fig. 10. Liquid Holdup vs Elevation for FH-2

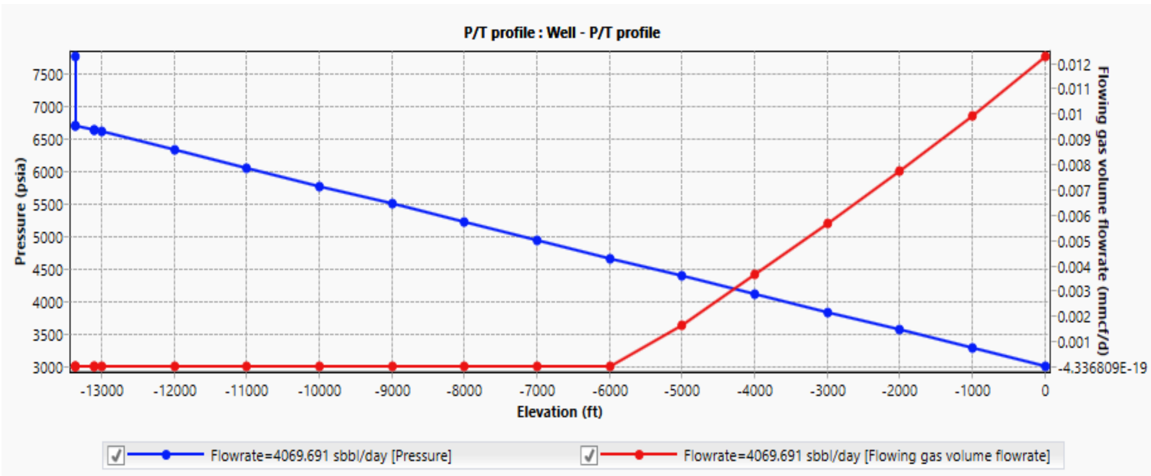

Fig. 11. Effect of Pressure and Elevation Decrease on Flowing Gas Flowrate for FH-2

