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An integrated approach to characterize naturally fractured reservoirs and quantify their properties in the Bugani field

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Abstract

Naturally fractured reservoirs are the most important geological features that contain large amounts of hydrocarbon reserves. Therefore, the identification and evaluation of fractured zones are crucial in the oil production optimization and field development decisions. While different techniques have been introduced to detect and characterize fractured zones, using each method in isolation may not lead to a full detailed reservoir description and lower hydrocarbon recovery. The purpose of this paper is to provide a combined approach to characterize naturally fractured reservoirs. Conventional petrophysical logs were used in combination to identify the reservoir fractures. Pressure transient analysis was conducted for the same wells to evaluate the properties of the detected natural fractures. The integration process was applied to three wells belonging to one of the Libyan oilfields known as the Bugani Field, located in the country's southeast region. Three fractures were detected at different depths where most of the fractures were large, open, non-horizontal, and filled with hydrocarbon. Well test analysis results showed different flow stages and models for the reservoir. Flow regimes for wells BU-02, BU-03, and BU-04 were 4, 5, and 9, respectively, where each flow regime was used to define specific fracture and reservoir properties. The skin factor was negative for all wells; thus, the fracture permeability was very high, varying between 2200-4500 md. Also, there was a variation in the two porosity system obtained from the well test.

Keywords: Naturally fractured reservoirs, Petrophysical log interpretation, Pressure transient analysis, Integrated characterization approach, Pressure build-up

Nomenclature

KBELEV	Kelly Bushing Elevation	S	Skin
Rw	Well Radius	Kz	Matrix Permeability
WOC	Water Oil Contact	Phi	Porosity
TD	Total Depth	Cr	Reservoir Compersibity
K_f	Fracture Permeability	Sw	Water Saturation
H	Net Tchniess	Rinv	Radius of Investigation
hw	Pay Zone	Re	External Radius
PI	Productivity Index	ω	dimensionless storage coefficient,
μ	Viscosity	λ	the inter porosity flow parameter

1. Introduction

Conventional petrophysical logs are designed to respond to various subsurface characteristics of the wellbore environment. They are essential in detecting reservoir fractures and assessing hydrocarbon-bearing zones. These tools can be classified into two categories: conventional (Gamma Ray, Caliper, Resistivity, and Density logs, etc.) and unconventional logging tools such as Nuclear Magnetic Resonance (NMR) and Magnetic Resonance Imaging (MRI). The volume of data obtained from petrophysical logs is insufficient to present a detailed fractured reservoir model. Therefore, it is vital to use all the available sources to increase the knowledge of the fracture networks and their properties [1, 2]. Analyzing well test and production data has always been the most basic and essential tool for identifying fracture properties such as permeability, storage capacity ratio, and the inter-porosity flow parameters in naturally fractured reservoirs [3, 4]. Pressure transient analysis may include generating and measuring pressure variations in wells. Analyzing pressure derivative provides different rock, fluid, and reservoir properties. Thus, this technique is reliable for detecting fractures and their properties at the well scale [5, 6].

In the recent oil and gas industry, there are various options to characterize and measure fracture geometries using direct methods (e.g., core analysis and microfracture analysis, petrophysical logs, well test and seismic sections), and indirect approach (e.g., optical microscopy, (NMR) and (MRI), tomography and drilling mud loss history). Indirect methods can only produce images at specific intervals, and the operating cost is considerably high [2, 7-9]. Furthermore, Aghli, Soleimani [10] and Ge, Fan [11] have added that

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all the direct and indirect techniques may have serious drawbacks. Therefore, selecting the right approach to identify fracture networks depends on economic viability and tool limitations.

Historically, natural fracture detection was solely based on static data, where all conventional log results are indirectly affected by the presence of fracture networks [2, 12]. Fractures in carbonate reservoirs can highly influence the rock porosity and permeability. Therefore, detecting these networks is an essential step towards accurate reservoir simulation characterization [13, 14]. Fracture detection can be done once all geological information and fracture properties are known. Nonetheless, fracture permeability and hydraulic fracture width can only be identified during the production phase [10, 15, 16]. Conventional logging approaches are useful in defining open or hydrocarbon-filled fractures [17]. However, it should be noted that a single well log is inadequate to determine the fractured zones [11]; instead, logging tools should be used in combination to detect reservoir fractures [18].

Pressure Transient Analysis (PTA) has long been recognized as an excellent tool to define flow regimes and quantify fracture properties. A fractal pressure transient mode model was presented by Chang and Yortsos [19] to analyze the pressure behavior of a naturally fractured reservoir. Their model was then developed by Beier [20] to account for hydraulically fractured wells and introduced the power-law behavior that occurs during linear and radial flow regimes. Acuna, Ershaghi [21] analyzed well test data for a fractured reservoir based on Chang and Yortsos [19] model. They found that pressure change in the wellbore is a power-law function of time, where the fraction or spectral dimension can be easily obtained. Assuming a pseudo-steady state transfer function between matrix and fracture systems, Olarewaju [22] has used a transient interporosity flow model to examine the transient pressure response of a NFR. Zeybek, Kuchuk [23] presented a field example of Interval Pressure-Transient Tests (IPTTs). His method was applied to a fractured carbonate formation using 12 tests to evaluate the vertical permeabilities and fracture conductivities' delineation.

To quantify the effect of natural fractures on pressure transient response, Izadi and Yildiz [23] have proposed a semi-analytical, fractures were discretized into multiple segments to reflect the real fracture geometry. Biryukov and Kuchuk [24] conducted well-testing study for a fractured and non-fractured reservoir. Their result indicated that flow regimes for fractured reservoirs differ significantly from conventional non-fractured reservoirs. Chen, Liao [25] have used arbitrarily-distributed hydraulic and natural fractures to analyze pressure transient response. Rbeawi and Tiab [26] developed a new analytical model for a hydraulically fractured horizontal well to investigate pressure behavior and flow regions. Multiple analytical solutions for the flow regimes were obtained using MATLAB codes. They concluded that these models can be used to determine different reservoir parameters, including directional permeability, fracture length, skin factors, and angle of inclination.

