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# Integrated Analysis of Production Potential and Profitability of a Horizontal Well in the Lower Glen Rose Formation, Maverick County, Texas

Authors:
James R. Ammer (DOE/METC)
Thomas H. Mroz (DOE/METC)
Anthony M. Zammerilli (DOE/METC)
Albert B. Yost II (DOE/METC)
J. G. Muncey (Consultant)
P. S. Hegeman (Schlumberger Well Services)

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# Integrated Analysis of Production Potential and Profitability of a Horizontal Well in the Lower Glen Rose Formation, Maverick County, Texas

J.R. Ammer,* T.H. Mroz*, A.M. Zammerilli,* A.B. Yost II,* DOE/METC
J.G. Muncey,* Consultant, and P.S. Hegeman,* Schlumberger Well Services

*SPE Members

## ABSTRACT

The U.S. Department of Energy/Morgantown Energy Technology Center (DOE/METC) awarded a contract in 1991 to Prime Energy Corporation (PEC) to demonstrate the benefit of using horizontal wells to recover gas from low permeability formations. The project area was located in the Chittim field of Maverick County, Texas. The Lower Glen Rose Formation in the Chittim field was a promising horizontal well candidate based on the heterogenous nature of the reservoir (suggested by large well-to-well variances in reserves) and the low percentage of economical vertical wells. Since there was substantial evidence of reservoir heterogeneity, it was unknown whether the selected wellsite would penetrate a reservoir with the desired properties for a horizontal well. Thus, an integrated team was formed to combine geologic analysis, seismic interpretation, reservoir engineering, reservoir simulation, and economic assessment to analyze the production potential and profitability of completing a horizontal well in the Lower Glen Rose formation.

A vertical well was drilled, and oriented core, geophysical well logs, and a repeat formation tester were used to determine the reservoir properties. A reservoir simulation was then conducted and an economic analysis of the forecasted recovery was used in a 48-hour decision process to: (1) kick-off and drill a horizontal well, (2) complete as a vertical well, or (3) plug and abandon. Although the analysis showed that the horizontal well would provide a very high rate of return, plans for a horizontal well were abandoned due to (1) a concern regarding the possible mobility of the gas-water contact and the associated risk of a limited reservoir and (2) absent a limited reservoir, the projected economics of the vertical well were very good making the incremental risks of horizontal drilling unattractive.

Subsequent to completion of the test well as a vertical producer, a 7-day well test was performed to investigate the reservoir away from the wellbore. Analysis of the well test showed evidence of reservoir heterogeneity and fracture porosity and permeability. However, the fracture-to-matrix permeability ratio of this system was small (3.5 to 1) compared with ratios typical of tight formations (> 1,000 to 1).

References and illustrations at end of paper

The integrated approach of using all of the available data and analysis techniques was vital in leading to the final decision not to drill a horizontal well. Reservoir simulation combined with economic analysis provided quick and inexpensive forecasts covering a wide range of possible reservoir properties. The analysis showed that the range of reservoir parameters conducive to drilling a horizontal well in a non-fractured reservoir is fairly small (though specific reservoirs should be analyzed case by case). Depending on the amount of data available for the reservoir, and the complexity and heterogeneity of the reservoir, a well test may provide better information on which to base the drilling decision than near wellbore measurements.

## INTRODUCTION

Horizontal wells are thought to be an efficient method for producing natural gas from low permeability reservoirs, especially where vertical fractures control production. Although several theoretical studies and case histories have been documented on the performance of horizontal wells, the methods for optimal profitability and production design of a horizontal well in low permeability formations are not fully understood. Research efforts at DOE/METC are currently focusing on the effectiveness of horizontal wells in low permeability natural gas reservoirs. A part of this research involves analysis of horizontal well production mechanisms and economics to gain insights into the effectiveness of horizontal drilling and completion methods. This paper demonstrates the importance of analyzing all information (geophysics, geology, reservoir engineering, numerical simulation, and profitability) to evaluate the production and economic potential of horizontal wells in low permeability formations.

## GEOLOGIC SETTING

The study area, shown in Figure 1, is situated in the east-central portion of the Maverick Basin in Maverick County, Texas. The Maverick Basin lies in the northwest end of the Rio Grande embayment where the Lower Cretaceous sedimentary rocks, primarily carbonates, accumulated in a rapidly subsiding basinal area[1].

The stratigraphy of the Lower Glen Rose in the study area is characterized by a middle shelf carbonate facies assemblage[2,3]. The target reservoir is composed primarily of grainstones, packstones, and boundstones that were deposited within or proximal to a mid-shelf patch reef. The porosity is complexly distributed and may be comprised of a variety of carbonate depositional facies, e.g., reef core, channels, bars, and beaches, related to the presence of the patch reefs. Well control suggests that the primary allochems in the patch reef facies assemblage are rudistids, stromatoporoids, and algae. Much of the original porosity has been lost to diagenetic processes with the remaining porosity greatest in the grainstones and packstones. Major porosity types are primary interparticle and secondary moldic that are locally enhanced by tectonic fracturing.

Structural geology of the Maverick Basin is characterized by Laramide-age, long, open asymmetric anticlines with southeast plunge. The Chittim Anticline exhibits in excess of 1,000 feet of vertical relief on the Buda Limestone. It is comprised of approximately 448 square miles or 287,000 acres of uplifted area, and is one of the largest surface anticlines in Texas[4]. Miocene-age antithetic and synthetic faults with primarily northeast and northwest trends are also present in the study area. However, local seismic control suggests that faulting is significantly more common at depths shallower than the Lower Glen Rose.

Figure 2 illustrates the structure on a Lower Glen Rose marker bed in the study area and shows the broad, open geometry of the Chittim Anticline. Wells within the Chittim field in the Lower Glen Rose reef interval produce from a combination stratigraphic-structural trap where a belt of reef-related porosity

and permeability intersects with the Chittim Anticline structural high.

## SEISMIC ANALYSIS

Seismic work on the PEC acreage and adjacent leases has shown that the gross reef interval is seismically resolvable and that seismic data can be effectively used in selection of drilling locations. Commercial gas production from the Lower Glen Rose can be correlated with a particular seismic amplitude anomaly. This amplitude anomaly is a couplet comprised of an onset trough with a following peak; both exhibit anomalously large amplitudes relative to adjacent traces giving the appearance of a bright spot in stacked multi-fold seismic data. These amplitude anomalies may persist for 2 or more miles along a given seismic profile. However, lengths of less than 2,000 feet are more typical. Where the anomaly is absent, it is likely that the reservoir facies is not present. In order to investigate its acreage for similar seismic anomalies, PEC acquired a grid of approximately 20-line miles of high-resolution vibroseis seismic data during 1992 and 1993.