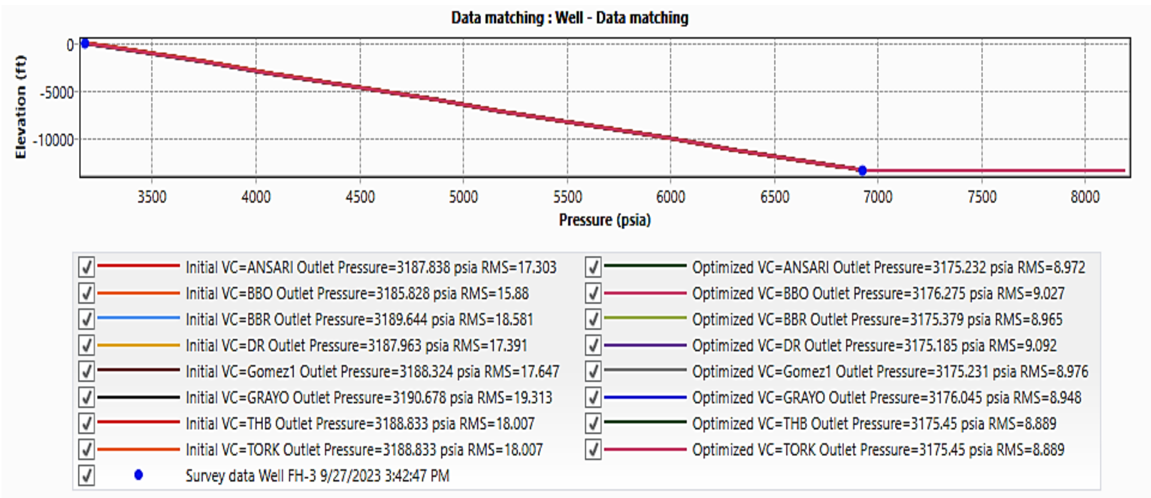

Fig. 12. Outlet Pressure Matching for Well FH-3

Table 8. Outlet Pressure Correlation Comparison for FH-3

Correlation	Test outlet pressure, psi	Calculated outlet pressure, psi	Absolute error %	RMS
Ansari	3175.7	3175.23	0.0147	8.972
Beggs and Brill original	3175.7	3176.27	0.0179	9.027
Beggs and Brill revised	3175.7	3175.37	0.0103	8.965
Duns and Ros	3175.7	3175.18	0.0163	9.092
Gomez1	3175.7	3175.231	0.0147	8.976
Gray original	3175.7	3176.04	0.0107	8.948
Hagedorn and Brown Tulsa	3175.7	3175.45	0.00787	8.889
Orkiszewski	3175.7	3175.45	0.00787	8.889

The findings for this well demonstrate that Hagedorn and Brown Tulsa correlation and Orkiszewsski correlation show similar results as they exhibit the lowest absolute error of (0.00787 %) and the lowest root mean square of (8.889. Therefore, Hagedorn and Brown Tulsa will have been chosen to construct the VLP curve in the FH-3 well. The other key parameters such as pressure, temperature, pressure gradient, hold-up, and regime distribution along the flow path for this well have also been calculated and are listed in Table 9.

From the table above, the total pressure drop across the system will be 5014.5psi, 1268.4 psi from the reservoir across the completion to the bottom hole, 67.6 psi from the bottom hole to the lower end of the tubing, and 3678.5 psi across the tubing as shown in Fig. 13 below. Also, the temperature starts from 153.2 °F at the wellhead and increases with depth until reaching 274 °F in the mid of completion as shown in Fig. 14 below. The liquid holdup was 100 % from the bottom hole up to 2000 ft elevation and started decreasing as the liquid moved up in the tubing reaching 95 % at the wellhead (0 ft elevation) as in Fig. 15. The flow pattern is the liquid phase from the bottom hole up to 2000 ft elevation and bubble flow from 1000 ft elevation up to the wellhead as shown in Fig. 15. gas starts to appear in the well from 2000 ft elevation up to the wellhead to be 0.304 mmscf/d flowing gas flowrate as in Fig. 16 below.

3.4. Vertical Flow Correlation Matching for Well FH-4

The outcome of vertical flow correlation matching for FH-4 utilizing the production test data provided in Table 2 is displayed in Fig. 17 and Table 10 below.

Between the different used correlations in the table above, the Gomez correlation gives the lowest absolute error of (0.0011 %) and the lowest root mean square of (6.622), depending on this result, Gomez will be choosing to construct the VLP curve in FH-4 well as it gives the best matching between the test and calculated outlet pressure. The pressure, temperature, pressure gradient, hold-up, and regime distribution along the flow path of that well are illustrated in Table 11 below.

From the table above, the total pressure drop across the system will be 5977.6 psi, 942.8 psi from the reservoir across the completion to the bottom hole, 80.1 psi from the bottom hole to the lower end of the tubing, and 4954.6 psi across the tubing as shown in Fig. 18 below. Also, the temperature starts from 215 °F at the wellhead and increases with depth until reaching 276 °F in the mid of completion as shown in Fig. 19 below. The liquid holdup was 100 % from bottom hole depth up to 7000 ft elevation and started to decrease as the liquid moved up in the tubing reaching 57.1 % at the wellhead (0 ft elevation) as in Fig. 20. The flow pattern is the liquid phase from the bottom hole up to 7000 ft elevation and dispersed bubble flow from 6000 ft elevation up to the wellhead as shown in Fig. 20. Gas starts to appear in the well from 6000 ft elevation up to the wellhead to be almost 6.82 mmscf/d flowing gas flow rate as in Fig. 21 below.

