COMPARISON OF LOW-PERMEABILITY HORIZONTAL DEVONIAN PRODUCTION, ECONOMICS, AND COMPLETION TECHNIQUES IN THE PERMIAN BASIN

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ABSTRACT

Production from thirty-two horizontal Devonian wells in the Permian Basin was studied in detail to determine if the impact of various completion methods might be distinguished from an existing reservoir overprint. Flowing transient pressure analysis was utilized to determine effective permeabilities and contributing lateral lengths. Production and economic performance were normalized for permeability, productive zone height, and initial static reservoir pressure on each of the wells, so that examinations into various completion processes would be more meaningful.

Some of the wells in the study were completed with cemented liners, while the remaining wells were completed with pre-drilled uncemented liners. **A** direct comparison is made between the two completion styles. **A** variety of stimulation processes were employed and examined.

Recommendations for various completion processes are presented, based on results of the study and industry-accepted rock mechanics concepts.

INTRODUCTION

Devonian reservoirs in the central Permian Basin have been produced for many years via conventional vertical completions with mixed success[1]. In the late 1990's, the industry went through a rather rapid shift towards horizontal completions in this formation. It was reasoned that horizontal successes in other formations would apply in the Devonian, and that the economies of scale and good oilfield infrastructure would all work towards making the process commercially viable.

Throughout the Permian Basin, Devonian lithologies consist of carbonates, cherts, combinations of the two, and large sections of both together[2,3]. The vast majority of the horizontal work focused on the carbonate portions of this formation, simply because of the ease of stimulating soluble rock with acidic fluids. Often, carbonates with naturally fractured chert layers immediately above were targeted, with the intent of taking advantage of easy drilling associated with the carbonate, and then stimulating up into the naturally fractured zone above. The majority of reservoirs targeted were primarily gas or gas with retrograde condensates.

While a number of completion methodologies were experimented with, two primary "competing" processes soon began to dominate nearly all the horizontal Devonian completions undertaken. The dominate process that emerged was known as the "sprinkler system" completion, and it involved running a bull-plugged 4-1/2" uncemented horizontal liner with pre-drilled holes to ensure relatively even distribution of acidic stimulation fluids when they were placed at "limited entry" rates[4]. The second method, while not as common, focused on cementing a 4-1/2" horizontal liner in place, then perforating and acidizing it in a limited entry or semi-limited entry scenario[4]. The two methods were utilized over roughly the same time period, therefore direct comparisons of each from a production standpoint were difficult, if not impossible to make during the field development process. Because both processes are so radically different and have substantial advantages and drawbacks, industry controversy surrounding a set of "best practices" has been extensive.

In late 2001, the authors were asked to examine a set of 22 existing horizontal completions. The study was unique in that complete access to information, including all facets of drilling, completion practice, and production history were readily available. These particular completions were all of the "cemented liner" variety, and were all completed by the same operator. While there were differences in formation lithology, reservoir parameters, and even some completion methodology, it was hoped that as a group, they might present an opportunity to make a direct comparison to wells that had been completed utilizing the "sprinkler system" process. In mid-2002, an opportunity to study an additional group of 10 horizontal non-cemented sprinkler system completions became available for a direct comparison. It was felt that if naturally occurring parameters could be normalized for each of the cases, meaningful process and fiscal conclusions could be drawn.

Inherent to the normalization process was the need to determine permeability for each well. Two different tools were chosen. First, pressure transient analysis utilizing the reciprocal of the productivity index (RPI)[5,6,7,8] was employed to analyze the actual production histories. **A** Miller-Dyes-Hutchinson[9,10,11] plot was the initial setting of the RPI analysis (see typical example, Figure 1). The linear slope best describing the middle-time or reservoir dominated portion of the well's performance was selected, and the actual production data as the bottomhole RPI value versus the log of time for radial systems (or square root of time for linear systems) was plotted. **A** Log-Log Agarwal/Gringarten Type Curve (see typical example, Figure 2) was utilized to plot the computed dimensionless pressure versus dimensionless time for the observed data. This was a merger of the Agarwal[12] type curve, which considers finite conductivity fractures, and the Gringarten[13] type curve, which presents the behavior of an infinite conductivity fracture in a bounded, square reservoir. **A** Pseudo-Steady State plot (a graphical presentation of the RPI values versus time, rather than the logs or square roots of various parameters)[5] was used to visualize and quantify the linear portion of the production (see typical example, Figure 3). The result of performing these 3 analyses was the generation of a production simulation match that was compared to actual production data. Values for permeability, effective lateral length, and drained reservoir area were then inferred from the matched values (see typical example, Figure 4).

The second tool that was employed was a fully coupled 3-dimensional reservoir and production simulator[14]. This package uses a numerical simulator to model multi-phase flow in the reservoir and around the wellbore of nearly any configuration, including within hydraulic fractures, to give an accurate prediction of well production rate and pressure response. Figure 5 is an example configuration that was simulated.

STUDY METHODOLOGY

Each well's production history was analyzed to determine permeability (k) and effective lateral length (L_{eff}). In each case (cemented wells and non-cemented) a single person picked values of height (h), porosity (*f*), initial reservoir pressure (P*), reservoir fluid viscosity *(m)*, static reservoir temperature (Ti), and water saturation (S_w) for consistency across each group. The primary reason that this simulator was employed was to verify the validity of the RPI analysis, and then to interpolate, extend, or extrapolate reservoir conditions beyond what was actually encountered in the two studies. Consistent values for commodity prices, production start date, discount rate, and drillingicompletion costs were then picked, so that a normalized Net Present Value (NPV) could be calculated for each well. This NPV was then compared to a wide variety of completion and process-related parameters, and the resulting relationships were examined to identify any associations that might conceivably have value in the drilling/completion decision-making practice.

Simultaneously, the available literature on horizontal mechanics and completion methodology was reviewed[15 - 36] in order to check that observed statistical results from the study were consistent with what the rest of the industry has found.

By coincidence, it happened that both studies had wells with calculated permeabilities that were relatively close to each other. Confidence in the normalization process was improved as a result, and efforts were undertaken to extend the study to permeability ranges not specifically covered by the 32 wells of interest. This was accomplished by utilizing the 3-D reservoir simulator to forecast results for a wider range of permeabilities.

