

RESERVOIR ENGINEERING STUDY OF A GAS FIELD IN THE LOWER BOKABIL SAND IN SURMA BASIN

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ABSTRACT

The paper presents some findings from a reservoir engineering study of a gas field producing from the lower Bokabil sand in the Surma Basin, Sylhet. The main objectives of this study were to combine production and geologic data to better understand historical reservoir performance and predict future production. Given the limitations of data and relevant information, different methods and techniques were applied to determine reservoir and well parameters. Alternative material balance methods such as static bottom hole pressure (SBHP) estimated from shut-in wellhead pressure, shut-in wellhead pressure (SWHP) flowing bottomhole pressure (FBHP) of the well and flowing wellhead pressure (FWHP) were applied to estimate the gas in place and recovery factor. Production data analysis (PDA) and pressure transient analysis (PTA) were used to estimate the permeability, skin factor, wellbore storage coefficient, production decline rate, and the future production of the well. Finally a reservoir simulation was conducted in a limited scale to match the well pressure and production history. Using the above methods, it was estimated that the gas initial in place is 24 BSCF in the lower Bokabil sand, which is close to the previous studies and officially published figures. The pressure transient analysis showed the average reservoir pressure about 2678 psia. The formation permeability is estimated about 135 md, which is very close to the core analysis report.

Keywords: Lower Bokabil Sand, Surma Basin, Material Balance, Production Data Analysis (PDA), Pressure Transient Analysis (PTA), Reservoir Simulation, Initial Gas In Place.

1. INTRODUCTION

A reservoir engineering study was conducted on a gas field producing from the lower Bokabil sand in the Surma Basin, Sylhet. Even though the gas field is comprised of multiple sands, and there are a total of 8 wells producing from different sands, the study was based on a single gas well producing from the Lower Bokabil sand only. The well in question ceased its production due to low wellhead pressure after 7 years of uninterrupted oil production. Then the first workover was performed in March 2005 [1] when it was recompleted as a gas producer in lower Bokabil sand. And the gas production ceased again in July 2008 due to obstruction deposition in the tubing and perforation. A second workover was conducted to remove the obstruction and commercial gas production started again in February 2010 from this well. Figure 1 shows the production history [2] of the well.

The main objectives of this study were to combine production and geologic data to better understand historical reservoir performance and predict future production of the producing sand. In the process the gas

initially in place, permeability and skin factors were also evaluated using various techniques, and compared with results published in the past works [2, 3 and 4].

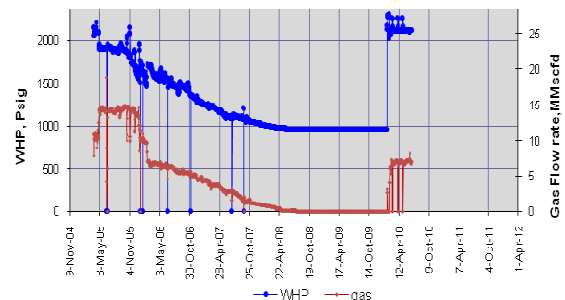


Fig 1. Production history of the subject well

Figure 2 shows the stratigraphy of the Surma basin [2]. It shows the locations and ages of different formations, reservoir sands and source rocks, seals, thickness, porosity and permeability of the sands.

Age	Group	Formation	Seals	Source	Reservoir	% ϕ	K mD	Net Pay (m)	ENVIRONMENT OF DEPOSITION
Pleistocene	Dupa Tila	Dupa Tila							Fluvial Channel
Pleistocene - Late Pliocene	Tispan	Gurjan Clay							Overbank Lacustrine Shales
Late - Early Pliocene		Tipam Sandstone							Braided Fluvial Sandstones
Early Pliocene	Surma	Upper Marine Shales				30	4000	80	BB20 Fluvial Valley Fill Sandstone
Late Miocene		Bokabil				16- 25	25- 400	0- 200	BB30 Bed load fluvial channel, braided BB50 Stacked fluvial, estuarine channel SS BB70 Prograding tidal deltaic bar SS
						10- 13	10- 300	0- 183	Sandstone and Shale prograding deltaic more Marine
Late - Middle Miocene		Bhuban							Thin bed pay
Middle - Early Miocene									
Early Miocene - ? Late Oligocene	Barail	Agram							Sandstone
Early Oligocene - Late Eocene		Ranjil							Sandstone
		Jenam							Shales and Coals
Middle - Early Eocene	Jenita	Laisong							Deltaic
		Kopli							Shelf Edge Limestone
Paleocene - Late Cretaceous		(Pre-Eocene sediments not encountered)							
Late Cretaceous		Orhalar							
Early Cretaceous		Bopur							
Jurassic		Rajmahal							
Triassic		Upper Gondwana							
Permian		Lower Gondwana							
Carboniferous									
Pre-Cambrian									

