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Applying Interpretation Results of Drill Stem Test to Evaluate the Lower Miocene Formation in Bao Den Oilfield, Cuu Long Basin

Nguyen Tuan[1], Tran Van Xuan[2]*, Tran Thi Mai Huong[3], Truong Quoc Thanh[4], Hoang Trong Quang[5]

1. Faculty of Geology & Petroleum Engineering, Vietnam National University, Ho Chi Minh City, Vietnam. E-mail: nguyentuan@hcmut.edu.vn
2. Faculty of Geology & Petroleum Engineering, Vietnam National University, Ho Chi Minh City, Vietnam. E-mail: tvxuan@hcmut.edu.vn
3. Faculty of Geology & Petroleum Engineering, Vietnam National University, Ho Chi Minh City, Vietnam. E-mail: ttmaihuong@hcmut.edu.vn
4. Faculty of Geology & Petroleum Engineering, Vietnam National University, Ho Chi Minh City, Vietnam. E-mail: tquocthanh@hcmut.edu.vn
5. Faculty of Geology & Petroleum Engineering, Vietnam National University, Ho Chi Minh City, Vietnam. E-mail: htquang@hcmut.edu.vn

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ABSTRACT

The present research is aimed at exploring the B1.1 sandstone sequence located in the lower Miocene formation within the Bao Den oilfield situated in the Cuu Long basin. This study involves utilizing Pressure-Volume-Temperature well parameters, such as bubble pressure, oil gas ratio, oil formation volume coefficient, density, viscosity, total compressibility, and BI.1 sandstone sequence parameter, including effective thickness, average porosity, well radius, and water saturation. Our focus will be on analyzing reservoir tests with two methods - the conventional and progressive approaches. This study will examine the Horner graph and how it can be used with formulas for determining initial reservoir pressure, slope, and fluid conductivity as part of the traditional method. Additionally, effective permeability, skin coefficient, and conductivity will also be analyzed. The advanced method involves using Ecrin software to interpret results, which shows that both methods yield favorable skin coefficients. The outcomes indicate that the well and reservoir parameters are precisely determined: the initial pressure of the reservoir is 2617.5 psia, hydro conductivity equals 7680 mD.ft, while permeability is 106 mD, coefficient Skin is 14, well storage coefficient evaluates to $5.61E^{-4}$ and distance to fault 439 ft. Based on the results, it is possible to assess that the BD-1X well in the Bao Den oilfield has promising potential as both oil and gas have favorable quality and volume attributes. This study's significance is providing input data for developing and exploiting oil fields resulting in choosing economical plans with commercial efficiency within the petroleum industry.

* Corresponding Author: T.V. Xuan (E-mail address: tvxuan@hcmut.edu.vn)

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Introduction

Currently, before investing and exploiting an oil field, the top question is always whether the oil field's reserves are large enough for commercial exploitation or not, and how reasonable the exploitation plan is. To solve these problems, the information about reservoirs must have high reliability. Information from geologists and geophysicists only provides the reservoir parameters in a static state. So, what happens when the reservoir is in an active state? Is the reservoir potential assessment based on those parameters still reliable?

Regarding the application of drill stem test (DST) to evaluate reach reservoir, there have been many studies from engineers and prominent names such as DST-petroleum geology that covered the detailed function of each component of the reservoir testing toolkit along with the reservoir testing procedure, then focused on interpreting the pressure diagrams; special applications of DST pressure data that can be determined mathematically through the DST pressure [1] graph; analysis of DST results at the Osobnica oil field, in terms of sampling the selected technology parameters [2]. This paper presented the geographical location, characteristics of the study area, and the analysis of the test results of DST at two wells of the Osobnica oil field. A review and analysis of drill-stem testing techniques helps readers understand the modern techniques of reservoir testing.

There are also several studies conducted in Vietnam, regarding a new approach in analyzing gas wells with high CO_2 content [3], determining the role and characteristics of CO_2 in interpreting the DST reservoir, evaluating the advantages and disadvantages of the applied method, and finally proposing a new approach to obtain reservoir parameters and devise a development plan for the oil field. One study addressed the challenges in developing the Su Tu Trang condensate gas field [4] and introduced the evaluation results. An important paper proposed a dual-porosity model for the fractured basement of the Ca Ngu Vang oil field [3]. The double-width model presents methods and procedures for building a dual-porosity model for flow simulation in the fractured basement object in the Ca Ngu Vang oil field.

From the published works, the research team has collected the necessary theory and databases, such as determining the reservoir parameters, establishing a calculation procedure to evaluate the quality of the reservoir, and performing it in the most accurate way.

In this study, the research team will focus on studying the BI.1 sandstone sequence, Bao Den oilfield, Cuu Long basin using Ecrin software [4], which is significant in contributing to the completion of data for development and exploitation. From there, it helps to choose a plan that achieves high economic efficiency. In addition, the topic is also a basis for future studies to evaluate the optimal quality in the Bao Den oilfield and other similar oil fields.

The study area is the Bao Den oilfield located to the east of Cuu Long basin, on the northwest edge of block Y with an area of about 5000 km2. Around here, many oil and gas fields have been discovered [5] (Fig. 1).

The exploration history of Block Y (together with block 01/100) is associated with the history of oil and gas exploration. So far, the exploration of blocks 01/100 & block Y and is divided into 3 main stages:

From 1992 to 2002: Petronas Company (Malaysia) conducted exploration activities of Blocks 01 and 02, destroying 563.73 km^2 of the 3D seismic route (2002) to the South and 13,870 km^2 of the 2D seismic route (1991, 2002). The company has drilled 3 exploration wells in the area of blocks 01/100 and block Y: 02-D-1X (Sapphire), 02-M-1X (Opal), and 01-E-1X (Agate) [6].