Fractured reservoirs are common in petroleum exploration and production despite their difficulties in detection and evaluation. Static and dynamic characterization of naturally fractured reservoirs is crucial during many field life stages, including appraisal and production phases. Identification of fracture distribution and properties is a vital step towards the realistic characterization of naturally fractured reservoirs. It also reduces uncertainty and optimizes hydrocarbon recovery [27, 28]. Several improvements were introduced to the analysis techniques listed above with new methods, such as numerical simulation methods [29-33] and analytical and semi-analytical [34-39], which were applied for different well types.

2. Data collection

An oil operation company provided the logging and pressure transient data for different wells of a carbonate reservoir with three main lithologies; dolomite, sandstone, and limestone. The well was drilled with conductive mud. The near-surface mud temperature is 17 °C with mud resistivity of 0.071 Ωm at 98 °C. As the depth increases, the mud resistivity varies from 0.022 Ωm to 0.035 Ωm. The initial reservoir pressure is 1368 psi, and the bubble point pressure is 134 psi, oil gravity is 40 API, gas-oil ratio is 16 scf/stb, and oil formation volume factor is 1.04 rb/stb.

3. Materials and methods

The methodology used in this study is divided into two sections, the first is concerned with fracture detection, and the second is dealt with identifying fracture properties as follow:

3.1 Fracture characterization using petrophysical well logs

In this paper, the local-scale approach is followed, where petrophysical well logs were used to detect natural reservoir fractures. For reliable fracture characterization, no single well log can be used separately for detecting the fracture sets. Instead, all logs are affected in one or another way by the presence of fractures. In order to identify fractured zones using petrophysical logs, it is essential to analyze the impact of fractures on some petrophysical logging tools response.

3.1.1 The impact of fractures on petrophysical log response

Advanced logging tools such as formation image logs are limited and not readily available for all wells due to high operating costs and restricted logging intervals. Therefore, this study is mainly based on conventional petrophysical well logs to develop a realistic fracture description for the Bugani field. The available well logs used for this study and their significance are indicated in Table 1.

As shown in Table 2, conventional logging responses have been obtained for three different wells (BU-02, BU-03, and BU-04). The first data set (Log 1) for well BU-02 covered the depth interval 5100-5450 SSTVD, with a formation sampling thickness of 350 ft. It comprised of Bulk Density, Caliper, Sonic Transit Time, and Gamma Ray logs. Log 2 for well BU-03 was measured between the depths 5425-5600 SSTVD with a sampling interval of 175 ft. The log range for this well included spherically focused resistivity log, Bulk Density, Photo Electric Effect and deep resistivity logs. The final logging data (Log 3) were collected for well BU-04 from 5400-6050 SSTVD covering a formation thickness of 650 ft. It comprised of Gamma Ray, Compensated Gama Ray, Neutron Porosity, and Photo Electric Effect logs.

Table 1 Summary of petro physical well logging significance in fracture detection

Petrophysical well Log	Significance in Fracture Detection
Caliper Log (CALI)	• It records the wellbore enlargement that might be caused by fractures presence. A more extensive fracture or fractured zone can be represented by an increase in the wellbore diameter over the drilled diameter.
Gamma Ray (GR)	• In the absence of spectral gamma ray data, the gamma ray log measurement is inconclusive for fracture identification. • A positive spike in the gamma ray log indicates fracture presence.
Compensated Gamma Ray (CGR)	• The compensated gamma ray curve follows the same trend as the gamma ray, but it is an improved gamma ray version.
Bulk Density Log (RHOB) and Density Correction	• A sharp decrease in bulk density log reading indicates the open fractures filled with drilling fluid. • The logged interval may contain fractures, large vugs, or caverns when the density log response shows high-porosity spikes not detected by the neutron log. • The density correction log is one of the best fracture identification tools. A large density correction indicates the presence of fractures, mostly when a weighted mud is used.
Neutron Porosity (NPHI)	• Neutron log exhibits similar behavior to the density log. An increase in the log value indicates fractured zones filled with fluid.
Resistivity Log (RS)	• In the presence of a fractured zone, the micro-resistivity log would show sharp conductive anomalies. When the response of the three curves i.e., LLd, LLs and Rxo is striking, fractures might be full of hydrocarbon away from the borehole. • In the presence of a fractured zone, micro-resistivity, spherically focused resistivity log (SFLU) log, and spherically focused resistivity log (SFLU) show sharp conductive anomalies
Sonic Transit Time Log (DT)	• Large and sub-horizontal fractures are known to cause cycle skipping and an increase in transit time. Fluid-filled fractures even contribute to a more substantial attenuation.
Photo Electric effect log (PEF)	• The photoelectric absorption value in a fractured zone would show a lower trend with a slight peak supporting a hydrocarbon-filled fracture. A dual behavior around fractured zones can be observed (increase and decrease) when the identified fractures are either closed or semi-closed • Heavy minerals result in exceptionally high PEF measurement. • Mud-filled fractures are indicated on the PEF log by a very sharp peak.

Table 2 A summary of the available logging data for the Bugani field

Log No	Well Name	Log Name	Interval SSTVD	Sampling Thickness
1	BU-02	RHOB, CALI, DT & GR	5100-5450	350
2	BU-03	SFLU, RHOB, PEF & RILD	5425-5600	175
3	BU-04	GR, CGR, NPHI & PEF	5400-6050	650

3.2 Fracture property quantification using pressure transient analysis

Pressure transient analysis is typically based on static and dynamic conditions where flow rate, pressure, and time are related mathematically. The slope on the log-log graph method is used to obtain the reservoir flow characteristics, description and divide the log-log pressure derivative plot into different stages and flow regimes. A slope characterizes some flow regimes to define their features. Several studies, including [28, 40-52], have discussed the flow regimes in naturally fractured reservoirs.