RESULTS OF THE TWO STUDIES

The first study [of 22 cemented wellbores] involved a group of Devonian horizontals that were located in Midland and Upton Counties. These were generally drilled through an ultra-low permeability and porosity limestone that was slightly naturally fractured (see Figures **6** and 7). Though this portion of the reservoir was not thought to be productive, the zone was overlain by a naturally fractured chert. Most of the wells were drilled through the limestone in order to control both drilling and completion costs, with the assumption being made that connectivity with the zone immediately above could be made during the stimulation process. Table 1 shows the results of the RPI analysis for each well. During the planning stages for the development of this group of wells, it was thought that ultra-long lateral lengths (5,000 – 9,000 ft) would perform significantly better than conventional lengths (3,000 – 5,000 ft), primarily due to work by Srinivasan[22], Tang[23], Dikken[24], Sherrard[25] and others. Unfortunately, the particular reservoir(s) in which several of these wells were drilled exhibited either a higher than average water saturation, or there was a portion of the productive reservoir that was stimulated that may have contained higher-than-desired water. It quickly became apparent that water and/or condensate were possibly limiting production due to liquid loading in the horizontal portion of the wellbore. The transient analysis for these wells calculated an average maximum effective lateral length of 2,289 ft, significantly shorter than the average actual wellbore length. An example of the liquid loading problem is shown in Figure 4, with the area between the simulated production curves and the actual curves representing lost production that may or may not ever be fully recovered.

Various wellbore parameters were plotted versus 10-year EUR's or normalized NPV. For this group of wells, several observations were made:

- Substantial positive or negative overall lateral dip (measured from heel to toe) appeared to impact production negatively. The best wells were those with nearly horizontal trajectories. See Figure 8.
- Wells with small variations in localized vertical dip along the length of the wellbore outperformed wells with larger variations. It is possible that this is a reflection of the presence or absence of "P-traps" that can hinder production of multiple-phase flow under the critical unloading rate. See Figure 9.
- Optimum lateral length for this group was about 4,000 ft. Again, this may have been due to a number of factors not related soley to length, including, but not limited to the presence of high quantities of formation liquids, the severity of vertical trajectory variation, etc. See Figure 10.
- Optimum lateral direction (azimuth) for this group was not discernable, since over three fourths of them were drilled in the same direction, and within this subgroup, there was a wide performance variation. See Figure 11.

Various treatment parameters were plotted versus normalized NPV:

- Treatments on the best wells were pumped at rates equal to or exceeding 1 bpm per 0.38" perforation. See Figure 12.
- The optimum acid volume was 26 gallons per ft of lateral length. It is possible that this value may be slightly on the high side, and may be impacted or masked by the excessively long lateral lengths and/ or the liquid loading problem. See Figure 13.
- CO, volumes greater than 30% were generally detrimental to well performance. Since all the treatments had CO, in them, it was not possible to compare to treatments without CO,. See Figure 14. However, the larger the volume of CO, pumped, the better the cleanup time. Cleanup time was measured consistently as that time required for maximum L_{eff} to be reached. See Figure 15.

The second study involved a group of ten uncemented sprinkler system completions. The vast majority of these wells were drilled through naturally fractured limey cherts or a cherty limes, with more conventional lateral lengths (3,000 – 4,000 ft). Some observations relating to the performance of these wells:

- The fraction of recovered oil & gas in place over a set time period had a relationship with permeability, height, and lateral length much as would be expected from the literature. In this particular group of wells, liquid loading, while present, was not as severe as in the first group. Overall water production was lower. See Figure 16.
- There appeared to be a relationship between well performance and lateral azimuth. The best wells were drilled in a 150°/330° direction. The worst wells were oriented 60°/240°. Primary natural fractures in the area were oriented at 53°/233°, and a secondary minor system at 113°/293°, indicating a possible relationship between wellbore trajectory and the interception of that same wellbore with the dominate natural fracture system at nearly 90 degrees. See Figures 17 and 18.
- A plot of normalized NPV vs flowback rate revealed that there was little or no production advantage to be gained by recovering load at high rates. See Figure 19.
- Wells that recovered only a small portion of load outperformed those that recovered large percentages. This might suggest that efforts to increase total load recovery volume could be without merit. See Figure 20.
- Optimum acid volume based on NPV for this completion style was 47 – 50 gallons per ft of lateral length. See Figure 21. Since, for the most part, similar acid systems were utilized for both studies, it was felt that there might have been some underlying physical and mechanical reasons for the huge differential between optimum volumes in cemented vs uncemented wellbores. Efforts to simulate this scenario were undertaken utilizing the 3-dimensional reservoir and production simulator. For a given permeability, fluid viscosity, porosity, and temperature, production rate into the wellbore tubulars may generally be expressed as a function of pressure drop and exposed surface area. It was found that actual production could easily be simulated simply by enlarging the wellbore diameter to about 10-1/2 inches. Because this diameter coincidentally represents approximately the same diameter that would be achieved if 47 gal/ft of acid were used to remove rock from a 6-1/8" wellbore, it was surmised that little (if any) etched and conductive fracture length away from the wellbore was being created during the stimulation treatments. See Figure 22.

- Net pressure was calculated for each uncemented case and was plotted versus the normalized NPV as shown in Figure 23. The resulting graph shows a strong relationship between net fracturing pressure generated versus ultimate value created by the completion. This could suggest that to the extent that hydraulic fractures are propagated, it is beneficial to the ultimate value of the well.
- Optimum lateral length for this group was also about 4,000 ft. See figure 24.

It soon became apparent that under some circumstances, it appeared to be fiscally advantageous to cement the wellbore rather than to leave it uncemented and perform a conventional sprinkler system type treatment. An effort was undertaken to compare the normalized NPV's for each case to each other. When fiscal parameters associated with the two projects were contrasted, there indeed was a substantial advantage to cementing, over and above the additional cost associated with the more expensive cementing process. Close examination of the data indicated that such advantage might be lost when values for reservoir permeability substantially exceeded the permeabilities encountered in the study, so the 3-dimentional reservoir and production simulator was utilized to extrapolate to higher and lower permeabilities than were actually encountered. It was found that the incremental NPV advantage for cementing the wellbore was lost when the overall effective permeability exceeded 0.06 – 0.07 md (see Figure 25), and that when permeabilities were higher, the lower cost sprinkler system methodology might be appropriate. It should be noted that auxiliary reservoir parameters for the study were held constant (h, f, m, perm anisotropy ratio, T_r, S_w, and DP), so the "0.06 – 0.07 md cutoff' could drastically change if these same parameters were different in another area.

