APPLYING INTERPRETATION RESULTS OF DRILL STEM TEST TO EVALUATE THE LOWER MIOCENE FORMATION IN BAO DEN OILFIELD, CUU LONG BASIN

Abstract: The present research is aimed at exploring the B1.1 sandstone sequence located in the lower Miocene formation within Bao Den oilfield situated in 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 for interpretation results, which show 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 BD-1X well situated in 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.

Keywords: prospect structure, reservoir parameters, hydrocarbon potential, lower Miocene, drill stem test.

1. INTRODUCTION

Currently, before investing and exploiting oil field, the top question is always whether the oil field's reserves are large enough for commercial exploitation or not. And how is the exploited plan reasonable. 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, that is exploitation? Is the reservoir potential assessment based on those parameters still reliable?

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

In Vietnam, there are also a number of studies: New approach in analyzing gas wells with high CO2 content [3] to clarify the role and characteristics of CO_2 in the process of interpreting the DST reservoir, then evaluating the advantages and disadvantages of the applied method, and finally analyzing and proposing a new approach to be able to obtain many reservoir parameters, to correct the development plan oil field development; Challenges in the development of Su Tu Trang condensate gas field [4] to introduce the results of exploration, evaluation and challenges in the development process of Su Tu Trang condensate gas field, Block 15-1, and finally a very important paper for the research team is Building 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 results of the overview study of the above published works, the research team has collected and inherited the necessary theoretical and data bases such as determining the reservoir parameters, forming the thinking, establish a calculation procedure to evaluate the quality of the reservoir and perform this study 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 basic for future studies to evaluate the optimal quality in Bao Den oilfield and other similar oil fields.

The study area is 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 there have been many oil and gas discoveries being exploited [5] (Figure 1).

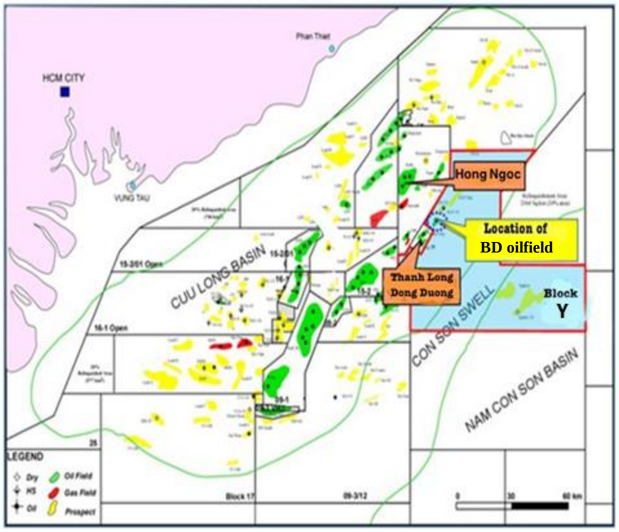

Figure 1: Geographical location of Bao Den oilfield, Cuu Long basin [5]

The exploration history of Block Y (together with block 01/100) is associated with the history of oil and gas exploration and exploration so far of blocks 01/100 & block Y (previous oil and gas contracts) signed usually includes these 2 lots) and is divided into 3 main stages:

From 1992 to 2002: Petronas Company (Malaysia) conducted exploration activities of Blocks 01 and 02, destroyed 563.73 km2 of 3D seismic route (2002) to the South and 13,870 km2 of 2D seismic route (1991, 2002). 1993 and 1995). The company has drilled 3 exploration wells on the area of blocks 01/100 and block Y: 02-D-1X (Sapphire), 02-M-1X (Opal) and 01-E-1X (Agate) [6].

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 km2 3D and reprocessed 864 km2 3D and 4,214 km of 2D seismic lines. Drilled 7 exploratory and appraisal wells and the results 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 put into the development stage and the rest (later Block 01/100 & block Y) is returned after the end of exploration period [7].

From 2010 to present: Operated by PVEP POC Company on the returned area of Lam Son JOC. PVEP POC has collected, exploded processed 1,408 km2 of 3D seismic in 2010 & 2012 and 1,676 km of 2D route in 2012; reprocess 520 square kilometers 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 oil [8].