Legend

- Reservoir
- Seals
- Potential Source Rock

Fig 2. Stratigraphy of Surma Basin

2. RESERVOIR ENGINEERING ANALYSIS

To complete the analysis, several independent techniques were employed as described next.

2.1 Conventional Production Data Analysis

Decline Curve Analysis methods, as formulated by Arps [5] in 1945, have been for many years the conventional technique for analysis and forecasting of well production data and Decline Type Curves are based on an empirical rate-time and associated cumulative-time equation.

This decline curve analysis was conducted on the producing horizon of the Lower Bokabil sand, assuming exponential decline. After the first work over, the well was producing gas from April 2005. But in July 2008, production was suspended due to obstruction accumulation inside the tubing. Current analysis was conducted using the production data from April 2005 to June 2010 which appears to be more or less uninterrupted by external interventions (Figure 1).

The instantaneous or current decline rate (D) is defined by equation (1):

$$D = - (\Delta q/q) / \Delta t = - (\Delta q/\Delta t)/q \quad (1)$$

Where, D is "the fractional change in rate per unit time", frequently expressed in "% per year". Exponential decline occurs when the decline rate, D, is constant. If D varies, the decline is considered to be either hyperbolic or harmonic, in which case, an exponent "b" is incorporated into the equation, to account for the changing decline rates.

Exponential decline is expressed in terms of rates and time as:

$$q/q_i = 1/e^{Dt} \quad (2)$$

It is also expressed in terms of rate and cumulative production as:

$$G_p = (q_i - q)/D \quad (3)$$

Where G_p is cumulative gas production, q_i is the initial gas flow rate and q is the final flow rate.

The analysis includes gas rate vs. cumulative production (Figure 3) and yielded a closer GIIP of sand-D which is about 28.22 BSCF.

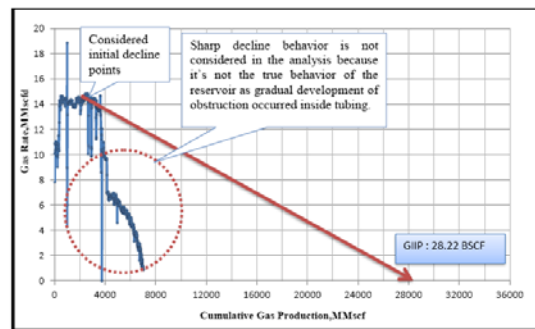


Fig 3. Gas Rate vs. Cumulative Plot

2.2 Advance Production Data Analysis

In 1980, Fetkovich [6] introduced a type-curve combining the theoretical response of a well in a closed reservoir, and the standard Arps decline curves. The motivation behind this work was to come up with a log log matching technique applicable to both the transient part of the data and the boundary dominated transient data on decline curves. It is important to remember that Fetkovich type-curve is based, for the depletion part, on the Arps decline curves. Like the decline curves, it suffers some limitations regarding constant bottom hole pressure, well behavior and the drainage area. Unlike conventional analysis, advance production data analysis techniques are based on sound theoretical foundation. Instead of plotting rates, time and cumulative production, these techniques involve plotting various transformations of these quantities. Two such techniques are presented next.

2.2.1 Blasingame Plot:

Blasingame [7] introduced two additional type curves which are plotted concurrently with the normalized rate type curve. The 'rate integral' and 'rate integral derivative' type curves aid in obtaining a more unique match [7].

