A METHOD FOR DETERMINING THE ORIENTATION OF A WATER INJECTION INDUCED FRACTURE

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Abstract

The objective of most all waterfloods is to inject water at rates as high as possible without fracturing the formation. Sometimes fractures of limited length are required to reach beyond near wellbore damage of an injection well. However, a fracture that grows to larger distances may drastically affect the volumetric sweep efficiency of a waterflood pattern.

As waterflood projects mature, increasingly higher water rates are necessary to maintain oil rates. Increasing water injection rates may exceed the fracture gradient and start or extend a fracture. A pressure falloff test conducted on an injection **well** provides an estimate of the fracture half-length, but the orientation of the fracture cannot be distinguished. A trial and error procedure is shown to determine the fracture orientation and possible affect on the volumetric sweep efficiency on Levelland area waterfloods by using the fracture half-length from a falloff test and a reservoir simulation program.

Introduction

Intentionally or unintentionally, it is likely that most all water injections wells in mature fields have been injected above the parting pressure such that a fracture of some size and shape has been created. These fractures may be part of a stimulation program or a result of over injecting to maintain a predetermined oil rate. While the length of the fracture may be useful in overcoming near-wellbore flow barriers, the orientation of the fracture may cause detrimental short- or long-term effects on the recovery of oil from a waterflood pattern, This would be most dramatic if the fracture was oriented in the general direction of producing wells in the pattern. For fields with hundreds of injection patterns, there is no expeditious method for finding fracture direction.

Due to the symmetry of a five-spot, the two extremes of fracture orientation is extending exactly between two producers and extending directly towards two of the producers on the diagonal of the pattern. A staggered line drive would have the same symmetry as the five spot. The extremes of a direct line drive would be the fracture extending towards the adjacent injectors and extending directly towards the producers.

Breakthrough time is the obvious choice for learning fracture orientation, but only if the fracture was present before and at breakthrough. Moreover, the affect of layers of varying permeability in the presence of fractured injector is unclear. In mature west Texas waterfloods this early data may not be available in the time intervals necessary to observe breakthrough differences between wells. A method of identifying fracture orientation that occurred in injection wells beyond water breakthrough is desired.

Other methods of identifying fracture orientation are reviewed in the next section.

Review of Previous Methods

The literature found on the subject of hydraulic fractures in water injection wells in waterfloods is divided into three general categories: identifying fracture length and orientation, modeling fracture growth, and quantifying the fracture's affect on sweep efficiency or recovery. (The papers pertaining to fracture growth models for water injection wells are not included in this literature review.)

Detection methods include a variety of techniques using pressure measurements during well tests and pattern monitoring, water breakthrough time, pattern and offset production and injection history, tiltmeter surveys, and borehole seismic measurements.

Using Pressure Transient Analysis for Determining Fractures

The detection of the presence of a water injection induced fracture in an injection well can be found using a pressure falloff (PFO) or injectivity test. The difference between the two tests is that a PFO is a shut-in (SI) test, and the injectivity test is an injection test. A PFO is analogous to a pressure buildup test, while an injectivity test is analogous to drawdown test.

The PFO is more popular from a testing and analyzing viewpoint due to the known, controllable, measurable rate of zero during SI. The injectivity test is a continuous injection test requiring a constant injection rate or accurate measurement of injection rate. Because most injection wells are part of a group of injection wells in series or parallel, the rate and pressure of every well in the group affects the "constant" rate and injection pressure of the test well. While the variations in rate will be seen on the pressure data measured during an injectivity test, the magnitude of the rate will not be known. (The remainder of this section pertains specifically to PFO; however, because of the similarities between PFOs and injectivity tests, the PFO specific comments are applicable to injectivity tests.)

A pressure falloff test can qualitatively and quantitatively indicate the presence of a fracture in a water injection well. The log-log or storage plot provides trends and patterns for qualitative interpretation of the presence of a fracture. The log-log plot consists of two pressure dependent curves (pressure and pressure derivative) as a function of SI time. The pressure curve Ap is the difference between the last bottom-hole injection pressure (p_{wf}) and the pressures measured during the SI (p_{ws}). The pressure derivative on the log-log plot is the slope of the Horner plot ($dp_{ws}/d((t_p+\Delta t)/\Delta t)$). (The pressure derivative can be taken with respect to the superposition function, also.)

A non-fractured wellbore may show a wellbore storage dominated segment indicated by a unit slope. Generally, the affect of a fracture on a pressure will influence pressure such that wellbore storage affects may be moderate at best. As a result, a fractured well bore may not show unit storage on the log-log plot such that the slope of the earliest data is less than one. A true fracture response has a slope of 0.5 or a half slope. The presence of a half-slope depends on significance of the fracture on the pressure measured during the test. A large fracture and a fracture in a very low perm reservoir are most likely to have a half-slope.

Another, qualitative indicator of a fractured well is the separation between the pressure and pressure derivative curves; a fractured well has significantly less separation compared to the non-fractured well.