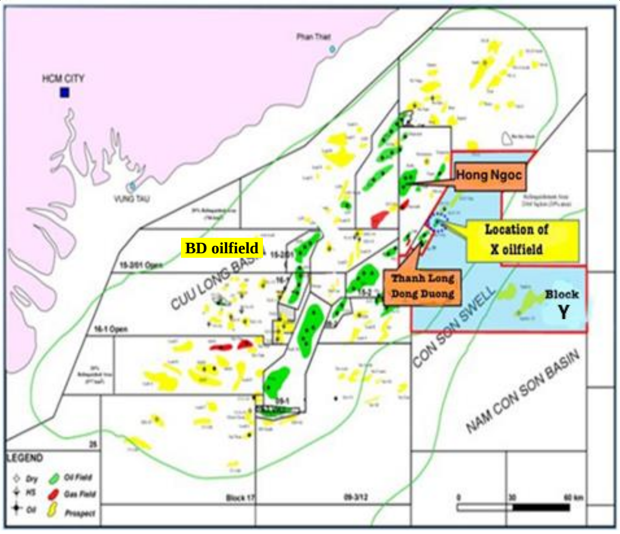

Fig. 1. Geographical location of the Bao Den oilfield, Cuu Long basin [5]

From 2003 to 2009: Petronas together with Petrovietnam Exploration & Production Corporation (PVEP) established Lam Son Joint Operating Company (JOC), operating on the area of blocks 01/97 & 02/97. Lam Son JOC has collected and exploded 538 km^2 3D, reprocessed 864 km^2 3D and 4,214 km of 2D seismic lines, drilled 7 exploratory and appraisal wells, and discovered the fields of Dong Do (DD), Thanh Long (TL) and HX South (HXS). Lam Son JOC has kept the area of DD, TL, and HXS oil fields in the development stage, and the rest (later Block 01/100 & block Y) is returned after the end of the exploration period [7].

From 2010 to present: Operated by PVEP POC Company on the returned area of Lam Son JOC. PVEP POC has collected, and exploded processed 1,408 km^2 of 3D seismic in 2010 & 2012 and 1,676 km of 2D route in 2012; then reprocessed 520 km^2 3D seismic. In April 2013, well BD-1X was drilled on structure BD Nam. The well has also discovered 5 oil and gas reservoirs and has the potential for more oil discoveries [8].

In the study area, the whole Cuu Long basin in general has had many exploration wells through Cenozoic sediments and pre-Tertiary rocks. The boundaries of the stratigraphic units coincide with the reflection surfaces of the seismic sets. The characteristics of the stratigraphic units are summarized in the aggregate stratigraphic column of the Cuu Long basin. The stratigraphic units present in the study area include pre-Cenozoic bedrock and Cenozoic formations [9]. Specifically, the Cenozoic sediments in the study area in particular, the Cuu Long basin in general include sediments dating from the Eocene to present and are divided into formations: Ca Coi Formation (Eocene), Tra Formation (Eocene - Early Oligocene); Tra Tan Formation; Bach Ho Formation (Early Miocene); Con Son Formation (Middle Miocene); Dong Nai Formation (Late Miocene) and Bien Dong Formation (Pliocene-Pleistocene) [10].

Two types of incompatibility are shown (Figs. 3 & 4). The most important unconformity surface in the Cuu Long basin includes the following nonconforming surfaces: The unconformable surface between the J3-K-age basement formations and the Cenozoic sediments. During the early Cenozoic rift, there were 3 nonconforming surfaces, which are sedimentary discontinuity surfaces shown in the interior of the Cuu Long early Cenozoic sedimentary basin, due to the change of the spreading axis after E, after D and C [11]. The surface incompatibility between the E and D layers is an angular incongruence that develops quite widely in many places in the Cuu Long basin but is noncontinuous. This surface is currently located at very different depths and is destroyed by the fault systems of NW-SE, NE-SW, longitude, and latitude. The mismatch between the Miocene and Oligocene is characterized by the disruption of the C seismic reflection sequence or sediment erosion [12].

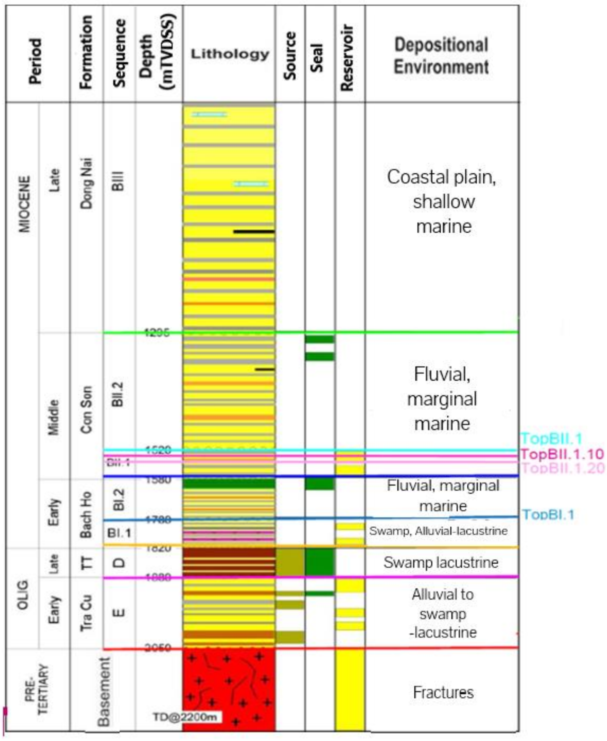

Fig. 2. Composites stratigraphic in the South of the Bao Den oilfield [5]

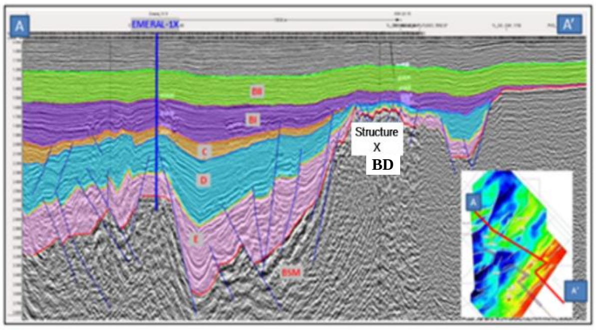

Fig. 3. Northwest-southeast cross-section through the northwest edge of Block Y showing the irregularities in the Cuu Long Basin [5]

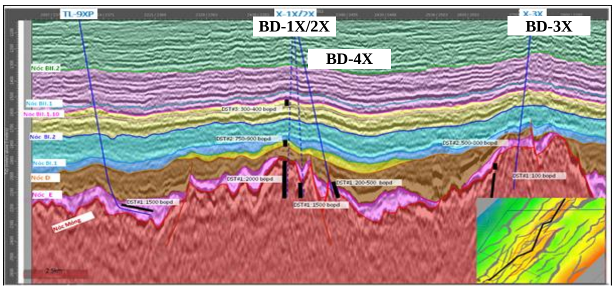

Fig. 4. Longitudinal section in the northeast-southwest direction through the northwest edge of Block Y [5]

Database

Well BD-1X, Bao Den oilfield is a type of exploration well that was tested by PVEP POC from May 6, 2013 to May 10, 2013. The purpose was to test the oil flow capability with DST#2 sandstone BI.1. The general information of the well BD-1X is shown in Table 1 and a summary of PVT parameters of the well in BD oilfield is shown in Table 2.