Normalized Rate:

$$PI(t) = q(t)/p_i - p_w(t) \quad (3)$$

Normalized Rate Integral:

$$PI \text{ int.} = 1/t_c \int_0^{t_c} PI(t) dt \quad (4)$$

Normalized Rate Integral Derivative:

$$PI \text{ Int. Derivative} = \partial (PI \text{ int}) / \partial \ln(t_c) \quad (5)$$

Figure 4 shows the Blasingame plot for the well data considered for the study. All three curves presented in Equations 4, 5 and 6 are plotted against t_c on a log log scale in the Figure 4.

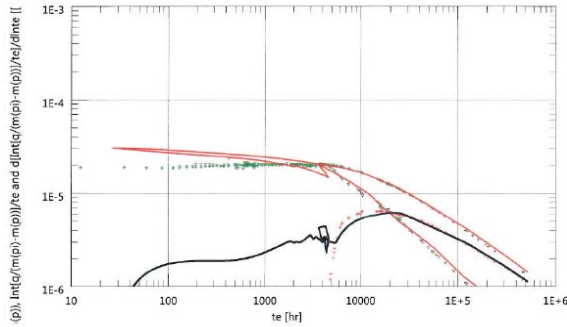


Fig 4. Blasingame Plot

This plot is used as a diagnostic tool, where the data and a model response are compared. The single step response shows the signature of the model in a clear and usable form, whereas the response to the real history is usually very erratic, because the equivalent time is jumping back and forth in time.

2.2.2 Log-Log Plot:

By replacing the time with an equivalent time, defined as the ratio of the cumulative to the flow rate, one can perform the variable flowing pressure test into a constant rate equivalent.

Integral of normalized pressure:

$$I(t_c) = 1/t_c \int_0^{t_c} \frac{PI - P_w(t)}{q(t)} dt \quad (6)$$

Derivative of the Integral of normalized pressure:

$$\text{Derivative, } \Gamma(t_c) = \frac{\partial I(t_c)}{\partial \ln(t_c)} \quad (7)$$

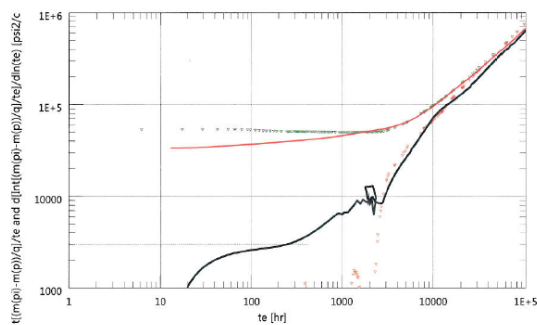


Fig 6. Log-log Plot

Figure 5 shows the log log plot for the well where the curves presented in Equation 7 and 8 are plotted against t_c on a log log scale in the Figure 5. Based on this production history, advanced production data analysis is conducted in this study. This analysis

indicates a GIIP for producing sand of 16.7 BSCF and the production history matching is shown in the Figure 6. In this analysis model production rate is matched reasonably but the pressure data are not satisfactorily matched because of poor quality and noisy production history. Time-dependent skin model is built to match the history of the model. Skin is observed about 40 and abnormally increased over time where as it was negative after first work over. This suggests about the accumulation of obstruction in the tubing.

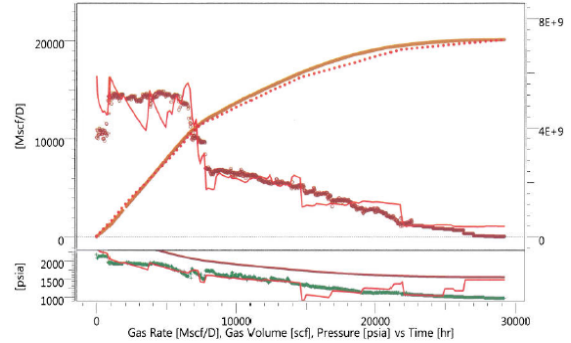


Fig 5. Production History Matching

2.3 Material Balance Analysis:

The material balance method uses actual reservoir performance data and therefore is generally accepted as the most reliable procedure for estimating original gas-in-place [8]. Once determined, the original gas-in-place can be used to reliably forecast the recoverable raw gas reserves under various operating scenarios.