3.2.1 Identification of the Interpretation model (Inverse Problem)

The parameters of an unknown system are estimated based on its observed output data. The characteristic behavior of the log-log derivative curve of the actual reservoir must closely match the diagnostic plots available in the Pansystem software. Identical behavior requires similar qualitative characteristics (i.e., similar shapes) for both the actual reservoir and the calculated model. Defining the appropriate model that matches the actual reservoir is the most critical stage of the pressure analysis process. Selecting the wrong model would lead to deriving incorrect reservoir and fracture parameters. Subsequently, field development decisions are likely to be inappropriate.

The change in pressure, Δp, was plotted vs. the elapsed time, Δt, on a log-log graph to represent the pressure derivative and flow stages. The shape of the pressure derivative curves can also help to identify flow characteristics. The main benefit of using the log-log plot is that Δp and Δt for the interpretation model and field data can be scaled in the same manner. This method can also accommodate the fracture's existence in the well for reservoir flow description and reservoir characterization

Several parameters were investigated concerning their impact on flow behavior and reservoir heterogeneity. Different flow stages have provided details about the reservoir and its fracture properties. Transient pressure responses are generated by varying the wellbore flow condition and recording the bottomhole flowing pressure. With the commercial software Pansystem, pressure data were analyzed and matched with appropriate analytical solution models. All flow models available in the Pansystem software can identify and verify the various flow regimes and models that dominate during a test. For some flow regimes, parameters such as wellbore storage might be obtained directly from the derivative without matching the model.

3.2.2 Model parameters interpretation (Direct Problem)

Once the appropriate reservoir model is selected for each well, its response is generated analytically. The parameters were varied till the best match (similar quantitative response as the actual reservoir) is obtained. Unknown properties are adjusted manually until the theoretical solution or ideal model matches the measured system behavior. The matching process ensured the identification of the reservoir conditions that led to selecting the appropriate model. Those adjusted parameters resulted from the matching process were used to represent the corresponding reservoir parameter values.

4. Results and discussion

To detect natural fracture networks, multiple conventional well logs were used. Different fracture sets with various size and shape were determined. Besides, to further confirm fractures presence, define their properties, and obtain detailed reservoir description, log-log plots for the pressure build-up test were analyzed. Pressure transient tests were conducted in barefoot using direct and back choke modes with initial, intermediate, and final shut-ins to record pressure build-up (PBU). The well testing analysis for the Bugani fractured reservoir has different flow behavior and models to match. All flow models were unique and complex to match.

Figure 1 shows RHOB, CALI, DT & GR log responses for well BU-02. A sharp negative peak indicates a fracture-filled with hydrocarbon from the bulk density log at a depth from 5290-5320 SSTVD. Furthermore, from the Caliper log, it can be seen that there is an increase in the size of the borehole diameter, which may indicate a larger fracture or fractured zone. At the same depth, a cycle skipping effect can be observed in the sonic log. Besides, the sonic log response shows an abrupt increase in the interval transit time. This suggests the presence of a sub-horizontal and light hydrocarbon filled fracture. Moreover, fracture presence can further be confirmed from the gamma ray where a spike was created by the gamma ray response at the same zone. The fact that all of these responses can be seen at various depths proves that the fracture is sub-horizontal.

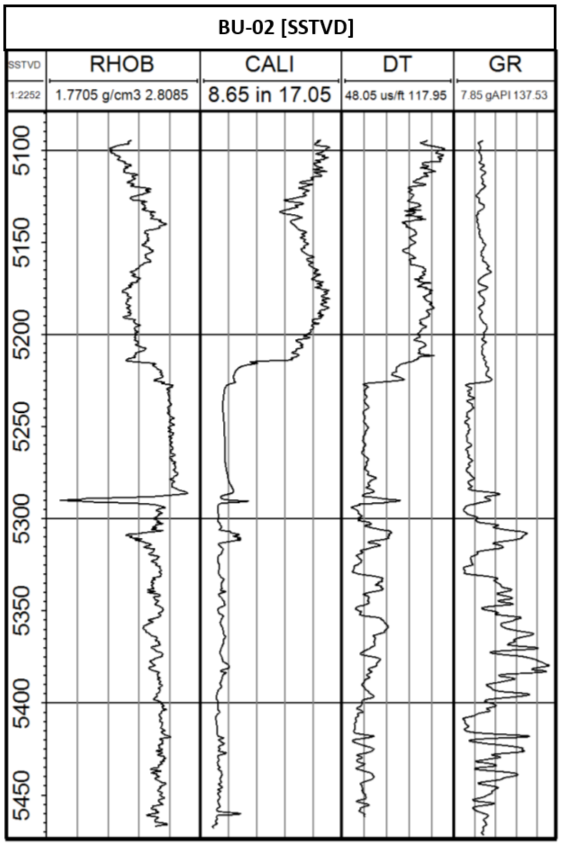


Figure 1 Location of fractured zones on petrophysical logs for well BU-02

Pressure Build-up for BU-02 (PBU#1)

The survey depth for this well was 5318.0 ft-ss within the range (5100-5450 SS-TVD) of the fractured zone obtained from well log analysis. The net thickness of this test was 163 ft.

The pressure transient responses undergo several processes as they travel through the reservoir formations known as flow stages or regimes. These depend on elapsed time, distance from the wellbore, and characteristic pressure distributions. In addition, the shape of the curve and its derivative will change according to different situations where various model parameters are used. Applying the slope analysis and diagnostic plot techniques, well BU-02 transient behavior exhibited four flow regimes, as shown in Figure 2. Each flow regime provides a different reservoir, well, and fracture characteristics. The respective detailed interpretations are as follows:

Regime 1

This flow region is known as the pure wellbore storage, where the dimensionless pseudo-pressure curve coincides with the dimensionless pressure derivative curve. A unit slope for both curves features this flow regime.