MECHANICS AND RESERVOIR PROCESSES THAT IMPACTED THE STUDY

Rock mechanics associated with open hole wellbores drilled in the direction of minimum and maximum stresses have been well publicized[37] In an open hole, the orientation of a hydraulic fracture is determined by the immediate stress field surrounding the bore hole. For a vertical well the fracture initiation or breakdown pressure (P_{bd}) is given by the well known Terzaghi[38] formula:

$$P_{bd} = 3\sigma_{hmin} - \sigma_{hmax} + T_n - \alpha P_{por}$$

where: σ_{hmin} and σ_{hmax} = minimum and maximum horizontal stresses
T = tensile stress of the rock
a'' = Biot's constant (usually 1)
P_{por} = pore pressure

For **a** horizontal well drilled along the minimum or maximum horizontal stress directions, an analogy for the Terzaghi equation can be written, substituting the two stresses with their counterparts.

$$P_{bd} = 3\sigma_{hmax} - \sigma_{vertical} + T_n - \alpha P_{por} \quad \text{for horizontal wellbores in the direction of } \sigma_{hmin}$$

$$P_{bd} = 3\sigma_{hmin} - \sigma_{vertical} + T_n - \alpha P_{por} \quad \text{for horizontal wellbores in the direction of } \sigma_{hmax}$$

where: $\sigma_{vertical} > \sigma_{hmax} > \sigma_{hmin}$

Open hole hydraulic fractures generally cannot be initiated perpendicular to the wellbore, but rather begin either longitudinally or at an angle less than approximately 45° relative to the wellbore axis[37]. Therefore, except for the most extreme stress conditions, open hole hydraulic fractures will initiate longitudinally, regardless of the principal stress direction[39]. Once initiated, the hydraulic fracture extends along the surface of the bore hole as long as the wellbore pressure exceeds the fracture-propagation pressure. This longitudinal extension (Figure 26) will continue until one of two events occur: 1) sufficient stress resistance is encountered that will force the fracture to grow away from the wellbore and turn in the direction of maximum stress, or, 2) fracture extension pressure (P_{ext}) is not maintained because of excess fluid leak-off. Therefore, creating transverse (Figure 27) and/or multiple fractures in an open hole horizontal wellbore may be difficult, if not impossible to achieve.

A longitudinal fracture configuration in low permeability formations has several advantages. Obviously, in the case of uncemented wellbores, there is greater contact between the wellbore and the fracture, thus minimizing flow restrictions. If properly conducted, post-stimulation clean-up would be more efficient. Smaller F_{CD} values can deliver optimum production rates because the entire stimulated lateral length could contribute to production. Excessive height growth into undesirable upper and lower intervals could be minimized. When more control of stimulation placement is required, the wellbore should be cased and cemented allowing the creation of multiple fractures simultaneously.

The transverse hydraulically induced fracture configuration lends itself exactly to the scenario where longitudinal fractures may be inadequate. This type fracturing allows multiple treatments placed in specific sections of the lateral, with the size and number of fractures being an issue of optimization[40]. Certainly for transverse fracturing, zonal isolation is imperative. Work done both in fracture mechanics and post treatment production prediction suggests that the perforated clusters should be spaced no more than one and one-half times the wellbore diameter[41]. The obvious reason is to minimize the chances of turning of the fracture. For this to occur, the casing must have adequate cement bonding to the wellbore with minimal annular voids and channeling. Therefore, for transverse hydraulic fracturing, acid soluble cements should not be used.

Naturally fractured formations are likely to exhibit horizontal permeability anisotropy with distinctive k_{hmax} and k_{hmin} directions. For vertical wells, the effective permeability is simply $(k_{hmax} \times k_{hmin})^{1/2}$. For horizontal wells, however, wellbore trajectory with respect to permeability direction is critical. Studies[42] have found that the direction of maximum permeability is also likely to be in the direction of maximum stress. If the horizontal well is drilled in line with the minimum horizontal stress and, therefore, perpendicular to the maximum horizontal permeability (Figure 28), higher production rates could be obtained. In fact, in cases of large permeability anisotropy, a properly directed horizontal well will outperform either a fractured vertical well or a longitudinally fractured horizontal well[43].

Therefore, whether or not to cement the casing in a horizontal wellbore can depend upon criteria other than zonal isolation. Reasons for ***not*** cementing include economic limitations, effective reservoir permeability constraints, and concerns over possible damage to natural fractures intersecting the wellbore. With proper attention to permeability anisotropy and the magnitude of effective permeability, the cementing decision can be determined by performing NPV calculations as outlined in this study.

CONCLUSIONS

The two projects studied had enough natural parameters and configuration characteristics in common that comparisons between them were justified. Several wellbore configuration conclusions may be drawn:

1. For cemented WB w/ large horizontal permeability anisotropy and low overall permeability: drill in the direction of minimum stress (assuming k_{max} is in direction of maximum stress). Design for transverse fractures.
2. For uncemented WB w/ large horizontal anisotropy: drill in the direction of minimum stress (assuming k_{max} is in direction of maximum stress). Design for longitudinal fractures.
3. For cemented WB w/ negligible difference in horizontal permeability: drill in the direction of maximum stress. Design for longitudinal fractures.
4. For uncemented WB w/ negligible difference in horizontal permeability: Drill in direction of maximum stress. Design for longitudinal fractures.
5. When geologically appropriate, drill all laterals as close to horizontal as possible, with as little localized vertical deviation as is practical.
6. Drill horizontals at least to the optimum lateral length, stopping at the next expense point.
7. For projects similar in nature to the two studied, there is an effective permeability cutoff of about 0.06 – 0.07 md, below which it may be fiscally more prudent to cement the wellbore, rather than utilize a sprinkler system type completion.
8. Tools are available to determine the optimum wellbore completion methodology when operating in areas with different reservoir characteristics from the two projects that were studied.