The Horner plot has a distinct shape for a fractured wellbore also. The typical "lazy S" shape of non-fractured disappears and shows a continuous, concave shape.

Quantitatively, fracture length and conductivity can be found from a **PFO.** In water injection wells that are unpropped, the assumption of infinite conductivity is most applicable. In this case conductivity is not calculated, and only the length can be found.

Using Field Observations and Other Tests for Determining Fractures

For new (pre-breakthrough) water injection patterns, Kuo et al. **(1984)** used a plot of daily wellhead injection pressure and water injection rate for wells adjacent to (or surrounding) a producer. Generally over only a few months, they established a general pressure-time trend that increased. (Their example showed about 20 psi/mo increase.) **Two to** three times each month, a moderate pressure increase from the established trend was followed by sharp decrease back to the general trend. They explained the modest increase as a "plugging" effect, and the sharp decrease was the fracture growth. They concluded this trend was a qualitative identification of the presence of a water injection induced fracture.

After water breakthrough for a producer, the analyses of the surrounding injection well's wellhead pressure were studied looking for the feature described above to identify which **of** the surrounding injection well's had a fracture. Combining the pressure trend with well history information such as injection start-up time, volume injected, and suspected fault locations, Kuo et al. identified the suspected fracture orientation.

Hozhausen and Egan **(1987)** primary concern for water injection induced fracture development was not in watertlooding, but in water injection in disposal wells. They reviewed three general monitoring techniques: pressure analyses, tiltmeter surveys, and borehole seismic measurements.

For pressure analyses, Hozhausen and Egan suggested calculating and monitoring the injectivity index (I), which is a ratio of the injection rate to the difference in the flowing bottom hole pressure and the average reservoir pressure. Under constant rate, **I** is constant or may decline after continuous injection. **A** sharp increase in I qualitatively indicates the presence of a fracture. They observe that no estimate of dimensions or orientation of the fracture can be made with the injectivity index only.

Hozhausen and Egan described hydraulic impedance analysis that requires the measurement of wellhead injection pressures that are influenced by an oscillatory source such as a variable choke or reciprocating water injection pump. The pressure oscillations change in the presence of a fracture they say that exact knowledge **of** the wellbore configuration is necessary. **A** modeling technique that was not described in this paper is required to identify fracture properties. (They reference four additional papers on this subject that were not reviewed by the authors.)

Tiltmeters placed near the surface around the water injection well are used to infer the presence of a fracture by measuring changes in elevation on the order of 10s of microns. Hozhausen and Egan show example patterns for fracture orientation, dip, and length. They recommend tiltmeters as the most reliable for fracture azimuth.

The last method reviewed by Hozhausen and Egan is triaxial borehole seismic surveys. A tool consisting of geophones is placed in the injection well below the zone water is injected into. The "sound" from the growth of the water injection induced fracture is recorded and estimated as the dimensions and orientation of the fracture. Noises created in the injection process mask the fracture growth noise; consequently, the analyzable measurements are taken during SI periods.

Affect on Oil Recovery of a Fractured Water Injection Well

The earliest published work on fracture affects on oil recovery was conducted using potentiometric models [Simmons et al. (1959) and Crawford et al. (1963)] and X-ray shadowgraphs of miscible displacement in porous models [Dyes et al. (1958)] of five spots. In all of these papers, fracture orientation had a greater influence on oil recovery than fracture length. (Crawford et al. studied horizontal fractures; however, analogous conclusions were found).

Areal sweep efficiency as a function of pore volumes injected was used to compare the influence fracture length and orientation has on recovery. Dyes et al. and Simmons et al. concluded that recovery at breakthrough was significantly lower than non-fractured cases; however, they also found that sustained injection recovered volumes similar (within 8-12 recovery percent less) to the non-fractured case.

A fracture length of at least 200 ft regardless of orientation affected breakthrough efficiency according to Simmons et al. (They used a 660'x660' reservoir model.) This implies that a fracture length less than approximately 1/3 of the distance between producers may not appreciably affect recovery.

Dyes et al. stated that "relatively long and highly conductive fractures were required to affect the sweep-out efficiency substantially". A fracture oriented towards the producer that extends less than half the distance between the injector and producer has little effect on ultimate recovery; however, a lengthy injection period is required to achieve this. For example, for the case of a fracture one-half the distance between injector and producer, 20% more injected volume is necessary to achieve recovery similar to the non-fractured case.

Dyes et al. showed that a fracture oriented between wells could have a length ¾ of the distance between wells without a substantial affect on recovery. They noted minimal affect of mobility ratio for the fractured and non-fractured case.

Bargas and Yanosik (1988) used a reservoir simulation model to study cases similar to Dyes et al. and Simmons et al. for unfavorable mobility ratios for five-spot and direct line drive patterns. Like previous researchers, they used a plot of sweep efficiency vs. pore volume injected to compare the affects of fracture length and orientation on recovery.

A five-spot pattern with an injector with a fracture of any orientation required a length of less than ¼ of the distance between wells regardless of the mobility ratio to maintain sweep efficiency similar to the non-fractured cases. For a line drive pattern, they found that orientation did not have a significant affect for fractures less than 15% of the distance between wells. Long fractures connecting injectors showed recovery greater than the non-fractured case.

