PRE-POST FRAC TEST DATA ANALYSIS FOR HYDRAULICALLY FRACTURED VERTICAL TIGHT GAS WELL- FIELD CASE STUDY

Hazim N. Dmour, Eissa M. Shokir

King Saud University,
Petroleum and Natural Gas Engineering Department
Kingdom of Saudi Arabia, Riyadh 11421
hdmour@ksu.edu.sa

Worldwide there are vast reserves of natural gas trapped in tight sandstone formation and due to the low viscosity of natural gas it can be easily recovered. To produce this huge amount of reserve from low permeability formation economically, hydraulic fracturing can be applied. Therefore, the objective of hydraulic fracturing for well stimulation is to increase well productivity by creating a highly conductive path (compared to reservoir permeability) a distance away from the wellbore into the formation.

The post treatment performance provides a good indication of stimulation success, whereas, pressure transient (PTA) and production data analysis for hydraulically fractured vertical well remains the most applied method to determine the reservoir and fracture parameters. Therefore, this analysis is a key element for optimization of hydraulic fracturing process and forecasting well performance.

This paper discus the analysis of pressure and production data from hydraulically fractured vertical well in low permeability sandstone reservoir. Whereas, Pressure transient analysis is used to evaluate the effective fracture parameters such as fracture half-length, fracture conductivity and reservoir properties. Field example of application of production data analysis for vertical fractured well are presented.

The aim of this study is to evaluate the gas well productivity as a result of hydraulic fracturing treatments compared to the pre fracturing productivity and to estimate the petrophysical properties of the gas well from MIT testing data. Moreover, a discussion of how significant the increment in gas productivity was achieved with a very high propped fracture treatment success rate, is also presented. Furthermore, a view of how the correct design of fracture treatments can enhance reservoir performance and the recovery rate is discussed in details.

***Keywords**: Tight reservoir, Hydraulic fracturing, Pre-post frac, Productivity index, Pressure transient analysis, MIT.*

INTRODUCTION

Tight sandstone gas reservoir term commonly used to refer to low permeability reservoir, which produce mainly dry natural gas. Therefore the definition of tight gas reservoir is one in which the expected value of permeability to a gas flow would be less than 0.1md [8]. so a typical tight gas reservoir can be deep or shallow, high-pressure or low pressure, high temperature or low temperature, blanket or lenticular, homogeneous or naturally fractured, and can contain a single layer or multiple layers [9,10].

In general, a vertical well drilled and completed in a tight gas reservoir must be successfully stimulated to be commercially viable. Therefore, hydraulic fracturing becomes an effective technique for significant increase in productivity of gas wells so that the well can achieve economic production rates.

To evaluate the stimulation effectiveness, we need to estimate reservoir and hydraulic fracture properties, such as effective permeability, fracture half length and fracture conductivity. The knowledge of these parameters are not only significant for predicting future production performance of fractured wells, but also have important impact on determining development strategies in exploitation of tight gas reservoirs, which has increased in recent years [1].

Good well productivity estimates are vital for evaluating project value and making suggestions a against the deliverability sales contract. Therefore Post fractured pressure transient test analysis is the most common technique used to evaluate reservoir and fracture parameters such as fracture half-length, fracture conductivity and forecasting the well performance.

This paper discusses and presents a field case from the low permeability sandstone reservoir treated with acid and hydraulic fracturing (proppant) respectively. Moreover, the study provides a general picture of how a pressure transient analysis becomes an integrated method to evaluate fracturing processes. Example applications of production data analysis are presented.

APPLICATION OF HYDRAULIC FRACTURING IN LOW PERMEABILITY GAS FIELD

Field Description

The RH gas field, the only gas field so far discovered in Jordan, is located in the eastern part of the panhandle of Jordan, close to the Iraqi borders. The discovery was made in 1986 after drilling well RH x. The field produces dry gas with small amount of water (condensate) from tight sandstone of 7-15 % porosity and less than 0.1 md permeability with natural fractures evident in some wells. Currently about 30 MMSCF/D of gas is produced from 13 wells, cumulative gas production is about 132 BCF.

The reservoir is considered a tight sandstone reservoir, which belong to the upper part of Ordovician age, and the reservoir found at depth 8497.3 ft with a interval is around 328 ft thick sand/shale sequences. The reservoir is very complex, having significant lateral facies and thickness changes.

The gas is being predominantly methane (90.8 mol percent), with a significant carbon dioxide content (7.8 mol percent), 1.3 mol percent nitrogen, and minor a mount of ethane and propane. No gas / oil or gas / water contacts were encountered. The term “RH Formation” has been applied to a unit of clean sand stones formation and siltstones.

Candidate selection

The data from one low permeability, hydraulically fractured gas well have been used in this study.

The well is identified as RH-x; it is located in very heterogeneous reservoir with three multilayered producing sand. The selected candidate (RH- x), exhibited low permeability and low porosity in the entire sandstone formation section. Core and open hole logs analysis indicated about 35 of net pay with an average porosity of 10 %. The Modular Dynamic Testing (MDT) formation pressure survey run across the reservoir section and showed a gas bearing zone at 9019.4-9139.2 ft, which was also conformed to density log. RH-x has a better reservoir development than other wells in the field.

In general, the average Young’s Modulus throughout the sandstone formation is 7.082E+6 with a crossesponding poisons ratio of 0.26 in the competent sand. The stresses across the sandstone formation have some contrast between the consolidated and unconsolidated rock depending on the degree of cementation and presence of shale.

The in-situ stress indicated a bout 6145 psi and the toughness is 1500 psi.in0.5.also the fracture gradient is about 0.82 psi/ft.

The reservoir is sandstone with unique characteristics, because it shows low permeability with a high degree of rock consolidation under subnormal reservoir pressure and high temperature conditions. The cross thickness is about 147.6 ft.

The reservoir properties for this example are presented in table 1. The data were obtained from log analysis, core analysis, and static pressure surveys. The fracture gradient was calculated from the fracture treatment data.

The well it was selected as a candidate which represent the good producer category, the well was tested after acid stimulation and showed good productivity potential , the absolute open flow potential (AOF) was estimated at 16 MMscfd , with extended draw-down flow rate of 12.4 MMscfd and 868 psi flowing wellhead pressure through 48/64" choke size (table 2).

In order to prepare the well for hydraulic fracturing the well was worked over and production string was installed. A pre fracture Modified Isochronal Test (MIT) test was run on this well and the reservoir parameters calculated and were used for treatment design. Then, the well was stimulated by hydraulic fracturing followed by a period of clean up in order to flush out the liquid used in the operation as proppant carrier, and then the well was closed for pressure build up.

Testing program was designed in order to evaluate the result of hydraulic fracturing and to estimate the well productivity. A Modified Isochronal Test (MIT) was performed using bottom hole electronic memory gauges for measurements of bottomhole pressure, Dead weight Tester (DWT) was used to measure the wellhead pressure (WHP), the test consisted of four flow periods for a duration of 12 hours for each flow, table 3. The amount of gas produced during the test was about 125 MMscf. Fig. 3 explain the sequence of operation graphically, pressure and flow rate vs. time.

The fracture treatment design and analysis data for the selected candidate is summarized in Table 4. Included in these data are estimates of created fracture height and propped fracture half length. The values of created fracture height were estimated using the UBI log, Fig. 1, 2 and post fracture pressure and production data analysis. The fracture half length was calculated using the estimated fracture height and the actual treatment data.