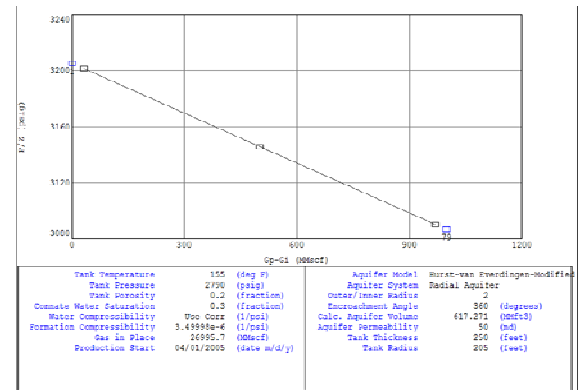


Fig 7. Conventional Material Balance - Analytical Plot

The important requirement is to accurately estimate the average reservoir pressure at the required time intervals. The standard practice is to estimate the average reservoir pressure from pressure buildup test conducted on individual wells in a reservoir. Pressure buildup test require shutting off production for some time. Therefore it is not conducted on a regular interval due to the demand-supply situation prevailing in the country. Therefore Conventional Material balance was conducted (Figure 7) with very limited data, which does not provide

much confidence in the results. It shows about 27 BCF of GIIP.

Material Balance Method has been modified by different researchers to bypass the strict requirement of the average reservoir pressure as an input parameter [8 and 9]. Instead, these techniques use static bottomhole pressure (SBHP) estimated from shut-in wellhead pressure, shut-in wellhead pressure (SWHP), flowing bottom hole pressure (FBHP) of the well and flowing wellhead pressure (FWHP). Results obtained by these methods are shown in figure 8-11 and summarized in Table 1.