They concluded that if fracture orientation is unknown or directed towards producers, limiting the fracture length to 1/10 of the distance between wells would ensure minimal affects to sweep efficiency regardless of the mobility ratio.

(Bargas and Yanosik discuss the affects of fracturing the producer only and the injector and producer. Because this was beyond the scope of this paper, this was not included in this review.)

Description of Proposed Method

This paper documents a combination of pressure falloff analysis (PFO) and reservoir simulation to identify fracture orientation in a five-spot waterflood pattern. The successful analysis of a PFO on a fractured water injection well yields perm (k), skin **(s),** and fracture half-length (x_f) of a water injector in the waterflood pattern. Unfortunately, the orientation of a fracture cannot be determined from a PFO or any single-well pressure transient test. Using the x_f from the PFO, a match of production/injection history of the pattern can be made by changing the fracture orientation in a reservoir simulation program.

As a consequence of the symmetry of a five-spot, the fracture orientation only needs to be made over 45°. The two extremes are that the fracture extends exactly between any two producers or the fracture extends directly towards two producers along a diagonal of the pattern. This creates a significant problem. A short fracture, regardless of the orientation, may have the same production/injection history. The orientation of a longer fracture has a more dramatic affect on the production/injection history and a match should be easier to see.

The breakthrough time, as defined as time between initial injection and the first water production at any of the producers, has been used to identify fracture orientation [Kuo et al., 1984]. This worked well for their examples, but they required other critical information such as the actual startup time of injectors and the time wells were drilled. In other words, **if** all wells were in place and injection started at the same time for all wells, the fracture orientation estimation would not be unique for their examples. Most importantly, for the time to breakthrough to be a parameter to use to identify fracture orientation, the injection wells must be fractured before breakthrough. **A** fracture developed in an injector ***after*** breakthrough would not benefit from an analysis of breakthrough time of producers in a waterflood pattern.

Breakthrough analyses was not conducted because fracture growth most likely occurred years after water breakthrough. **Also,** when patterns are realigned or infill drilling reduces a waterflood pattern, a newly drilled producer may have a watercut greater than zero. This makes breakthrough due to the injection pattern difficult if not impossible when the well initially produces water. Prior to this work recovery plots and oil cut plots are attempted to observe the affects of fracture orientation. A generic reservoir model was used to demonstrate the feasibility of the proposed method. Merlin, a black-oil reservoir simulation model from Gemini Solutions, Inc., was used to develop the reservoir models.

Applying the Method to Simulated Data

Single-layer, Homogeneous Model

To prove the concept of identifying fracture orientation using a PFO and reservoir simulation, a horizontal well was used in a single layer, homogeneous model of a five-spot. Only the two extremes of orientation were used and three lengths were selected.

Figure 1 has pattern oil production for a five spot. While measurable differences are seen in terms of breakthrough time and deviations in oil cut from 100%, the recovery (as a percent of OOIP) looks very similar and probably could not be distinguished in a field application even for the single layer homogenous model. Many of the reviewed publications suggested this, also.

From the homogenous reservoir case, there are two unique features that may be identifiable from field observations. The models of a fracture oriented between producers (Od) do not differ significantly from the non-fracture case and most likely could not be identified from field-acquired data. Following breakthrough, these cases show a rapid, sharp decrease in oil cut (large slope).

A fracture oriented towards a producer (45d) has a tendency to have earlier breakthrough followed by a very modest change in pattern oil-cut for an extended period of production. At a later time a very rapid decrease in oil cut similar in magnitude to the fracture orientation between wells occurs.

Five-layer, Heterogeneous [illegible]

To [illegible] d the affects of multiple layers with widely differing permeability, a five-layer model was built to observe the affects of heterogeneity on the oil-cut plot. The perm for each layer w[illegible] 0.01, 0.1, 1.0, 1[illegible] and 100 [illegible] The affect of the permeability variation was to have chan[illegible] in t[illegible] oil cut at earlier recovery with [illegible] less [illegible] change in oil-cut over a much larger interval of oil recovery. In other words, the slope of the plot [illegible] as [illegible] er compared to the homogeneous cases (figure 2). This plot is total oil production from the [illegible]

T[illegible] oil cut for individual wells within a given are affected [illegible] by the fracture orientation. Fi[illegible] 3 shows the nomenclature that will be used in this paper to describe the well [illegible] s. [illegible] is for a p[illegible] well with the fracture directed towards it, while "perpendicular" de[illegible] the [illegible] well in the [illegible] that does not have the fracture towards it. To [illegible] an[illegible] in oil cut for individual wells, Figure 4 shows [illegible] from the individual wells within the [illegible] attern The well wit[illegible] the [illegible] ture t[illegible] it shows earlier water [illegible] and a much [illegible] slope (like the [illegible] us cases). [illegible] he [illegible] well in the pattern without the fracture directed toward it has later water [illegible] rough[illegible] d a lesser slope.