Table 9. Tubing Correlation Comparison for Hagedorn and Brown – Gradient Traverse Calculations Results for Well FH-3

Elevation ft.	Pressure psi	Temperature °F	Hold up	Regime	Pressure gradient psi/ft.	Elevation pressure gradient psi/ft.	Friction pressure gradient psi/ft.	Acceleration pressure gradient psi/ft.
0	3175.6	153.21	95	Bubble	0.287	0.279	0.0079	2.7*10^-7
1000	3462.1	170.03	98	Bubble	0.285	0.277	0.0076	9.9*10^-8
2000	3746.6	185.75	100	Liquid	0.283	0.276	0.0074	0
3000	4030.0	198.67	100	Liquid	0.283	0.275	0.0073	0
4000	4312.7	211.10	100	Liquid	0.282	0.274	0.0073	0
5000	4594.7	222.97	100	Liquid	0.281	0.274	0.0073	0
6000	4876.1	234.20	100	Liquid	0.281	0.273	0.0073	0
7000	5156.9	244.71	100	Liquid	0.280	0.273	0.0073	0
8000	5437.2	254.36	100	Liquid	0.280	0.272	0.0073	0
9000	5717.1	263.06	100	Liquid	0.279	0.272	0.0073	0
10000	5996.6	270.65	100	Liquid	0.279	0.272	0.0073	0
11000	6276.0	276.97	100	Liquid	0.279	0.271	0.0073	0
12000	6555.4	281.85	100	Liquid	0.279	0.272	0.0073	0
13000	6834.8	285.05	100	Liquid	0.279	0.272	0.0073	0
13068.9	6854.1	285.21	100	Liquid	0.279	0.272	0.0073	0
13068.9	6854.1	285.21	100	Liquid	0.272	0.272	0.0002	0
13316.9	6921.7	286.18	100	Liquid	0.272	0.272	0.0002	0
13316.9	6921.7	286.18						
13316.9	8190.1	274						