A portion of an east-west oriented seismic section (Line 92-2) is presented in Figure 3 along with the location of the test well, La Paloma 1-84. The data are 2-dimensional, 30-fold vibroseis that have been migrated prior to stacking. No automatic gain control was applied to the data. Surface-consistent trace balancing was applied to preserve relative amplitudes.

Two examples of the characteristic amplitude anomaly can be seen in Figure 3. The onset trough of the eastern anomaly at the wellsite of La Paloma 1-84 occurs at a 2-way travel time of about 0.825 seconds. The following peak of the anomaly occurs at a 2-way travel time of approximately 0.835 seconds. Analysis of the seismic data suggests that the characteristic amplitude anomaly may be a result of tuning. Seismic analysis also suggests that the offset-dependent amplitude variation (AVO) effects contribute to the observed amplitude anomalies. However, additional

well control and modeling is necessary to fully evaluate the utility of AVO analysis for wellsite selection.

During analysis of the seismic profiles, an apparent subtle increase in the Lower Glen Rose interval transit time was noted in the vicinity of many of the amplitude anomalies. This increase was interpreted to indicate (1) local thickening related to the presence of a patch reef, and/or (2) a local velocity anomaly related to the presence of the relatively low-velocity reef complex. The porous rocks of the reef complex are known to have compressional wave velocities on the order of 15,000 to 16,000 feet per second (fps) whereas the surrounding, relatively non-porous, wackestone facies typically exhibit velocities on the order of 20,000 fps.

Figure 4 presents a map of the Lower Glen Rose interval transit time (isochron). Also shown are the locations of line 92-2 (previously discussed) and other seismic lines. Local occurrences of the characteristic amplitude anomaly are indicated in Figure 4 by shading along the seismic traverses. Note the close correspondence of the amplitude anomalies and local thickening of the Lower Glen Rose isochron.

## ENGINEERING ANALYSIS

Since its discovery in 1929, the Chittim field has produced in excess of 50 billion cubic feet (Bcf) of natural gas and approximately 200,000 barrels of condensate from the Lower Glen Rose carbonates. Ultimate reserves range from 100 million cubic feet (MMcf) to 10 Bcf per well.

Production and pressure data were available for 49 wells producing from the Lower Glen Rose formation. A histogram of projected ultimate recoveries is presented in Figure 5. About 50 percent of the wells will recover less than 250 MMcf while almost 70 percent will have a cumulative recovery of less than 750 MMcf.

Analyses of geophysical well logs in the Chittim field show that the Lower Glen Rose net pay ranges from 15 to 25 feet. Water saturation varies from less than 20 to around 60 percent. Water production starts to become significant at water saturations greater than 60 percent. Porosity ranges from 7 to 12 percent. Information on permeability was not available so numerical simulations were conducted to determine the magnitude of permeability that could be expected in the Lower Glen Rose. Two wells, La Paloma 106 and Chittim 23, were used to determine the expected range of permeability. La Paloma 106, which had a 10-year cumulative recovery of about 260 MMcf, was used to determine the lower end of expected permeability. Chittim 23, which had a 4-year cumulative recovery of about 2.3 Bcf and a 10-year projected recovery of 4.2 Bcf, was used to determine the upper end of expected permeability.

Available seismic data were used to determine the size of the reservoir. Thickness, porosity, and water saturation were determined from log analysis. Monthly gas production and bi-annual, shut-in bottom hole pressure data were obtained from Dwight's Energydata, Inc. Monthly gas production was entered into the reservoir simulator and permeability was varied until a reasonable match with bottom hole pressure was obtained. Figure 6 shows the history match of shut-in bottom hole pressure for Chittim 23. An effective permeability (absolute permeability x relative permeability) of 3.5 md was obtained from the match. Actual bottom hole pressures for La Paloma 106 varied drastically and can probably be explained by the low permeability in conjunction with inadequate and varying shut-in times. Although the match was fair, it did give a feel for the order of magnitude of permeability. An effective permeability of 0.1 md to 0.2 md was obtained for La Paloma 106.

## SENSITIVITY ANALYSIS

A sensitivity analysis was then conducted to determine the reservoir properties necessary for a horizontal well in the Lower Glen Rose to be commercial. Seismic data shows that the size of the anomaly is approximately 2,500 feet by 3,300 feet at the wellsite of La Paloma 1-84. A low permeability area surrounding the anomaly was included since analyses of other wells in the Chittim field show pressure support and reserves from areas larger than the anomalies detected by seismic. Although faulting suggested the possibility of a natural fracture system, only a single porosity system was modeled at this time. Table 1 gives the reservoir properties used for the sensitivity analysis.

Reservoir pressure, net thickness, and permeability were varied to determine the limits of an economical horizontal well. The areal extent was held constant since the seismic analysis gave a good estimate of the anomaly. Net thickness was varied because the Chittim field shows a range between 15 and 25 feet. Porosity and connate water saturation were held constant at 7 and 58 percent, respectively. These values were determined to be the productive limit of a gas well in the Chittim field. Permeability was varied based on the range of ultimate recoveries for the field (see Engineering Analysis above). Vertical permeability was set equal to the horizontal permeability. The effect of vertical permeability on recovery was investigated by setting the vertical permeability equal to 1/10 of the horizontal permeability. However, due to the thin nature of the reservoir, it had little effect on the recovery. Initial reservoir pressure was varied between 1,500 and 2,500 psia. Initial reservoir pressure in the Chittim field is about 2,500 psia; pressures below that range represent partial depletion scenarios. Horizontal well length was modeled as 1,400 feet in the center of the reservoir. The well was flowed at a constant wellhead pressure of 400 psi.

Table 2 shows the initial gas-in-place, and the first-year and 10-year cumulative gas recovery for the sensitivity cases. Reservoir pressure is very important because it effects both the first-year and overall recovery (compare Runs 1 and 2). Thickness effects both the first-year and overall recovery, too (compare Runs 1 and 4). Because the net pay is thin, an addi-

tional 5 feet of thickness can have a large impact. Permeability also had a significant effect on recovery (compare Runs 1 and 7). However, although Run 7 recovered more gas in the first year compared to Run 4, the recovery of significant additional gas in Run 4 leads to better economics.