In the study area in particular, 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].

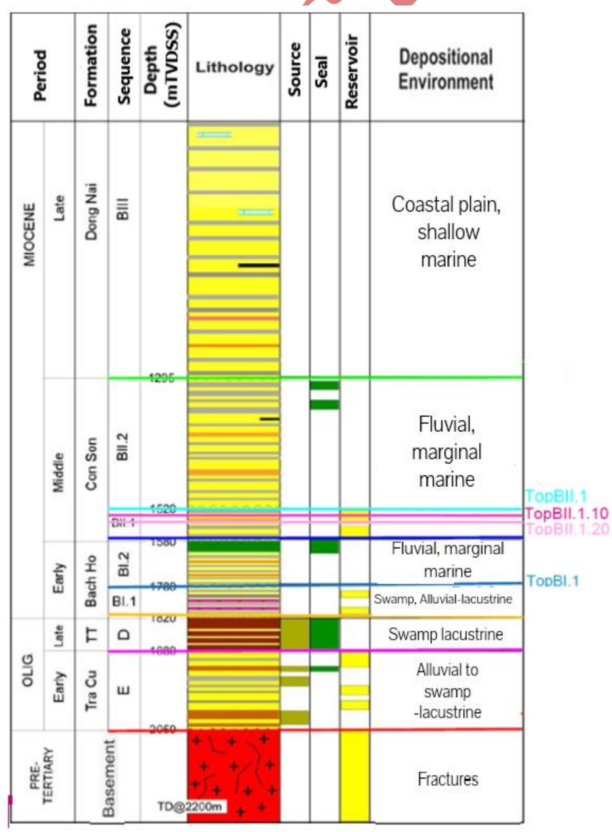

Figure 2: Composite stratigraphic in the South of Bao Den oilfield [5]

Two types of incompatibility are shown (Figures 3 and 4). The most important unconformity surface in the Cuu Long basin includes the following unconforming surfaces: The unconformable surface between the J3-K-age basement formations and the Cenozoic sediments. During the early Cenozoic rift, there were 3 unconforming 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 not continuous. This surface is currently located at very different depths and is destroyed by the fault systems of NW-SE, NE-SW, Longitude, Latitude. The mismatch between the Miocene and Oligocene is characterized by the disruption of the C seismic reflection sequence or sediment erosion [12]. Besides, the mismatches in Miocene: BI, BI.2, BII...

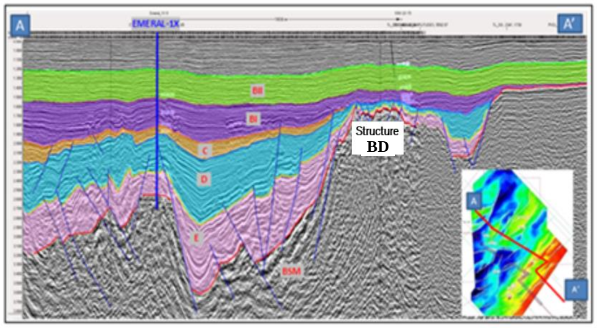

Figure 3: Northwest - Southeast cross-section through the northwest edge of Block Y showing the irregularities in the Cuu Long Basin [5]

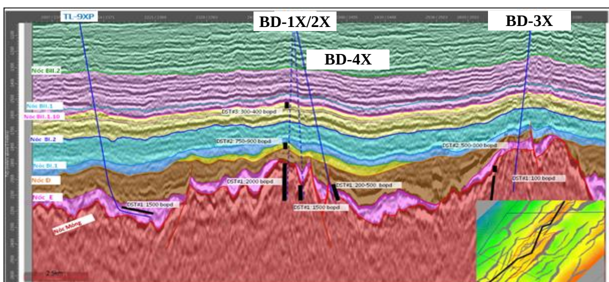

Figure 4: Longitudinal section in the northeast - southwest direction through the northwest edge of Block Y [5]

2. DATABASE

Well BD-1X, Bao Den oilfield is a type of exploration well that was tested by PVEP POC from May 6, 2013 and ended on May 10, 2013. The purpose is 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 (pi, T), sampling at the well surface and bottom for PVT analysis fluid characterization, exploitation characteristics and calling potentials or valuate the characteristics of the reservoir such as k_h, k, skin, boundary or fracture of the reservoir [13-14].

