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Full Length Research Paper

Pressure transient test of Kailastila gas field

Arifur Rahman* and Fatema Akter Happy

Department of Petroleum and Mining Engineering, Shahjalal University of Science and Technology, Sylhet-3114, Bangladesh

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Well test analysis has been used for many years to assess well condition and obtain reservoir parameters. One of the most useful aids in analyzing gas well performance is the flowing well test. A complete analysis and understanding of the results of an appropriate well test enables one to determine stabilized shut-in reservoir pressure, determine the rate at which a well will flow against gas back pressure and estimate the reservoir flow characteristics. In this study, the pressure transient analysis was perform to measure the initial pressure, estimate a minimum reservoir volume, evaluate the well permeability and skin effect, and identifies heterogeneities and boundaries based on pressure and production data. These parameters was estimated on the basis of pressure data observed at the wellbore and production data using buildup test (MBH) and deliverability test methods. Deliverability test was performed to measure reservoir capabilities. This paper represents the contribution in identifying the effects of wellbore storage along with the skin intensity on gas wells. All the analysis was based on pseudo-pressure and pressure squared method along with generalized charts of type curves.

Keywords: Build-up test, deliverability test, type curve, skin factor, permeability, wellbore storage.

INTRODUCTION

Well test analysis is a branch of reservoir engineering. Information derived from pressure transient tests serves as resource for the reservoir engineer to estimate the reservoir properties. Estimates of horizontal permeability and the well condition (this parameter governs flow in the immediate vicinity of the wellbore) are imperative to determine the productive capability of a reservoir. Pressure transient analysis also yields estimates of the average reservoir pressure. Average reservoir pressure which is a reflection of density for single phase systems can be directly used in materials balance computations.

Well test can also be designed to render values of vertical permeability, to measure the direction of permeability trends in the reservoir, and to estimate variations in rock permeability in the vertical and areal senses. Additionally, special pressure transient tests can be used to determine the areal extent of a reservoir and to estimate the volumes of fluid in place. Because pressure measurements can be interpreted to yield quantitative estimates of the well condition, the efficacy of stimulation treatments on well productivity can be evaluated.

A well test is a record of the variations in bottom-hole pressure with time at a well and possibly a group of adjacent wells. For the duration of the tests, the well rate is controlled in a specified manner (a constant surface rate, a sequence of constant rates, constant pressure, etc.). Under certain conditions both pressure and production rate may be measured simultaneously at the sandface. As in any experiment, accurate measurements and accurate control of the conditions during the

*Corresponding Author's E-mail: djarif30@yahoo.com
Tel.: +88-01717265093

experiment are vital for obtaining useful information.

In well test interpretation, we use a mathematical model to relate pressure response (output) to flow rate history (input). By specifying that the flow rate history input in the model be the same as that in the field, we can infer that the model parameters and the reservoir parameters are the same if the model pressure output is the same as the measured reservoir pressure output. Clearly, there can be major difficulties involved in this process, since the model may act like the actual reservoir even though the physical assumptions are entirely invalid. This ambiguity is inherent in all inverse problems, including many others used in reservoir engineering (e.g., history matching in simulation, decline curve analysis, material balance). However, the dangers can be minimized by careful specification of the well test in such a way that the response is most characteristic of the reservoir parameters under investigation. Thus in most cases, the design and the interpretation of a well test is dependent on its objectives.

METHODOLOGIES AND OBJECTIVES

The objectives of a well test usually fall into three major categories: (i) reservoir evaluation, (ii) reservoir management, and (iii) reservoir description

Reservoir evaluation

To reach a decision as to how best to produce a given reservoir (or even whether it is worthwhile to spend the money to produce it at all) we need to know its deliverability, properties, and size. Thus we will attempt to determine the reservoir conductivity *(kh,* or permeability-thickness product), initial reservoir pressure, and the reservoir limits (or boundaries). At the same time, we will sample the fluids so that their physical properties can be measured in the laboratory. Also, we will examine the near wellbore condition in order to evaluate whether the well productivity is governed by wellbore effects (such as skin and storage) or by the reservoir at large. The conductivity *(kh)* governs how fast fluids can flow to the well. Hence it is a parameter that we need to know to design well spacing and number of wells. If conductivity is low, we may need to evaluate the cost-effectiveness of stimulation. Reservoir pressure tells us how much potential energy the reservoir contains (or has left) and enables us to forecast how long the reservoir production can be sustained. Pressures in the vicinity of the wellbore are affected by drilling and production processes, and may be quite different from the pressure and the reservoir at large. Well test interpretation allows us to infer those distant pressures from the local pressures that can actually be measured. Analysis of reservoir limits enables us to determine how much reservoir fluid is present (be it oil, gas, water, steam or any other) and to estimate whether the reservoir boundaries are closed or open (with aquifer support, or a free surface).

Reservoir management

During the life of a reservoir, we wish to monitor performance and well condition. It is useful to monitor changes in average reservoir pressure so that we can refine our forecasts of future reservoir performance. By monitoring the condition of the wells, it is possible to identify candidates for workover or stimulation. In special circumstances, it may also be possible to track the movement of fluid fronts within the reservoir, such as may be seen in water flooding or in-situ combustion. Knowledge of the front location can allow us to evaluate the effectiveness of the displacement process and to forecast its subsequent performance.

Reservoir description

Geological formations hosting oil, gas, water and geothermal reservoirs are complex, and may contain different rock types, stratigraphic interfaces, faults, barriers and fluid fronts. Some of these features may influence the pressure transient behavior to a measurable extent, and most will affect the reservoir performance. To the extent that it is possible, the use of well test analysis for the purpose of reservoir description will be an aid to the forecasting of reservoir performance. In addition, characterization of the reservoir can be useful in developing the production plan.

The objectives of this study were to analyze the well test data for well KTL-01, KTL-02, and KTL-04 to estimate the following parameters and finally these parameters are compared well with the previous study.