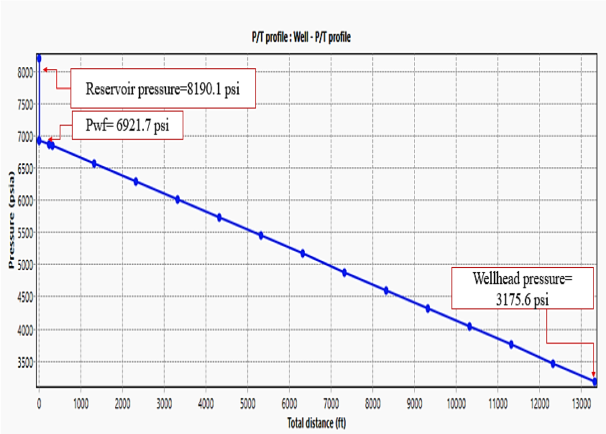

Fig. 13. Pressure Distribution for Well FH-3

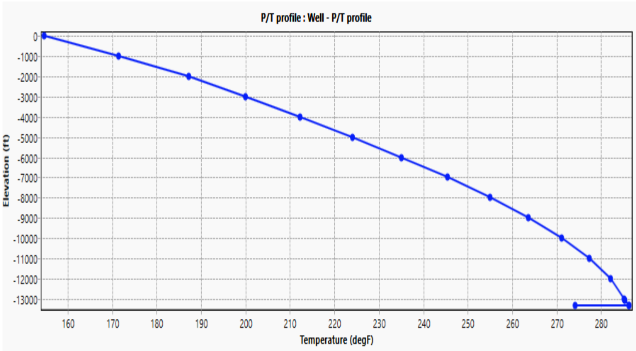

Fig. 14. Elevation vs Temperature for FH-3

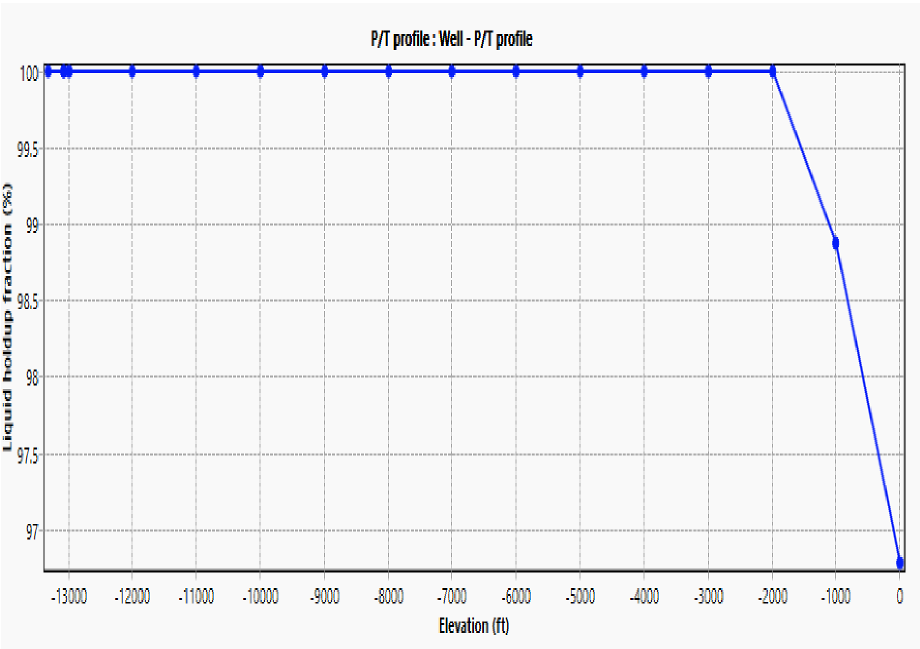

Fig. 15. Liquid Holdup vs Elevation for FH-3

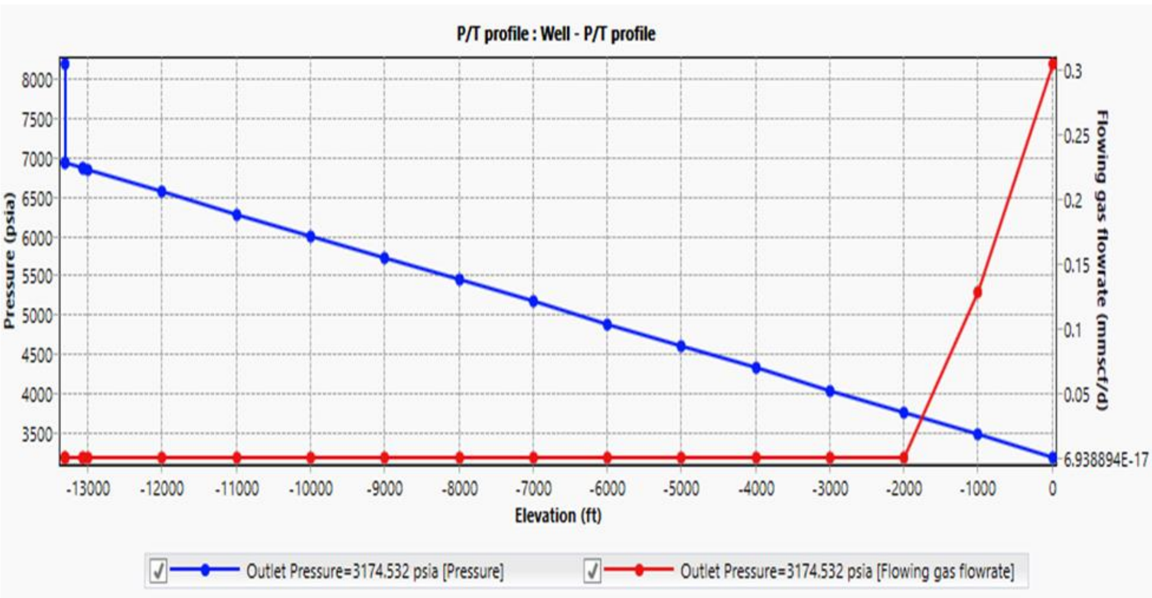

Fig. 16. Effect of Pressure and Elevation Decrease on Flowing Gas Flowrate for FH-3