Interpretation of DST by Horner's method during the Main Buildup. The primary period took place during t = 46 hrs. Before this period is the main flow phase with the average oil flow 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. flow tank during main flow) during operation t_p = 13.7 hours (data taken from Figure 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			-	-		

Figure 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.

3. METHODOLOGY

When evaluating the BI.1 sequence at Bao Den oilfield by the method of interpreting the DST data, in order to have an accurate assessment result with the least possible error, the research team will first solve it by the traditional method. Being systematic with existing formulas is to find results; then, using Ecrin software as the advanced method is 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 + Δt)/Δt] from the delay period. Use the Excel tool to draw a linear equation (Figure below). The equation of the linear line in the phase delay is:

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

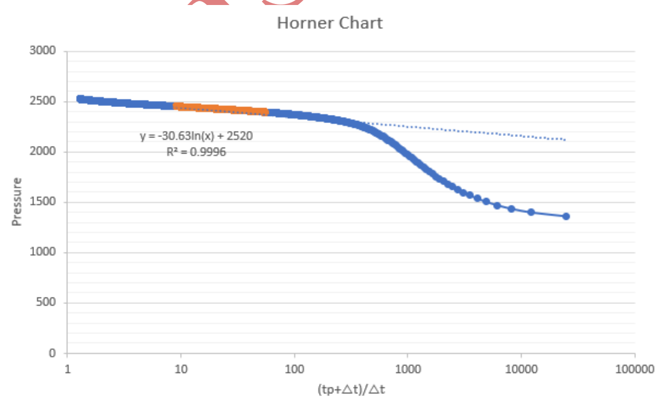

Figure 6: Horner Graph of Main Buildup

Table 4: Calculation formulas [2]

Parameters	Calculation formulas
Initial reservoir pressure (Pi)	$log\dfrac{T_p + \Delta t}{\Delta t} = 0$
Slope (m)	$m = tan \propto = \dfrac{\Delta p}{\Delta log(\frac{T_p + \Delta t}{\Delta t})}$
Fluid Conductivity (kh/μ)	$\dfrac{k_0 h}{\mu_0} = \dfrac{162{,}6 q_0 B_0}{m}$
Water Conductivity $(k_0 h)$	$k_0 h = \left(\dfrac{k_0 h}{\mu_0}\right)\mu_0$
Effective permeability (k)	$k = \dfrac{k_0 h}{h}$

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 use Ecrin v4.02 software, which is widely used software today includes 4 analytical functions: −Diamant: Data management −Sapphir: Transition pressure analysis −Topaz: Mining analysis −Rubiz: Reservoir simulation [15].

In this study, the transition pressure analysis function (Sapphir) will be applied to support the interpretation of DST documents with input data including: Pressure and flow data files from time to time 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... [16].

Figure 7: Kappa Ecrin Software

The process of interpreting the DST by Ecrin software:

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, improve the model along with correction for the most accurate results

Through the steps of interpretation by Ecrin software, in general, 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].

4. RESULTS AND DISCUSSION

4.1 The explanatory results of the traditional method

Calculate the initial pressure pi

The initial pressure value is calculated by giving (t_p) then: Initial pressure: pi=2520 psi. [19]

Calculate the slope m of the linear return line

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

$$m = \frac{2378.94 - 2449.47}{log\,log\,(100)\ - log(10)} = -70.53$$

⇨ Slope: $m = -70.53$ psi/cycle

Determination of permeability k

$$kh = \frac{162.6q_0B_0\mu}{|m|} = \frac{162.6 * 838 * 1.14 * 3.1}{70.53} = 6827.61\ (mD.ft)$$

$$For\ h = 72.18\ ft, we\ have{:}\ k = \frac{kh}{h} = \frac{6827.61}{72.18} = 94.59\ (mD)$$