Regime 2

This flow regime is known as the early-time transition flow period. This flow regime is effective once the wellbore storage impact is completed. It is modeled by a hump in the dimensionless pressure derivative curve, reflecting the common effect of skin and wellbore storage.

Regime 3

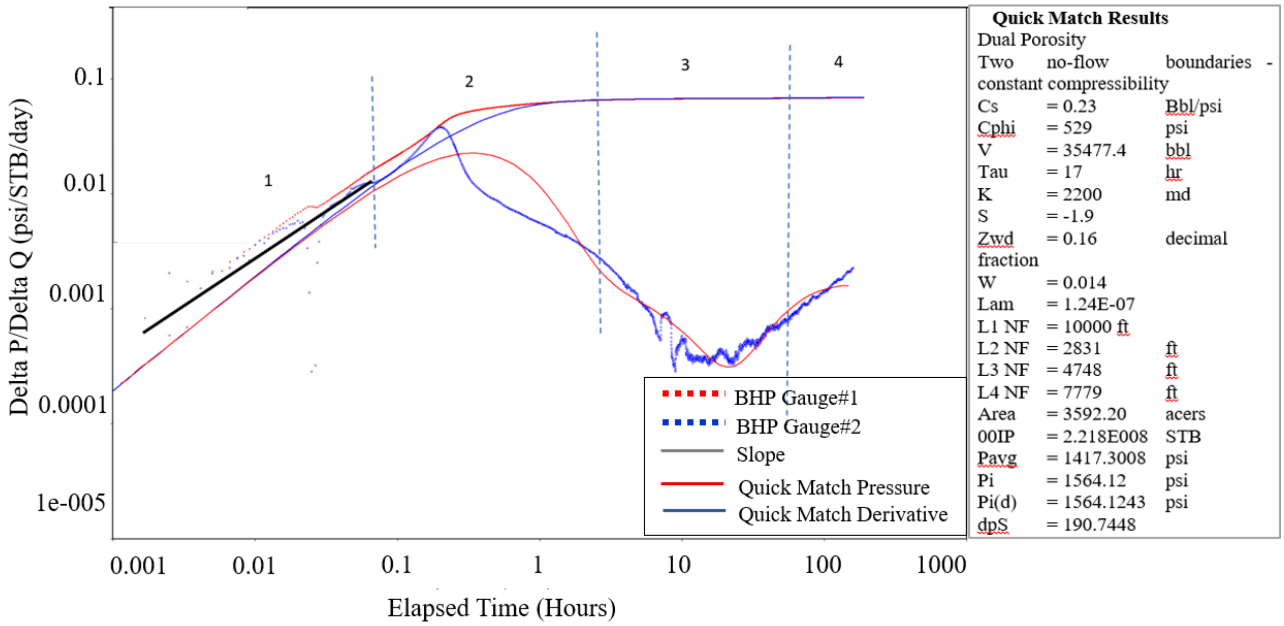
There is a dip in the pressure derivative curve at this flow regime, which indicates the inter-porosity flow of matrix to fracture systems.

Regime 4

This regime is the boundary dominated flow stage. Observing this flow regime shows that the pressure build-up period was insufficient to fully define the reservoir's external boundary. The derivative curve was still changing when the data collection stopped. However, the pressure curve and its derivative began to take an upward move, which indicates that the reservoir is finite with a closed boundary. The well test results summary for well BU-02 are indicated in Table 3.

Table 3 Summary of well test results for well BU-02

Parameter	Unit	BU-02
Survey Depth	ftKB	6028.0
	ft-ss	5318.0
KBELEV	ft	710
Type of Pressure Transient		PBU (Analytical)
Well Radius (ft)	Open Hole	
	Cased Hole	0.29
WOC	ft	6685
Casing	ft-KB	6179
Plug/TD	ft-KB	6180
Pay zone (hw) (ft)	Gross	170
	Net	163
k_f	md	2200
k*h	mdft	358600
PI	STB/D/psia	3.4
k/µ	md/cp	2037.037
Skin		-1.9
Kz		0.13
Phi	%	6
Cr	psi-1	2.132E-05
Sw	%	27
Rinv	ft	2800
Re	ft	900
Two Porosity	ω	0.014
	λ	1.24E-07



Quick Match Results
Dual Porosity
Two no-flow boundaries - constant compressibility
Cs = 0.23 Bbl/psi
Cphi = 529 psi
V = 35477.4 bbl
Tau = 17 hr
K = 2200 md
S = -1.9
Zwd = 0.16 decimal fraction
W = 0.014
Lam = 1.24E-07
L1 NF = 10000 ft
L2 NF = 2831 ft
L3 NF = 4748 ft
L4 NF = 7779 ft
Area = 3592.20 acers
00IP = 2.218E008 STB
Pavg = 1417.3008 psi
Pi = 1564.12 psi
Pi(d) = 1564.1243 psi
dpS = 190.7448

Figure 2 Pressure derivative curve for well BU-02 (PBU#1)

It can also be observed from Figure 2 that due to long wellbore-storage-dominated flow, many flow regimes were not reached in the earlier field data. In this case, influenced data by wellbore storage contains little details about the reservoir. For well BU-02 we can draw a conclusion that as the size of the natural fracture increases, the V-shape in flow regime 3 gradually becomes deeper but the duration of the V-shape remains constant. This conclusion was also based on petrophysical well log analysis as the fracture was large and filled with hydrocarbon.

Figure 3 illustrates the log response for well BU-03, including resistivity logs (SFLU and RILD), RHOB, and PEF. At a depth of around 5500-5540 SSTVD, it can be observed that there is a dramatic decrease in the density log value, which indicates the presence of a large fracture. Furthermore, the PEF log response showed a sharp decrease at the same depth, suggesting a semi-closed hydrocarbon-filled fracture. In addition, both resistivity logs (SFLU and RILD) showed a sharp conductive anomaly, which indicates the presence of a fracture that might be full of hydrocarbon away from the borehole.