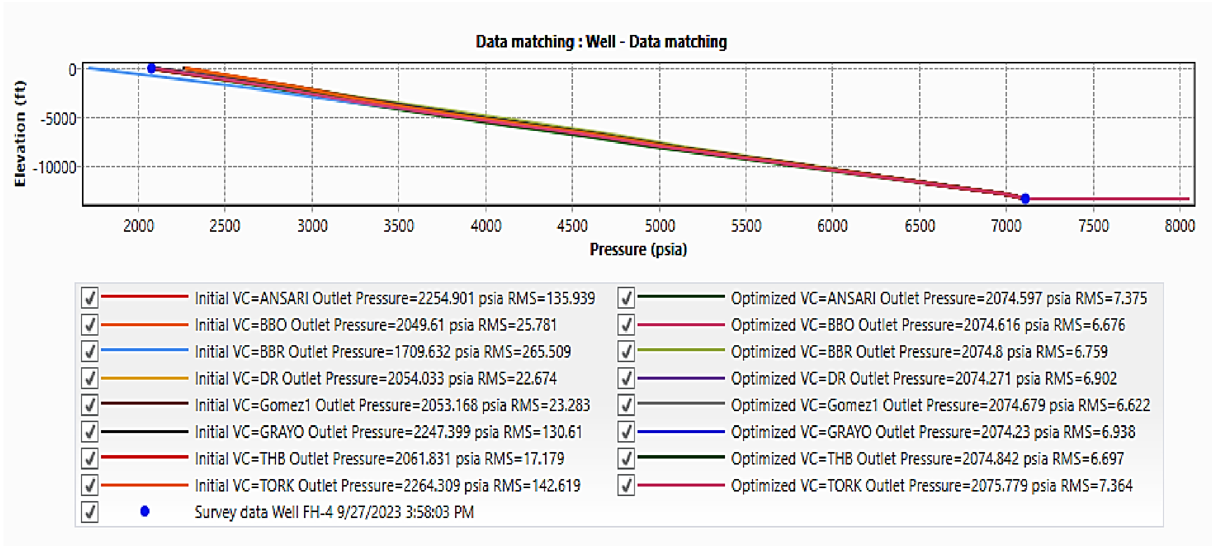

Fig. 17. Outlet Pressure Match for Well FH-4

Table 10. Outlet Pressure Correlation Comparison for FH-4

Correlation	Test outlet pressure, psi	Calculated outlet pressure, psi	Absolute error %	RMS
Ansari	2074.7	2074.59	0.0053	7.37
Beggs and Brill original	2074.7	2074.61	0.0043	6.67
Beggs and Brill revised	2074.7	2074.8	0.0048	6.75
Duns and Ros	2074.7	2074.27	0.0207	6.90
Gomez1	2074.7	2074.676	0.0011	6.622
Gray original	2074.7	2074.23	0.0226	6.93
Hagedorn and Brown Tulsa	2074.7	2074.84	0.0067	6.69
Orkiszewski	2074.7	2075.77	0.0515	7.36

Table 11. Tubing Correlation Comparison for Gomez – Gradient Traverse Calculations Results for Well FH-4