## ECONOMIC ANALYSIS

A deterministic cash flow model was used to evaluate the before Federal income tax profitability of the forecasted recovery for the sensitivity cases above along with two comparison runs for a single vertical well. Drilling and completion costs for a horizontal well of $500,000 (1.5 times a vertical well) and $750,000 (2.3 times a vertical well) were used to determine ROR, Payback, and net present value ($NPV) at a discount rate of 25 percent using the simulated gas production over a 10-year period. Direct operating costs were held constant at $10,000 per year. Initial and final working interest were set at 100 percent, and initial and final revenue interest were set at 75 percent. A current regional gas price of $1.70/Mcf escalated at 4.0 percent/year was used in the analysis. Severance tax and ad valorem tax were set at 7.5 percent and 3.0 percent of net gas revenue, respectively.

As shown in Table 2, for a drilling investment of $500,000, all runs revealed an acceptable ROR of 25 percent or better except for Runs 3 and 9. All runs except Runs 3, 4a, 6 and 9 provided a very good $NPV. At an investment of $750,000, however, less than half (6 of 13) of the runs resulted in acceptable economics, showing the importance of minimizing drilling and completion costs. Runs 1a and 10a are for a vertical well with a drilling and completion cost of $325,000. Comparison of Runs 1 and 1a shows substantially improved economics from horizontal drilling. Comparison of Runs 10 and 10a also shows improved economics with horizontal drilling but to a much less extent than shown by Runs 1 and 1a. Since Run 10a (vertical well) shows very good

economics, some companies would choose not to incur the incremental risks of horizontal drilling.

These sensitivity runs and economic analyses show that, absent a dual-porosity system, the range of reservoir parameters conducive to drilling a horizontal well is fairly narrow. Given "poor" reservoir properties and/or low gas-in-place, a horizontal well is uneconomic. On the other hand, given "good" reservoir properties and high gas-in-place, a vertical well provides a significant ROR such that the risks of drilling a horizontal well may not be warranted. However, with the presence of natural fractures, the chances of intersecting natural fractures are much higher for a horizontal well than for a vertical well. Hence, for a dual-porosity system, the range of reservoir parameters conducive for drilling horizontal may be greater.

## DRILLING RESULTS

The La Paloma 1-84 well was drilled in January of 1993. A testing program was set up to determine critical reservoir properties such that DOE/METC and PEC could make a decision within 48 hours whether or not to drill horizontal. The testing program consisted of geophysical well logging to identify porosity, thickness, and water saturation; oriented core to determine permeability; and a repeat formation tester (RFT) to determine reservoir pressure.

The well was drilled to a depth of 5,261 feet. One hundred and twenty-one (121) feet of magnetically-oriented whole core was cut in the gross reef section from 5,261 to 5,382 feet, of which 86 feet was recovered. All of the lost core was from below the pay zone. Table 3 shows the average porosity, horizontal permeabilities, and vertical permeability (core permeability is absolute) for the pay zone. A suite of geophysical well logs, consisting of SP, gamma ray, apparent water resistivity, induction resistivity, density porosity, neutron porosity, and sonic velocity, was run. The log-derived average water saturations and porosities are also shown in Table 3. The pay zone

was divided into three layers for modeling purposes based on the higher permeability in Zone 1, the higher water saturation in Zone 3, and the perforated interval (though all simulations conducted before completion assumed that the well was completed over the entire interval, Zones 1-3). The RFT showed a reservoir pressure of 2,400 psia.

## SIMULATION AND ECONOMIC ANALYSIS

Based on the reservoir properties determined from the core, logs, and RFT (Table 3), a simulation analysis was used to forecast production for both a vertical well and a horizontal well at the site of La Paloma 1-84. Gas-in-place was approximately 3.5 Bcf based on volumetrics. Projected cumulative gas recovery at 10-years was 1.6 Bcf for a vertical well and 2.4 Bcf for a horizontal well. The ROR and $NPV at an investment of $325,000 for the vertical well were 91 percent and $546,000, respectively. At an investment of $500,000, the horizontal well provided an ROR of over 100 percent and a $NPV of $1 million. At an investment of $750,000, the horizontal well provided an ROR of 74 percent and a $NPV of $760,000.

## DECISION

During the 48-hour decision period, additional geologic analysis led to a concern regarding the mobility of the gas-water contact and the associated risk of a limited reservoir. DOE/METC and PEC decided not to drill horizontal because of this concern and the highly favorable economics calculated for the vertical well.

La Paloma 1-84 was completed as a vertical well. The well was perforated from 5266 to 5276 feet and was acidized using 1,000 gallons of 15 percent HCl.

## FRACTURE ANALYSIS

A detailed fracture analysis identified 304 fractures over the cored interval. Of the 304 fractures, only about 15 percent (44 of 304) are high angle, the rest are low-angle bedding plane/flexural-slip fractures. All of the open high-angle fractures are oriented parallel to the axis of the Chittim Anticline or parallel to its conjugate shear direction. A zone of open high-angle fractures is present within and below the pay section. A rose diagram of the fracture strike azimuth of the high-angle fractures is presented in Figure 7.

(The fracture analysis was conducted after completion Thus, a dual-porosity system was not modeled in any of the simulation studies. The fracture analysis is presented here to help explain well test results.)

## WELL TEST AND ANALYSIS

In March of 1993, a well test was performed on La Paloma 1-84. The well test consisted of a 3-day flow at about 2,160 Mscf/d, followed by a 4-day buildup. A log-log plot of the buildup period is shown in Figure 8. There is a subtle dip in the buildup derivative curve from about 4 to 30 hours, which is often characteristic of heterogenous systems. The buildup data have a fairly large separation between the delta m(p) curve and the derivative curve at mid to late times. This separation is usually indicative of large skin, which was expected to be primarily due to the lower 5 feet of net pay not having been perforated. Toward the end of the 4-day buildup, the derivative becomes somewhat noisy and erratic, so there is some ambiguity as to where, or if, an infinite-acting radial flow regime occurs.

The core data suggested a vertically heterogenous system, with the top 5 to 7 feet of the pay zone being 3 to 5 times more permeable than the lower 10 to 11 feet. In addition, only the top 10 feet of the zone had been perforated. Thus, the core and completion data suggested the model shown in Figure 9a. Hence, the first attempt to match the buildup data was with a two-layer, dual-permeability model[5] as shown in

Figure 9b. Each zone has a separate value of skin to account for the partial completion of the thicker, less permeable lower layer.