Table 1. Summary table of information on wells BD-1X [5]

Contractors	PVEP POC
Oil field	BD
Well	BD-1X
Testing type	Open Hole Drill Stem Test
Testing code	DST#2
Well type	Exploration
Testing range	1770 - 1810 mMD
Depth	3011 mMD/2140 mTVD
Date of test	From 6/5/2013 to 10/5/2013

Table 2. Summary table of PVT parameters of BI.1 sequence [5]

PVT parameters of BI.1 sequence		
Bubble pressure (Pb)	1150	Psig
Oil gas ratio (Rs @ Pb)	160	scf/stb
Formation volume coefficient of oil (Bo @ Pb)	1.14	rb/stb
Density (d @ Pb)	0.851	g/cc
Viscosity (μ @ Pb)	3.1	cP
Total Compression (ct)	3E-6	psi-1

Table 3. Reservoir parameters [5]

Parameters of BI.1 sequence		
Effective thickness (h)	72.1785	Ft
Average porosity (ϕ)	0.17	
Well radius (r_w)	0.400833	ft
Water Saturation (S_w)	0.15	

The object of study is an oil reservoir, so the formulas and calculation methods outlined below apply only to the oil reservoir.

The main purposes of well testing are to determine the presence of CO_2 and H_2S, the initial pressure and temperature of the reservoir (p_i, T), sampling at the well surface and bottom for PVT analysis fluid characterization, exploitation characteristics and calling potentials or evaluate the characteristics of the reservoir, such as k_h, k, skin, boundary or fracture of the reservoir [13-14].

Interpreting DST by Horner's method during the main buildup, the primary period took place during t = 46 hrs. Before this period, the main flow phase flew with the average oil flow of q_{last} = 838 bbl/d (because the flow flows evenly through the unstable phases, but q_{last} needs to be a stable number, we take the average) during operation tp = 13.7 hours (data taken from Fig. 5).

FP	Operation	Time	Duration	Choke size	BHP	BHT	WHP	WHT	Oil Rate	Gas Rate	Water Rate	Oil Cum	Gas Cum	Water Cum	GOR	BS&W	Oil SG	Gas SG
#		m/dd/yyyy hh:mm	hrs	/64"	psi	degC	psi	degC	bbl/d	MMscf/d	bbl/d	bbl	MMscf	bbl	scf/bbl	%	API @ 60 degF	SG
1	Initial flow	5/6/13 1:20	0.3		1986	82	25	27							-	-		
2	Initial BU	5/6/13 1:40	6.8		2582	81		27										
3	Clean up flow with N2	5/6/13 8:29	8.1	30	1828	83	332	32	413	0	35	79	0	37	-	-	25.2	
		5/6/13 16:33	8.2	40	1304	85	167	34	964	0.03	0	311	0.06	37.5	193	10.8	24.1	0.974
		5/7/13 0:45	7.7	44	1184	85	118	35	1020	0.18	0	585	0.09	37.5	154	6.0	24.4	0.98
4	Clean up BU	5/7/13 8:25	1.8		2491	84	295	33							-	-		
5	Main Flow with N2	5/7/13 10:15	13.7	40	1320	86	144	35	838	0.02	0	477	0.18	0.0	378	0.0	25.1	0.943
6	Main BU	5/8/13 0:00	46.0		2527	82									-	-		
7	BHS	5/9/13 22:01	7.2	16	2322	85	143	28			0			0.0			25	
8	Flow after BHS with N2 cushion	5/10/13 5:10	1.3	36	1923	84	26	28	349			19			-	-		

Fig. 5. Summary table of results obtained at the main stages of reservoir testing

In general, the PVT parameters and reservoir parameters that the research team collected, are quite complete and accurate. This will be the basis of the data to calculate the results of the reservoir test most accurately.

Methodology

When evaluating the BI.1 sequence at Bao Den oilfield by the method of interpreting the DST data, to have an accurate assessment result with the least possible error, the research team will first solve it by the traditional method. Then, we use Ecrin software as the advanced method to interpret documents and find results. When using this software, the research team will explain each step. When the results of the two methods are available, the research team will compare and have detailed discussions about the data found between the two methods to analyze the reliability to evaluate the reservoir.

Traditional Method

The traditional method will use the Horner graph analysis method. The first step in this method is to determine the initial pressure value of the reservoir. This is determined based on the relationship between pressure P and log [$(t_p + \Delta t)/\Delta t$] from the delay period. We used the Excel tool to draw a linear equation (Fig. 6). The equation of the linear line in the phase delay is:

$$P_{ws} = -30.63 * log[(t_p + \Delta t)/\Delta t] + 2520 \quad (1)$$

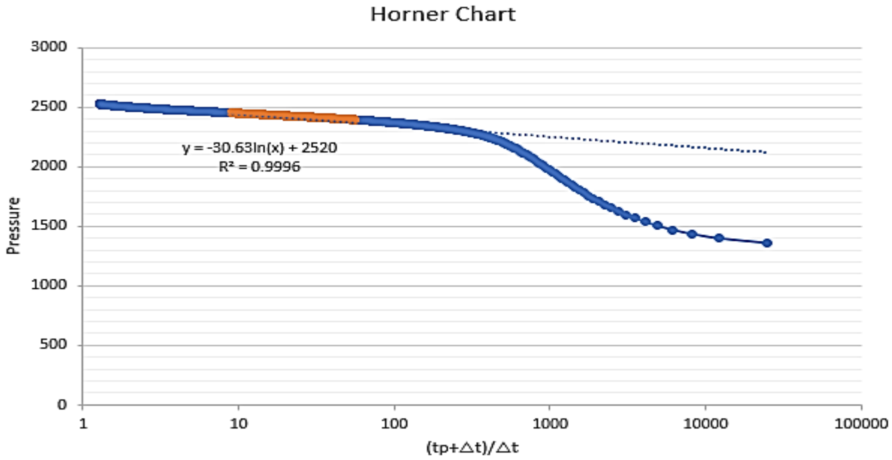

Fig. 6. Horner Graph of Main Buildup

Table 4. Calculation formulas [2]