Elevation ft.	Pressure psi	Temperature °F	Hold up	regime	Pressure gradient psi/ft.	Elevation pressure gradient psi/ft.	Friction pressure gradient psi/ft.	Acceleration pressure gradient psi/ft.
0	2074.7	215	57.1	Dispersed bubble	0.365	0.199	0.165	0.00011
1000	2441.76	225	64.7	Dispersed bubble	0.368	0.216	0.151	7.6*10^-5
2000	2811.90	234	71.8	Dispersed bubble	0.371	0.229	0.142	5.2*10^-5
3000	3185.22	244	78.5	Dispersed bubble	0.374	0.239	0.135	3.5*10^-5
4000	3561.15	253	85	Dispersed bubble	0.376	0.245	0.131	2.2*10^-5
5000	3938.96	263	91	Dispersed bubble	0.378	0.250	0.127	1.1*10^-5
6000	4317.92	273	97.9	Dispersed bubble	0.379	0.253	0.125	2.4*10^-6
7000	4696.97	278	100	Liquid	0.379	0.255	0.124	0
8000	5076.64	280	100	Liquid	0.380	0.256	0.123	0
9000	5457.10	282	100	Liquid	0.380	0.257	0.123	0
10000	5838.31	283	100	Liquid	0.381	0.258	0.122	0
11000	6220.22	284	100	Liquid	0.382	0.259	0.122	0
12000	6602.82	285.3	100	Liquid	0.382	0.260	0.122	0
13000	6986.10	285.1	100	Liquid	0.383	0.261	0.121	0
13112.7	7029.34	285.05	100	Liquid	0.383	0.261	0.121	0
13112.7	7030.11	285.04	100	Liquid	0.264	0.261	0.002	0
13412.1	7109.45	285.3	100	Liquid	0.265	0.262	0.002	0
13412.1	7109.45	285.3						
13412.1	8052.3	276						