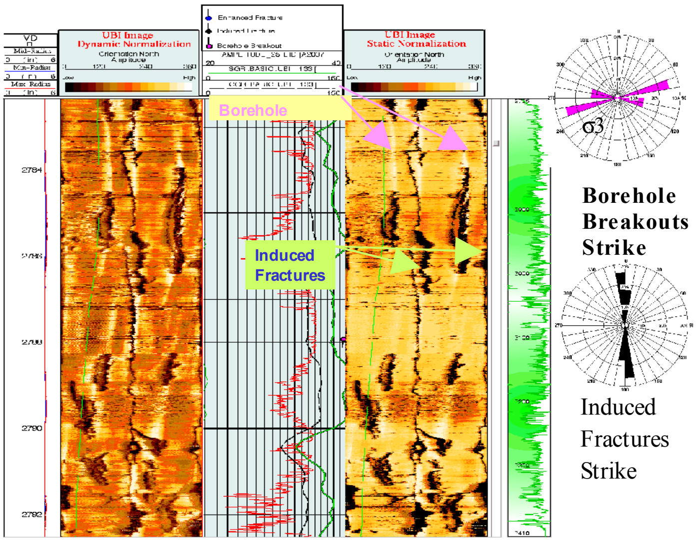

Figure1. Fractures and stress profile evaluation
Induced Fractures and Borehole Breakouts and Orientation

Fracture classification system, UBI image shows both the dynamic (right) and static (left) normalization. The fracture flow system relation

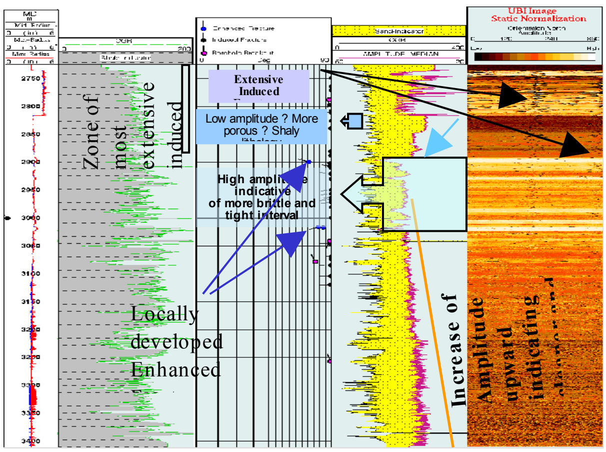

Figure 2. Lithology evaluation using Borehole Images
(Fracturing and formation bedding)

It was not possible to conduct the same schedule of the pre stimulation test, to make an easy and much more accurate comparison, due to the change in well bore configuration, which yield a change in flow pattern in the reservoir, and required longer time for flow and shut-in period to hopefully reach the stabilization state. Also it was not possible to flow the well through the same choke size due to the increase in production rate. Therefore, the decision was taken to flow the well through larger choke size to prevent possibility of freezing and plugging in the flow lines.

Pre- and post-frac test data

Prior to test evaluation the gas properties viscosity, z-factor and pseudo-pressure at different pressure points were calculated to enable processing data on these properties using locally custom designed software. Correlations for each of the properties were arranged as shown in Figs. 9, 10.

According to the objective of the testing, which includes the need to estimate the improvement in well productivity after fracturing, it was necessary to review the pre fracturing test data, comparing them with the post fracturing data and results. Therefore, this study includes the discussion of the following topics:

- Pressure transient testing
- Deliverability of the well
- Future production forecast

Pressure transient analysis has been used successfully to obtain estimates of reservoir and fracture properties. Bottom hole pressure data was interpreted to estimate reservoir parameters and to identify the reservoir model using semi log and log-log plots and type curve matching .This work was done by Fekete software package

In general, the Pressure response in ideal hydraulic fractured well is expected to behave as follows:

Wellbore storage effect at the early time, where the value of well bore storage coefficient depends on the tubing capacity , volume of well bore below packer and geometry of the well , well bore storage is usually large for a fractured well and for horizontal well. Immediately after the end of Wellbore storage period ***a*** *linear flow of half slope* appear for short duration of time, (this line could be masked by the well bore storage period), if the fracture conductivity is low this line with half slope would not exist, this flow represent the flow from the artificial fracture. After the end of previous stage, the adjacent reservoir begins to contribute forming *a quarter slopes called bilinear flow*. Finally, the flow regime will represent the reservoir and the boundary condition.

Pre-frac

A pre-fracture estimate of the formation average permeability *k* is necessary for the interpretation of fracture properties in the post-fracture transient analysis, unless the transient data contain at least some pseudoradial flow, for which an estimate of formation permeability can be computed directly from the transient data. Depending on the formation permeability, fracture half-length and conductivity, the pseudoradial flow regime may not be exhibited for an extensive period of time, making it impractical to obtain post-fracture estimates of formation permeability with well tests.

The pre-frac test indicated a heterogeneous reservoir. Near wellbore the permeability ranging between 3 and 7 md and the bulk formation permeability less than 1md. The shape of derivative indicates a complex reservoir with a mix of high and low permeability zones, Fig. 4. The good match at late-time confirms low permeability (0.7 md) of the bulk of the reservoir, Fig. 14.

Post-frac

The post-frac test indicated a heterogeneous reservoir. Near wellbore permeability ranging between 3 and 5 md, limited in a real extent, as evidenced by the late-time flattening of the radial analysis plot p* = 3310 psi compared to pi = 3386 psi, skin = - 4 confirming a successful fracture treatment, bulk formation permeability less than 0.3 md, indeterminate (infinitely large) area, the forecast of future production using this composite reservoir model confirms that the deliverability should decline from 18 MMcfd to 7 MMcfd in 1 year (Figs. 6, 7).

Even though there is no linear flow (1/2 slope) evident on the derivative plot, the negative 4 skin, and the improved deliverability, confirm that the fracture treatment was clearly successful. It improved the short-term deliverability from 12 MMcfd (at flowing pressure = 1545 psi) to 23 MMcfd (at flowing pressure = 2088 psi) (Fig. 6).

The shape of the buildup indicates that the near-wellbore area is stimulated and has a permeability of approximately 5 md. However; it is evident by the downward trend of the derivative at late time that the area of this permeability zone is limited. The semilog plot also shows that the 5md zone is depleting, but that it is probably in contact with a lower permeability zone, which would then have recharged the pressure back to initial pressure if the buildup had been extended longer.

The Pre-post modified isochronal test data, tables 2, 3 was modelled using a composite model, Figs. 18-19. This model represents a stimulated 5 md zone of limited areal extent in communication with an extensive low permeability (0.3 md) reservoir.

A 12-months forecast of production using this model, assuming an infinitely large reservoir (0.3 md), and shows that at a flowing sandface pressure of 800 psi, the deliverability will decline from 18 MMcfd to approximately 7 MMcfd in 1 year (Fig. 16).

Production Data Analysis

The well was placed on production after the test. Both the flow rates and wellhead pressures were measured on a daily basis, Fig.14-16. The wellhead pressures were converted to sandface pressures by a multi-step calculation that accounts for the variation of gas density with pressure and temperature.

The calculated sandface pressures were analyzed by two methods: Pressure Transient Analysis and Rate Transient Analysis using WellTest and RTA software (F.A.S.T. ™).

Both methods look at the same data, but from different perspectives, the first being focused on the pressure data and the second being focused on the rate data.