- The formation (permeability) and completion characteristics (skin) of the wells.
- Any reservoir barriers to flow in the vicinity of the wells.
- Current reservoir pressure, temperature, liquid holdup etc.
- Productivity of the formation and well deliverabilities.
- Determine the Absolute-Open-Flow-Potential (AOFP) of the well
- Finally the analysis results are matched with the vertical modeling and recommendations based on the result of analysis.

Methodologies

There are several methods used accomplish the desired goals. To estimate the reservoir parameters pressure build-up, type curve, deliverability, Dietz_MBH methods was used to complete this study.

Deliverability tests

This is a test that is used to determine the long term production performance of a well. It is typically run on gas wells. The well is initially shut in to establish a static pressure. In a conventional back pressure test, the well is subjected to a series of constant rate production and the bottomhole pressure is measured as a function of time. The rates and pressure records can be analyzed to determine the inflow performance relationship (IPR) and the open flow potential (AOF) of the well. The IPR curve describes the relationship between surface production rate and bottomhole flowing pressure for a specific value of reservoir pressure. The IPR curve can be used to evaluate gas-well current deliverability potential under a variety of surface conditions, such as production against a fixed backpressure. In addition, the IPR can be used to forecast future production at any stage in the reservoir's life.

Pressure build-up tests

This test is conducted on a well that has been producing for some time at a constant rate. A pressure recorder is lowered into the well opposite the producing horizon and the well shut-in, usually at the surface. The build-up bottomhole pressure is recorded for several hours or days depending on the anticipated formation permeability. The recorded pressures can be analyzed to estimate the formation permeability, skin factor, average reservoir pressure, distance to a fault if present, fracture length and fracture conductivity. A major disadvantage of pressure build-up test is that because the well is shut-in production is lost during the test.

Type curve analysis

Type curve matching provides methods for analyzing transient gas well tests with known dimensionless pressure P_D and dimensionless time t_D. Type curve matching techniques may be used for drawdown, buildup, interference, and constant pressure testing. The basic steps involved in the type curve matching procedure may be explained as follows:

1. Plot the actual pressure changes versus time in any convenient units on log-log tracing paper. Use the same scale as the type curve.
2. Place the points plotted on the tracing paper over the type curve. Keeping the two coordinate axes parallel, shift the field curve to a position on the type curve that presents the best fit of the measurements.
3. To evaluate reservoir constants, select a match point anywhere on the overlapping portion of the curves, and record the coordinates of the convenient point on both sheets of paper. Once the match is obtained, use the coordinates of the match point to compute reservoir parameter kh and $\varphi c_t h$.

RESULTS AND DISCUSSIONS

This section presents the discussion on parameters obtained from analytical (conventional) analysis, vertical model analysis and previous study model analysis for KTL-01, KTL-02 and KTL-04.

Deliverability test analysis

This analysis shows the various sand face and wellhead production or deliverability rate corresponds to different deliverability pressure

The obtained value of 'n' for KTL-01 and KTL-02 from both pseudo-pressure method and pressure squared method in case of sand face flow and well head flow indicate the Darcy flow which are consistent with assumption of the empirical equation. On the other hand, the value of n for KTL-04 in case of sand face flow indicates the non-Darcy flow but in case well head flow it indicates a Darcy flow. This is because; it was not possible to record the production test appropriately for KTL-04 due to inactiveness of gas flow meter.

The flow-after-flow test analysis results obtained from this study are so much dissimilar with the results obtained from previous study. This may happen for several causes as, previous study performed model analysis only which is theoretical, the obtained value of 'n' from their study is 1.15 for KTL-01 which should be in between 0.5 to 1.0. (Table 1-6) (Figure 1-6)

Buildup analysis with type curves

From Table -7, it is observed that the total skin effect is negative for well KTL-01 but negative for KTL-02 and KTL-04. It is tough to conclude that the wells are stimulated or damaged as all the skin components have not been analyzed here. The average reservoir pressure Pavg (3500.9psia) and (3487.7psia) from Dietz_MBH analysis for KTL-01 and KTL-04 respectively in Table-7 is closer to initial reservoir pressure indicates that the reservoir is at its early stage of production. But in case of KTL- 02, the average reservoir pressure is greater than the initial reservoir pressure. This may be the error at the time of data recording. The areal extents indicate the reservoir is rectangular in shape which is consistent with assumption. The results are tabulated here from pre-ssure semi-log plots, pressure derivative type curves and

Table 1. Deliverability test results for KTL-01 in terms of pressure squared.

Parameter	Sand face value	Well head value
P_{avg}(psia)	3599.3	2860
AOF(mmscfd)	244.216	192.851
$C[(mmscfd/10^6)/(psi^2)^n]$	$1.736e^{+3}$	$6.244e^{+2}$
n	0.726	0.794

Table 2. Deliverability test results for KTL-02 in terms of pressure squared.

Parameter	Sand face value	Well head value
P_{avg}(psia)	3221.8	2712.7
AOF(mmscfd)	795.533	80.593
$C[(mmscfd/10^6)/(psi^2)^n]$	$2.986e^{+3}$	$2.091e^{+2}$
n	0.773	0.813