The log-log match for the buildup is shown in Figure 10. An excellent match was obtained using the 2-layer, dual-permeability model, and as expected, the skin for the lower layer of +11.2 is much larger than the -2.55 value of skin for the upper layer. The negative skin in the upper layer was thought to be due to the combined effects of a good completion (acidizing) and some natural fracturing in the formation noted during the core analysis. The omega value of 0.08 from the match indicates that only about 8 percent of the pore volume is in the upper layer, suggesting that it might effectively be as little as 1 to 2 feet thick. The total permeability-thickness product of 80 md-feet is almost 3 times larger than that indicated by the core data, further indicating that natural fractures identified in the core analysis are contributing to the production. However, the low fracture-to-matrix permeability ratio of this system compared with ratios typical of tight formations (greater than $10^3$:1) suggest that a classical dual-porosity system is not prevalent.

Often, well test data alone do not provide a unique solution to the reservoir characterization problem, and such is the case with this test. A second model that also exhibits the characteristics of the buildup data is that of a single layer, homogeneous system with a sealing boundary (e.g., a fault), located approximately 320 feet from the well. This match is almost identical to the match shown in Figure 10. A permeability-thickness of 156 md-feet and a skin of +6.22 was obtained in this match.

## CONCLUSIONS

In the presence of uncertainty regarding reservoir properties, the integrated application of geology, geophysics, reservoir engineering, and economics can be an effective approach in deciding between a vertical well completion or taking a well horizontal.

When the final decision is made at the wellsite, the operator is able to make the decision based on actual reservoir data. Otherwise, this decision is based on expected reservoir properties. In a highly heterogenous reservoir, such as the Lower Glen Rose Formation of the Chittim field, the ability to make this decision at the wellsite could have a substantial impact on project economics. Without the multi-disciplinary analysis and integration of actual reservoir properties into the vertical completion-vs.-horizontal drilling decision process, the La Paloma 1-84 well would have been taken horizontal. Based on the deterministic economic modeling, substantial incremental risks would have been incurred for only marginally improved economics.

Analysis showed that the range of reservoir parameters conducive to drilling a horizontal well in a non-fractured reservoir is relatively small. "Poor" reservoir properties and/or low gas-in-place lead to uneconomic horizontal (and vertical) wells. "Good" reservoir properties and high gas-in-place lead to excellent vertical well economics. Hence, a horizontal well may not provide a sufficient productivity increase to offset the incremental risks and costs associated with horizontal drilling. Further studies of the effects of fractures and the order of magnitude of the fracture-to-matrix permeability ratio on increasing the "window of opportunity" for horizontal drilling need to be conducted.

Finally, the use of near-wellbore data (cores and logs) can lead to significant errors in very heterogenous and complex reservoirs. For the La Paloma 1-84, near well reservoir properties were worse than those determined by the well test that had a radius of investigation of about 1,000 feet. Hence, the predicted well performance was pessimistic. However, if the opposite situation had occurred, drilling a horizontal well could have resulted in a costly error. Therefore, depending on the amount of data available and the complexity of the reservoir, a well test may provide better information on which to base the drilling decision than can be provided by near well measurements.

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**Table 1. Reservoir Properties for Sensitivity Analysis**

| Property | Area | |
|---|---|---|
| | Anomaly | Outer Low Permeability Area |
| Area (acres) | 190 | 360 |
| Net Pay (feet) | 15,20 | 15,20 |
| Porosity (%) | 7 | 7 |
| Water Saturation (%) | 58 | 58 |
| Effective Permeability (md) | 0.25,0.5 | 0.05 |
| Pressure (psia) | 1500<br>2000<br>2500 | 1500<br>2000<br>2500 |

## Table 2. Sensitivity Analysis Results

| Run No. | Pressure (psia) | GIP (Bcf) | 1-Yr Cum. (MMcf) | 10-Yr Cum. (MMcf) | ROR (%) | | NPV at 25% ($K) | |
|---|---|---|---|---|---|---|---|---|
| | | | | | 500K | 750K | 500K | 750K |
| K = 0.25 md, H = 15 feet | | | | | | | | |
| 1 | 2500 | 2.1 | 479 | 1,467 | 69 | 36 | 408 | 158 |
| 1a[+] | 2500 | 2.1 | 107 | 723 | 26[+] | | 9[+] | |
| 2 | 2000 | 1.7 | 343 | 1,088 | 49 | 18 | 155 | (95) |
| 3 | 1500 | 1.2 | 206 | 689 | 14 | 1 | (107) | (357) |
| K = 0.25 md, H = 20 feet | | | | | | | | |
| 4 | 2500 | 2.8 | 626 | 1,949 | >100 | 57 | 714 | 464 |
| 4a[*] | 2500 | 2.8 | 229 | 1,064 | 29 | 14 | 48 | (202) |
| 5 | 2000 | 2.2 | 447 | 1,445 | 64 | 33 | 370 | 120 |
| 6 | 1500 | 1.6 | 270 | 916 | 28 | 11 | 32 | (218) |
| K = 0.5 md, H = 15 feet | | | | | | | | |
| 7 | 2500 | 2.1 | 647 | 1,618 | 98 | 52 | 583 | 333 |
| 8 | 2000 | 1.7 | 474 | 1,213 | 61 | 28 | 293 | 43 |
| 9 | 1500 | 1.2 | 293 | 783 | 24 | 5 | (11) | (261) |
| K = 0.5 md, H = 20 feet | | | | | | | | |
| 10 | 2500 | 2.8 | 877 | 2,156 | >100 | 84 | 958 | 708 |
| 10a[+] | 2500 | 2.8 | 261 | 1,405 | 73.7[+] | | 412[+] | |
| 11 | 2000 | 2.2 | 638 | 1,617 | 95 | 51 | 570 | 320 |
| 12 | 1500 | 1.6 | 394 | 1,043 | 44 | 19 | 165 | (85) |

+ Vertical Well -- Drilling and Completion Costs = $325,000.      * K = 0.05 md.