Pressure Transient Analysis

To perform the analysis of the production data, it was assumed that both a radial flow and a boundary dominated flow analysis should be attempted, because the well had been on production for approximately 10 months. The normalized flowing pressure was plotted against superposition time, Fig 15. The radial analysis resulted in a permeability of approximately 4 to 8 md, and a skin value ranging from – 2 to +3, with boundary effects evident after 3-4 months. The boundary dominated flow analysis gave a unique value of Gas-In-place of 11 BCF, Fig. 15.

The well test interpretation indicated that this well had a high flow capacity (kh) near the well and a low value of kh in the bulk of the reservoir. Accordingly, a composite reservoir model was used to simulate the measured production data.

Three cases were simulated, and each gave a reasonable match of the measured flowing pressures. However, when these matched models were used to forecast production, and the forecast rate compared to the actual measured production, one of the models (8.5 BCF case) was eliminated, Fig.16. The other two models gave forecasts that were consistent with the measured production rates. These models indicated Gas-In-Place of 51 BCF or 98 BCF, but the bulk of these reserves were contained in very low permeability rock (< 0.1 md), Figs 14-16.

Rate Transient Analysis

The rate and pressure data were normalized - q/ (delta p) - and analyzed using material-balance-pseudo-time in F.A.S.T. RTA. The analysis resulted in a permeability of 4, skin of -2 and a gas-in-place of 8.5 BCF, Fig. 17.

Discussion of results

It appears that there are approximately 8.5 BCF of gas contained in rock of reasonable permeability (2 to 4 md). There also exists an additional 40 to 90 BCF of gas contained in low permeability (<0.1 md) rock, which does contribute to production but only at low rates.

The production rate has declined from 17 MMcfd to 7 MMcfd in 10 months. The forecasts resulting from the various models indicate that the predicted rate after 2 years of starting production will be 2 to 4 MMcfd. The models that assume an original gas-in-place of 8.5 BCF give the lower forecast rate. However, the models that assume 50 to 100 BCF do not result in a significantly higher rate, because, even though the reserves are 5 to 10 times larger, those extra reserves are contained in low permeability rock which contributes relatively little to the production rate.

AOF & Deliverability of the well

Absolute Open flow Potential (AOF) at sand-face as well as at wellhead was analyzed, pressure squared and pseudo pressure values were used in the calculation as shown in Tables 6-8 and Figs. 8-13.

Well Deliverability curves were prepared for both of the sand-face and wellhead data, different techniques of analysis were used.

Fig. 12 represents well deliverability graphically at wellhead data for pre and post treatment conditions in one figure. This figure is direct plotting of the production rate versus well head pressure and the last reading of each flow period denote the flow rate and the flowing well head pressure. The curve lines, which intersect the initial reservoir pressure and with the minimum flow rate of each flow period is the well deliverability (at the initial reservoir pressure). Extrapolation of this line to zero pressure is the graphical value of AOF.

Figs. 11-12 and Table 8 shows the deliverability of the well at sand-face condition using the diffusivity equation. The results of analysis of pressure transient (reservoir parameters) were used as input for diffusivity equations. Therefore, flowing bottom hole pressure at different static reservoir pressure can be predicted according this figure.

To estimate the improvement in well deliverability as result of fracturing the separation between the two curves indicate the value of improvement in production rate.

The percentage of increasing in Productivity index is calculated against each choke size. Therefore the percentage of Increase in PI by hydraulic fracturing is 89.50 % as shown in Table 8.

Future production forecast.

Well test analysis showed that there was no indication of depletion in production, the reservoir acted as infinite acting system with constant pressure boundary at the end of final pressure buildup.

To predict the future performance of the well two approaches were used as explained below:

Forecasting using diffusivity equation.

Forecast of future well performance has been prepared in two ways, the first was based on the reservoir parameter calculated from the well test analysis and used as input to diffusivity equation Table 3 and Figs 15, 16 show that it is possible to produce 60 BCF of gas during 10 years with expected reservoir static pressure of 2200 psi and 920 psi flowing pressure.

Forecasting using Material balance equation

Second way of forecasting well production performance is to take into account the estimation of gas initial in place (GIIP). The GIIP was categorized in three values, depending on the probability of occurrence. The lowest value of GIIP with 90 % probability (GIIP = 190 BCF) was chosen for this analysis. Also the coefficients of back pressure equation (c, n) were used in calculating flowing pressure. This method will combine the use of material balance equation (P/Z vs. gas produced, Gp) with backpressure equation thereby the value of GIIP estimated volumetrically.

Result of prediction showed that 63.87 BCF could be produced during 10 years at 2180 psi static reservoir pressure and 870 psi flowing pressure.
Results are shown in Tables 6-8 and Figs. 17-18.

CONCLUSIONS

This paper discussed the analysis of pressure and production data from hydraulically fractured vertical gas well in low permeability sandstone formation.

The following main conclusions can be drawn from this work:

Hydraulic fracturing is an effective technique for increasing the productivity of wells producing from low permeability formations or wells with formation damage.

A general procedure for analyzing pressure and production data of low permeability reservoir was outlined.

It has been shown that it is possible to forecast the OGIP of low permeability gas reservoir, using a combination of the material balance equation and pressure transient techniques,

Pressure and production data analysis are the only accurate way to forecast reserves and to optimize the reservoir performance and to determine the effective fracture length and conductivity.

Material balance methods can provide accurate results in low permeability sandstone reservoir if the wells will be shut in long enough to obtain an accurate average reservoir pressure.

The significance of pre frac test diagnostics must be highlighted. The extra cost to perform the MIT is a very small part of the cost of stimulation.

Analyzing of actual field data imply (show) how close the actual well productivity is the potential maximum for the amount pf proppant injected. The actual fracture conductivity and half length determined by the analysis can be used to enhance future job execution.

NOMENCLATURE

Frac = Fracture
h= Net pay, m
k= Permeability, mD
p_i = Initial reservoir pressure, psi
P^* = Extrapolated pressure, psi
n = Exponent of the backpressure equation
c= Performance coefficient
AOF= Absolute open flow, MMscfd/psi
WHP= Wellhead pressure, psi
BHP = Bottom hole pressure, psi
MIT = Modified isochronal test
GIIP = Gas initial in place
UBI = Ultra borehole image
Fcd= Fracture conductivity
kh = Flow capacity
Q = Gas flow rate, MMscfd
PI = Productivity index, scfd/psi

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Table 1

Formation properties for selected candidate well

Well	Formation Type	Depth (ft)	Reservoir Pressure (psi)	Reservoir Temperature (F)	Net Gas Pay (ft)	Gas poro-sity (%)	Frac Gradie nt (psi/ ft)	water satu-ration (%)
RH-x	Sandstone	8937.6	3400	300	29.5-42.6	7	0.82	35

Table 2

Summary of pre fracturing MIT test

Period	Duration hrs	Choke size inch	WHP psi	BHP psi	Flow rate MMscfd
Initial shut-in	136.00	Closed	2766	3383.52	0
First flow	3.95	24/64	2019	2579.70	6.69
First Shut-in	4.00	Closed	2749	3351.72	0
Second flow	4.00	32/64	1513	2075.31	9.25
Second shut-in	4.00	closed	2736	3325.21	0
Third flow	4.00	40/64	1145	1761.74	11.14
Third Shut-in	4.00	Closed	2725	3303.47	0
Forth flow	4.00	48/64	871	1572.55	12.31
Extended flow	32.00	48/64	868	1545.22	12.04
Final shut-in	201.50	Closed	2758	3379.37	0