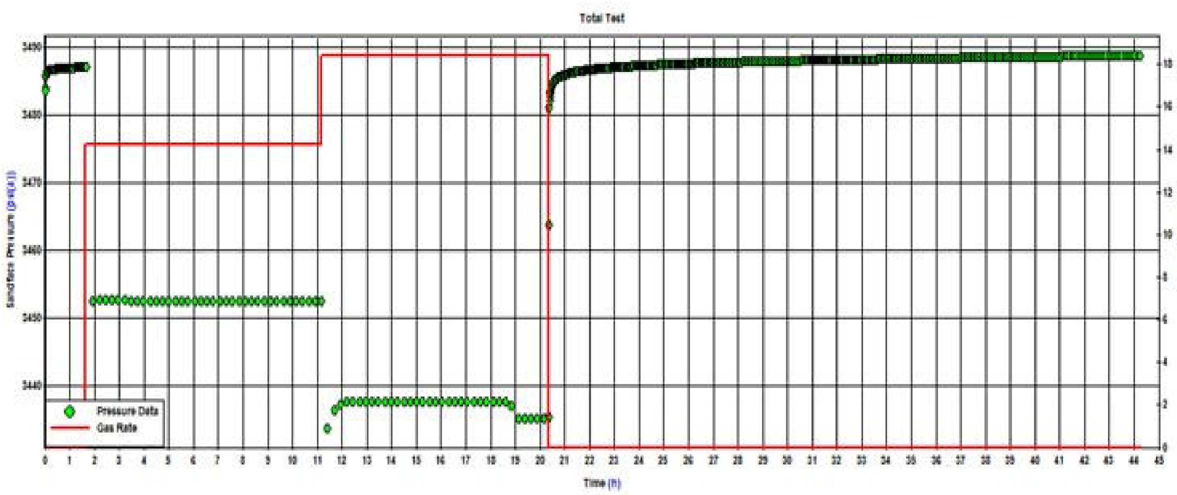

Figure 1. Total Test curve of well KTL-04.

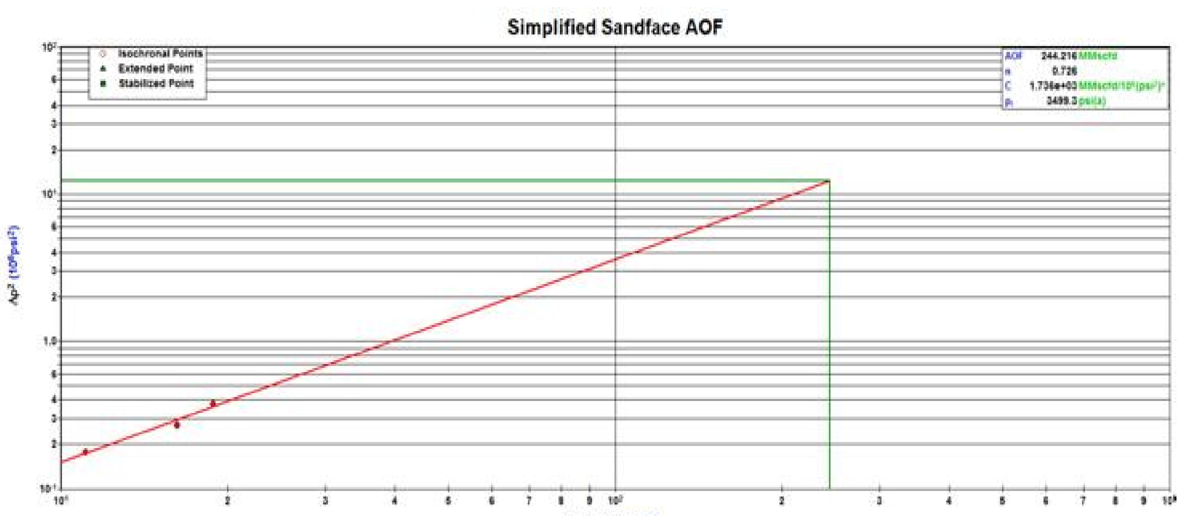

Figure 2. Sandface AOF curve in terms of pressure squared for well KTL-01.

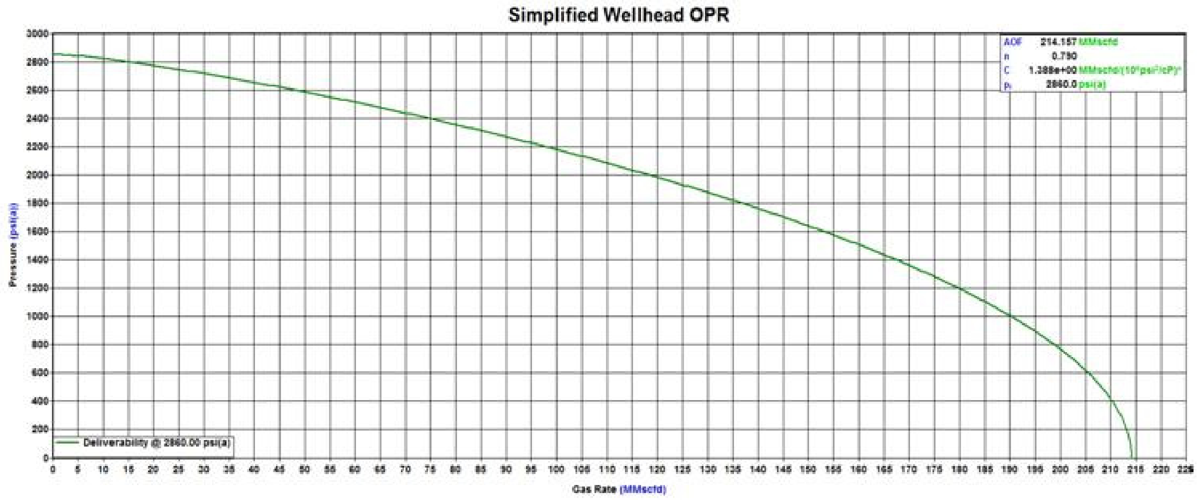

Figure 3. Wellhead OPR curve in terms of pseudo pressure for well KTL-01.