Several stimulation conclusions may be drawn:

1. High percentages of CO_2 in the stimulation fluid may be detrimental to NPV.
2. Efforts to increase the volume of load recovery or speed up the rate of load recovery may be detrimental to production. High recovery rates may have caused early gas breakthrough in the portions of the lateral nearest the heel, thereby limiting cleanup in other portions of the lateral.
3. There are separate optimum acid volumes per ft of lateral length, depending upon completion style.
4. Stimulation of uncemented wellbores may not be effective in creating significant etched fracture length away from the wellbore.

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Table 1
Selected Miscellaneous Data Pertaining to the Two Projects Studied

Wellbore	Effective Perm	Drilled Lateral	Max Eff Lateral	Min Eff Lateral	Time to Max Lat
	(md)	(ft)	(ft)	(ft)	(days)
Cemented #1	0.0078	5689	4968	2218	2
Cemented #2	0.0127	5399	3566	2480	16
Cemented #3	0.0174	5686	2894	2254	36
Cemented #4	0.0170	4344	2064	1318	25
Cemented #5	0.0076	4012	2084	880	16
Cemented #6	0.0054	5598	2670	1358	9
Cemented #7	0.0058	5779	1962	1278	6
Cemented #8	0.0220	9413	3826	2708	25
Cemented #9	0.0235	9592	2806	1900	25
Cemented #10	0.0077	3049	1896	1338	9
Cemented #11	0.0153	8093	1966	1198	8
Cemented #12	0.0277	9093	2244	2244	64
Cemented #13	0.0101	5689	3360	2488	44
Cemented #14	0.0126	5688	2740	1870	23
Cemented #15	0.0079	5687	3712	300	340
Cemented #16	0.0254	9105	2600	2600	9
Cemented #17	0.0086	8307	1052	618	6
Cemented #18	0.0093	7495	1014	1014	16
Cemented #19	0.0060	4001	1666	1666	60
Cemented #20	0.0178	7897	1458	1146	3
Cemented #21	0.0256	7357	1166	1090	25
Cemented #22	0.0057	7122	1242	1242	60
Open Hole #1	0.0147	3339	1152	998	8
Open Hole #2	0.0059	4040	2806	1196	15
Open Hole #3	0.0142	3750	738	362	20
Open Hole #4	0.0039	4205	1354	838	18
Open Hole #5	0.0056	2627	1054	714	18
Open Hole #6	0.0104	4418	2574	1712	8
Open Hole #7	0.0261	7315	2302	1990	21
Open Hole #8	0.0084	3905	1092	1030	15
Open Hole #9	0.0035	3782	1170	250	5
Open Hole #10	0.0153	2469	1222	1222	10

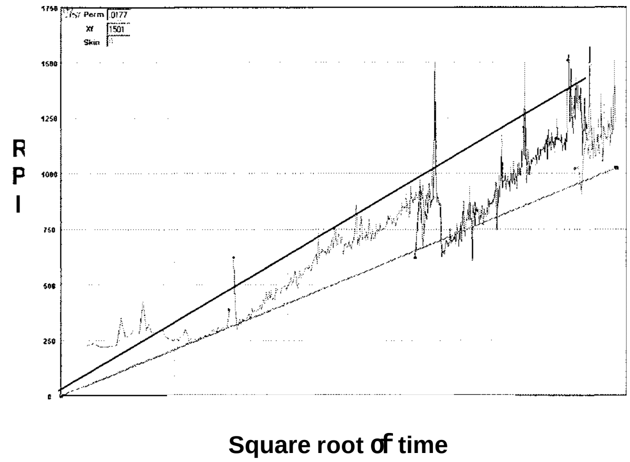


Figure 1 - Typical Miller-Dyes-Hutchinson Plot.

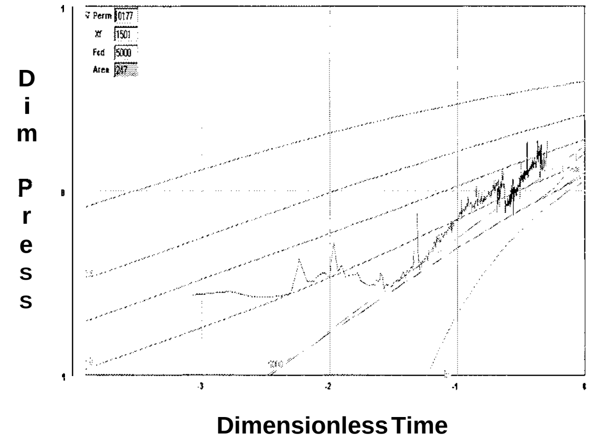


Figure 2 - Typical Merger of the Log-Log Agarwal/ Gringarten Type Curve

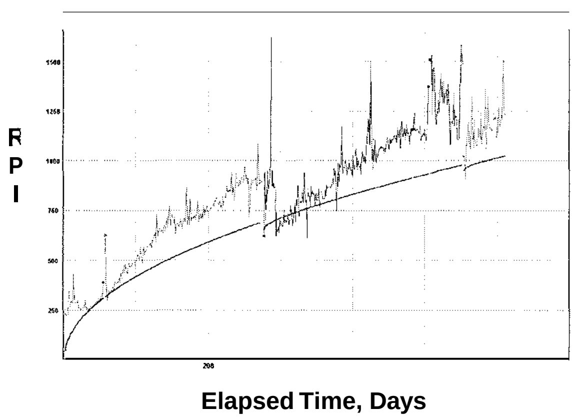


Figure 3 - Typical Pseudo-Steady State Plot

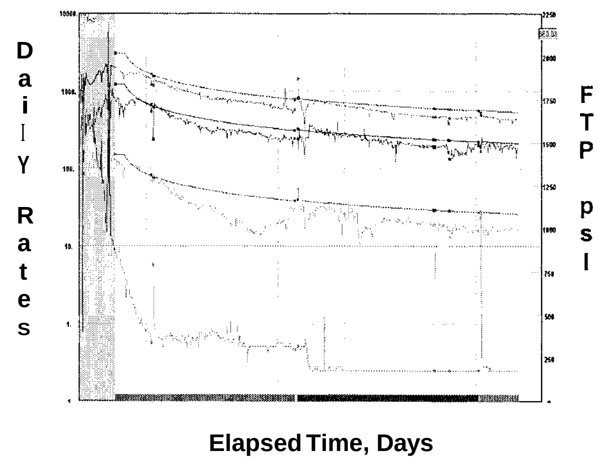


Figure 4 - Typical RPI Match- The smooth lines represent the simulated solution; rough lines actual data. K = .018 md, L_{eff} = 3,002 ft.