The calculated slopes are 4.5/mmbbl and 9.2/mmbbl for the well perpendicular to the fracture and the well parallel to the fracture for the 400' fracture half-length, respectively. These were the extreme cases for the heterogeneous model.

Summary of Model Results

Based on the observations of the homogenous case, a fracture in the heterogeneous case should cause the oil-cut plot to look more like the homogenous cases with a sharper transition from pre-breakthrough and post-breakthrough. The downside of this observation is an injector without a fracture in homogenous reservoir appears similar to an injector with a fracture in a heterogeneous reservoir. Therefore, it is necessary to know the degree of heterogeneity prior to this analysis.

The producing well with the fracture oriented towards it exhibited the following characteristics:

- early water breakthrough
- flat, modest change in the oil-cutlrecovery plot immediately following water breakthrough
- steeper slope on the oil-cut/recovery plot following the flat trend
- the oil-cutlrecovery trend falls below the other wells and the pattern average curve

The producing well that is perpendicular to the fracture exhibits characteristics nearly opposite of the description above. The waterflood pattern models were all inverted five spots. Consequently, a comparison of model results to field results may be affected by the adjacent patterns in the field. A pattern model assumes all of the surrounding patterns are a mirror image of the pattern.

The guidelines for determining fracture orientation are below:

- Identify changes of total pattern oil cut as a function of oil production. A gradual change in oil cut means the fracture is directed toward one or more of the producers and a sharp change in oil cut means the fracture is between all producers.
- Compare the performance of the particular well against the total performance of all other producers in the pattern. If the slope deviates below the total well line then this well is probably fractured.
- Determine the actual slope on the oil-cut versus cumulative oil produced plot immediately following the breakthrough time point. This may avoid misusing changes in the trend due to field operations (workovers) that change the oil and water production for an individual well.

Applying the Method to the Levelland Unit

Initially four water injection patterns were included in this study, but two unsuccessful pressure falloff tests reduced the patterns available for this paper to two. (PIE Well Testing Software by Well Test Solutions, Inc. was used to analyze the PFO tests.) Wellhead pressures were used to conduct PFO tests in the injectors of two five-spot patterns in the Levelland (LLU) and May Montgomery Units (MMU). The pressure measuring equipment was only capable of recording pressure in 10 psi increments. For the two failed PFOs, the 10 psi increment was inadequate to analyze the tests for any reservoir parameters, namely permeability, skin, and fracture half-length.

Figures 5 and 6 show the log-log plot for the two successful PFOs for the wells MMU 12 and LLU 94. While the data is scattered, the general trend of the derivative exhibits fracture-like behavior. The fracture half-lengths calculated are 50 and 135 ft; moreover, the calculated values of permeability are reasonable for the San Andres in this area. The literature suggested fractures this small would have minimal affect on recovery, but did not suggest that the small fracture length could not be detected.

The observations from the oil cut plot from the model runs were used to qualitatively examine the oil producing wells around the injection wells identified as fractured from the PFO tests.

Figures 7 and 8 are the oil-cut plots for the wells in the MMU12 and LLU94 patterns, respectively. (These plots are oil-cut vs. cumulative oil production; there should be no difference in the trend, because %OOIP divides cumulative oil by a constant.)

In the MMU 12 waterflood pattern, all of the producing wells show consistent trends except for the M83, which shows a very large increase in oil cut of about 140,000 bbl oil produced. Based on the slope, general trend, and position relative to the pattern production MMU 83 and MMU 85 exhibit fracture behavior similar to the model runs; these producers were on opposite sides of the injector and suggested a NE-SW fracture orientation.

In the LLU 94 waterflood pattern, all of the wells show consistent trends. Only one well in this pattern, the LLU 662, has a convincing pattern of fracture influence. The trend is below the field average, has an early flat trend followed by a later large decrease in oil cut. This suggested a NW-SE fracture orientation. The well opposite the LLU 662 is the LLU 453, which does not show any fracture behavior; this may be because the LLU 662 is only 560' from the injector while, the LLU 453 is 949' from the injector. The PFO test results gave a fracture half-length of only 50'. The effect of a relatively small fracture is more apparent as compared to wells further from the injector.

In a series of five-spot patterns, every producer is shared by four different five spots; i.e. the production of every producer is influenced by four injectors. If a producer is fractured, it should exhibit fracture characteristics on the oil cut plot regardless of which waterflood pattern the producer was included in. In the LLU 94 waterflood pattern, the LLU 662 showed a fracture-like response on the oil cut plot. Therefore, if the oil cut plot of the wells in the other three waterflood patterns that the LLU 662 produces from (LLU 661, 95, and 105) are studied, the LLU 662 should appear fractured, also. Figures 10, 11, and 12 are the oil cut plots for these patterns. In comparison to all of the other wells in the respective patterns, the LLU 662 appears fractured.