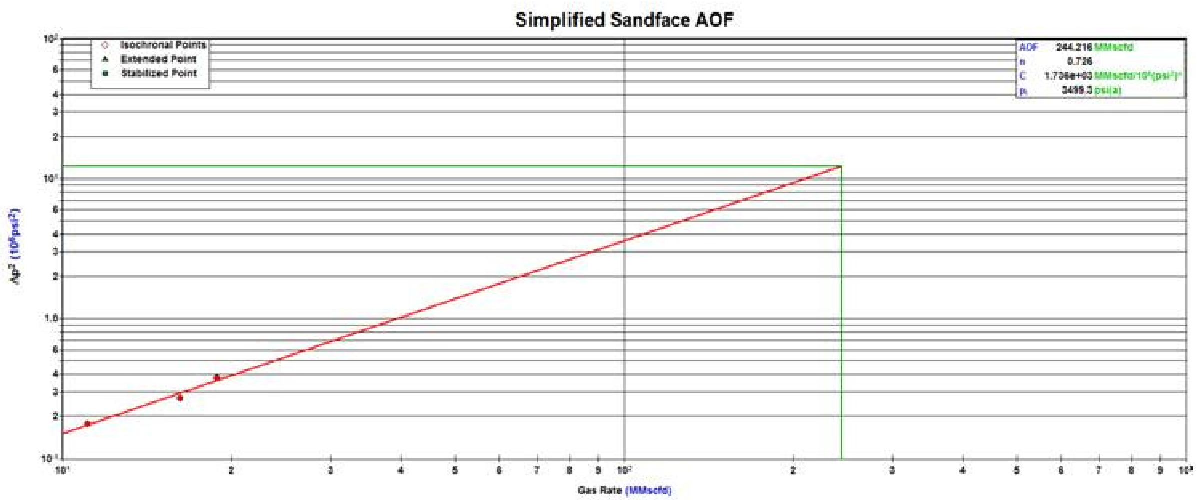

Figure 4. Sandface AOF curve in terms of pressure squared for well KTL-02.

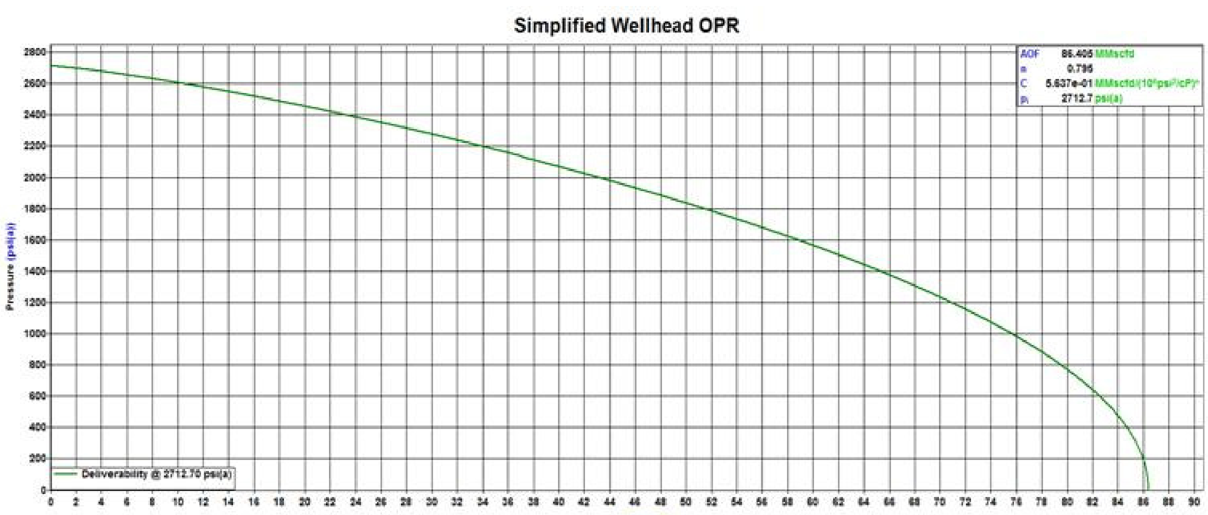

Figure 5. Wellhead OPR curve in terms of pseudo-pressure for well KTL-02.

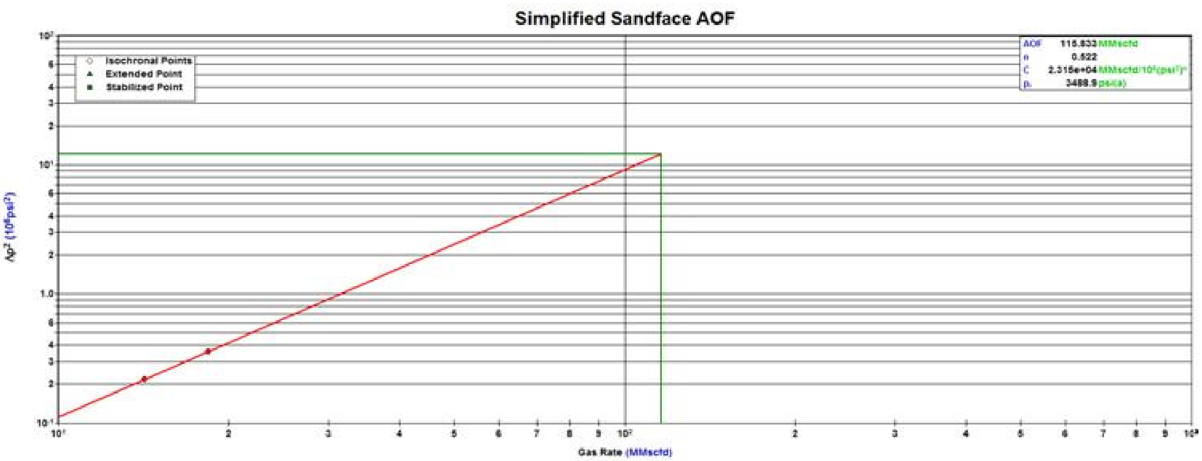

Figure 6. Sandface AOF curve in term of pressure squared for well KTL-04.

Table 3. Deliverability test results for KTL-04 in terms of pressure squared.

Parameter	Sand face value	Well head value
P_{avg}(psia)	3488.9	2856
AOF(mmscfd)	115.833	55.053
C[(mmscfd/10^6)/(psi^2)^n]	2.315e^{+4}	1.928e^{+4}
n	0.522	0.500

Table 4. Comparison of sand face flow-after-flow test results in terms of Pseudo-pressure with Previous study model value results for KTL-01.