Parameters	Calculation formulas
Initial reservoir pressure (Pi)	$log\ \frac{T_p + \Delta t}{\Delta t} = 0$
Slope (m)	$m = tan\ \propto = \frac{\Delta p}{\Delta log(\frac{T_p + \Delta t}{\Delta t})}$
Fluid Conductivity (kh/μ)	$\frac{k_0 h}{\mu_0} = \frac{162{,}6 q_0 B_0}{m}$
Water Conductivity $(k_0 h)$	$k_0 h = \left(\frac{k_0 h}{\mu_0}\right)\mu_0$
Effective permeability (k)	$k = \frac{k_0 h}{h}$
Skin factor (S)	$S = 1{,}151\left[\frac{P_{ws(\Delta t=1hr)} - P_{wf(\Delta f=0)}}{m} - log\left(\frac{k}{\phi\mu c_0 r_w^2}\right) + 3.23\right]$
Pressure dropping add the near well area $(\Delta p)_s$	$(\Delta p)_s = 141.2\left(\frac{qB\mu}{kh}\right)s$ or $(\Delta p)_s = 0.869ms$
Damage Ratio (DR)	$DR = \frac{q_t}{q_a}$
Production Index (PI)	$PI = \frac{q_a}{P_i - P_{wf}}$ $q_a = \frac{mkh}{162{,}6B_0\mu}$
Flow Efficiency (FE)	$FE = \frac{PI_{ideal}}{PI_{actual}} = \frac{p_i - p_{wf} - (\Delta p)_s}{p_i - p_{wf}}$
Radius influence (r_e)	$r_e = \left(\frac{kt}{948\phi\mu_0 c_t}\right)^{\frac{1}{2}}$

Advanced Method

In the framework of the article, the research team uses Ecrin v4.02 software, which is a widely used software and includes 4 analytical functions: −Diamant: data management −Sapphire: transition pressure analysis −Topaz: mining analysis −Rubiz: reservoir simulation [15].

In this study, the transition pressure analysis function (Sapphire) will be applied to support the interpretation of DST documents. The input data includes pressure and flow data files from time to time, meter records in ASCII format (but usually a .txt file), PVT data provided by the contractor (viscosity, volume coefficient, etc.), and other data such as effective reservoir thickness, radius, bore well, etc [16].

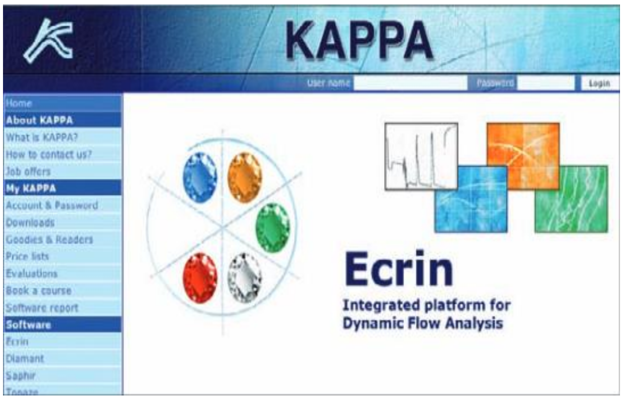

Fig. 7. Kappa Ecrin Software

The process of interpreting the DST by Ecrin software includes:
Step 1: Enter reservoir data and PVT data.
Step 2: Select data field, display type, unit... for parameters.
Step 3: Enter the traffic change data for each period based on the given data.
Step 4: Run the program.
Step 5: Select, and improve the model along with correction for the most accurate results.

Through the steps of interpretation by Ecrin software, it is not too complicated and compared with the traditional method. The advanced method will help us save more time and effort. To analyze and compare the results between the two methods, the research team will perform in the next section [17, 18].

Results and Discussion

The Explanatory Results of the Traditional Method

Calculate the Initial Pressure p_i

By giving t_p, the initial pressure value is calculated to be 2520 psi [19].

Calculate the Slope m of the Linear Return Line

On the semi-log line, we take any two points, provided that they are separated by one log unit. From there, we can determine the slope value m**:**

$$Slope: m = \frac{2378.94-2449.47}{loglog\,(100) - log\,(10)} = -70.53 \tag{2}$$

Determination of Permeability k

$$k_h = \frac{162.6q_0B_0\mu}{|m|} = \frac{162.6*838*1.14*3.1}{70.53} = 6827.61\ mD.ft$$
$$h = 72.18\ ft, : k = \frac{k_h}{h} = \frac{6827.61}{72.18} = 94.59\ mD \tag{3}$$

Skin Factor

$$S = 1.151\left[\frac{p_{1h}-p_{wf}}{|m|} - log\ log\ \left(\frac{k}{\varphi\mu c_t r_w^2}\right) + 3.2274\right] = 12.09 \quad (4)$$

where P_{1h} is the well bottom pressure 1 hour after closing the well (P_{1h} = 2437.67 psia), and P_{wf} is the well closing pressure at the time of well closing, (P_{wf} = 1320 psia).

Pressure Drop Plus Near Well Area $(\Delta p)_s$

$$(\Delta p)_s = 141.2\left(\frac{qB\mu}{kh}\right)S = 141.2\left(\frac{838\times1.14\times3.1}{6827.61}\right)(12.09) = 740.46\ psia \quad (5)$$

Radius of Influence r_i

$$r_i = \left(\frac{kt}{948\varphi\mu c_t}\right)^{\frac{1}{2}} = \left(\frac{94.95\times46}{948\times0.17\times3.1\times3\times10^{-6}}\right)^{\frac{1}{2}} = 1707.09\ ft \quad (6)$$

Production Index PI

$$PI = \frac{q}{p_i-p_{wf}} = \frac{838}{2520-1320} = 0.6983 \quad (7)$$

Flow performance FE

$$FE = \frac{PI_{actual}}{PI_{ideal}} = \frac{p_i-p_{wf}-(\Delta p)_s}{p_i-p_{wf}} = \frac{2520-1320-740.46}{2520-1320} = 0.3830 \quad (8)$$

The results of interpretation by the Horner method are summarized in Table 5.

Table 5. Interpretation results table by Horner method

Parameters	Results	Unit
P_i	2520	Psia
M	-70.53	psia/cycle
K_h	6827.61	mD.ft
K	94.59	mD
S	12.09	
$(\Delta p)_s$	740.46	Psia
r_i	1707.09	Ft
PI	0.6983	
FE	0.3830	

Explained Results of Advanced Methods

Based on the parameters from Table 3, we enter the reservoir data.