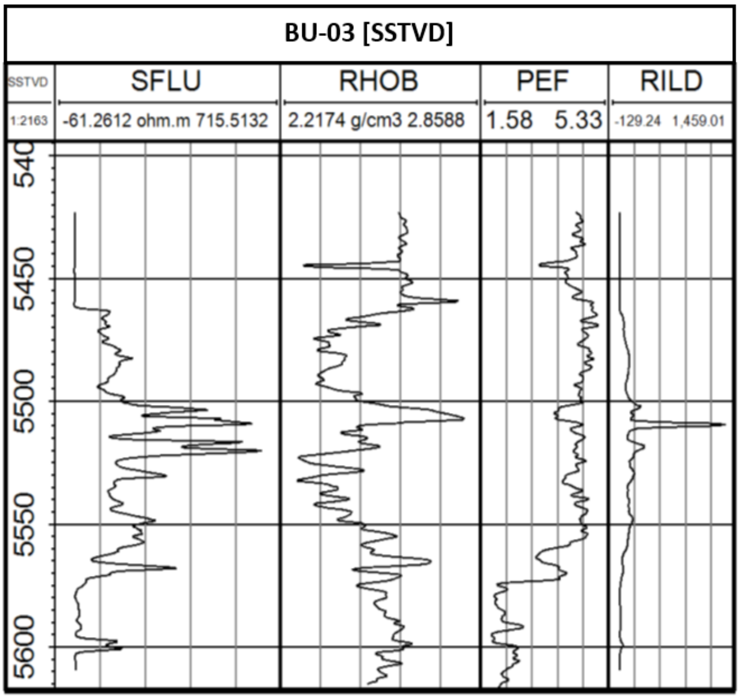


Figure 3 Location of fractured zones on petrophysical logs for well BU-03

Pressure Build-up for BU-03 (PBU#2)

The survey depth for this well was 5520 ft-ss within the range (5500-5540 SS-TVD) of the fractured zone obtained from well log analysis. The net thickness of this test was 120 ft.

Applying the slope analysis and diagnostic techniques, Figure 4 illustrates that the transient behavior of well BU-03 exhibits five different flow regimes. Each flow regime provides a reservoir, well, and fracture characteristics. The respective detailed interpretations are as follows:

Regime 1

This test's distinct feature is a long wellbore storage period due to shut-in at the surface to record PBU. This regime is mainly dominated by wellbore storage and skin. A unit slope can be identified, which indicates the wellbore storage effect.

Regime 2

The pressure derivative curve at this flow regime shows a straight line with (1/2) slope. Throughout this flow period, fluid losses of the inner region (the matrix) are compensated by the fracture system in the outer region. At this regime, there is an increasing trend on the derivative curve to a higher value. This flow region is mainly dominated by fracture permeability.

Regime 3

It can be seen that the hydrocarbon flows into the wellbore in a slow pattern, which results in decreasing the pressure depletion. Hence, the pressure derivative drops accordingly, causing the first radial flow regime. A horizontal line slope distinguishes this region. It can also be observed that this stage is long, which indicates a large fracture and good properties of the fracture.

Regime 4

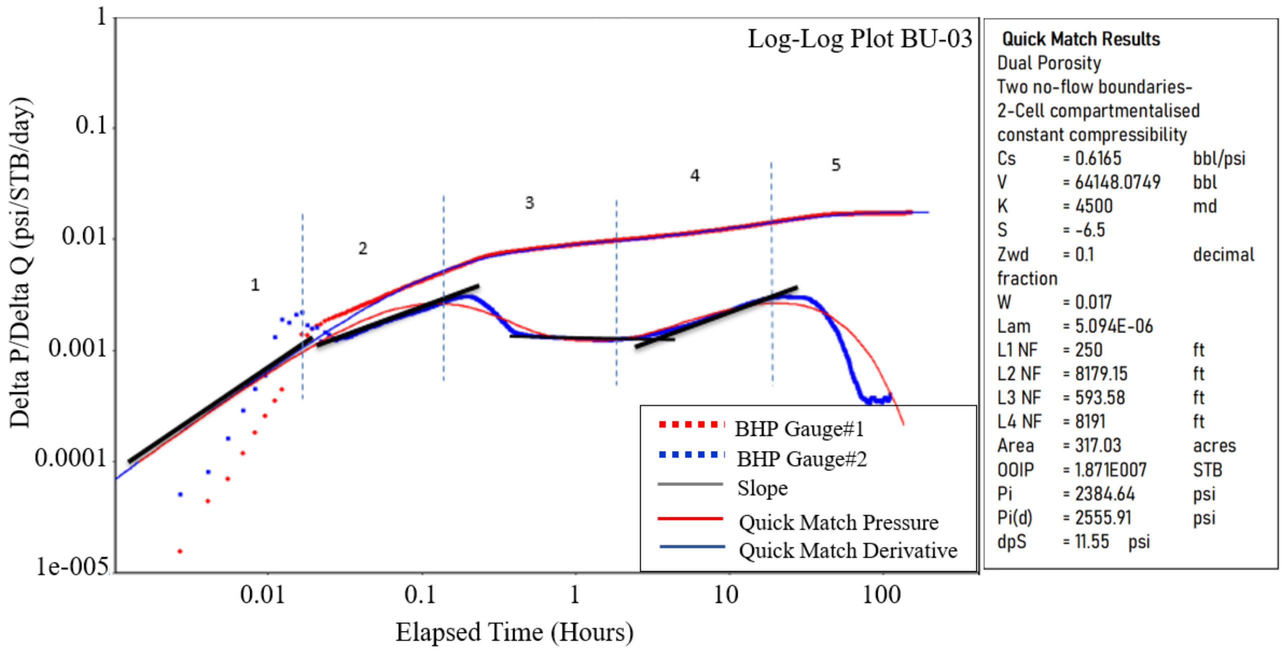
At this stage, the pressure wave reaches the fracture's tip, which marks the intermediate time pseudo-radial flow regime. The dimensionless pressure derivative shows a straight line with a particular slope (1/2) rather than a horizontal line.