## Table 3. Reservoir and Fluid Properties from Oriented Core and Well Logs

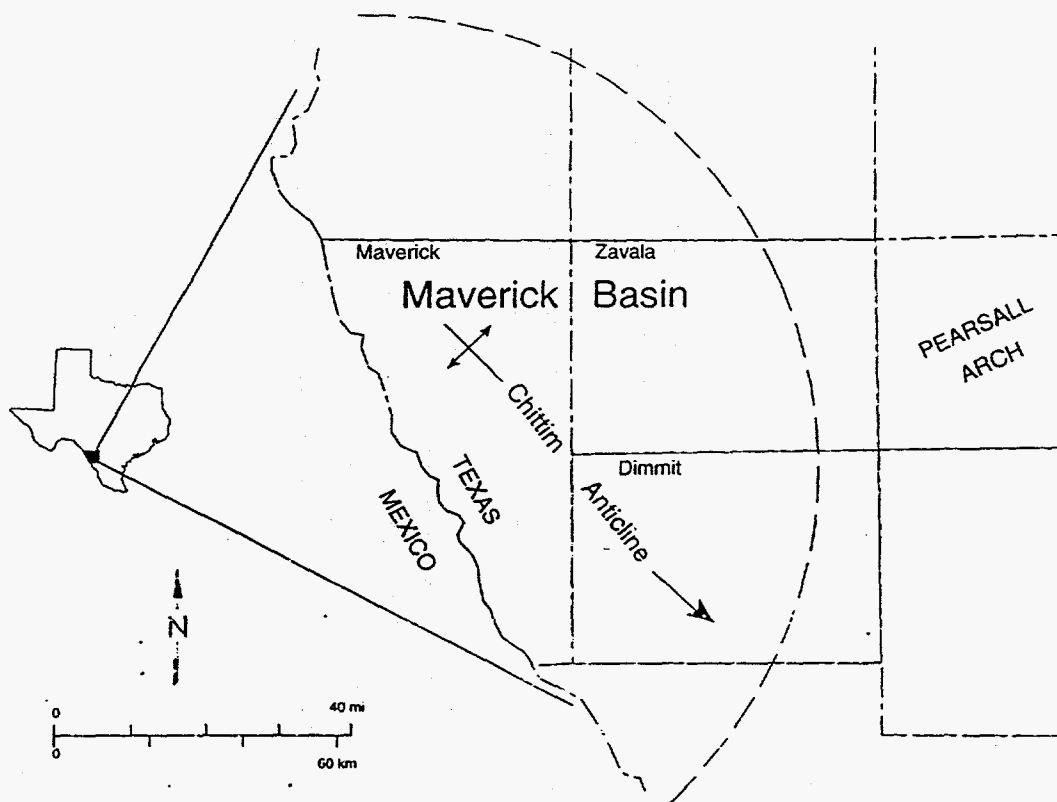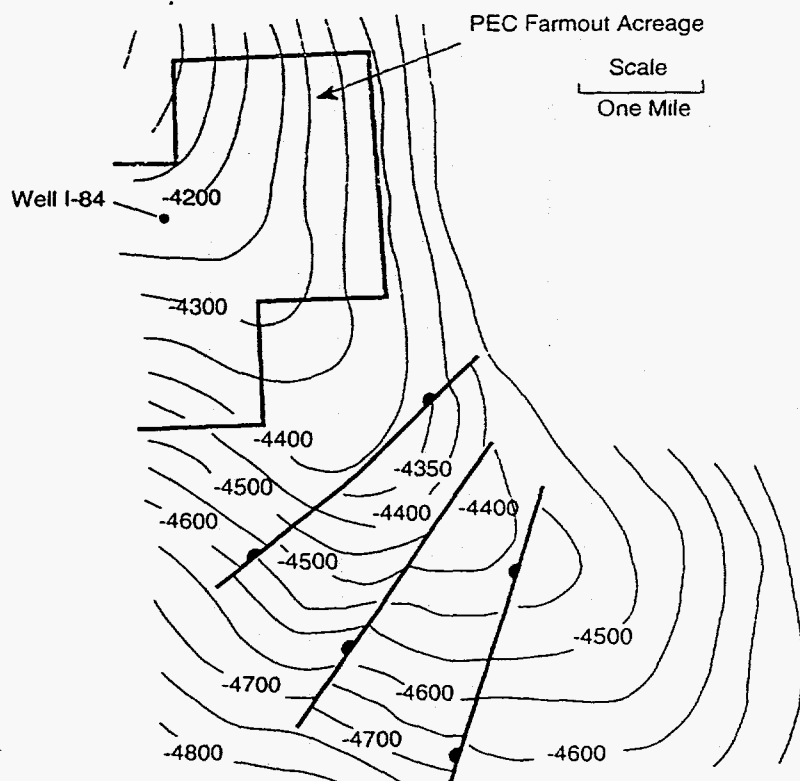| Zone No. | Depth (ft) | Average Log Porosity (%) | Average Core Porosity (%) | Average Log Water Saturation (%) | Average E-W Permeability (md) | Average N-S Permeability (md) | Average Vertical Permeability (md) |
|---|---|---|---|---|---|---|---|
| 1 | 5264-71 | 12.5 | 12.4 | 22.6 | 3.1 | 3.2 | 2.5 |
| 2 | 5271-77 | 13.7 | 9.3 | 29.0 | 0.6 | 1.0 | 0.4 |
| 3 | 5277-82 | 11.4 | 8.3 | 41.6 | 0.7 | 1.7 | 0.9 |

Figure 1.  Location of study area



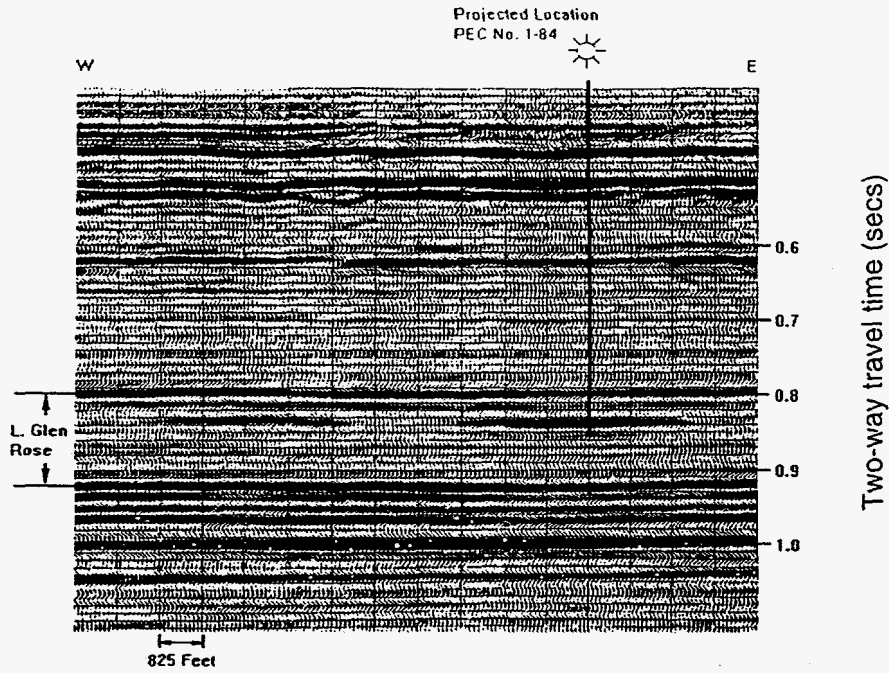Figure 2.  Structure on a Lower Glen Rose marker bed