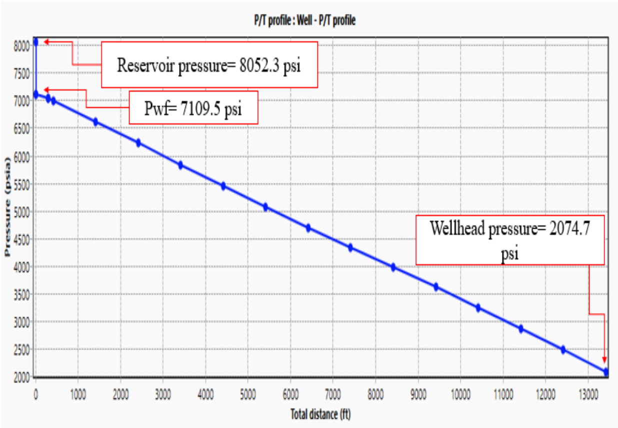

Fig. 18. Pressure Distribution for Well FH-4

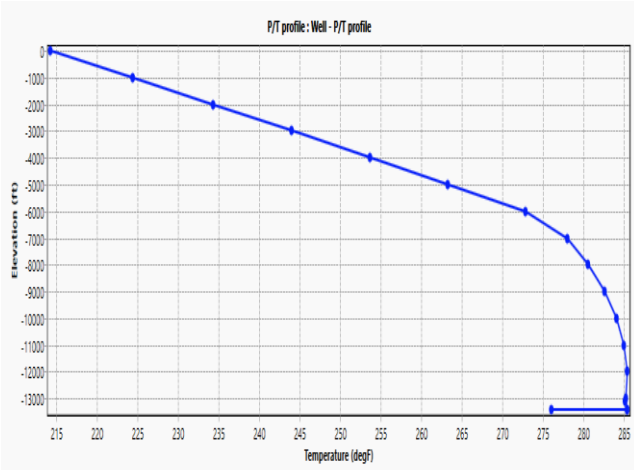

Fig. 19. Elevation vs Temperature for FH-4

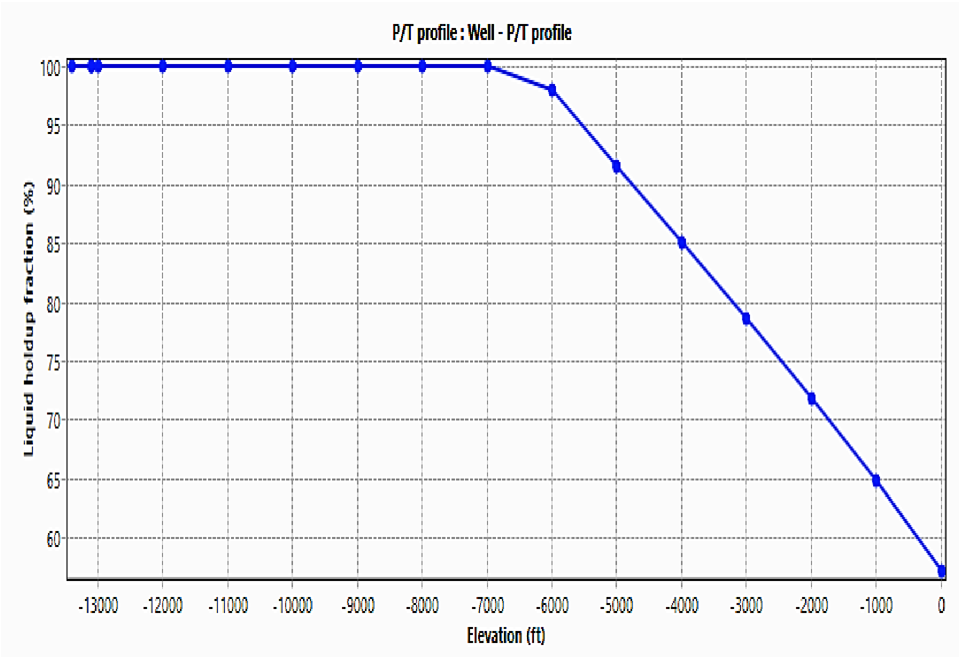

Fig. 20. Liquid Holdup vs Elevation for FH-4

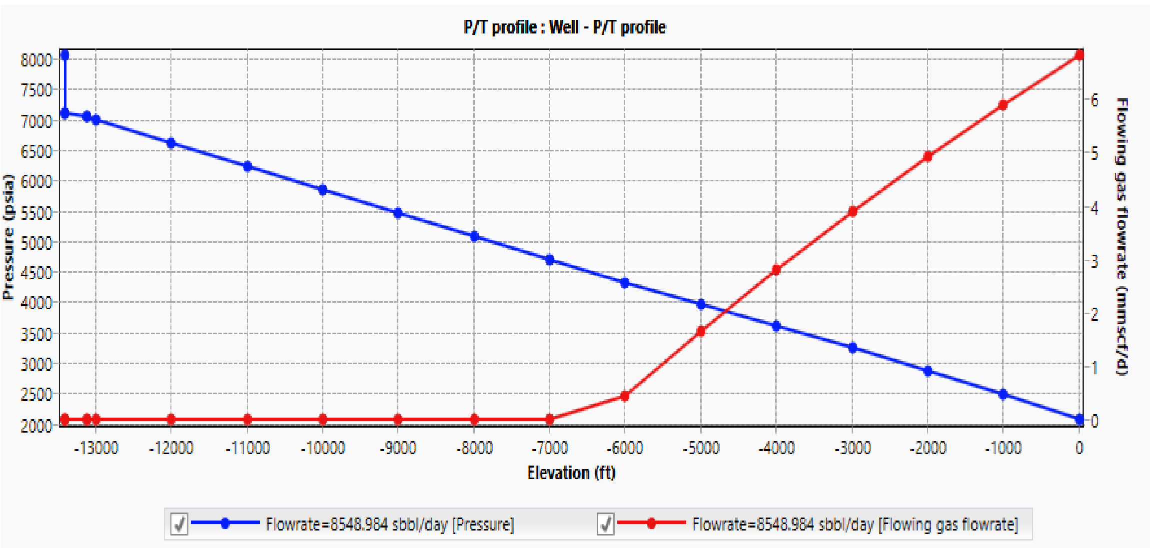

Fig. 21. Effect of Pressure and Elevation Decrease on Flowing Gas Flowrate for FH-4

4- Conclusions

The objective of this study was to identify the most accurate multi-phase flow correlation for calculating pressure drop in tubing sections from the Yamama reservoir in the Faihaa oil field, from the fluid entering the wellbore until reaching the surface. The main conclusions of this study are as follows:

The Hagedorn and Brown (HB) model provided the most accurate results for FH-1 and FH-3, and the Beggs Brill Original (BBO) model was the best fit for FH-2 while the Gomez mechanistic model provided the most accurate results for FH-4. However, it is noteworthy that the Beggs and Brill original (BBO) model exhibited the lowest accuracy results for well FH-1, Orkiszewski for well FH-2, Duns and Ros for well FH-3, and ANSARI for well FH-4.