Likewise the other producers in the LLU 94 waterflood pattern that did not show fracture characteristics (LLU454 and 461), should not have fracture characteristics when compared to the two other waterflood patterns that these wells produce from. Using the oil cut plot guidelines developed, neither of these wells appears to be fractured (figure 10 and 12). LLU **467** does show **a** slight degree of fracture behavior on figure 12. At the time of this publication, a pressure falloff test of the surrounding injectors and oil cut plots for the other five-spot patterns that share LLU 467 were unavailable.

The table shown on the next page summarizes the application of each guideline for each well in the LLU **94, 95,** 105, and 661 injection patterns:

Descriptions		Oil Cut Plot Guidelines			
Model/ Waterflood Pattern	**Well** Location with Respect to Fracture	Pattern Early Trend Gradual Decrease	Well Trend Deviates Below Total Pattern	Slope (1/mmbbl)	
				Well	All Wells
Simulation	No Fracture	-	-	5.4	-
	Perpendicular	-	-	4.2	-
	Parallel	-	-	9.2	-
LLU 94	L662	Present	Yes	5.2	3.8
LLU 661	L662	Present	Yes	5.6	2.2
LLU 95	L662	Present	Yes	5.6	2.2
LLU 105	L662	Present	Yes	5.6	2.2
	L467		Yes	3.6	2.2

Conclusions

A plot of oil cut vs. oil recovery (or cumulative oil production) was used to qualitatively indicate the presence of a fracture in a water injection well in a five-spot pattern. A layered heterogeneous reservoir tends to flatten the oil-cut curve compared to a homogeneous reservoir.

Wellhead pressures used for PFO were limited to tests with large pressure changes because the pressure acquisition equipment was incapable of measuring in pressure increments less than 10 psi.

In the two leases in the Levelland unit, pressure falloff analyses showed fracture half-lengths between 50 and 135 ft. The literature suggested these lengths are inadequate to identify in terms of recovery **vs.** pore volumes injected. This work shows that oil cut trends that infer the presence of a fracture can be detected if the fracture is directly towards the producer.

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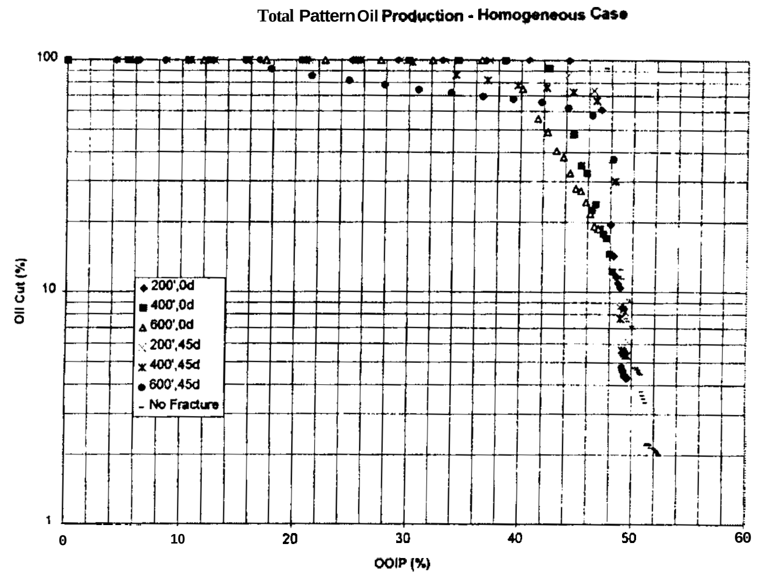


Figure 1 - Homogenous, Single Layer 40 Acre Model Results with Two Variations of Fracture Orientation [(1) between producers-0d and (2) directed toward producers-45d] and Three Variations of Fracture Half Lengths (200,400, and 600').
Fracture orientation between wells (0d) has a sharp change in oil cut while fractures directed toward the producers (45d) have a gradual change in total pattern oil cut.

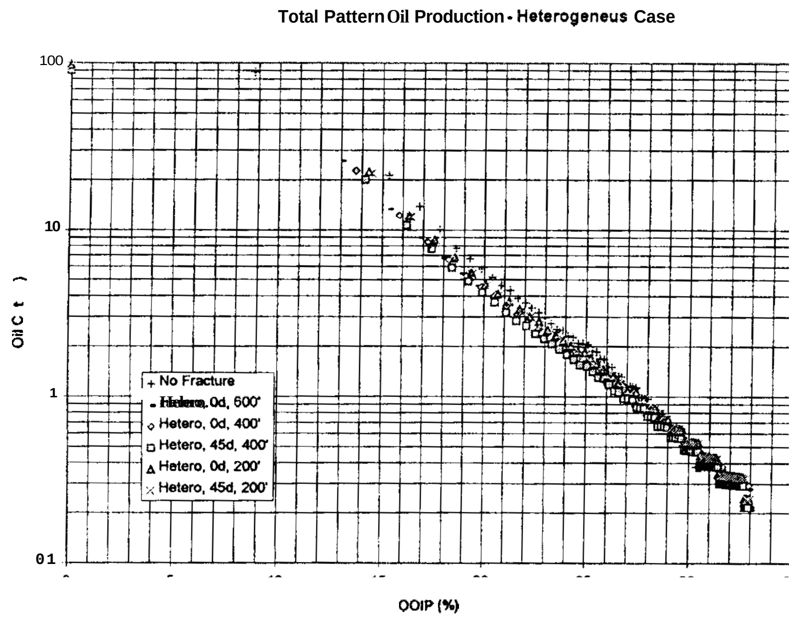


Figure 2 - Heterogenous, Five-Layer 40 Acre Model Results with Two Variations of Fracture Orientation [(1) between producers-0d and (2) directed toward producers-45d] and Two Variations of Fracture Half Lengths (200 and 400')