⇨ permeability: $k = 94.59\ mD$

Skin factor

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

P_{1h}: Well bottom pressure 1 hour after closing the well, P_{1h}=2437.67 psia

P_{wf}: Well closing pressure at the time of well closing, P_{wf}=1320 psia

$$S = 1.151\left[\frac{2437.67 - 1320}{70.53} - log\,log\left(\frac{94.59}{0.17 \times 3.1 \times 3 \times 10^{-6} \times 0.4008^2}\right) + 3.2274\right] = 12.09$$

⇨ Skin factor: $S = 12.09$

Pressure drop plus near well area $(\Delta p)_s$

$$(\Delta p)_s = 141.2\left(\frac{qB\mu}{kh}\right)S$$
$$= 141.2\left(\frac{838 \times 1.14 \times 3.1}{6827.61}\right)(12.09)$$
$$= 740.46(psia)$$

⇨ Pressure dropping add the near well area: $(\Delta p)_s = 740.46\ psia$

Radius of influence r_i

$$r_i = \left(\frac{kt}{948\varphi\mu c_t}\right)^{\frac{1}{2}} = \left(\frac{94.95 \times 46}{948 \times 0.17 \times 3.1 \times 3 \times 10^{-6}}\right)^{\frac{1}{2}}$$
$$= 1707.09(ft)$$

⇨ Radius of influence: $r_i = 1707.09\ ft$

Production index PI:

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

⇨ Production index: PI = 0.6983

Flow performance FE:

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

⇨ Flow performance: $FE = 0.3830$

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

Table 5: Interpretation results table by Horner method

Parameters	**Results**	**Unit**
pi	2520	psia
m	-70.53	psia/cycle
kh	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	

4.2 Explained results of advanced methods

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

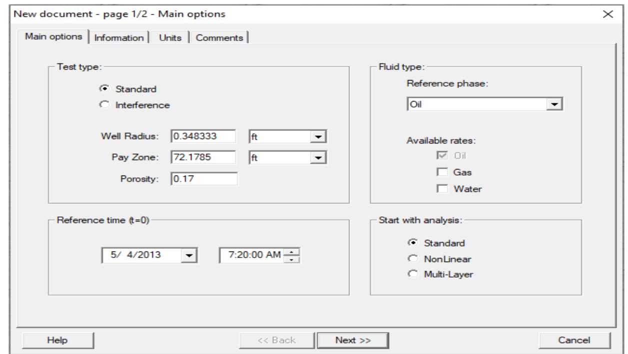

Figure 8: Data entry of reservoir test layer

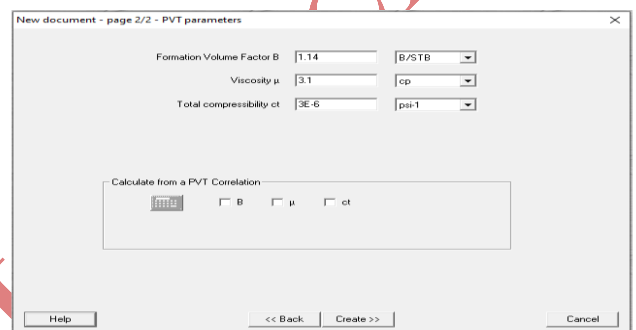

Figure 9: Input PVT data on well fluid BD-1X

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

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

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

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

Click Load to continue.