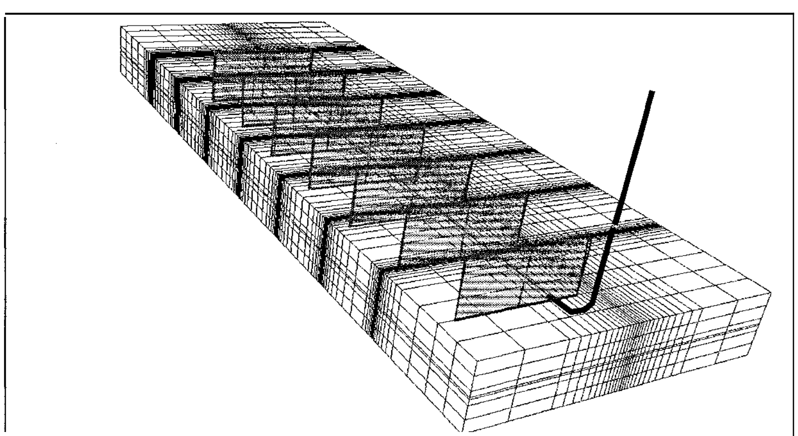


Figure 5 - Typical 3-dimensional Simulation Scenario for a Cemented Wellbore with Transverse Hydraulic

n a c

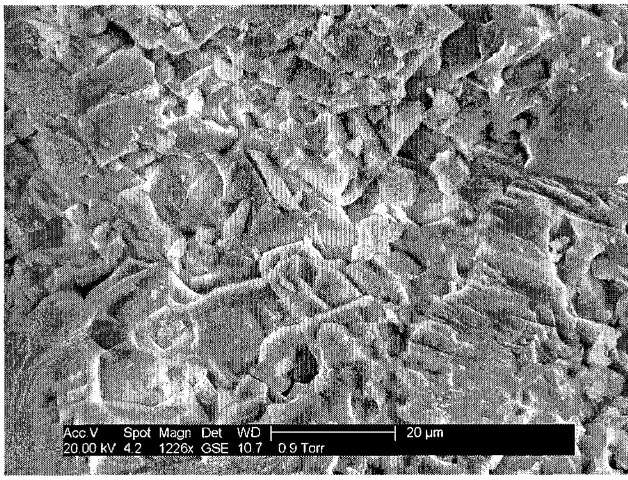


Figure 6 - SEM shows Microporosity between calcite crystals is visible in this view, but is poorly connected

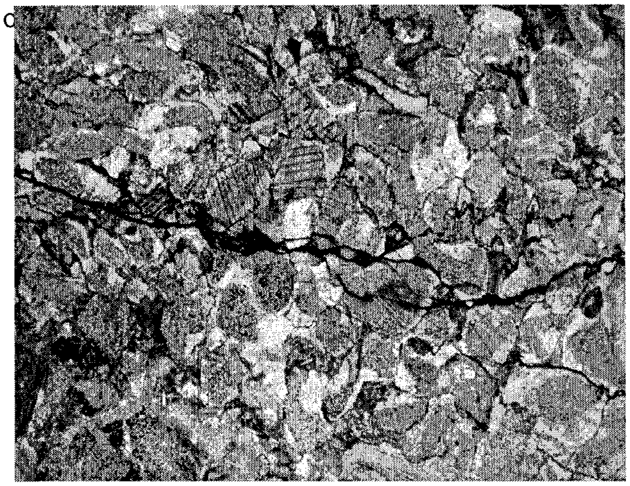


Figure 7 - Thin Section Photomicrograph- An open frature is visible filled by blue-dyed epoxy. Porosity other than fracture porosity is minimal.

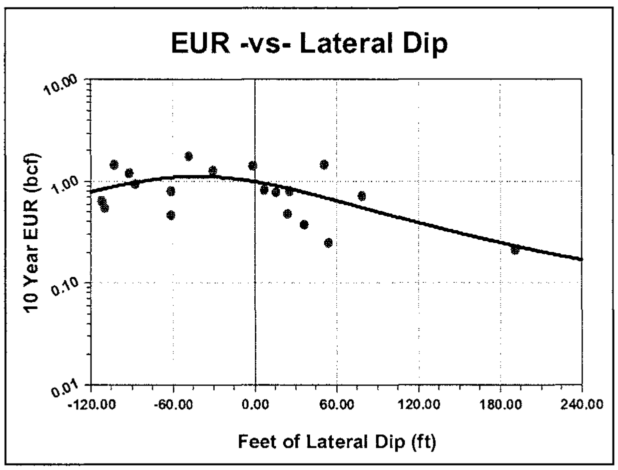


Figure 8 - Impact of Overall Lateral Dip on Well Performance (cemented wellbore)

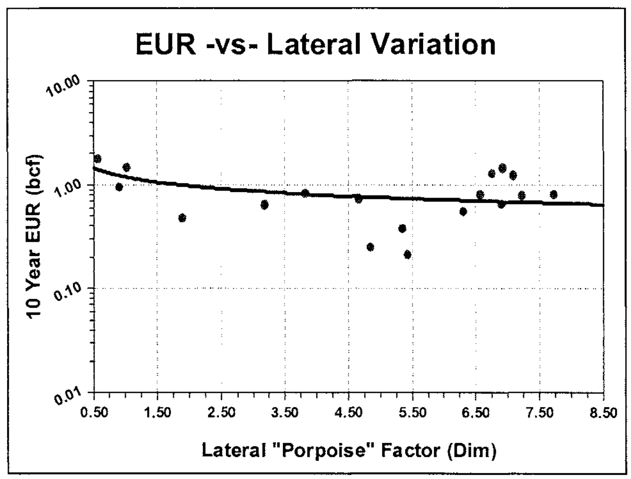


Figure 9 - Impact of Localized Vertical Trajectory

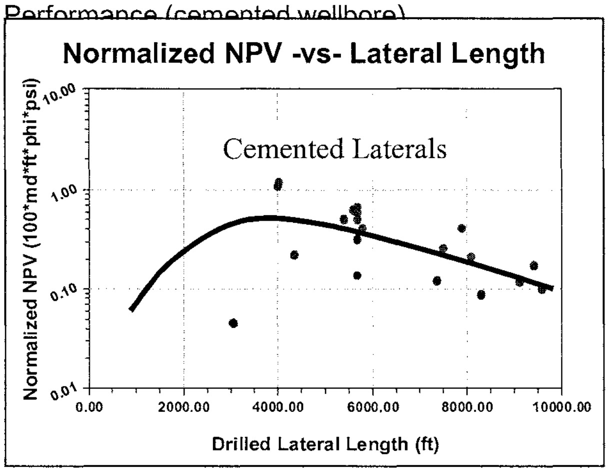


Figure 10. Impact of Lateral Length on Well Performance (cemented wellbore)