Table 3

Summary of post fracturing MIT Test

Period	Durati on hrs	Choke size inch	WHP psi	BHP psi	Flow rate MMscfd
Shut-in		0	2757	3365.22	0
First flow	12.00	32/64	2092	2763.82	12.75
First Shut-in	12.00	0	2737	3314.14	0
Second flow	12.00	40/64	1739	2534.14	16.87
Second shut-in	12.00	0	2718	3277.2	0
Third flow	12.00	48/64	1419	2374.71	20.14
Third Shut-in	25.33	0	2715	3278.69	0
Forth flow	11.67	64/64	932	2200	24
Extended flow	48.00	64/64	878	2083.09	22.7
Final shut-in	90.00	0	2707	3117.95	0

Table 4

Post-Frac analysis using design parameters

Fluid(YF140HTD, Borate cross-link)	
Prop type (20/40 mesh ceramic)	
Total proppant volume(lb)	233732
Total fluids volume(gal)	92133
Average Injection Rate (bpm)	21.3
Prop concentration	2to12 PPG
Propped fracture half length (m)	83.5
Fracture Height (m)	71.6
Width (inch)	0.167
Average Gel Concentration (lb/mgal)	1265.5
Average Gel Fluid Retained Factor	0.6
Average Conductivity (md.ft)	1918
Average Fcd	3.7
Net pressure (psi)	991
Efficiency	0.249
Average Treating Pressure (psi)	5528
Maximum Treating Pressure (psi)	8015
Maximum Injection Rate (bpm)	35.5

Table 5

Results of pressure transient test analysis

	Pre-frac		Post-frac	
Well parameters	Semi log	Derivative	Semi log	Derivative
Final rate, MMscfd			22.7	22.7
Net pay (h), ft	50	50	50	50
Porosity			8%	8%
Wellbore radius ft	0.26	0.26	0.26	0.26
Formation temperature, F	286	286	286	286
K, md			4.862	4.013
Kh, md-ft	150		243.1	243.1
Skin, S			-3.917	-4.013
Extrapolation pressure, P*, psi	3376.33		3383.42	3399.9
C, bbl/psi		2.922E-2		1.409E-1
C_D,		382.4		1845.5

Table 6

Simplified analysis

Pressure Squared		n	c MMscfd/(psi^2)n	AOF (MMscfd)
Sand-face		1	3.25E-06	36.80
Well-head		0.904	1.51E-05	25.00
Pseudo Pressure		n	c MMscfd/ (psi^2/cp.)n	AOF MMscfd
Sand-face		1	5.70E-08	38.89
Well-head		0.798	2.48E-06	25.08

Table 7

Production enhancement through hydraulic fracturing

Pre treatment flow data					
Choke size inch	WH P psi	BHP psi	Q MMscfd	PI scfd/psi	
32/64	1513	2075	9.25	7435	
40/64	1145	1761	11.14	6910	
48/64	868	1545	12.04	6373	
Post treatment flow data					
Choke size inch	WH P psi	BHP psi	Q MMscfd	PI scfd/psi	Increase PI %
32/64	2092	2764	12.75	19173	157.85 %
40/64	1739	2534	16.87	16572	139.80 %
48/64	1419	2375	20.14	15052	136.16 %

Table 8

Productivity index Calculations

Pre - Frac. Data (Well head)	
$P_{\text{average (well head)}}$	2757 psi
Pwf	868 psi
Choke size	48/64 inch
Q Calculated	12.04 MMscfd
Post-Frac. Data (Well head)	
Pwf	878 psi
Choke size	64/64 inch
Q Calculated	22.7 MMscfd
PI calculation	
PI Post- Frac	12080.89 scfd/psi
PI Pre- Frac	6373.74 scfd/psi
Increase in PI	89.50%