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

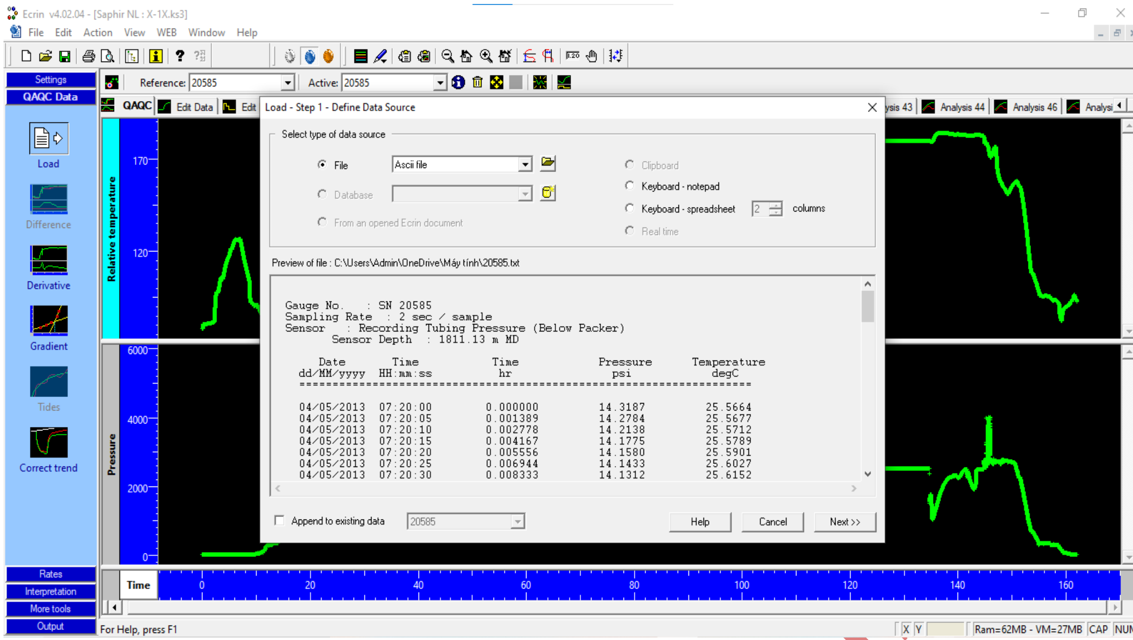

Figure 10: P pressure load dialog

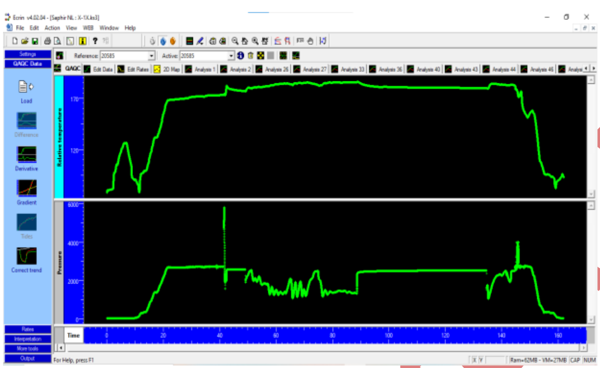

Figure 11: Graph of pressure, temperature over time after loading P and selecting parameter field

	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		

Figure 12: Q flow data table for each period

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

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

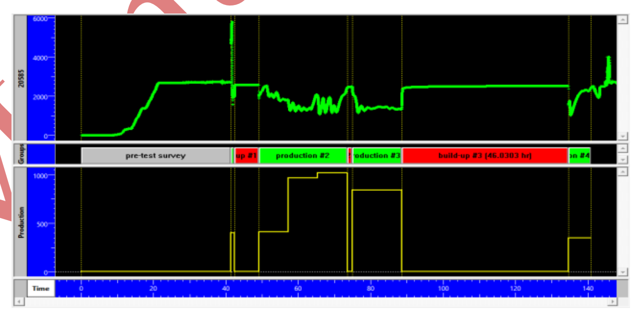

Figure 13: Exploit history after entering the flow Q for each period

Run the Program

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

Select the Extract dP command and select the corresponding analysis stage (Figure 14). Here authors choose the analysis phase as the Main Buildup phase (Build-up #3). (Figure 15)

Next, we choose the model. (Figure 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 layers porosity, Radial Composite, Liner Composite, Infinite boundary model (Infinite), Circle, Square, One fault, Parallel faults, Intersecting faults Model selection must also be combined with geologic data nature of the reservoir and depends on the experience of the analyst. Conduct analysis of possible cases in model selection.