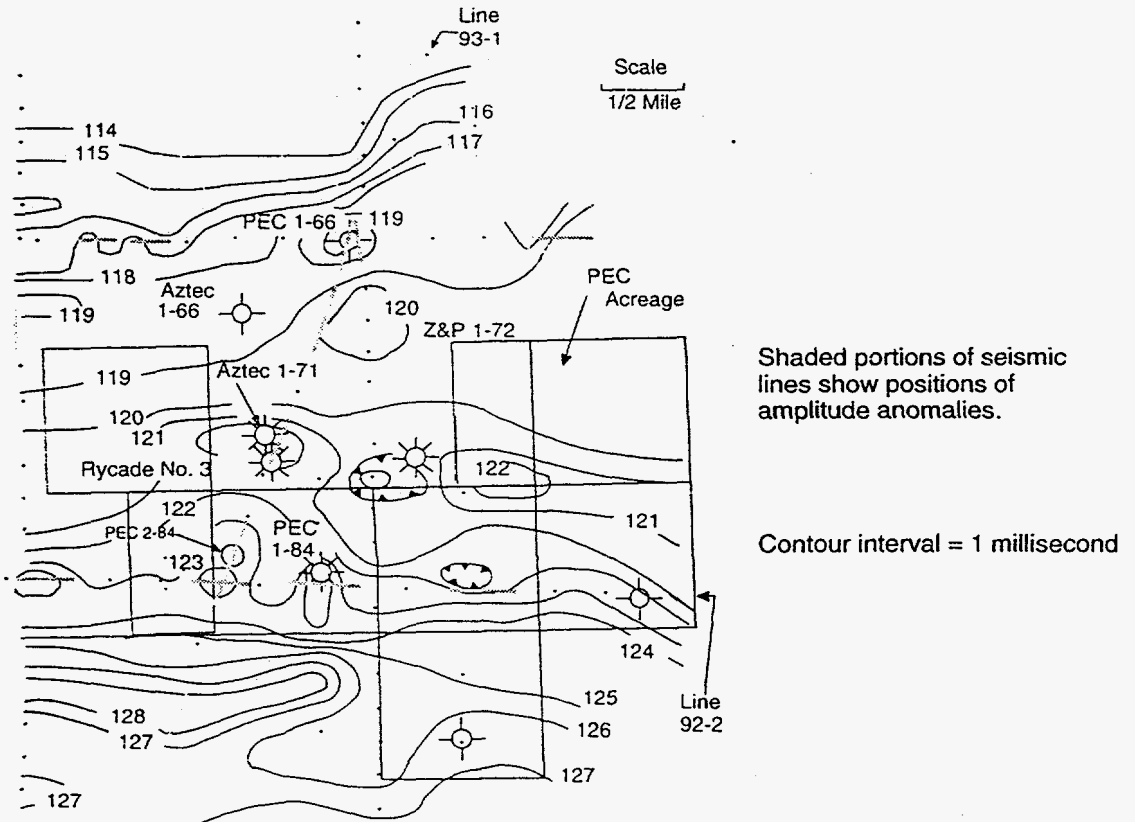Figure 3.  Seismic data for a portion of Line 92-2



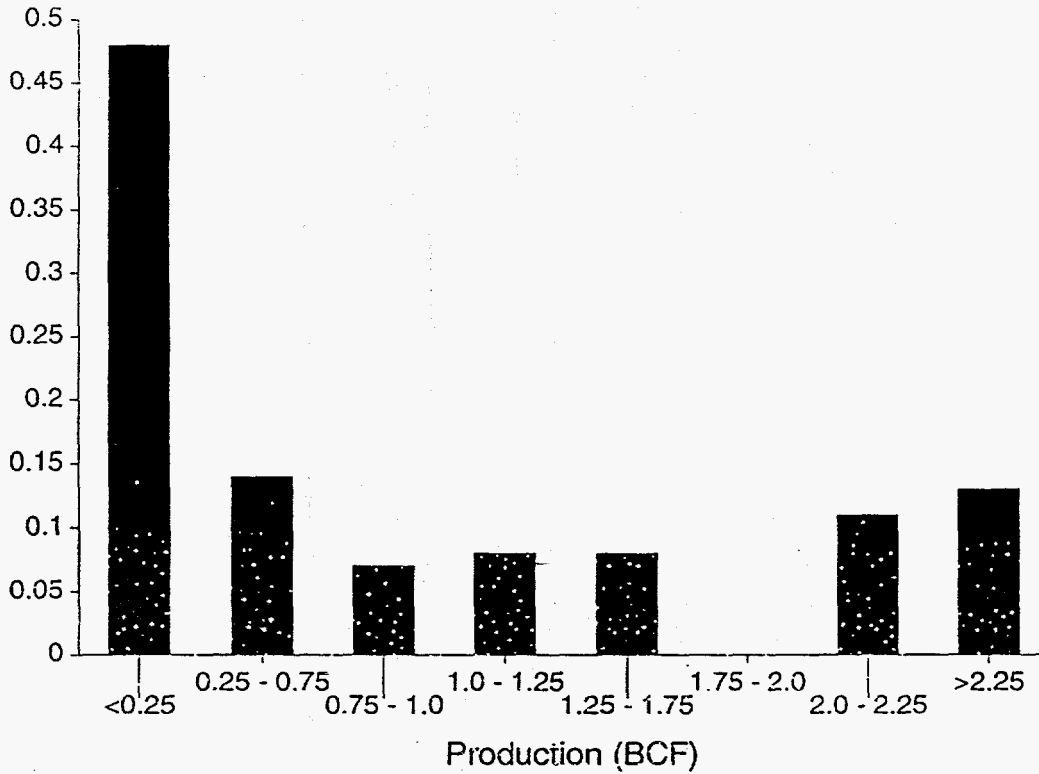Figure 4.  Isochron map of the Lower Glen Rose Formation