Regime 5

This flow regime illustrates the external boundary response stage. The downward trend indicates that the boundary of the reservoir is a finite reservoir with constant pressure. This stage is dominated by the outer radius of the reservoir boundary. The two humps in the log-log plot indicate that the reservoir is compartmentalized. The overall well test results are shown in Table 4.

Table 4 Summary of well test results for well BU-03

Parameter	Unit	BU-03
Survey Depth	ftKB	6200
	ft-ss	5520
KBELEV	ft	680
Type of Pressure Transient		PBU (Analytical)
Well Radius (ft)	Open Hole	0.32
	Cased Hole	
WOC	ft	6720
Casing	ft-KB	6167
Plug/TD	ft-KB	6289
Pay zone (hw) (ft)	Gross	135
	Net	120
k_f	md	4500
k*h	mdft	540000
PI	STB/D/psia	18
k/μ	md/cp	4166.667
Skin		-6.5
Kz		0.26
Phi	%	12
Cr	psi-1	4.67582E-05
Sw	%	25
Rinv	ft	725
Re	ft	80
Two Porosity	ω	0.017
	λ	5.09E-06



Quick Match Results
Dual Porosity
Two no-flow boundaries-
2-Cell compartmentalised
constant compressibility
Cs = 0.6165 bbl/psi
V = 64148.0749 bbl
K = 4500 md
S = -6.5
Zwd = 0.1 decimal fraction
W = 0.017
Lam = 5.094E-06
L1 NF = 250 ft
L2 NF = 8179.15 ft
L3 NF = 593.58 ft
L4 NF = 8191 ft
Area = 317.03 acres
OOIP = 1.871E007 STB
Pi = 2384.64 psi
Pi(d) = 2555.91 psi
dpS = 11.55 psi

Figure 4 Pressure derivative curve for well BU-03 (PBU#2)

The occurrences and duration of the flow regimes illustrated in Figure 4 depend on the matrix permeability and fracture conductivity, distribution, and size. All these flow regimes occur in a certain chronological order. The well log and pressures results indicated the presence of large fracture with good flowing properties. With the increase of fracture size and fracture conductivity, the natural fracture effect on transition flow of the pressure derivative curve for well BU-03 becomes significant. In normal porous media flow, the fluid accelerates through the relatively narrow pores and inversely decelerate when passing larger ones. In well BU-03, there might be a change in velocity and inertial losses due to the presence of a large fracture.

Figure 5 showed conventional well log response for GR, CGR, NPHI & PEF representing well BU-04. For PEF log, it can be seen that there is a sharp decrease in the log value at approximately 5430 – 5470 SSTVD, indicating the presence of a hydrocarbon filled fracture. This also suggests that the fracture might be closed or semi-closed. It can also be seen that the fracture is located between two different depths, which illustrated that the fracture might be in a vertical or semi-vertical state. In addition, at the same zone, the gamma ray reading demonstrated non higher formation shaliness except for a sharp rise in the log value at almost the same depth, which indicates a fractured porous medium. The compensated gamma ray curve follows the same trend as the gamma ray, the spike is not presented sharply. Also, observing the neutron porosity log at the same depth shows a fractured zone as the log value has dramatically increased. It also indicates an increase in the formation fluid.

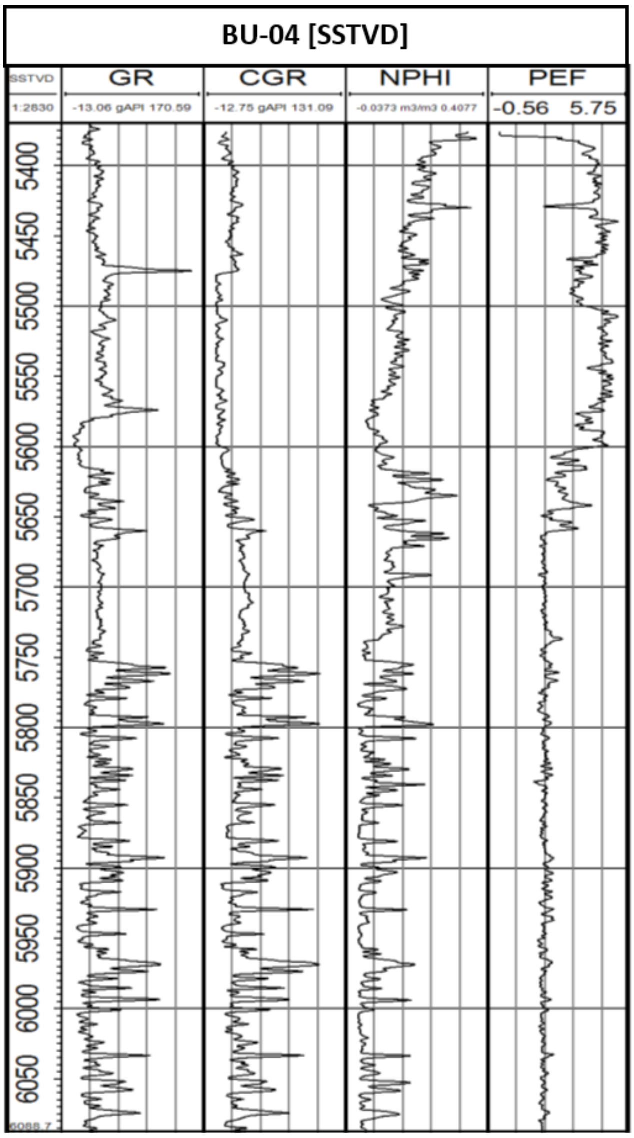


Figure 5 Location of fractured zones on petrophysical logs for well BU-04

Pressure Build-up for BU-04 (PBU#3)

The survey depth for this well was 5463.6 ft-ss within the range (5430 – 5470 SS-TVD) of the fractured zone obtained from well log analysis. The net thickness of this test was 169 ft.