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 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 not yet occurred. Well bottom and well vicinity. So 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. (Figure 16)

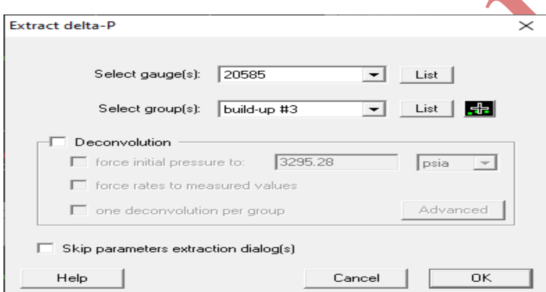

Figure 14: Extract dP dialog box

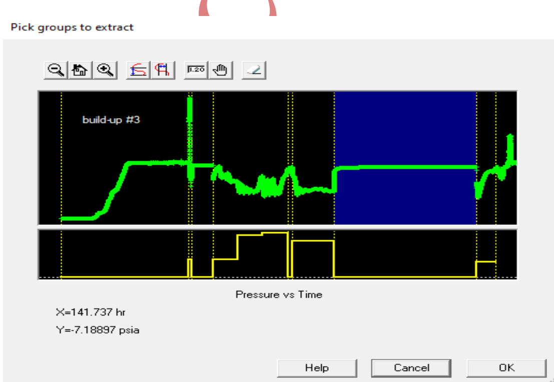

Figure 15: Analysis stage selection table (Build-up #3)

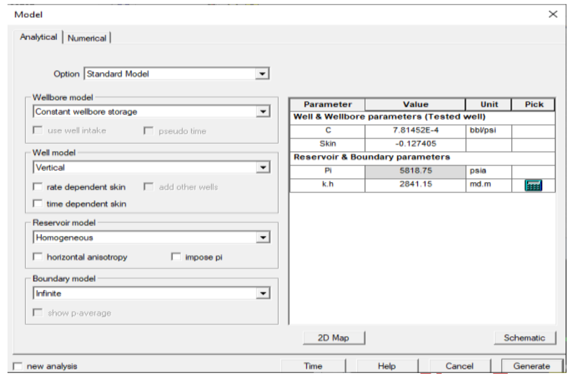

Figure 16: Dialog box for selecting well, reservoir, and boundary models

Preliminary interpretation results show that the model is suitable for the reservoir as shown in Table 4

Table 4: 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	
pi	2617.5 psia
Skin	14
kh	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 Improve command to open the dialog box, proceed to improve the model. (Figure 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 Figure 20.