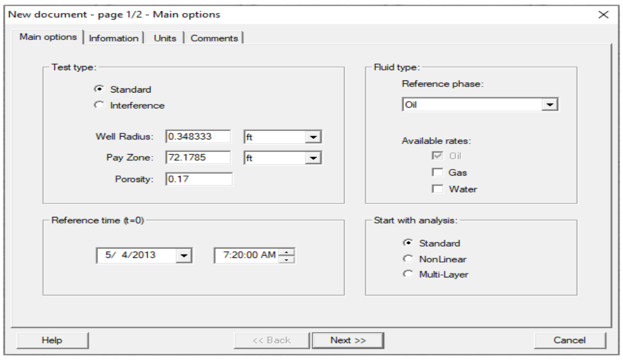

Fig. 8. Data entry of reservoir test layer

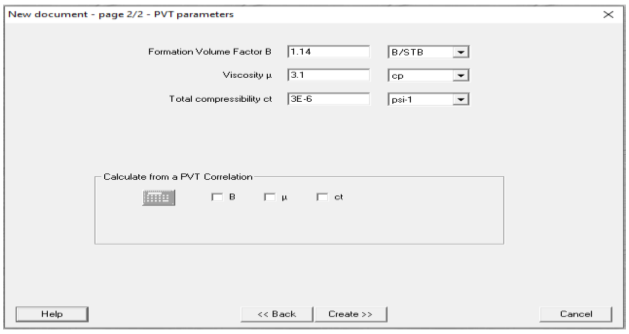

Fig. 9. Input PVT data on well fluid BD-1X

Next, click Next to switch to importing fluid PVT data. The parameters are shown in Fig. 8.

Next, click Create to start loading the pressure data P.

Click the icon  to load the ASCII file, and select the data file to interpret.

Then click Next to continue. Select data fields, display types, units ... for parameters (Fig. 10).

Click Load to continue.

The graph of pressure, and temperature over time after loading P and selecting the unit field for the parameters is shown as shown below (Fig. 11).

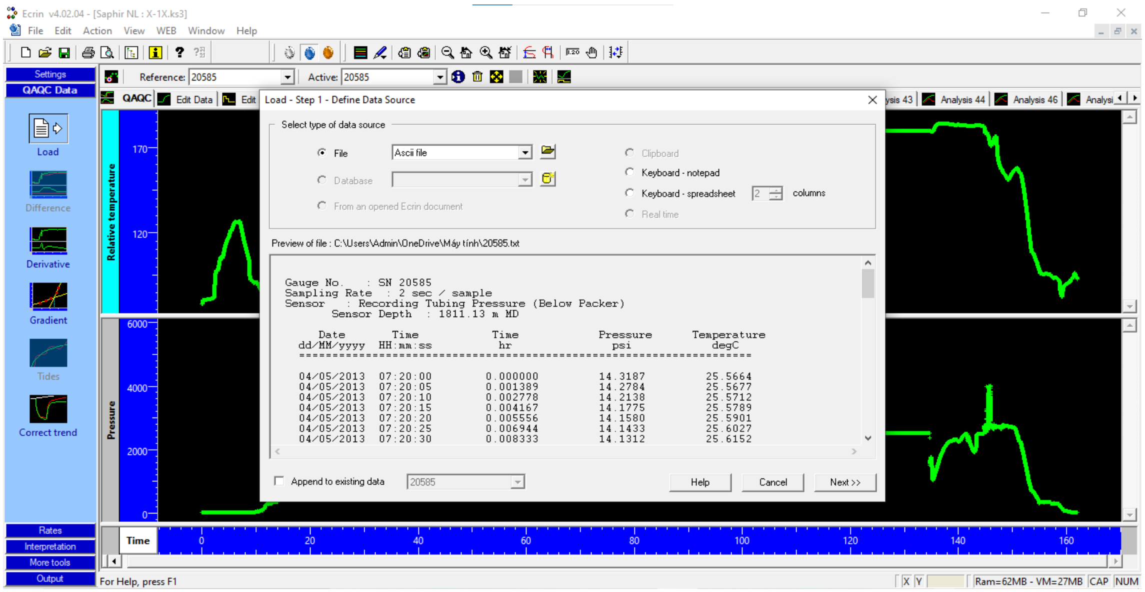

Fig. 10. P pressure load dialog

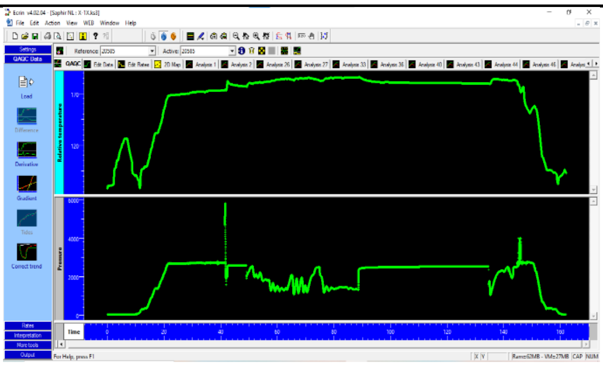

Fig. 11. Graph of pressure, and temperature over time after loading P and selecting parameter field

	Duration	Liquid Rate	G	G
	hr	STB/D		
1	41.4445	0		
2	0.897635	400.000		
3	6.80489	0		
4	8.05924	413.000		
5	8.16309	964.000		
6	8.30926	1020.00		
7	1.23160	0		
8	13.7566	838.000		
9	46.0303	0		
10	6.24946	349.000		

Fig. 12. Q flow data table for each period

Next, we proceed to enter the flow change data for each period (Fig. 12) based on the given data.

The resulting image of the well exploitation history is shown in Fig. 13.

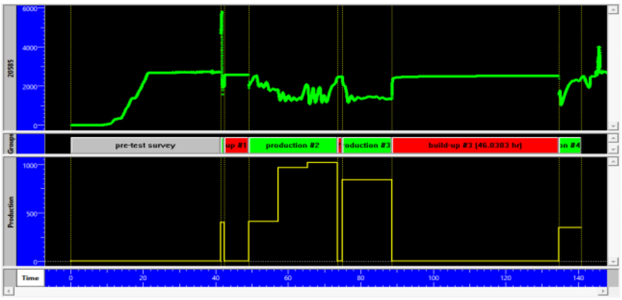

Fig. 13. Exploit history after entering the flow Q for each period

Run the Program

After entering the given input data, we begin the interpretation process.

Select the extract dP command, then select the corresponding analysis stage (Fig. 14). Here authors choose the analysis phase as the main buildup phase (Build-up #3) (Fig. 15).