Parameters	Analysis Value	Previous study value
AOF (mmscfd)	282.757	852.2
C [mmscfd/($10^6$$psi^2$/cp)^n]	2.199e^0	4.86e^{+1}
n	0.724	1.15

Table 5. Comparison of sand face flow-after-flow test results in terms of Pseudo-pressure with Previous study model value for KTL-02.

Parameters	Analysis Value	Previous study value
AOF (mmscfd)	935.809	3575
C [mmscfd/($10^6$$psi^2$/cp)^n]	5.658e^0	7.99e^{05}
n	0.772	0.638

Table 6. Comparison of sand face flow-after-flow test results in terms of Pseudo-pressure with Previous study model value for KTL-04.

Parameters	Analysis Value	Previous study value
AOF (mmscfd)	127.873	2490
C [mmscfd/($10^6$$psi^2$/cp)^n]	3.869e^0	0.103e^0
n	0.521	0.720

dimensionless type curves. The resultant values of a specific parameter obtained from all analysis methods are the same. For this reason, the specific method has not been mentioned in Table 7 containing results. The

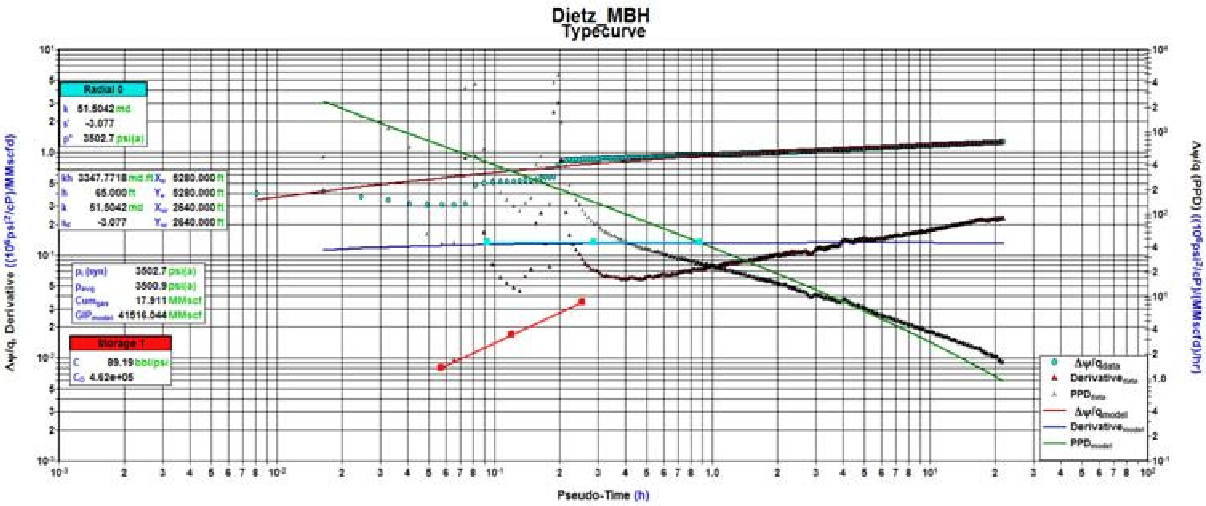

Figure 7. Dietz_MBH type curve for well KTL-01

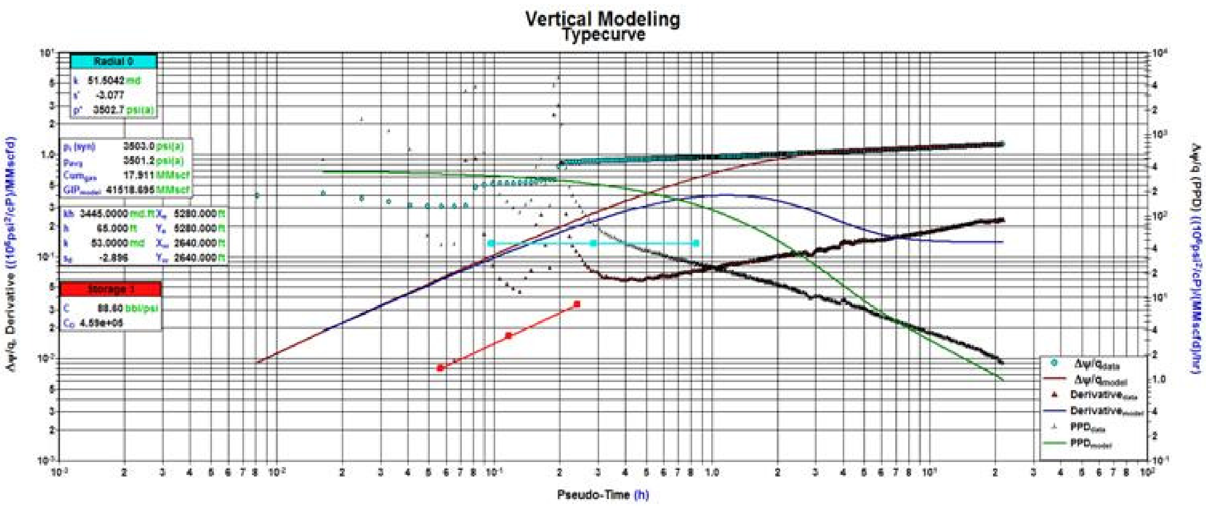

Figure 8. Vertical modeling type curve for well KTL-01.