Applying the slope analysis and diagnostic techniques, Figure 6 illustrates that the transient behavior of well BU-04 exhibits nine flow regimes. Each flow regime provides a reservoir, well, and fracture characteristics. The respective detailed interpretations are as follows:

Regime 1

It is the pure wellbore storage flow regime, where a unit slope is observed for the pressure curve and its derivative.

Regime 2

This regime is known as the first transition flow. The skin effect at this stage appears due to the interaction between the fluid and well wall, which reduces the pressure remarkably. Therefore, the pressure derivative curve increases first and descends afterward. The high wellbore storage effect was identified, and the skin was negative due to the presence of a natural vertical fracture.

Regime 3

This region is characterized by the first radial flow regime, where a horizontal line slope represents the pressure derivative curve. During this flow period, the hydrocarbon in the first flow regime begins to infiltrate into the wellbore.

Regime 4

It is the second transition flow section. Regime 3 ends and transits to regime 5. The pressure drops again at this stage.

Regime 5

A (-1/2) slope on the derivative curve shows a spherical flow regime. This flow is associated with reduced thickness of the fractured formation.

Regime 6

This flow regime is known as the vug storage segment. The derivative curve slope is equal to 1 again.

Regime 7

This is the pseudo-steady inter-porosity flow regime. It occurs because of the matrix-fractures fluid interaction. A cross-flow occurs between the two continua due to the pseudo-steady condition assumption as well the pressure difference between the matrix and natural fractures. The main characteristic of this period is modeled by a dip in the dimensionless pressure derivate curves.

Regime 8

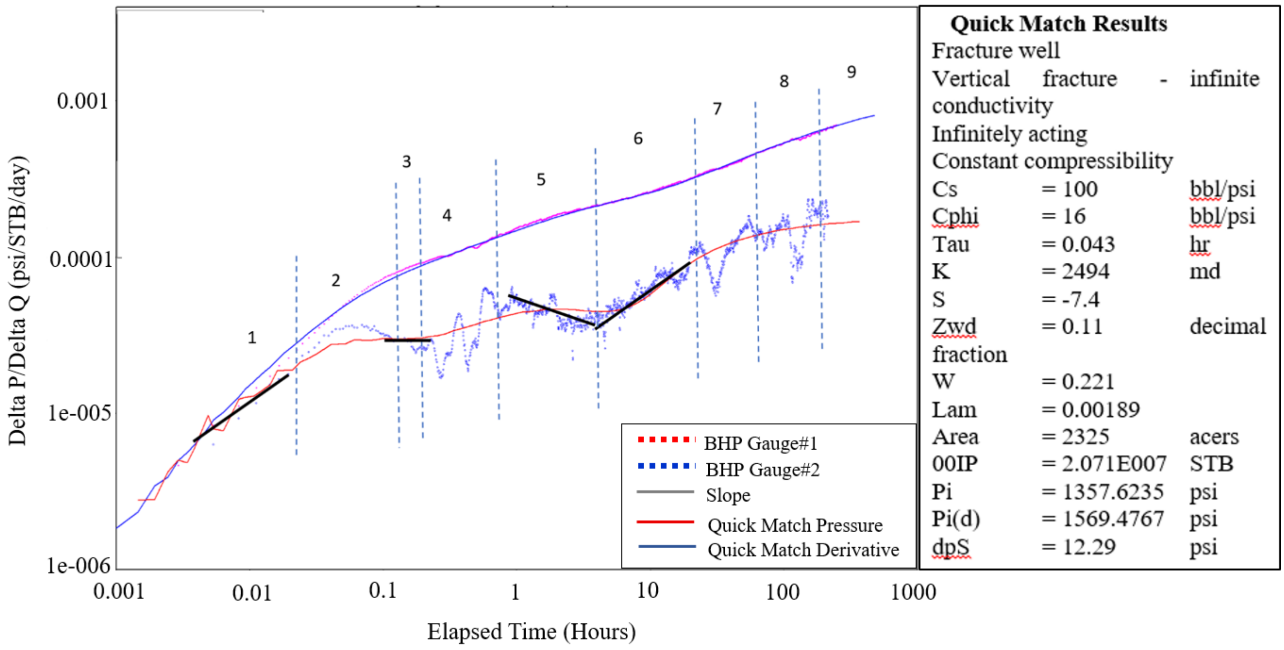
This is the third transition flow section. Regime 7 ends and transits to regime 9 and the pressure decreases again.

Regime 9

It is the boundary dominated flow stage. The derivative curve takes a downward shape, indicating that the reservoir's external boundary is a finite reservoir with constant pressure. The well test results are displayed in Table 5.

Table 5 Summary of well test results for well BU-04

Parameter	Unit	BU-04
Survey Depth	ftKB	6187.6
	ft-ss	5463.6
KBELEV	ft	724.0
Type of Pressure Transient		BU (Analytical)
Well Radius (ft)	Open Hole	
	Cased Hole	0.292
WOC	ft	6955
Casing	ft-KB	6295
Plug/TD	ft-KB	6296
Pay zone (hw) (ft)	Gross	183
	Net	169
k_f	md	2494
k*h	mdft	421486
PI	STB/D/psia	40
k/µ	md/cp	2309.259
Skin		- 7.5
Kz		0.129
Phi	%	8
Cr	psi-1	2.1779E-06
Sw	%	55.419
Rinv	ft	418
Re	ft	77
Two Porosity	ω	0.221
	λ	0.00189