The flow pattern observed in our studied wells extended from the well bottom to almost a depth of 6000 ft, characterized by liquid phase behavior Beyond this depth, slug flow phenomena became prominent, persisting at the wellhead and, causing significant production problems. Therefore, it is crucial to accurately select the optimal operation conditions including wellhead pressure and tubing size, to anticipate the onset of slug flow regimes and their associated production complications.

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التنبؤ بسلوك التدفق متعدد المراحل واختيار الارتباط الأمثل لأداء الرفع الرأسي في حقل الفيحاء النفطي، العراق

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الخلاصة

اكتسب الجريان متعدد الأطوار داخل أنابيب الإنتاج اهتمامًا كبيرًا بسبب التحديات التي لم يتم حلها الى الان. يعد التنبؤ الدقيق بهبوط الضغط وضغط قاع البئر أمرًا ضروريًا لنمذجة ادائية البئر بطريقة فعالة. يركز هذا البحث على التنبؤ بسلوك الجريان متعدد الاطوار في أربعة آبار تقع في حقل الفيحاء النفطي في جنوب العراق باستخدام برنامج PIPESIM . تم اختيار المعادلة الأكثر ملائمة لتمثيل سلوك الجريان متعدد الاطوار عن طريق استخدام بيانات الإنتاج لتمثيل هبوط الضغط داخل الابار ثم عمل مطابقة لهذه البيانات مع مجموعة المعادلات المتوفرة في برنامج PIPESIM .كشفت النتائج أن معادله(HB) Hagedorn & Brown تمثل النموذج الأكثر دقة لحساب الضغط في الابار FH−1 و FH−3 ،و ثبت أن معادلة (BBO) Beggs & Brill الاصلية هي الأنسب لحساب الضغط في البئر ٢ −FH. وفي البئر FH−4 يمثل نموذج Gomez النمموذج الأكثر دقة في حساب الضغط. حيث تظهر هذه المعادلات أدنى قيم للجذر المتوسط التربيعي (RMS) وهي ١١,٥ و ٧,٥٦ و ٨,٨٨٩ و ٦,٦٢٢ للآبار الأربعة على التوالي، مصحوبة بأقل نسب خطأ قدرها ٠,٠٠٦٩٢٪ و ٠,٠٠٠٣٣٪ و ٠,٠٠٧٨٧٪ و ٠,٠٠١١٪ على التوالي. على العكس من ذلك، فان النتائج الأقل دقة تنتج عن معادلة Beggs & Brill (BBO) الأصلية في البئر FH−1، وعن معادلة Orkiszewski للبئر FH−2 وعن معادلة Duns and Ros للبئر FH−3، وعن معادلة ANSARI للبئر FH−4. وايضا تحدد الدراسة أن التدفق أحادي الطور يهيمن ويحدث داخل أنابيب الانتاج حتى عمق ٦٠٠٠ قدم في معظم الآبار المدروسة، وبعدها يبدأ الجريان من نوع Slug بالضهور داخل البئر مما يتسبب في مشكلات إنتاجية كبيرة. لذلك، يوصى باختيار الظروف التشغيلية المثلى بعناية، بما في ذلك ضغط رأس البئر، وحجم أنابيب الانتاج، وغيرها من الظروف الاخرى المتعددة، بحيث تمنع حدوث نوع الجريان Slug وتخفيف مشاكل لإنتاج المرتبطة به التي من أهمها هو الجريان غير المستقر.

الكلمات الدالة: معادلات الجريان ثنائي الطور، أدائية الرفع العمودي، برنام Pipesim ، سلسلة الأنابيب الهيدروليكية، حقل الفيحاء النفطي.