Next, we choose the model. (Fig. 16)

Model: The software provides a list of well, reservoir, and boundary models with different pressure curves and pressure derivatives. The interpretation process is to select the probable model to match so that the curves from the real data have the same shape as the standard curve provided by the software.

Model of wellbore: No well storage, Constant Wellbore Storage, Changing Wellbore Storage.

Well model: vertical well (vertical), fracture uniform flux, fracture infinite, conductivity, horizontal, limited entry, slanted well.

Reservoir model: homogeneous 2-layer porosity, radial composite, liner composite, infinite boundary model (Infinite), circle, square, one fault, parallel faults. Intersecting faults model selection must also be combined with the geologic data nature of the reservoir and depends on the experience of the analyst. Analysis of possible cases in the model selection is performed.

Selection of well model: Through geological analysis, well BD-1X drilled obliquely. There was no sign of horizontal drilling. Therefore, the vertical well model (vertical) is the most suitable. PVT analysis results show that the saturation pressure is pb = 1150 psia. During the test process, the pressure at the bottom of the well and the surrounding area has dropped below the saturation pressure, specifically the pressure at the time of well closing p_{wf} = 1320 psia, so the gas separation from the oil has yet to occur at the well bottom and its vicinity. Here we choose the constant well storage model (constant wellbore storage).

Reservoir model selection: Based on the test history of the reservoir, DST#2 drills only at the BI.1 sequence. Therefore, the homogeneous reservoir model is the most suitable in this case. Selection of boundary model: With the shape of the pressure derivative as above, it is easy to see that Slope = 1. Combined with geological data, it can be seen that faults appear near the wells. From this, we predict that this boundary model may be petrographic. Therefore, here authors choose one fault boundary model. The dialog box predicts well, reservoir and boundary models (Fig. 16).

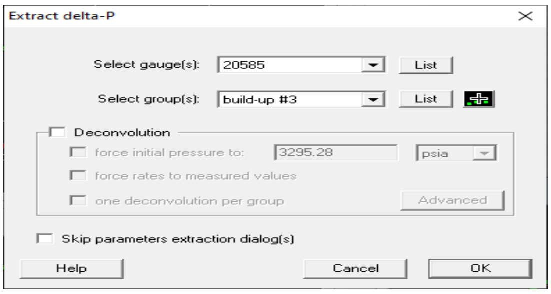

Fig. 14. Extract dP dialog box

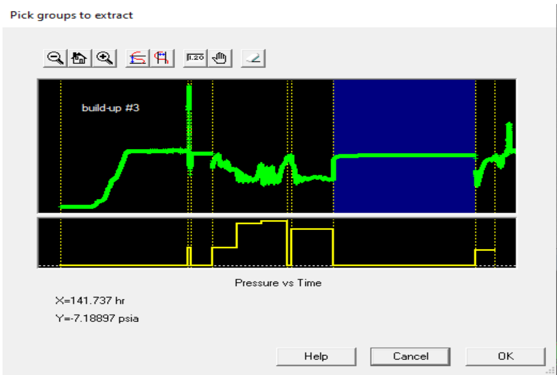

Fig. 15. Analysis stage selection table (Build-up #3)

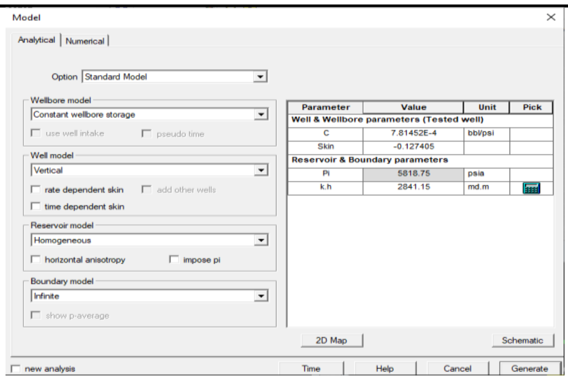

Fig. 16. Dialog box for selecting well, reservoir, and boundary models

Preliminary interpretation results show that the model is suitable for the reservoir, as shown in Table 6.

Table 6. The model selection and results

Model selection	
Model of well storage	Constant Wellbore Storage
Well model	Vertical well
Reservoir model	Homogeneous
Boundary model	One fault
Results	
P_i	2617.5 psia
Skin	14
K_h	7680 mD.ft
K	106 mD
C	$C = 5.61E^{-4}$
L	439 ft

Next, we proceed to improve the model (improve) to get the most accurate results. This function helps to improve the process of matching the real data model with the theoretical model by changing the model's parameters. This is an important stage in the interpretation process.

Select the improved command to open the dialog box, and proceed to improve the model. (Fig. 19)

Click Run to continue. Continue to adjust the parameters so that the prediction model matches the real data model. The results of interpretation by software Ecrin v4.02 are shown in Fig. 20.