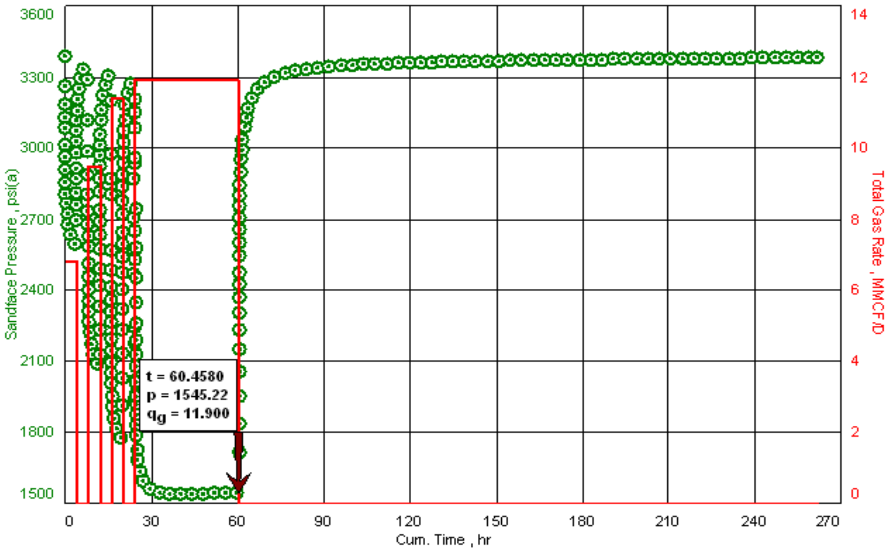

Figure 3. Pre Frac Modified Isochronal Test Data

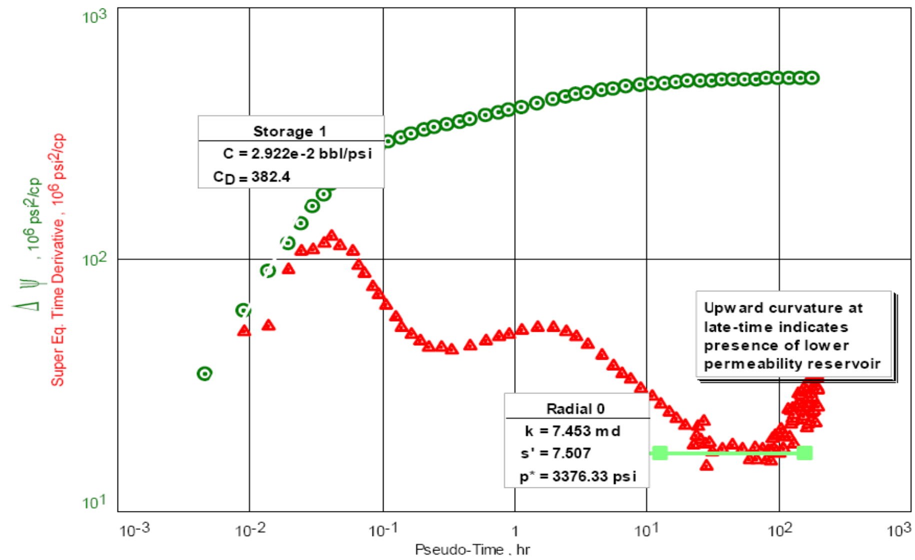

Figure 4. Derivative Response -Pre Frac Pressure Buildup Data analysis

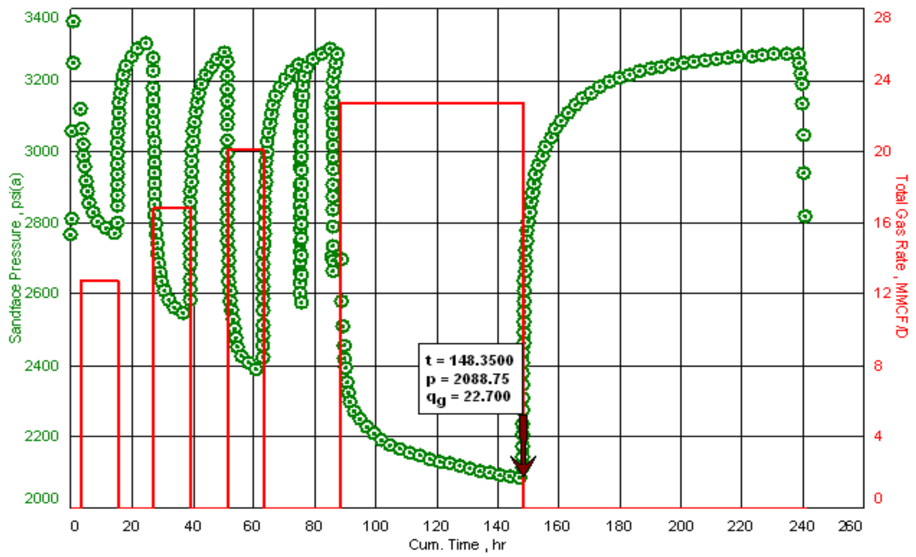

Figure 5. Post Frac Modified Isochronal Test Data

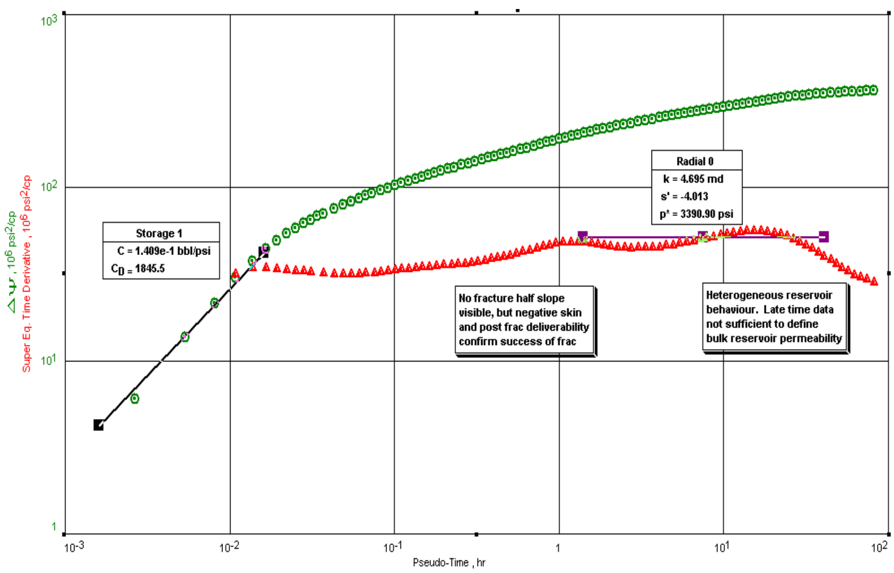

Figure 6. Derivative Response-Post Frac Pressure Buildup Data Analysis

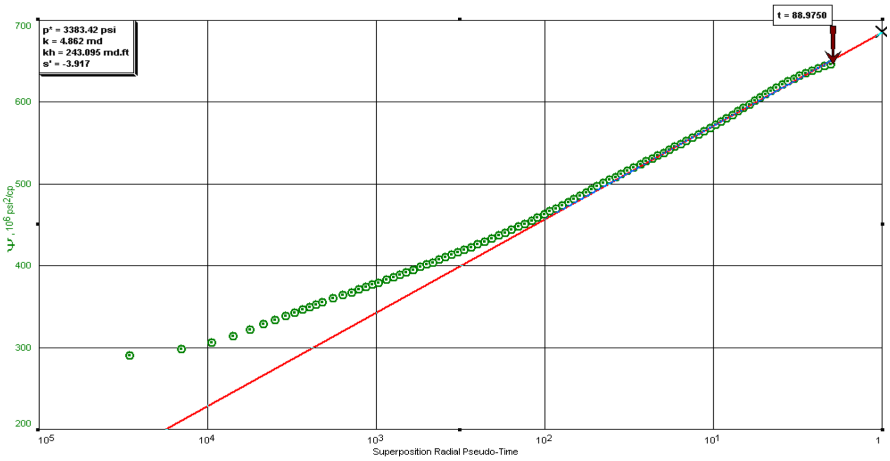

Figure 7. Final Buildup Analysis

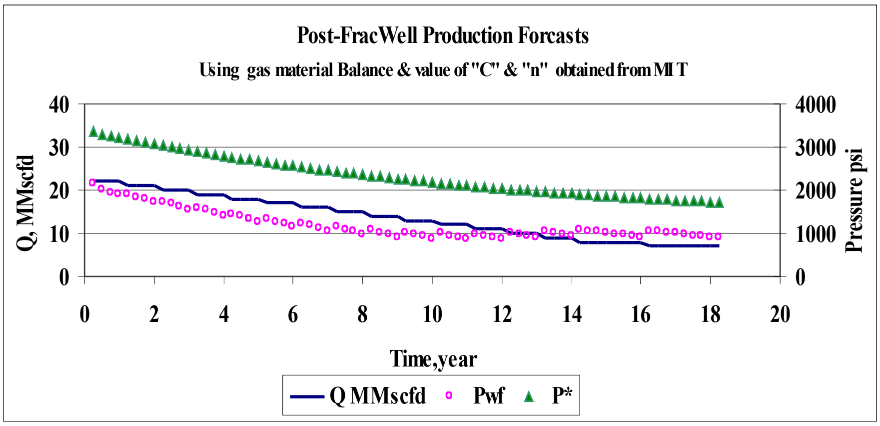

Figure 8. Post Frac Well Production Forecast by Material Balance