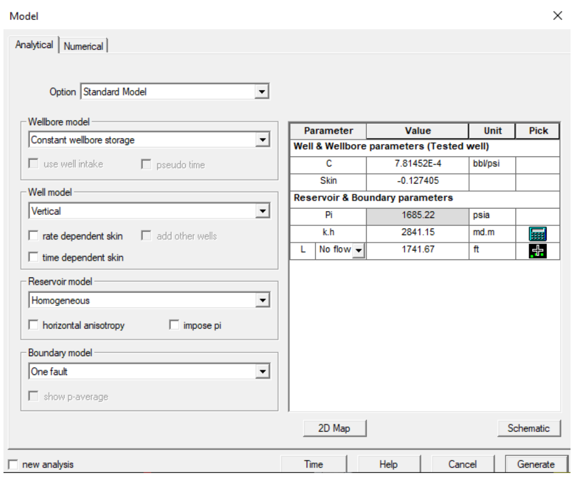

Figure 17: Model prediction dialog for wells, reservoirs, and boundaries

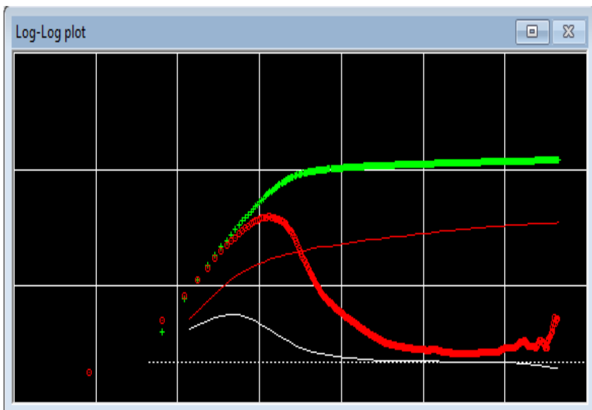

Figure 18: Log-log graph after selecting well, reservoir and boundary models

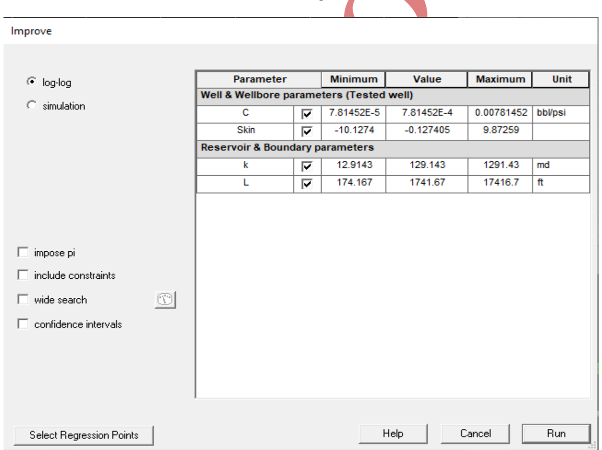

Figure 19: Parameters dialog box in Improve

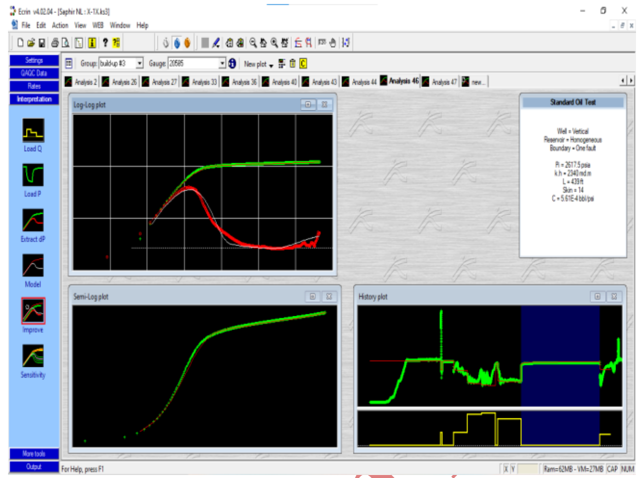

Figure 20: Results explained by software Ecrin v4.02

Graph of mining history of the Main Buildup phase from the software

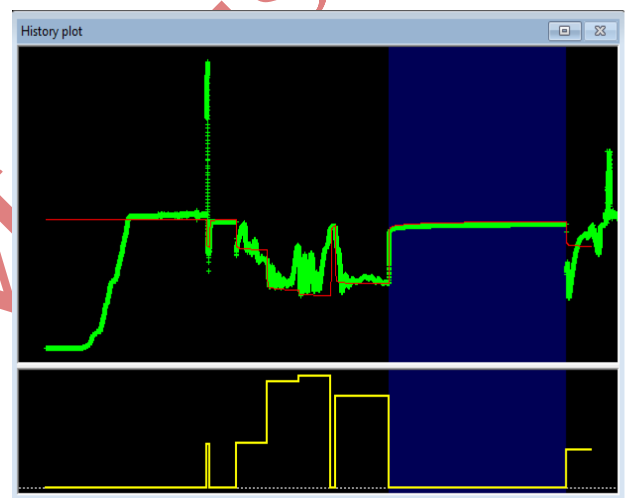

Figure 21: Exploit history graph of Main Buildup stage from software

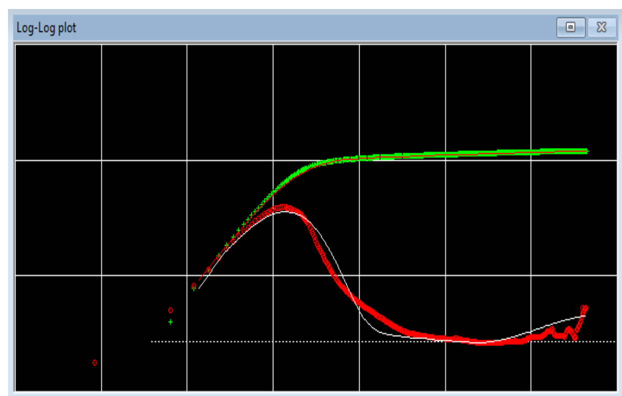

Figure 22: Log-log graph of Main Buildup phase exported from software

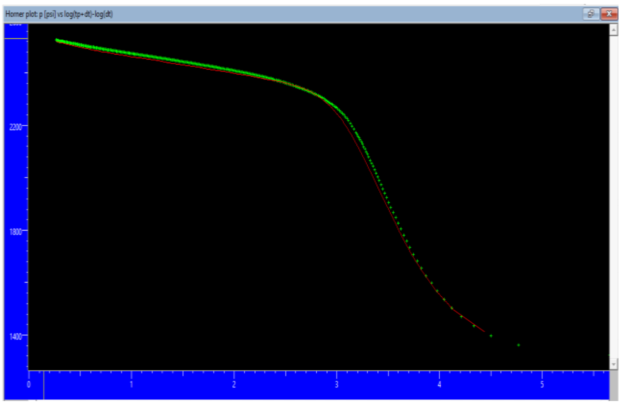

Figure 23: Horner graph of Main Buildup phase from software

4.3 Comparing the results of the two methods:

When we done, the results of the reservoir testing of the two methods are shown in Table 5 below for comparison.

Table 5: Comparison table of interpretation results by traditional and advanced methods.

Parameter	Symbol, unit of measure	Traditional method (Horner)	Advanced method (Ecrin software)
Initial pressure	pi (psia)	2520	2617.5
Water conductivity	kh (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	ri (ft)	1707.09	
Production Index	PI	0.6983	
Line performance	FE	0.3830	

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. And Ecrin software can determine the influence of boundary conditions, suitable reservoir and well model will help the results obtained with high accuracy. In addition, the traditional method is still different due to errors in the calculation process.

Analyze 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, documents of other wells in the same reservoir, compare and contrast with actual conditions, obtained data, and at the same time requires the interpreter 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 value of pressure P, flow Q in the data processing of Ecrin software is representative while choosing the value of pressure P or flow Q in the traditional interpretation by hand is only are the average values to facilitate the interpretation process, leading 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 "improve" the model. Meanwhile, the observation for the visual interpretation method is more error.

5. CONCLUSIONS AND RECOMMENDTIONS

Conclusions

The process of testing the DST#2 reservoir in the BI.1 sandstone of 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 through surveying the flow in the well and the pressure recovery ability capacity of the reservoir.