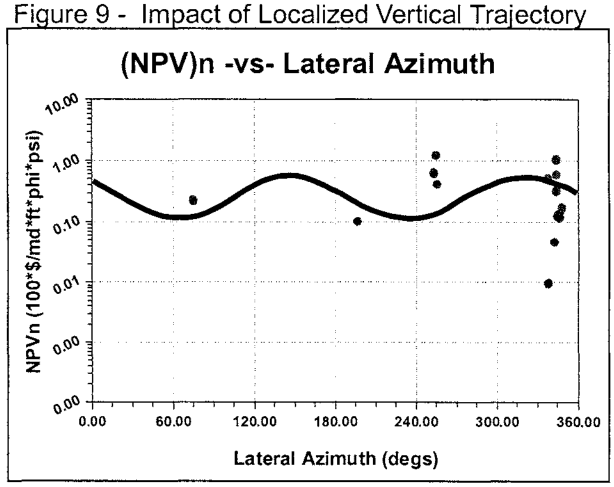


Figure 11. Impact of WB Trajectory Direction on Cemented Well Performance. No correlation poss.

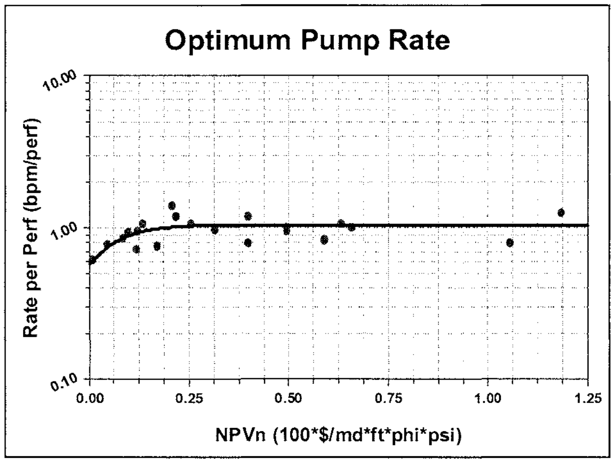


Figure 12 - Impact of Pump Rate on Well Performance - None of these treatments were pumped at limited entry (cemented WB).

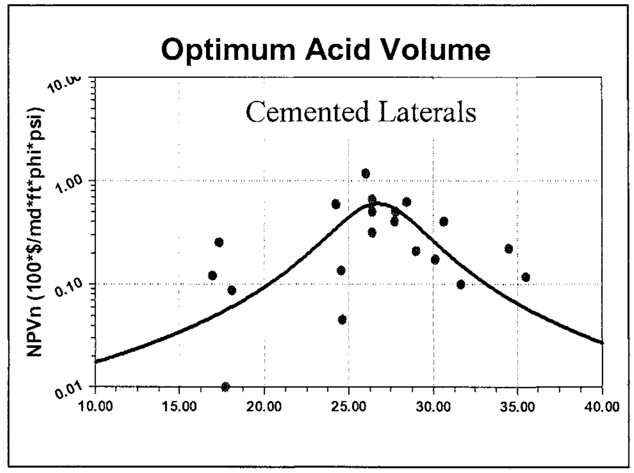


Figure 13 - Impact of Acid Volume on Well Performance (cemented wellbore)

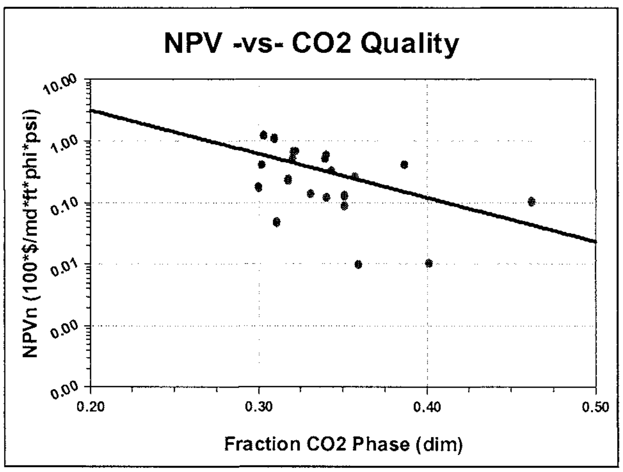


Figure 14. Impact of CO_2 Percentage on Well Performance (cemented wellbore)

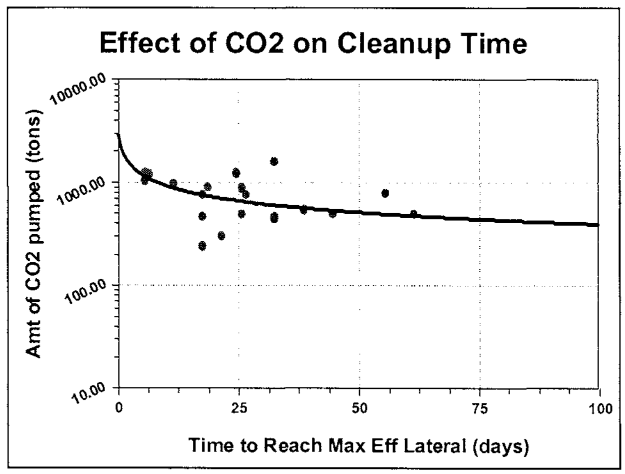


Figure 15. Impact of CO2 Volume on Cleanup Time (cemented wellbore)