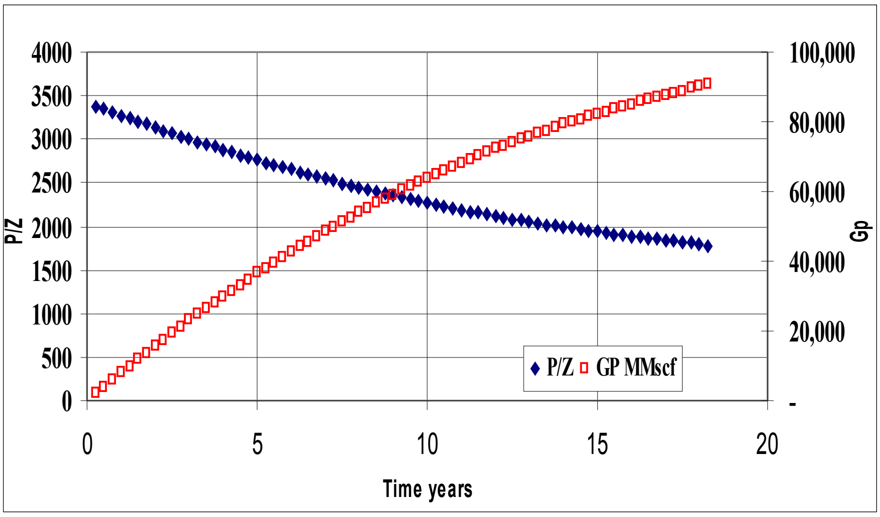

Figure 9

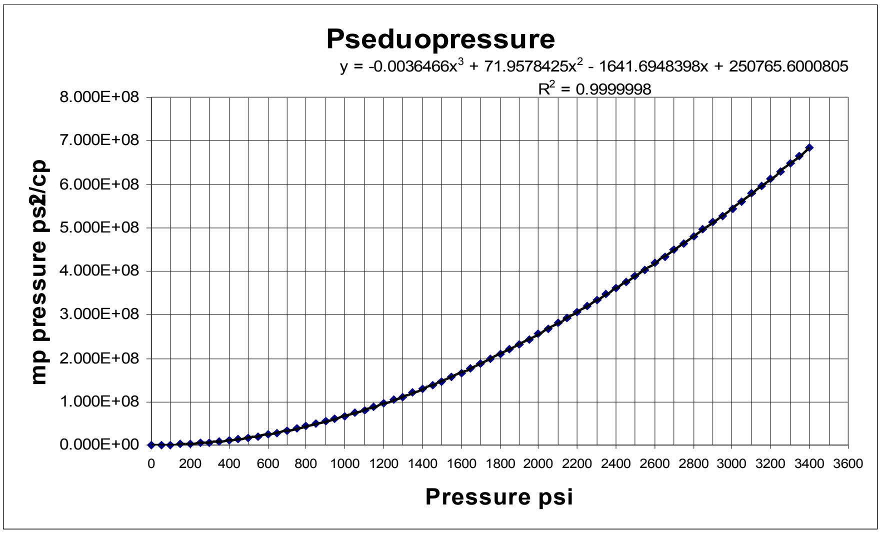

Figure 10. Real Gas Pseudo Pressure, as a Function of the Actual Pressure

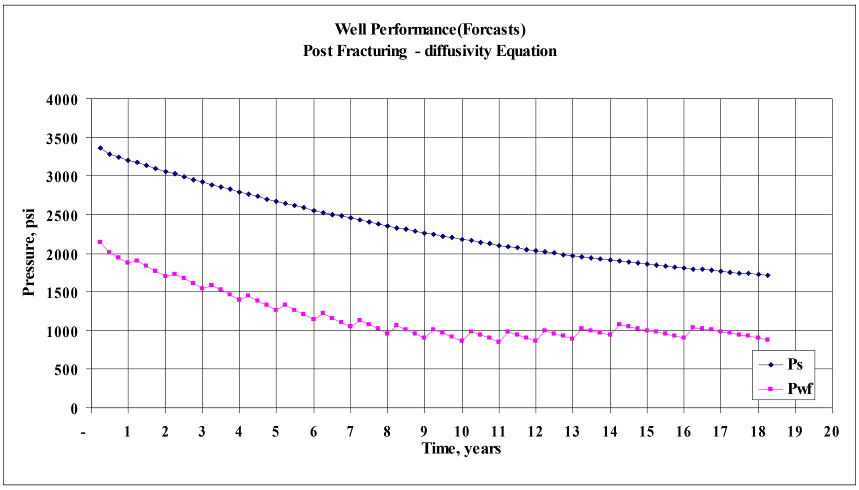

Figure 11. Post Frac Well Performance

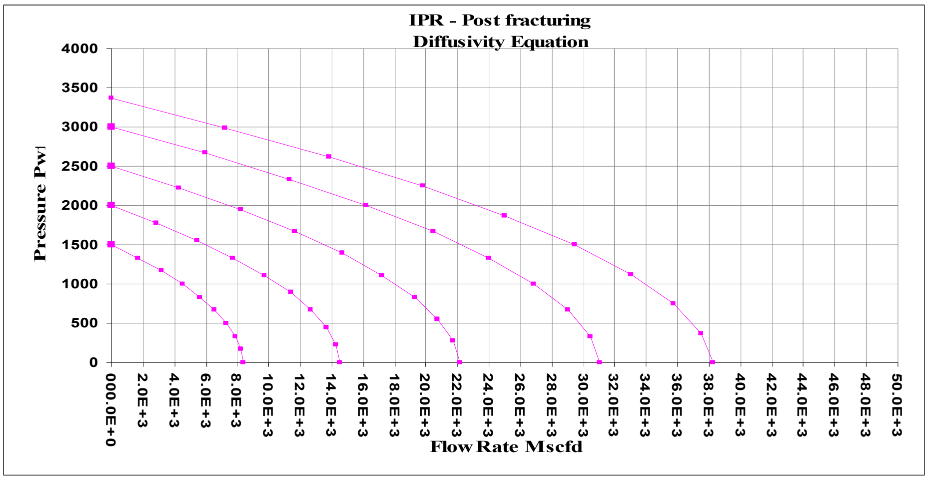

Figure 12. Post Frac Inflow Performance Curves Analysis by Diffusivity Equation

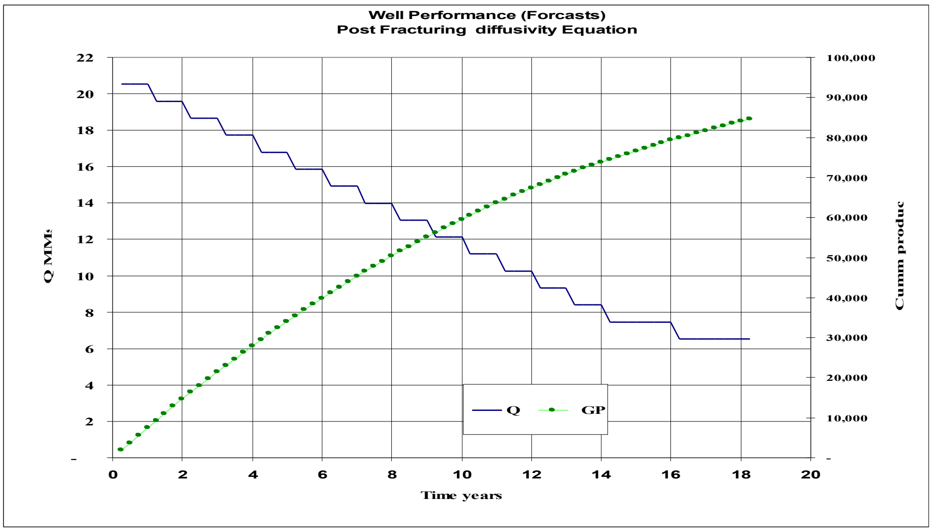

Figure 13. Post Frac Well Performance by Diffusivity Eauation

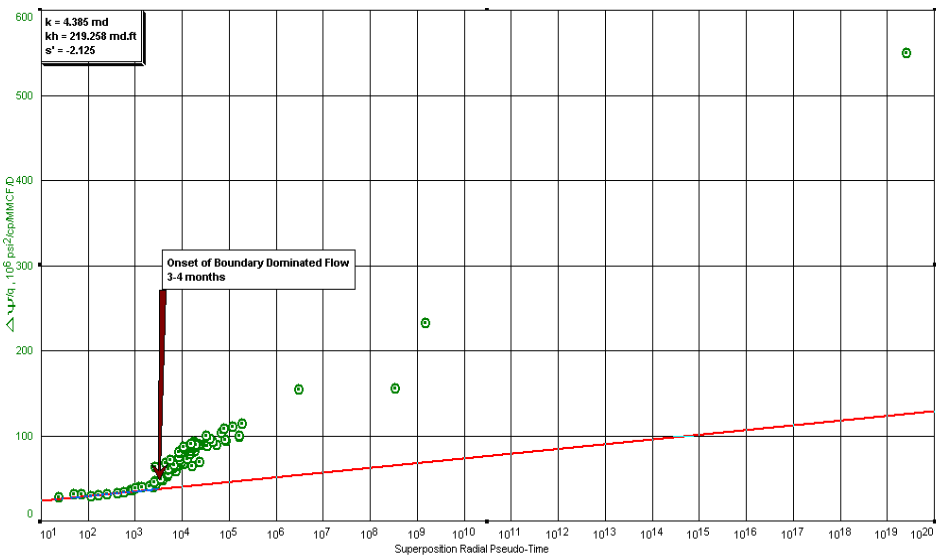

Figure 14. Post Frac Production Data -Radial flow analysis