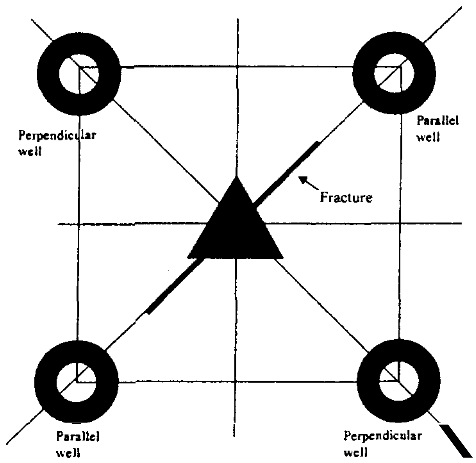


Figure 3 - Terms Describing Well Location with Respect to Fracture Orientation.
Legend descriptions of "parallel" is for a producing well with the fracture directed towards it, while "perpendicular" is for the producing well in the pattern that does not have.

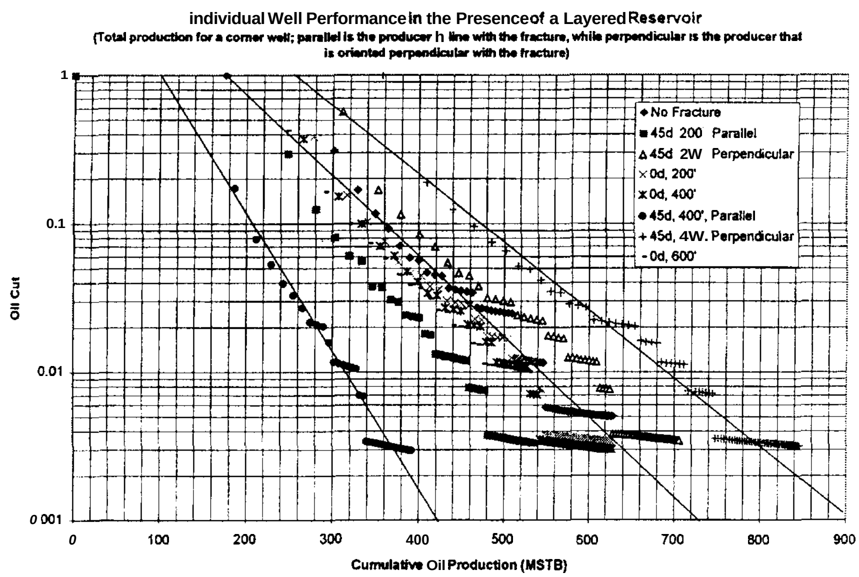
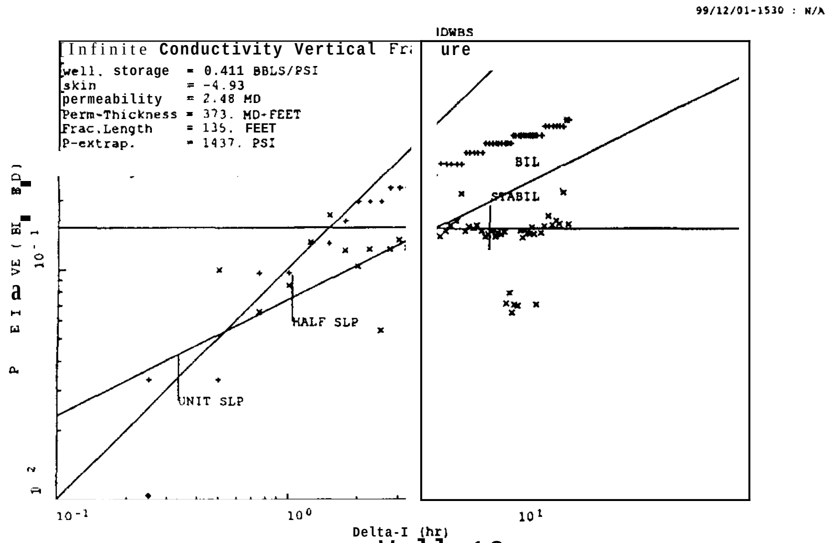
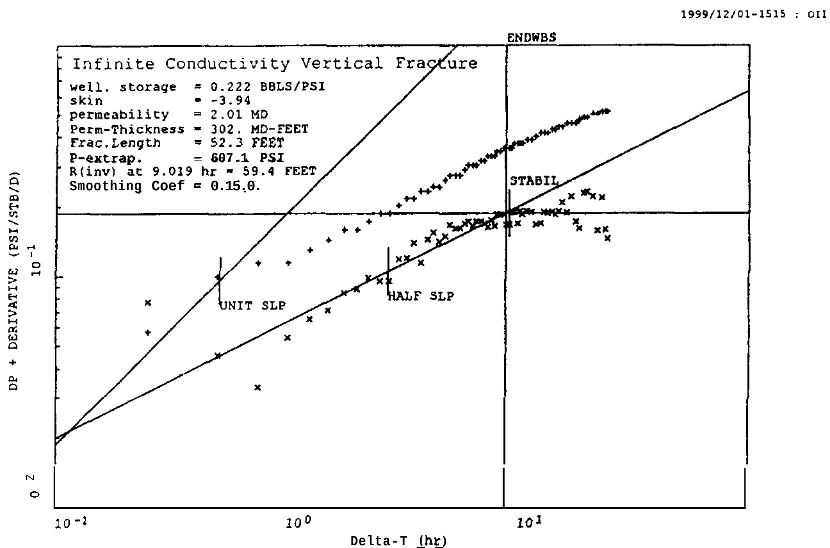