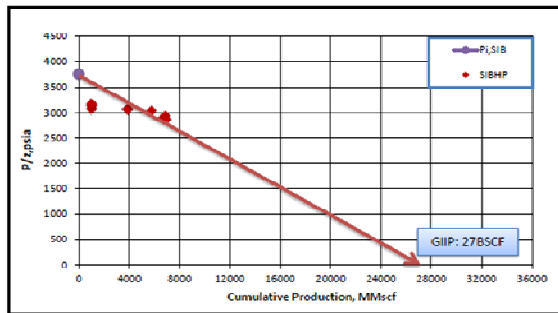


Fig 8. P/z SIBHP vs. Cumulative Production

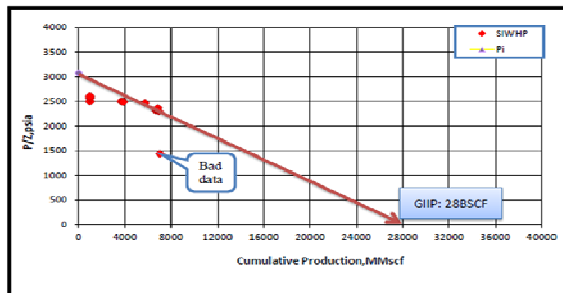


Fig 9. P/z SIWHP vs. Cumulative Production

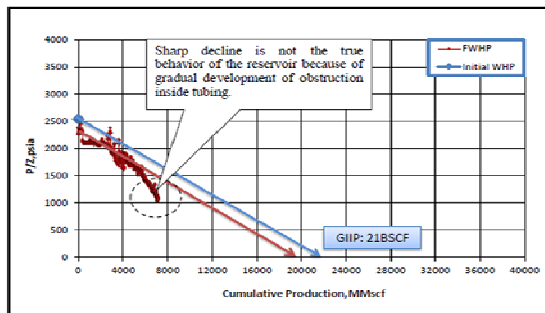


Fig 10. P/z FWHP vs. Cumulative Production

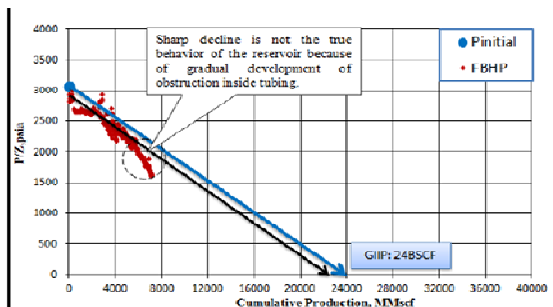


Fig 11. P/z FBHP vs. Cumulative Production

Table 1: GIIP estimates from alternative MBAL Techniques

Sand	GIIP, BCF				
	SBHP	SWHP	FBHP	FWHP	Conv.
LBB	27	28	24	21	26.99

2.4 Pressure Transient Analysis

A bottom hole pressure survey was conducted on producing horizon. This test was included in flow after flow (FAF) test with three different rates followed by a pressure build up.

A reservoir model has been built for pressure transient analysis (Figure 12) on producing horizon to investigate the reservoir parameters. The model is considered the homogeneous channel reservoir with one fault surrounding.

The pressure transient analysis has yielded the average reservoir pressure of 2678 psia and permeability of the formation is about 140 md. Skin value observed about 40 which is abnormally high. It could be happened due to presence of accumulation in the tubing or mud filtrate entered in the formation during completion which reduced the pressure. From the historical performance, it is also experienced that after first work over, pressure decline for the well occurred sharply due development of obstruction inside tubing. Second work over was done to clean the obstruction inside tubing. According to the official work over report, the deposition contains high paraffin and asphalt.

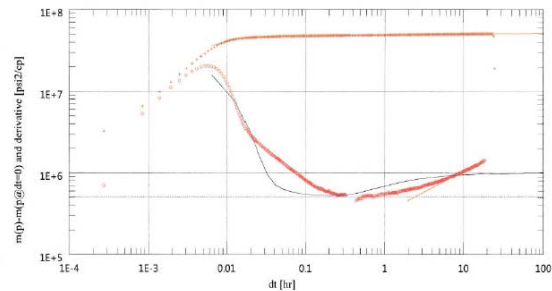


Fig 12. Pressure Transient Analysis

Reservoir parameters observed in PTA are shown in Table 2.

Table 2: PTA result

Analysis	Average reservoir pressure, psia	Skin	Permeability, md
Pressure Transient Analysis	2678	139-145	40-45
Blasingame Plot	2670 -2680	35-40	139
Log-Log Plot	2675	45	145

A Comparison of GIIP in BCF estimates on producing sand by PDA is shown in Table 3.

Table 3: Comparison of GIIP using PDA

PDA with Production	PDA with BHP Data as a production Data	Conventional Decline Curve Analysis
16.70	13.10	28.20

2.5 Reservoir Simulation

A reservoir simulation was conducted in a limited scale to match the well pressure and production history, and to forecast future production. A geological model of the reservoir was necessary to perform reservoir simulation. In this study however, the geological model was simplified using coarse grid system. Some of the values obtained from the above methods were used as the input parameters for the simulation, and some were obtained from previous studies and reports. Industry standard software tools were used to perform the above tasks. The producing reservoir sand of the well has been simulated by history matching using a commercial reservoir simulator. Implicit black oil model has been used to simulate the reservoir. The confidence level of the forecasts depends heavily on the accuracy of the geological data as well as the fluids and reservoir properties. The producing sand has been simulated till 2015. The prediction of future field performances involves prediction of the reservoir pressure depletion along with the off take rate of reservoir fluids. It is important that for a model to behave like the actual reservoir it must mathematically incorporate all the physical aspects of the actual reservoir. In simulation model, reservoir parameters (porosity, permeability, transmissibility etc.) are considered homogeneous for the whole producing sand and for the entire period of time productivity index assumed constant. So the model is limited to uncertainties due to heterogeneity of reservoir because of data inadequacy.