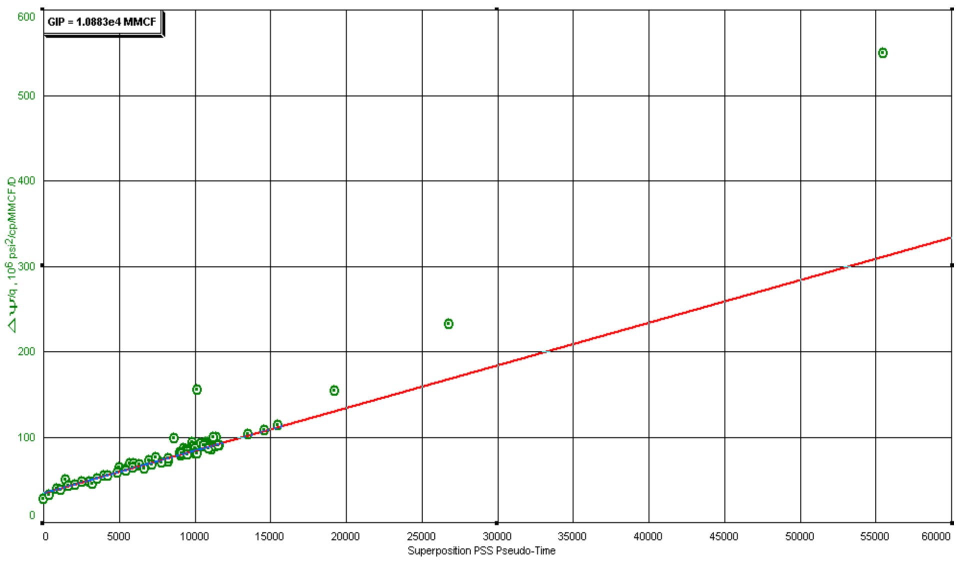

Figure 15. Post Frac Production data -Boundary Dominated Flow Analysis

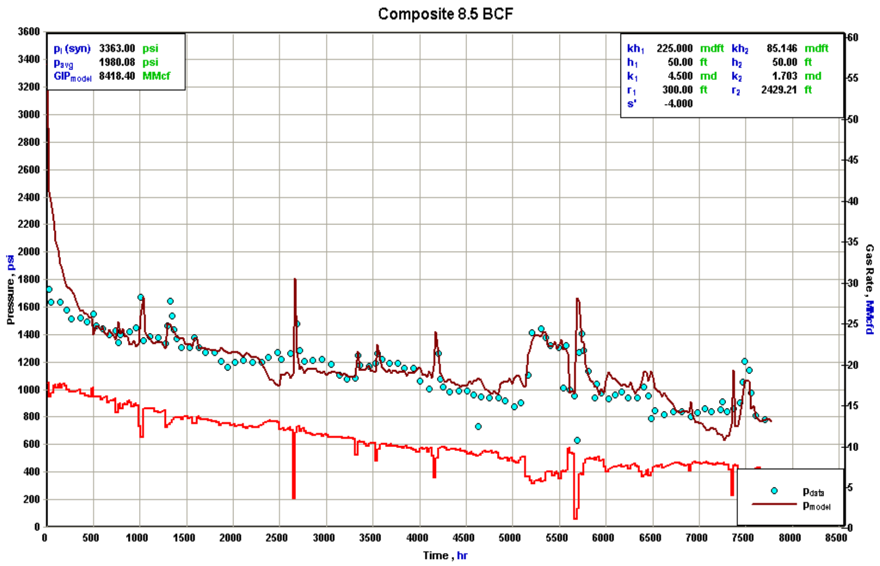

Figure 16. Post Frac Production History Match Test

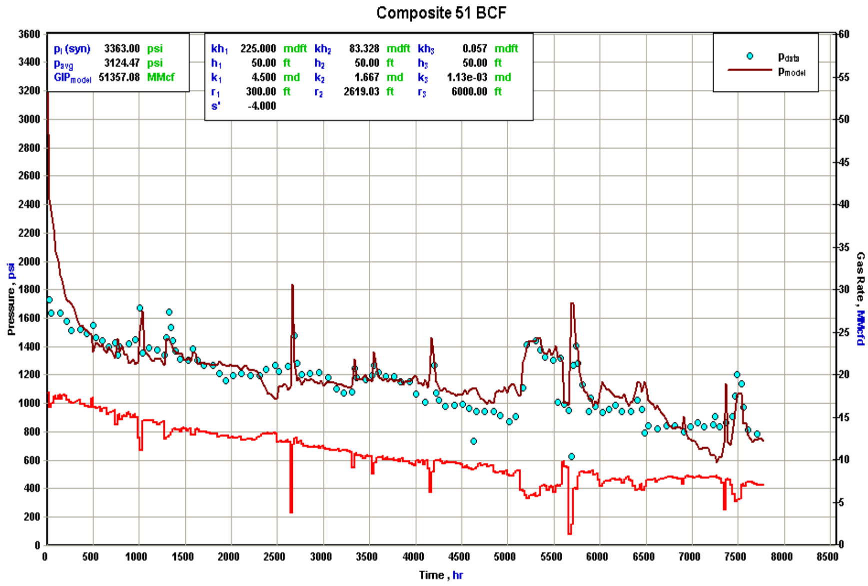
Composite 51 BCF
p_i (syn) 3363.00 psi
p_{avg} 3124.47 psi
GIP_{model} 51357.08 MMcf
kh_1 225.000 mdft kh_2 83.328 mdft kh_3 0.057 mdft
h_1 50.00 ft h_2 50.00 ft h_3 50.00 ft
k_1 4.500 md k_2 1.667 md k_3 1.13e-03 md
r_1 300.00 ft r_2 2619.03 ft r_3 6000.00 ft
s' -4.000
p_{data}
p_{model}
Pressure , psi
Gas Rate , MMcfd
Time , hr