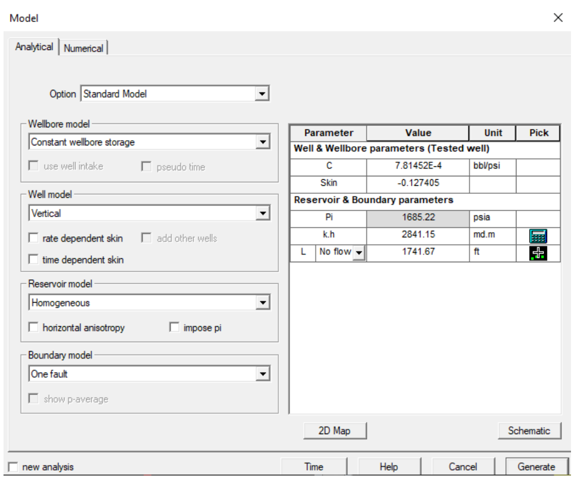

Fig. 17. Model prediction dialog for wells, reservoirs, and boundaries

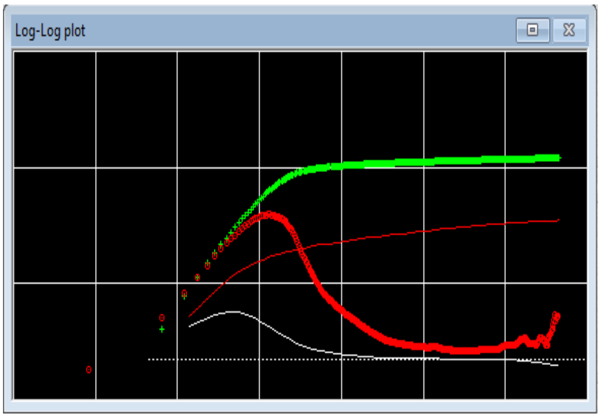

Fig. 18. Log-log graph after selecting well, reservoir, and boundary models

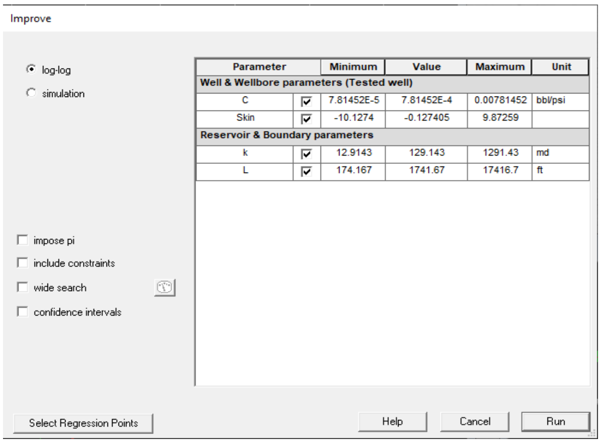

Fig. 19. Parameters dialog box in Improve

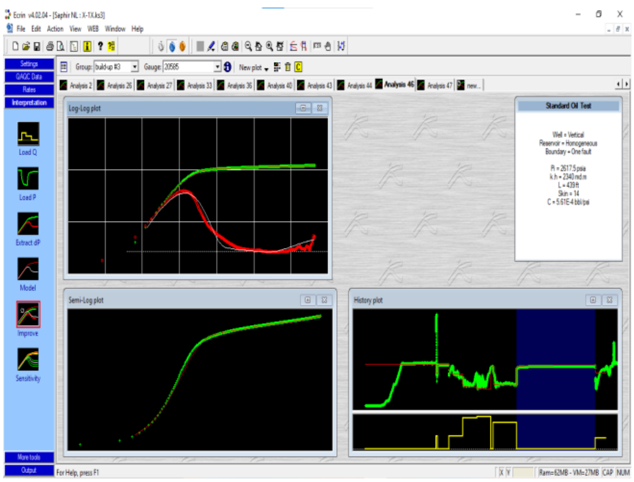

Fig. 20. Results explained by software Ecrin v4.02

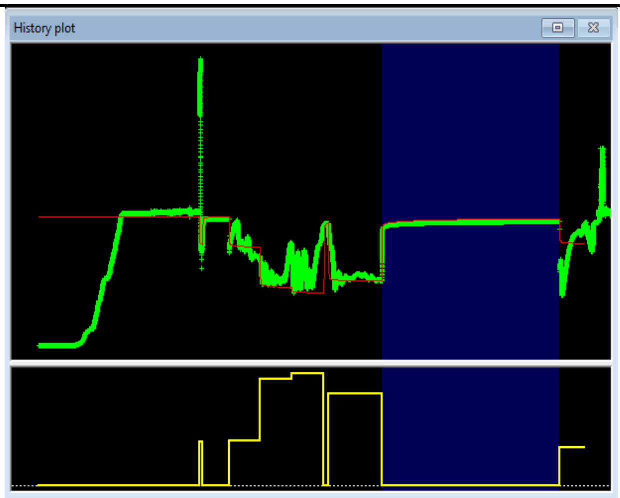

Fig. 21. Exploitation of the history graph of the main buildup stage from software

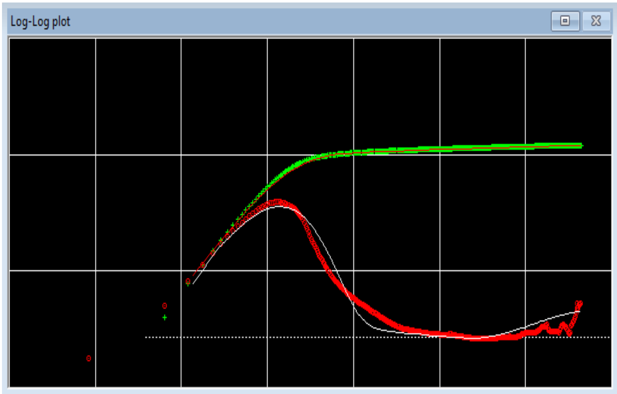

Fig. 22. Log-log graph of Main Buildup phase exported from software

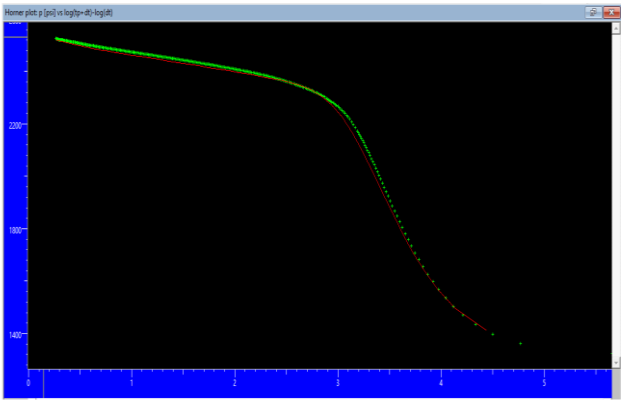

Fig. 23. Horner graph of Main Buildup phase from software

Comparing the Results of the Two Methods

When we are done, the results of the reservoir testing of the two methods are shown in Table 7 below for comparison.

Looking at the summary table of the results calculated by the two methods, which are relatively close to each other, the deviation is insignificant and consistent with the geological data [20].

Both methods give positive Skin coefficient results. This is explained by the fact that the reservoir has not been treated with acid in the initial return period and the flow process is not long enough to clean the formation around the well. However, the results obtained from Ecrin software have higher reliability, because the Horner method determines the pressure value extrapolated from the graph, not determining the geological conditions of the reservoir. Ecrin software can determine the influence of boundary conditions, suitable reservoirs, and well models will help to obtain results with high accuracy. In addition, the traditional method is still different due to errors in the calculation process.

Table 7. Comparison table of interpretation results by traditional and advanced methods

Parameter	Symbol, unit of measure	Traditional method (Horner)	Advanced method (Ecrin software)
Initial pressure	p_i (psia)	2520	2617.5
Water conductivity	k_h (mD.ft)	6827.61	7680
Permeability	k (mD)	94.59	106
Skin coefficient	S	12.09	14
Well storage coefficient	C		5.61E-4
Distance to fault	L (ft)		439
Pressure drop plus near well area	(Δp_s) (psia)	740.46	
Radius of influence	r_i (ft)	1707.09	
Production Index	PI	0.6983	
Line performance	FE	0.3830	

Analysis of the Reliability of the Results of Reservoir Test Interpretation

Reliability analysis is the analysis of the effects of inputs on outputs. The experience of the reservoir tester or the error in the calculation process is also a cause that affects the interpretation results.