Figure 4 - **A** Comparison of Individual Well's Oil-Cut for Wells with the Water Injector Induced Fracture Oriented Towards It (parallel) and the Wells that are Perpendicular to the Fracture (perpendicular). Oil-cut from all wells within models with the fracture oriented between wells (Od) were identical: consequently only one well from these models is on this graph.



Well 12

Figure 5 - Log-Log Plot of Pressure (+) and Pressure Derivative (x) for MMU12 PFO Test. Derivative smoothing of 0.1 was required to observe reservoir features. Half-slope indicative of a fracture is present through about 1/2 log cycle of **SI** tim e. The x_f calculated is 135'. Stair-step appearance of the pressure curve due to pressure acquisition equipment limitation to measuring/recording pressure changes greater than 10 psi pressure.



Well 94

Figure 6 - Log-Log Plot of Pressure (+) and Pressure Derivative (x) for LLU 94 PFO Test. Derivative smoothing of 0.15 was required to observe reservoir features. Half-slope indicative of a fracture is resent through about 3/4 log cycle of SI time. The x_f calculated is 52'.

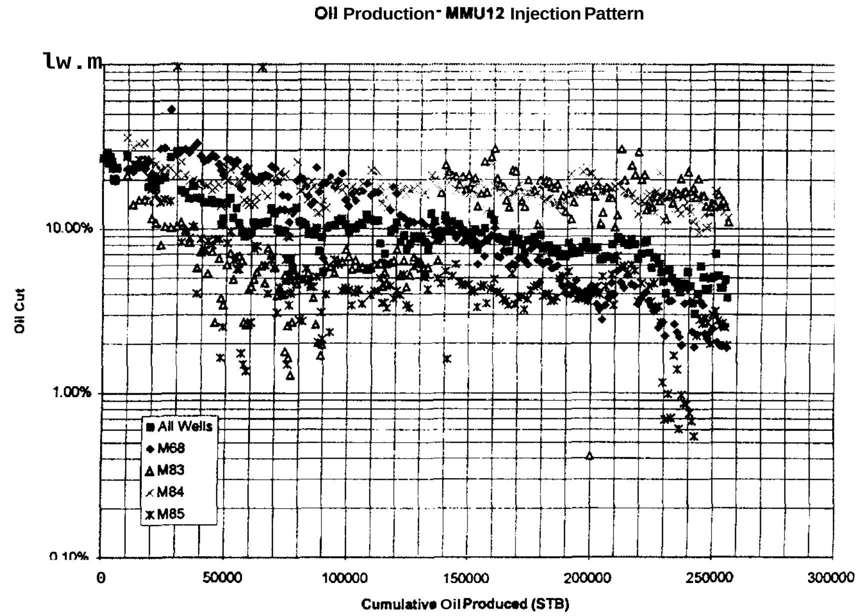


Figure 7 - Oil Cut for **All** Producers in the MMU12 Waterflood Pattern.
The MMU 83 and 85 exhibit fracture behavior as identified in the model results.