Quick Match Results

Fracture well

Vertical fracture - infinite conductivity

Infinitely acting

Constant compressibility

Cs = 100 bbl/psi
Cphi = 16 bbl/psi
Tau = 0.043 hr
K = 2494 md
S = -7.4
Zwd = 0.11 decimal fraction
W = 0.221
Lam = 0.00189
Area = 2325 acers
00IP = 2.071E007 STB
Pi = 1357.6235 psi
Pi(d) = 1569.4767 psi
dpS = 12.29 psi

Figure 6 Pressure derivative curve (PBU#3) for well BU-04

Notice in Figure 6, the characteristic trough that separates region 5 and 6 is indicative of the transition period for this reservoir. Its depth is dependent on the dimensionless wellbore storage coefficient, but independent of the inter-porosity flow parameter. It is ideal to assume that the matrix system is separated by a uniformly continuous fractured zone characterized by the pseudo-steady flow. Comparing the well log analysis for this well and its pressure transient analysis it can be seen that the results are well matched where the fracture is vertical. The storage capacity ratio, ω, links the pressure transient analysis and the fracture compliance estimated from well logs. This ratio indicated that there is a hydrocarbon in the fracture which confirms the results of the well log analysis.

Due to vertical fracture presence and constant pressure boundary, the flow transition zone changes from "hump" to "dip". This V-shape can also be used to estimate the property and distribution of natural fractures. In general, a pseudosteady-state flow regime may occur as a first or second flow regime in fractured reservoirs when the contrast between the fracture permeability and matrix permeability is high (i.e., while the fluid in fractures is quickly being depleted but the fluid into fractures is not replenished readily by the matrix elements).

4.1 Summary of results

Table 6 shows the fractures' depth and details obtained from the petrophysical well log analysis. It can be seen that the Bugani reservoir contains three fractures at different depths. Most of the fractures are large, open, and filled with hydrocarbon. Thus it is clear the fracture sets affect the fluid flow behavior and its production recovery mechanisms. Furthermore, fractures at various depths are to be non-horizontal. This information is insufficient to provide a detailed description of the fractured reservoir (Bugani Field); therefore, a pressure trainset analysis was used to shed more light on the fracture properties and their role in impacting the fluid flow movement through the fracture networks. Table 7, indicates a summary of the fracture and reservoir parameters obtained from the pressure build up test.

Table 6 Summary of petrophysical logging Results

Log No	Well name	Fracture depth (SSTVD)	Fracture details
1	BU-02	5100-5450	• Sub horizontal large, light Hydrocarbon filled fracture.
2	BU-03	5425-5600	• Large fracture. • Semi-closed hydrocarbon filled fracture. • Fracture full of hydrocarbon away from the borehole.
3	BU-04	5400-6050	• Hydrocarbon filled fracture. • The fracture might be closed or semi-closed. • Increased formation fluid in the fracture. • Vertical or semi-vertical fracture.

Table 7 Build-up Analysis Results for All Wells

Parameter	Unit	BU-02	BU-03	BU-04
Survey Depth	ftKB	6028.0	6200	6187.6
	ft-ss	5318.0	5520	5463.6
KBELEV	ft	710	680	724.0
Type of Pressure Transient		PBU (Analytical)	PBU (Analytical)	BU (Analytical)
Well Radius (ft)	Open Hole		0.32	
	Cased Hole	0.29		0.292
WOC	ft	6685	6720	6955
Casing	ft-KB	6179	6167	6295
Plug/TD	ft-KB	6180	6289	6296
Pay zone (hw) (ft)	Gross	170	135	183
	Net	163	120	169
k	md	2200	4500	2494
k*h	mdft	358600	540000	421486
PI	STB/D/psia	3.4	18	40
k/µ	md/cp	2037.037	4166.667	2309.259
Skin		-1.9	-6.5	- 7.5
Kz		0.13	0.26	0.129
Phi	%	6	12	8
Cr	psi-1	2.132E-05	4.67582E-05	2.1779E-06
Sw	%	27	25	55.419
Rinv	ft	2800	725	418
Re	ft	900	80	77
Two Porosity	ω	0.014	0.017	0.221
	λ	1.24E-07	5.09E-06	0.00189

As indicated in Table 7, fracture presence increases the overall compressibility of the reservoir because the fracture porosity and fracture permeability are more sensible to changes in stress than their corresponding matrix properties. In addition, the negative skin factor and the presence of natural fractures in all wells correspond to high permeability values. The radius of investigation shows how far a pressure transient moved through the reservoir. Higher value of the radius provides an indication of the formation traversed. When this radius reaches beyond the natural fractures, the pressure derivative curve enters the final pseudo-radial flow regime. The higher radius of investigation in well BU-02 explains the difference in the reservoir pressures and that surrounding production is actually drawing the reservoir pressure down. However, the low value in well BU-04, indicates that the buildup time was insufficient to identify all the reservoir parameters.

In order to analyze fluid flow in the matrix and fracture systems, it was crucial to use two main dynamic parameters, which are known as fracture conductivity λ and fracture storativity, ω as shown in Table 7. The fracture storativity measured the percentage of fracture contribution to reservoir fluid storage. A smaller value of ω indicates a more fracture effect on pressure variations. However, when ω value is close to unity, the reservoir behaves like homogeneous that made up solely of fractures. Fracture conductivity measured the ability of the matrix blocks to allow fluid to flow into the fracture networks. λ is related to the contrast in fracture and matrix permeabilities, i.e., the scale of heterogeneity. A smaller value of the fracture conductivity indicates a delay in the total system flow (transition period).

5. Conclusion

In this paper, we developed an integrated approach to characterize naturally fractured reservoirs and their properties. Different petrophysical logs were used to identify fractured zones, which was validated using the pressure transient analysis technique. Conventional well log responses can help identify and characterize natural fractures locations and define conductive and resistive fractures. Various fracture and reservoir parameters were obtained by analyzing the build-up pressure curve and its derivative. This method is more scalable and accurate to characterize a complex fracture system because each fracture's property is defined separately. It has been proven that combining more than one approach is useful in naturally fractured reservoir characterization.

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