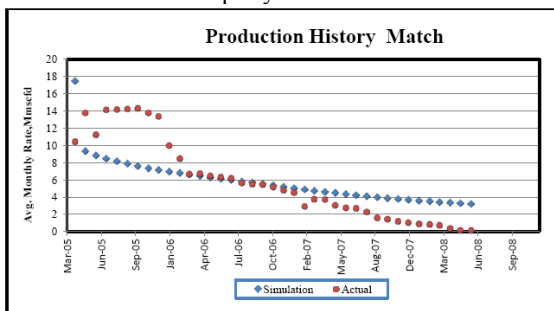


Fig 13. Production History Matching



Fig 14. Pressure History Matching

The producing sand has been simulated using a commercial simulator. The simulated results (Figure 13 and Figure 14) compared reasonable with the actual production and pressure history of the producing sand. Considering the pore volume connected with limited pressure and production history matching, GIIP yielded 32.51 BCF. As of July 2008, the cumulative production of the field is 7.087 BCF. According to the current model prediction, reserve at the abandonment p/z of 1000 psia is 21.20 BCF. Remaining reserve for this location is 11.31 BCF. The recovery factor for this sand is about 65.21% (See Table 4).

Table 4: Simulation results

GIIP,BCF (Considering connected pore volume with History Matching)	Reserve@ 1000 psia Abandon (BCF)	Cum Prod. (till July 2008) (BCF)	Remaining Reserve, (BCF)	Recovery Factor, (%)
32.51	21.20	7.078	11.31	65.21

3. SUMMARY AND CONCLUSION

- The GIIP Lower Bokabil sand obtained by advance production data analysis and conventional decline curve analysis are 16.7 BSCF and 28.20 BSCF respectively.
- The pressure transient analysis has yielded the reservoir pressure 2678 psia and permeability about 135 md which are used to match the production data analysis and reservoir simulation.
- Geo-model based on 2D seismic shows that sand-D is not affected by the fault which suggest no compartmentalization. On the other hand, well test data suggests the evidence of barrier which could be due to porosity variation or facies change.
- Based on available data no aquifer support observed in the D-sand of Field.
- The GIIP of Lower Bokabil sand of Field obtained by flowing bottom hole pressure method (FBHP) and conventional material balance using average reservoir pressure are 24.0 BSCF and 26.89 BSCF respectively.
- Reservoir simulation study result limited to the uncertainties due to heterogeneity of reservoir which are not considered due to data inadequacy. Producing sand simulated assuming homogeneous porosity and permeability. Considering the pore volume connected with history matching, GIIP yielded 32.51 BCF.
- The reserve estimates for the producing sand was done using different methodologies. Considering all these methods it seems that the flowing material balance (FBHP) is the better approach because this method is based on the pseudo steady state pressure behavior. GIIP using FBHP approach as 24 BCF, reserve at the abandonment p/z of 1000 psia is 16 BCF. Remaining reserve for this sand is 8.913 BCF. The recovery factor of this well is 66.67%.

4. RECOMMENDATION

- Proper attention should be given for pressure and flow monitoring in the well which will help to reduce the uncertainties in data quality for analysis.
- Uncertainties involve in reservoir pressure and draw down will be reduced by conducting periodic bottom hole pressure survey and that will help to accurately model the reservoir and analysis.
- Conducting 3D seismic survey in future will help to understand the Sylhet structure more which may create a more opportunities.

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6. NOMENCLATURE

Symbol	Meaning	Unit
BSCF	Billion Standard Cubic Feet	-
P	Pressure	(psi)
Z	Gas deviation Factor	-
PI	Productivity Index	(STB/d /psi)
SWHP	Shut in Well Head Pressure	(psi)
SBHP	Shut in Well Head Pressure	(psi)
FWHP	Shut in Well Head Pressure	(psi)
FBHP	Shut in Well Head Pressure	(psi)
GIIP	Gas Initially In Place	(BCF)
G _p	Cumulative Gas Production	(BCF)
HCPV	Hydrocarbon Pore Volume	(BCF)
P _i	Initial reservoir Pressure	(psi)
P _w	Pressure at Wellbore	(psi)
Z _i	Initial Gas Deviation Factor	-
R _b	Reservoir Barrel	(bbl)
t _e	Equivalent Time	(hr)
q	Flow Rate	(bbl/d)
IPR	Inflow Perform relationship	-
VLP	Vertical Lift Performance	-
PTA	Pressure Transient Analysis	-
PDA	Production Data Analysis	-
3D	Three Dimensional	-
LBB	Lower Bokabil	-