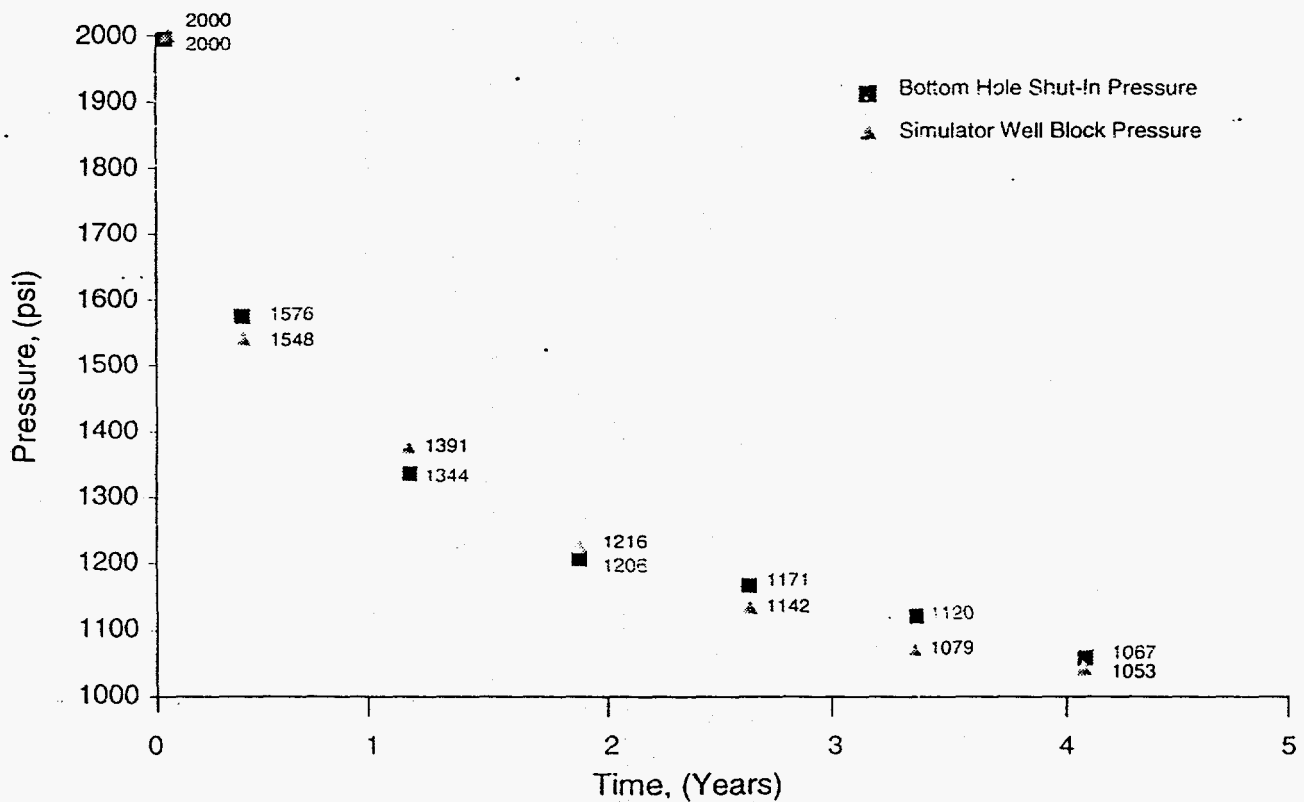Figure 5.  Histogram of Lower Glen Rose Formation ultimate gas recovery
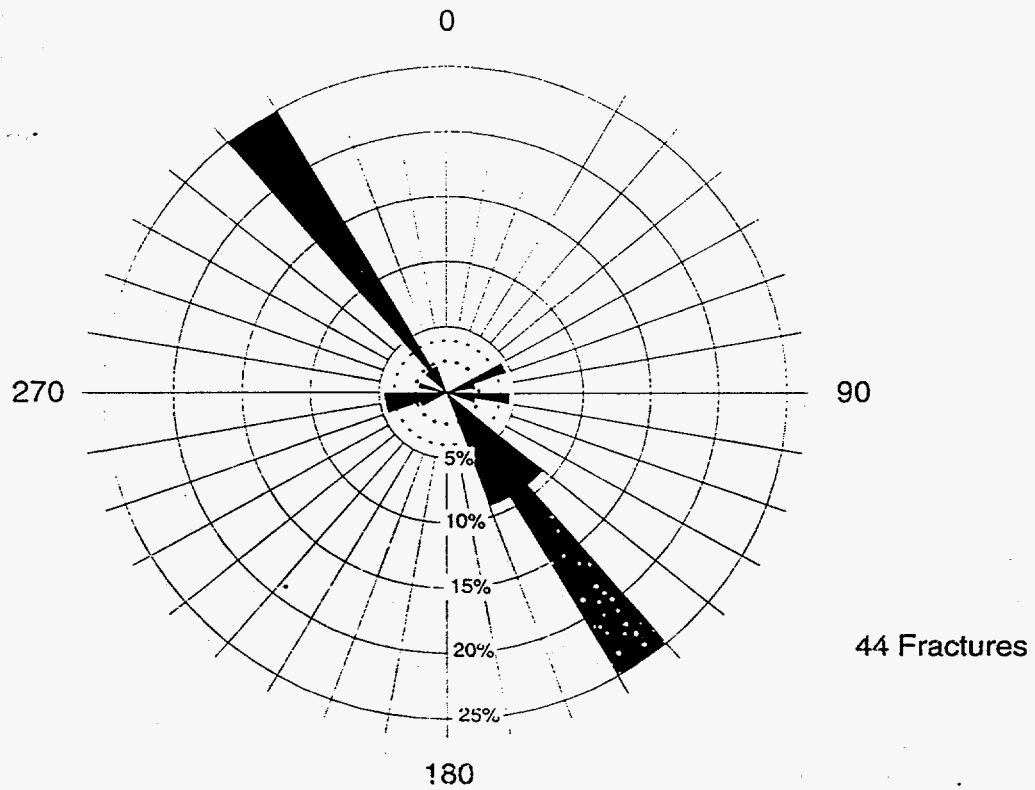