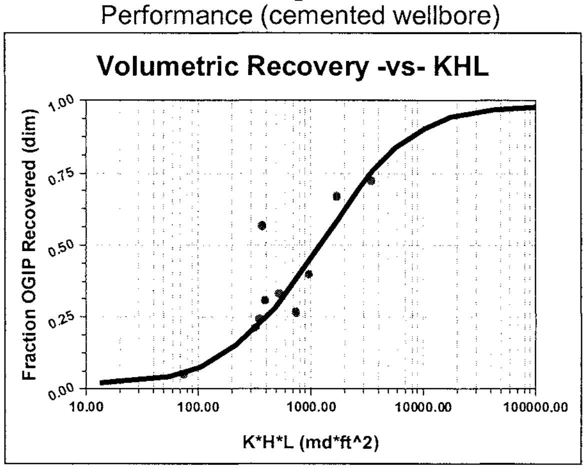


Figure 16 - Impact of Permeability, Zone Height,

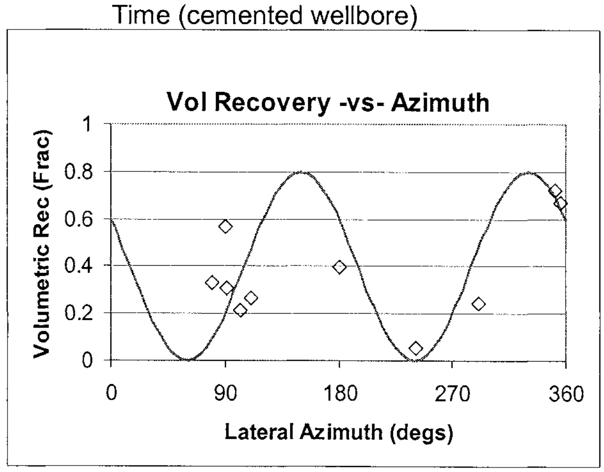
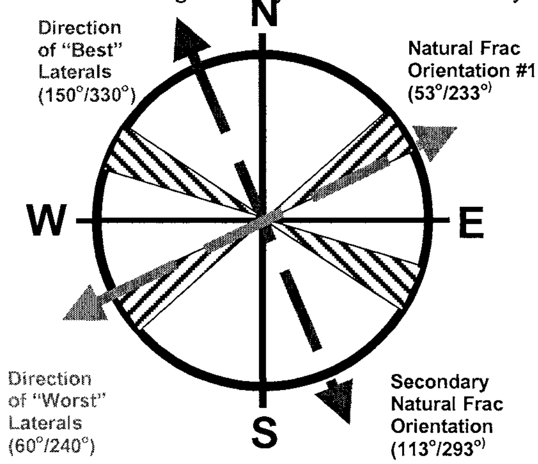


Figure 17. Impact of WB Trajectory Direction on

and Lateral Length on Hydrocarbon Recovery



Hydrocarbon Recovery (open hole case)

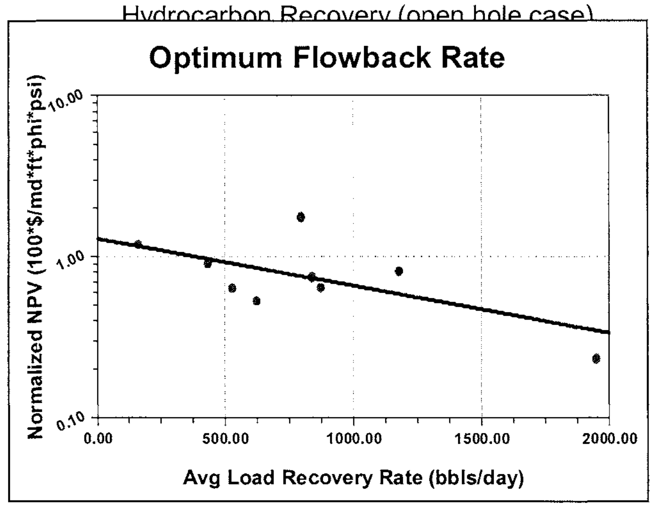
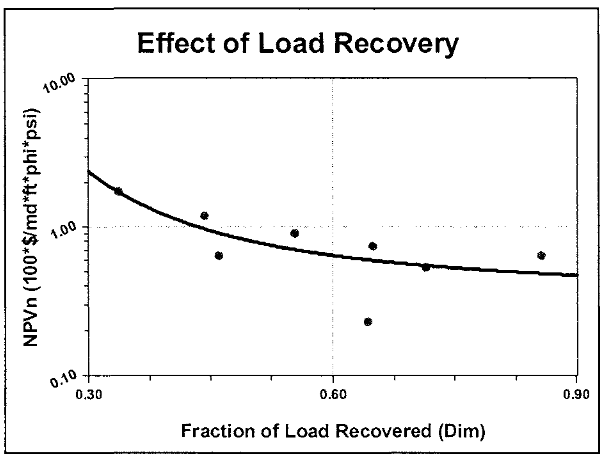


Figure 18 - Visual Representation of Lateral natural Fracturing Direction

Figure 19 - Impact of Flowback Rates on Well Performance(open hole wellbore)



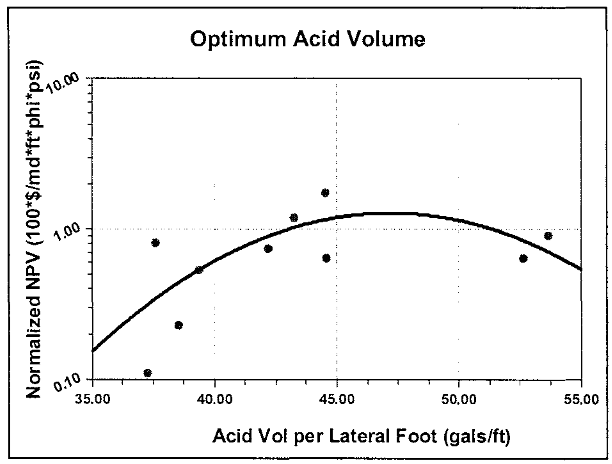
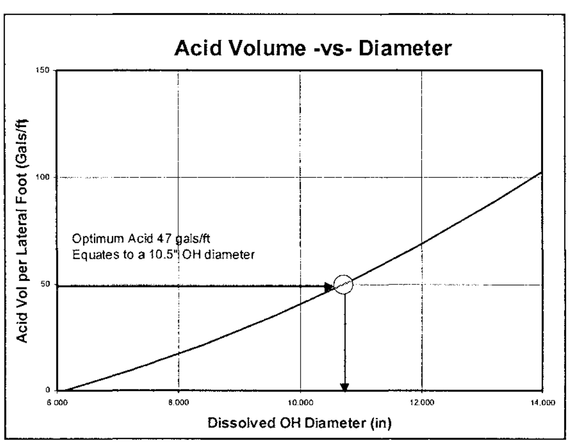