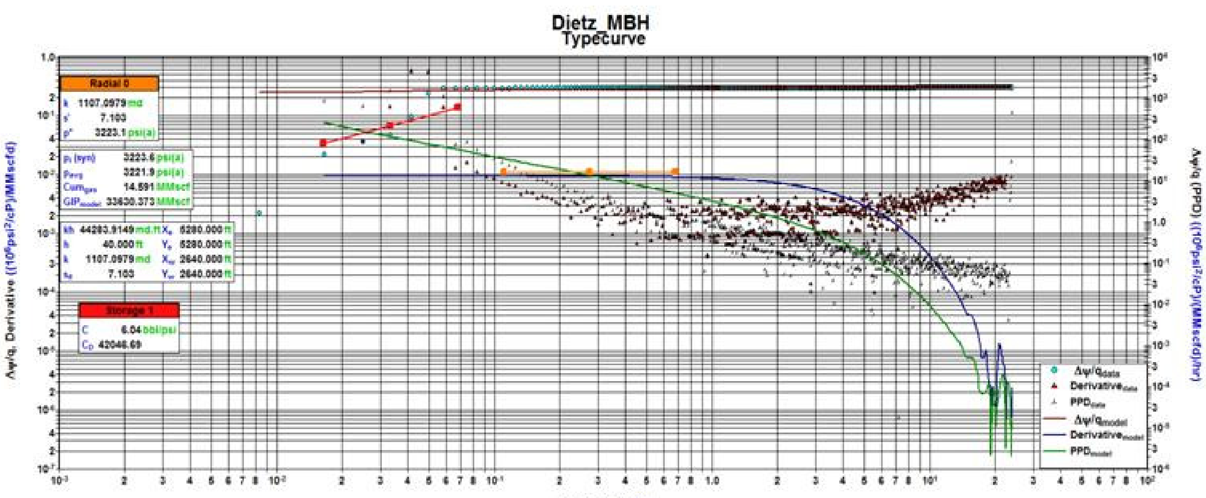

Figure 9. Dietz_MBH type curve for well KTL-02.

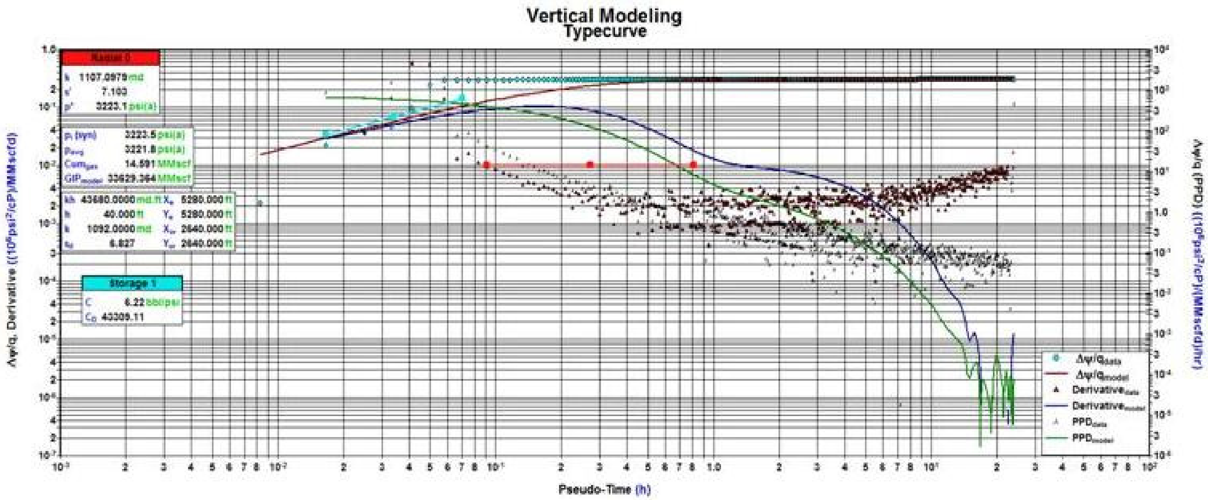

Figure 10. Vertical modeling type curve for well KTL-02.

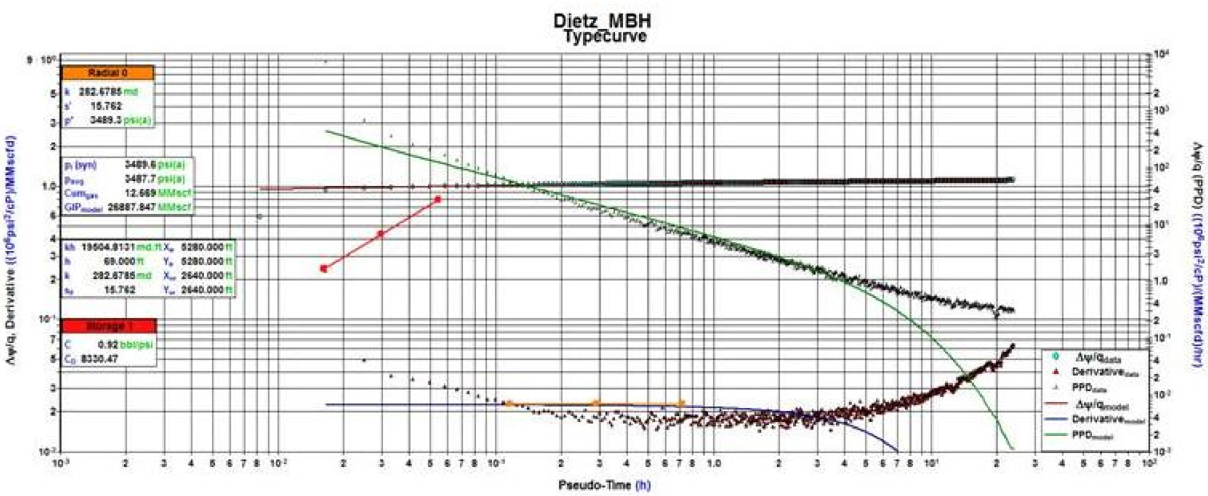

Figure 11. Dietz_MBH type curve for well KTL-04.