DST is the most popular reservoir test method, contributing to solving the problem of assessing the potential of a structure to come up with a reasonable exploited method. The process of interpreting 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 the Ecrin method can determine the influence of boundary conditions, suitable reservoir and well model will help to obtain accurate the results.

The parameters of the well and the reservoir are determined as follows: Initial reservoir pressure: pi=2617.5psia, Hydroelectricity: k_h=7680mD.ft, Reservoir permeability: k=106mD, Skin coefficient: S=14, Well-accumulation factor: $C=5.61E^{-4}$, Distance to fault: L=439 ft.

From the interpretation results, we can evaluate the formation: The application of the interpretation results to the oil initially in place calculation has shown that well BD-1X of 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

In order to be able to clearly explain and evaluate more accurately 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 from analysis results of core samples and wells geophysics, thickness and porosity-permeability properties of rock, formation of the reservoir.

In the future, if conditions allow, in order to evaluate more accurately the reservoir characteristics, it is necessary to continue more detailed studies such as: Conducting enhanced methods such as well stimulation, opening, widen the well wall to clean and treat acid near the bottom of the well, to limit sealing (sludge infiltration). The hydraulic fracturing to improve the recovery coefficient. Carry out additional core sampling and further study on the geophysical data of the wells of the reservoir and test the reservoir at other intervals of the aquifer for accurate and complete assessment.

ACKNOWLEDGMENT

The authors would like to thank you to PetroVietnam, PetroVietnam Exploration Production Corporation, Hoang Long JOC, VietsovPetro for the support and permission to publish this work. To the technical assistance and comments for this manuscript from PetroVietnam Domestic Exploration Production Operating Company and Ho Chi Minh City University of Technology are greatly acknowledged and appreciated.

This research is funded by Ho Chi Minh City University of Technology–VNU-HCM, under grant number **T-DCDK-2023-08**.

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Appendix

Parameters	**Calculation formulas**	**Nomenclatures**
Initial reservoir pressure (Pi)	$log\,\frac{T_p + \Delta t}{\Delta t} = 0$	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

the near well area $(\Delta p)_s$		B: Formation volume factor, bbl/STB 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}