Figure 20 - Relationship Between Load Recovery and Well Performance (open hole WB)

Figure 21 - Impact of Acid Volume on Well Performance (open hole WB)



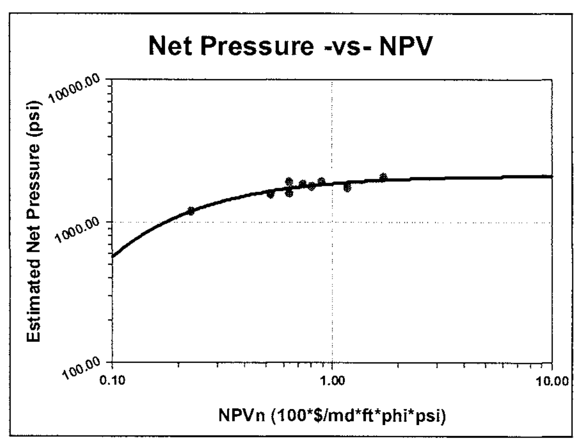
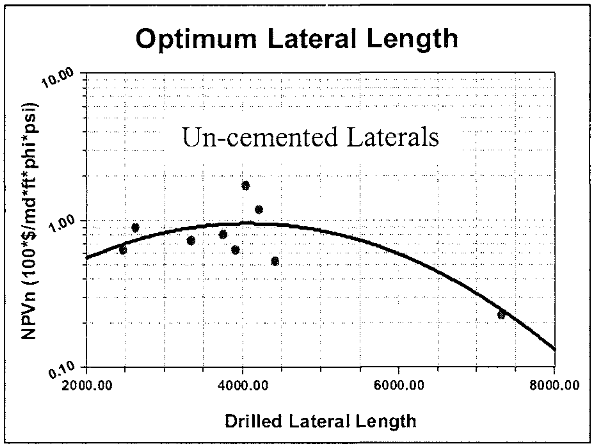


Figure 22 - Theoretical Impact of Removing a Certain Volume of Rock Evenly Along a Wellbore

Figure 23 - Relationship Between Net Pressure and Well Performance (open hole wellbore)



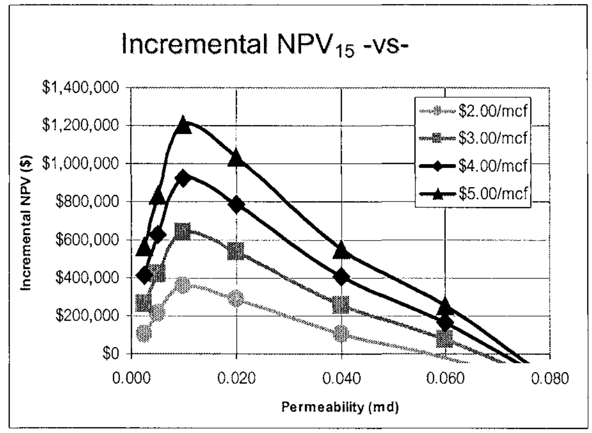
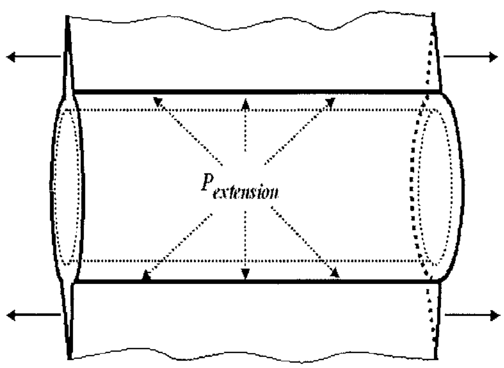


Figure 24 - Relationship Between Lateral Length and Performance (open hole wellbore)

Figure 25 - Added Value Over a 10-Year Period Associated with Cementing the Wellbore



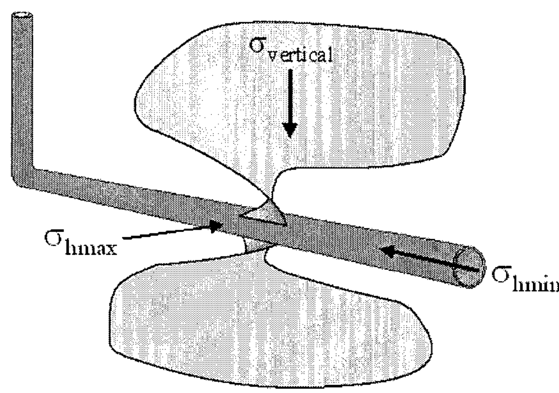


Figure 26 - Fracture initiates and grows as P_{ext} is maintained.

Figure 27 - Industry Perception of a Transverse Fracture Initiating from a Longitudinal Openhole or Sprinkler System Scenario

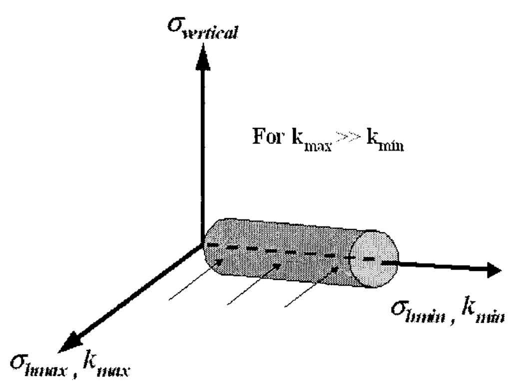


Figure 28 - Ideal Case for Large k Anisotropy; where $_{vertical} > s_{hmax} > s_{hmin}$