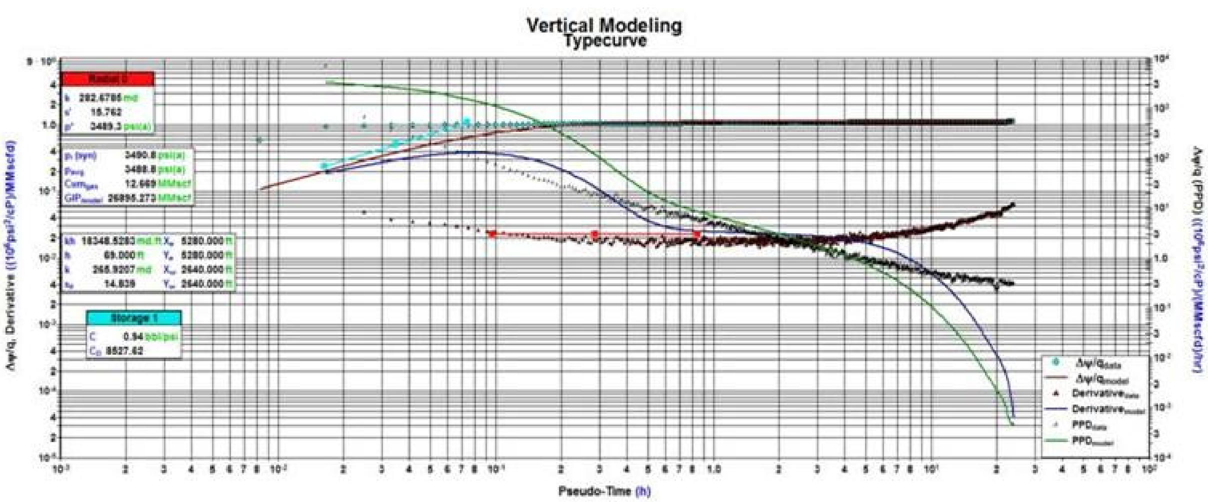

Figure 12. Vertical modeling type curve for well KTL-04.

Table 7. Results and Comparison of analysis and model value of this study with previous model study of Wells KTL-01, KTL-02 and KTL-04.

Parameters	Analysis Value			Model value			Previous study model value			Remarks
	KTL-01	KTL-02	KTL-04	KTL-01	KTL-02	KTL-04	KTL-01	KTL-02	KTL-04	
K(md)	51.5052	1107.0979	282.6785	53	1092	265.9207	147	4700	342	Average permeability
Kh(md.ft)	337.7718	44283.9149	19504.8131	3445	43680	18348.5283	9550	197000	23600	Total conductivity
S^-	-3.077	7.103	15.762	-2.896	6.827		3	25	20.6	Total skin
S_d	Not found	Not found	Not found	Not found	Not found	Not found	Not available	Not available	Not available	Skin due to damage
P_i(psia)	3515	3221	3491	3515	3221	3491	3515	3221	3491	Initial pressure
P^*(psia)	3502.7	3223.8	3489.3	Not found	Not found	Not found	Not available	Not available	Not available	Extrapolated pressure
$P_{(avg.)}$(psia)	3500.9	3221.9	3487.7	3501.2	3221.8	3488.8	Not available	Not available	Not available	Average reservoir pressure
$P_{(syn)}$(psia)	3502.7	3223.6	3489.6	3503	3223.5	3490.8	Not available	Not available	Not available	Synthetic pressure
C(bbl/psi)	89.19	6.04	0.92	88.60	6.22	0.94	0.154	1.5	0.179	Wellbore storage coefficient
C_D	4.62e+5	42046.69	8330.47	4.59e+5	43309.11	8527.62	Not available	Not available	Not available	Dim. Wellbore storage constant
Cum_{gas}(mmscf)	17.911	14.591	12.669	17.911	14.591	12.669	Not available	Not available	Not available	Cumulative production gas
GIP_{gas}(mmscf)	41516.044	33630.373	12887.847	41518.695	33629.364	26895.273	Not available	Not available	Not available	Gas initially in place
Xe(ft)	5280	5280	5280	5280	5280	5280	6000	4000	1250	Reservoir length
Ye(ft)	5280	5280	5280	5280	5280	5280	6000	4000	1000	Reservoir width
Xw(ft)	2640	2640	2640	2640	2640	2640	300	Not available	Not available	Well location in X-direction
Yw(ft)	2640	2640	2640	2640	2640	2640	300	Not available	Not available	Well location in Y-direction

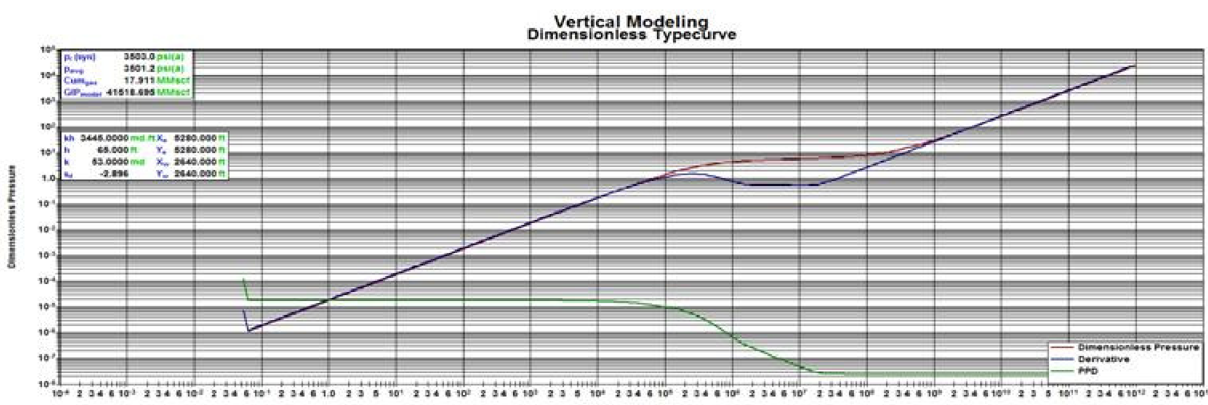

Figure 13. Vertical Modeling dimensionless type curve for well KTL-01.