When interpreting the reservoir, the interpreter should rely on geological documents, and documents of other wells in the same reservoir, compare and contrast with actual conditions, and obtain data. At the same time, the interpreter is required to have certain qualifications and experience, from which to find the right answer, avoid errors in the calculation process, and misjudge the properties of the reservoir.

The values of pressure P and flow Q in the data processing of Ecrin software are representative while choosing the value of pressure P or flow Q in the traditional interpretation by hand leads to errors in the results. In addition, the fitment of the semi-log curve or the pressure derivative of the log-log plot is easily matched by the software, by "improving" the model. Meanwhile, the observation for the visual interpretation method contains more errors.

Conclusion

Testing the DST#2 reservoir in the BI.1 sandstone of the Bao Den oilfield in the Cuu Long basin proved the existence of oil. Reservoir testing plays an important and practical role in the process of oil and gas prospection, as well as evaluating the properties of the reservoir by surveying the flow in the well and the pressure recovery capacity of the reservoir.

DST is the most popular reservoir test method, contributing to solving the problem of assessing the potential of a structure, in order to come up with a reasonable exploited method.

The interpreting of the reservoir test documentation is carried out by both traditional methods – Horner and advanced methods – Ecrin.

The results obtained from the methods are relatively similar. However, the results obtained from Ecrin software have higher reliability, because it can determine the influence of boundary conditions, suitable reservoir, well model, and help to obtain accurate results.

The parameters of the well and the reservoir are determined as follows: initial reservoir pressure: p_i = 2617.5 psia, hydroelectricity: k_h = 7680 mD.ft, reservoir permeability: k = 106 mD, skin coefficient: S = 14, well-accumulation factor: C = 5.61 E^{-4}, distance to fault: L = 439 ft.

From the interpretation results, we can evaluate the formation: the results have shown that well BD-1X of the Bao Den oilfield has very good oil and gas potential. In terms of quality: the existence of oil has been demonstrated in the reservoir. The formation has not been cleaned, is contaminated by mud, and has not been treated with acid, because the cleaning process is not long enough. In terms of quantity, the permeability and hydro conductivity are relatively high. The radius of influence of the well is small, because the time to carry out the test process is not long enough.

Recommendations

To clearly explain and evaluate the parameter values obtained from the reservoir testing and predict the reservoir model, it is necessary to clearly understand the geological structure of the prospective structure, mineral composition, petrographic characteristics of the reservoir and wells geophysics, thickness and porosity-permeability properties of rock, and formation of the reservoir.

In the future, to accurately evaluate the reservoir characteristics, it is necessary to continue more detailed studies such as: conducting enhanced methods like well stimulation, opening and widening the well wall to clean and treat the acid near the bottom of the well, and limit sealing (sludge infiltration), the hydraulic fracturing to improve the recovery coefficient. It is important to carry out additional core sampling and further studies on the geophysical data of the wells and test the reservoir at other intervals of the aquifer for accurate and complete assessment.

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Appendix

Parameters	Calculation formulas	Nomenclatures
Initial reservoir pressure (P_i)	$log\, \frac{T_p + \Delta t}{\Delta t} = 0$	Δt: shut-in time (hour) T_p: production time (hour)
Slope (m)	$m = tan \propto = \frac{\Delta p}{\Delta log(\frac{T_p + \Delta t}{\Delta t})}$	Δp: drawdown pressure, psia Δt: shut-in time (hour) T_p: production time (hour)
Fluid Conductivity (kh/μ)	$\frac{k_0 h}{\mu_0} = \frac{162{,}6 q_0 B_0}{m}$	k_o: permeability to oil, md h: Length of flow path, ft μ_0: oil viscosity, cp q_o: oil flow rate, STB/day B_o: Oil formation volume factor, bbl/STB
Water Conductivity $(k_0 h)$	$k_0 h = \left(\frac{k_0 h}{\mu_0}\right)\mu_0$	k_o: permeability to oil, md h: Length of flow path, ft μ_0: oil viscosity, cp
Effective permeability (k)	$k = \frac{k_0 h}{h}$	k_o: permeability to oil, md h: Length of flow path, ft
Skin factor (S)	$S = 1{,}151 \left[\frac{P_{ws(\Delta t=1hr)} - P_{wf(\Delta f=0)}}{m} - log\left(\frac{k}{\phi \mu c_0 r_w^2}\right) + 3.23\right]$	$P_{wf(\Delta t=0)}$: Flowing well pressure immediately before shut-in, psia $P_{ws(\Delta t=1hr)}$: Pressure after 1 hour shut-in, psia ϕ: porosity, % r_w: wellbore radius, ft c_o: oil compressibility, psi^{-1} μ: viscosity, cp
Pressure dropping add	$(\Delta p)_s = 141.2\left(\frac{qB\mu}{kh}\right)s$ or $(\Delta p)_s = 0.869ms$	q: volumetric flow rate, STB/day B: Formation volume factor, bbl/STB

the near well area $(\Delta p)_s$		μ: viscosity, cp
Damage Ratio (DR)	$DR = \frac{q_t}{q_a}$	q_t: Theoretical rate of flow, STB/day q_a: Actual rate of flow, STB/day
Production Index (PI)	$PI = \frac{q_a}{P_i - P_{wf}}$ $q_a = \frac{mkh}{162{,}6 B_0 \mu}$	P_i: initial pressure, psia P_{wf}: wellbore following pressure. psia B_o: Oil formation volume factor, bbl/STB μ: viscosity, cp
Flow Efficiency (FE)	$FE = \frac{PI_{actual}}{PI_{ideal}} = \frac{p_i - p_{wf} - (\Delta p)_s}{p_i - p_{wf}}$	PI_{actual}: actual drawdown pressure PI_{ideal}: ideal drawdown pressure P_i: initial pressure, psia P_{wf}: wellbore following pressure. Psia
Radius influence (r_e)	$r_e = \left(\frac{kt}{948 \phi \mu_0 c_t}\right)^{\frac{1}{2}}$	T: time, hour ϕ: porosity, % μ_0: oil viscosity, cp C_t: total compressibility, psi^{-1}