Figure 6.  History match of Chittum 23

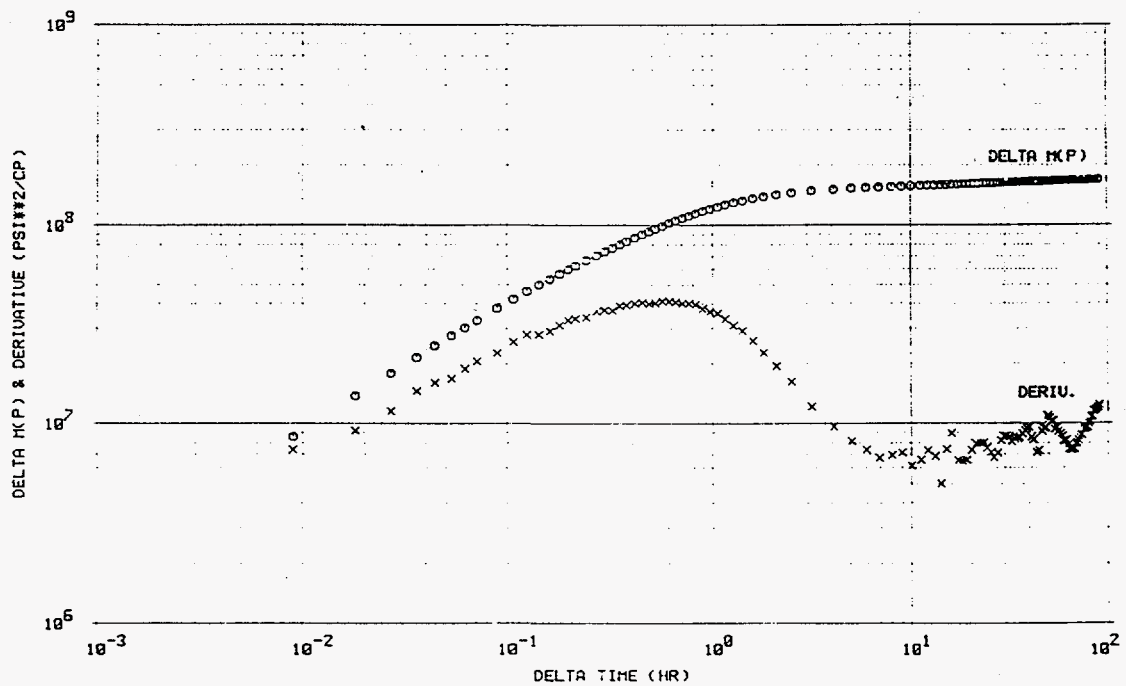Figure 7.  Percent distribution of true fracture azimuth for high-angle fractures



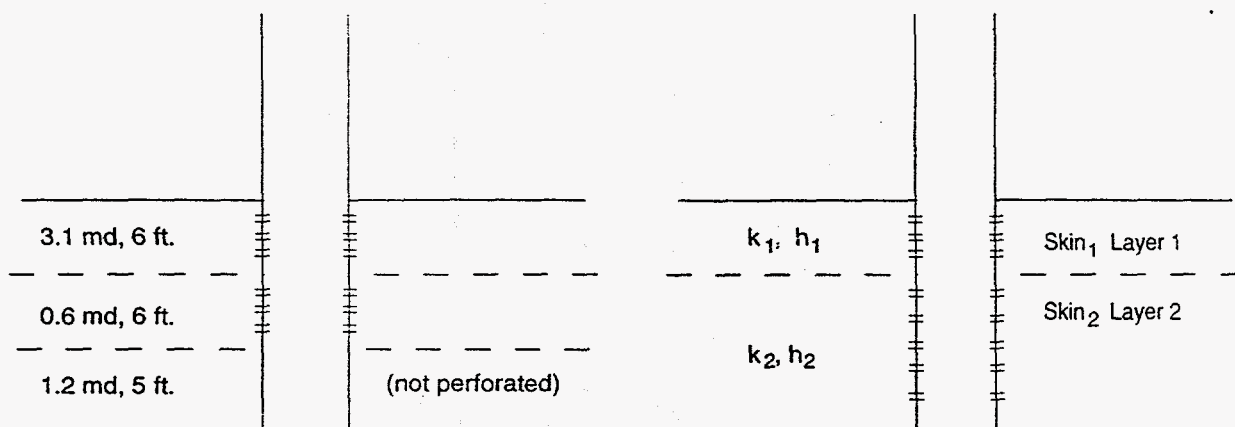Figure 8.  Log-log plot for buildup period

| 3.1 md, 6 ft. | $k_1, h_1$ | Skin$_1$ Layer 1 |
| 0.6 md, 6 ft. | | Skin$_2$ Layer 2 |
| 1.2 md, 5 ft. | (not perforated) $k_2, h_2$ | |

Figure 9a.   Reservoir model indicative of      Figure 9b.   Two-layer model used for
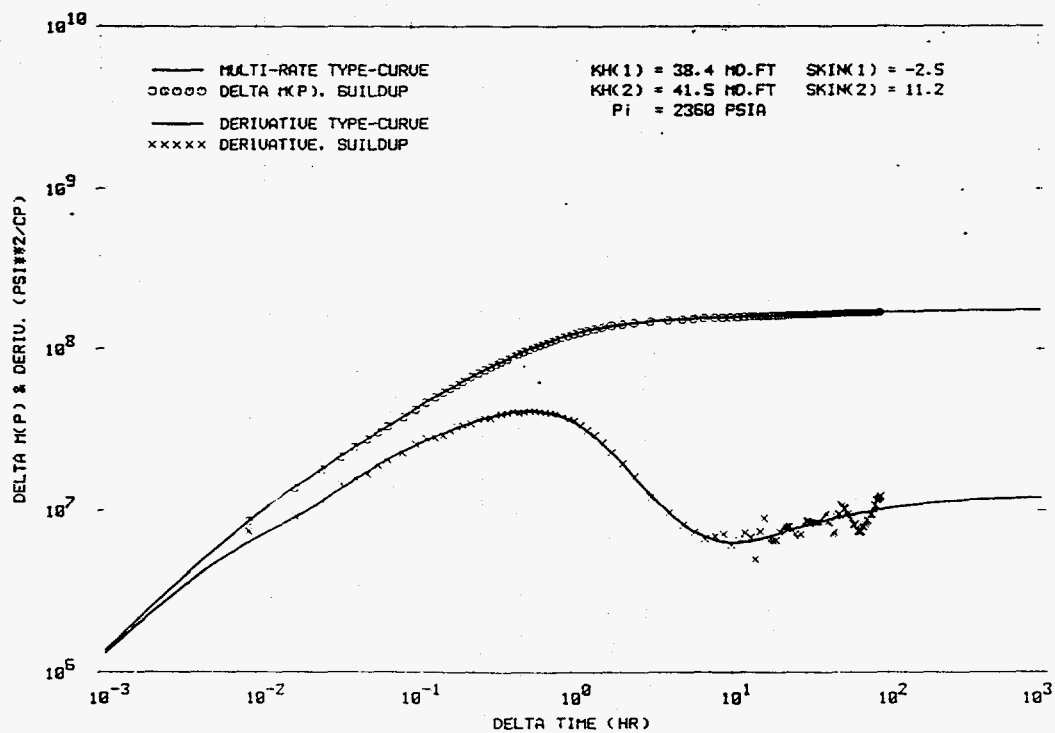core and completion data      well test buildup match

Figure 10.   Log-log match for buildup, two-layer system