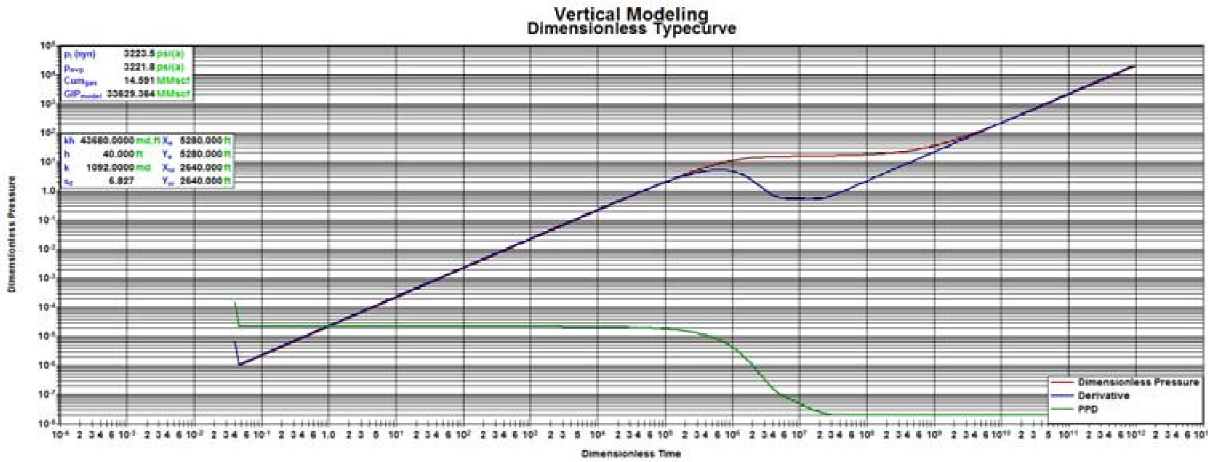

Figure 14. Vertical Modeling dimensionless type curve for well KTL-02.

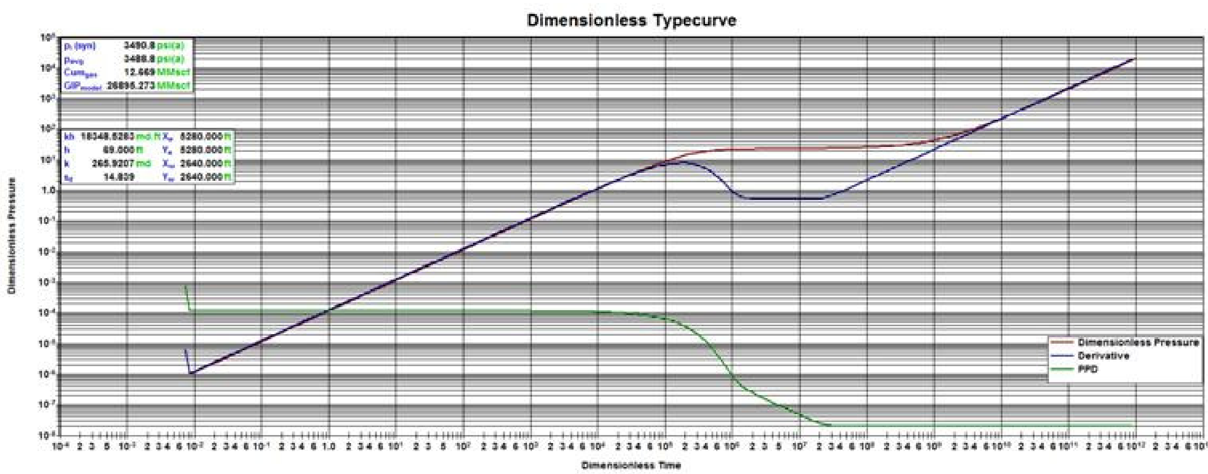

Figure 15. Vertical Modeling dimensionless type curve for well KTL-04.

results obtained from this study are dissimilar with the results of previous study model though all the input parameters are near about the same. The main reason of this dissimilarity is that previous study did not perform any diagnostic analysis. They found their results by model analysis only. It is also pointed out that they mentioned in their report that their results were erroneous but they did not mention any reason of erroneous results. (Figure 7-15) (Table 7)

RECOMMENDATIONS

From the above study we can recommend the following steps:

1. Down-hole shut-in and down-hole flow measurements are necessary for a better analysis.
2. The wellbore storage effect may also be minimized to provide better formation characteristics which are now being masked by the wellbore storage.
2. It is recommended that the build-up test be performed for a longer period to properly analyze the boundary effects.
3. The flow rate should be measured accurately with a flow measurement device.

CONCLUSION

In this study, we have dealt with the inverse problem concerning the determination of reservoir parameter estimation from well pressure and production data. The analysis and methodology developed in this work can be easily extended to the general problem of determination of parameter distributions in arbitrary dynamic systems from the input-output data. The interpretation of pressure buildup data can be carried out through the use of both specific graph of analysis and type-curve matching. The application of the drawdown pressure derivative-type curves has limitations in the analysis of pressure buildup data at intermediate values of shut-in time. The superposition time based on radial flow can be applied to analyze data measured after a variable rate flowing period. A general approach involving a combination of sets of first and second derivative function-type curves can be used to analyze an entire buildup test. This approach is based on the superposition time derivative of buildup data. In this study, pressure buildup data and deliverability data are analyzed and different reservoir parameters are estimated. These parameters are compared well with the previous study. These values should be used for further analysis such as reservoir forecasting, production planning and decision making. Finally it should be noted that Kailastila gas field has large reserve. If we effectively develop this field, it can meet the further demand of energy resources in our country.

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