Figure 17

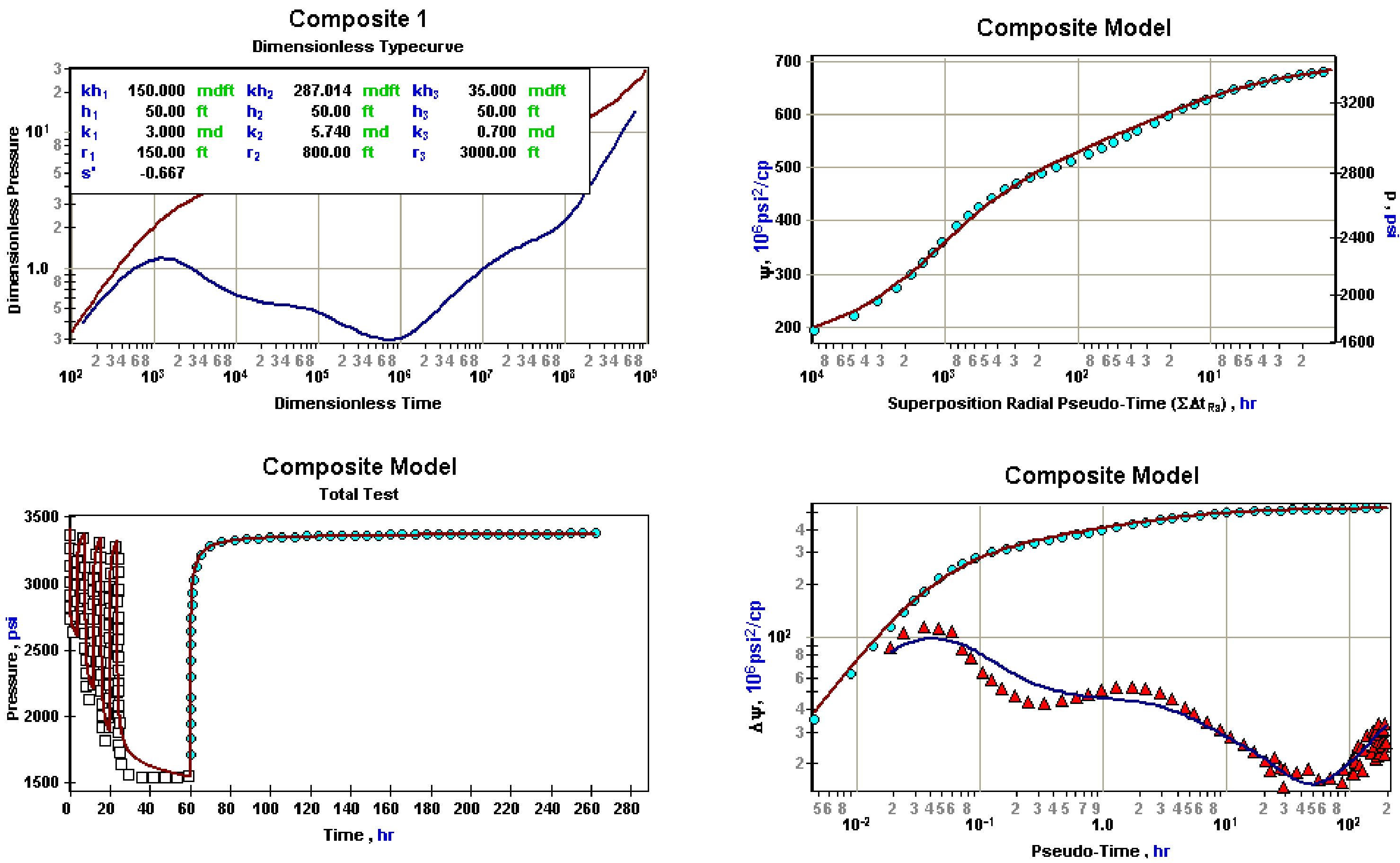

Figure 18. Pre Frac Composite Models Analysis

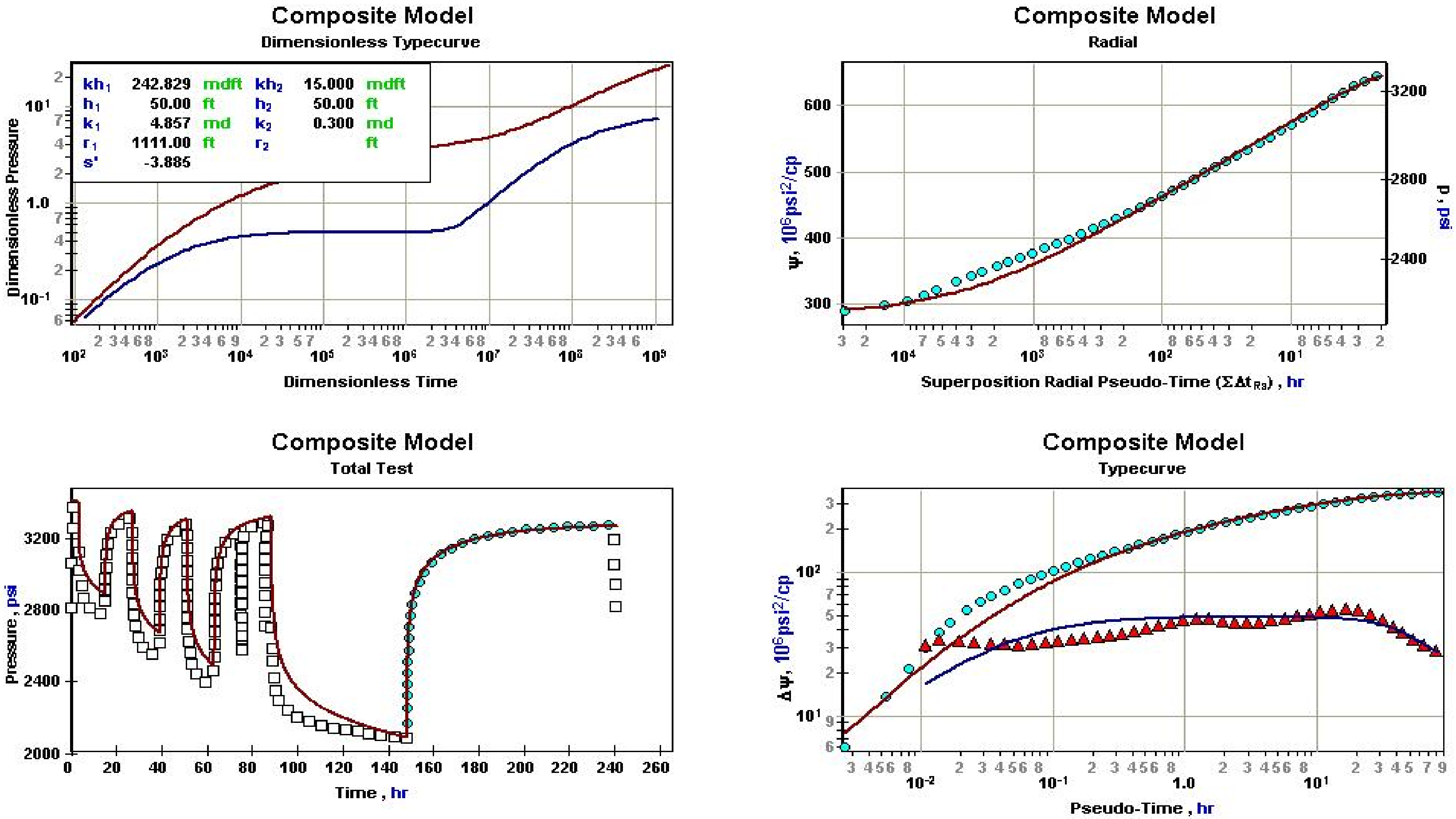

Figure 19. Post Frac Composite Models analysis

The Shape of derivative indicates complex reservoir with a mix of high and low permeability zones. Good match at late time confirms low permeability of the bulk of the reservoir. For this model, a simplified flow history was used. The rate was assumed constant for each flow period (rate measurements were approximate as they were calculated from the chock setting). As a result, the emphasis of the modeling was matching the final build up and not the preceding flow history