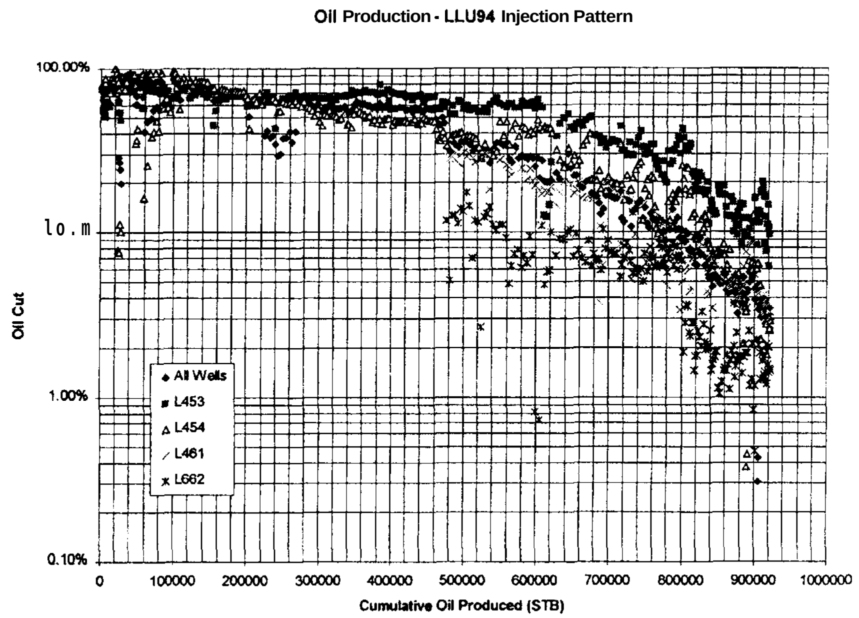


Figure 8 - Oil Cut for **All** Producers in LLU 94 Waterflood Pattern.
LLU 662 exhibits fracture behavior as identified in the model results.

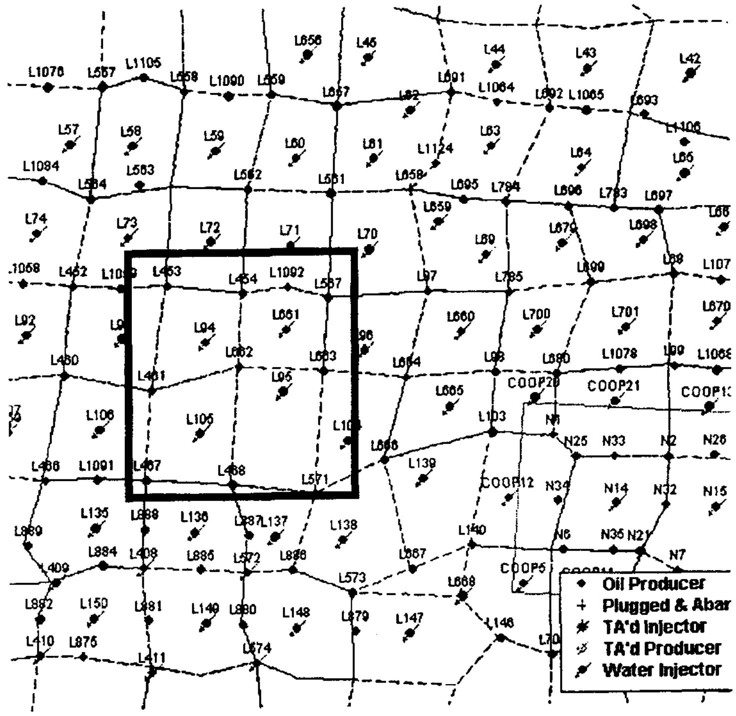


Figure 9 - Map of the LLU Unit that Shows the 4 (four) Injection Patterns Around LLU 94, 661, 95 and 105 Injection Wells.

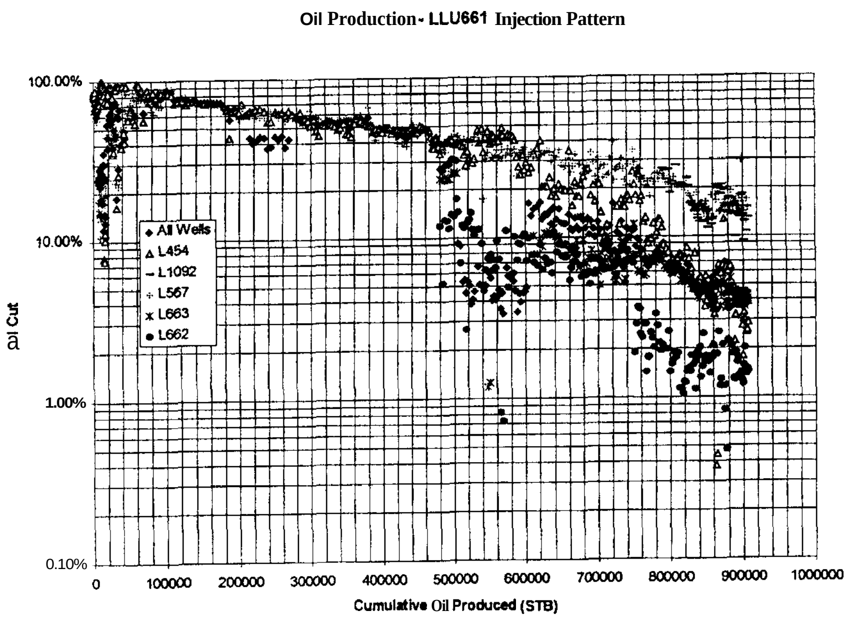


Figure 10 - Oil Cut for All Producers in LLU 661 (Noreast section) Waterflood Pattern. LLU 662 exhibits fracture behavior as identified in the model results.

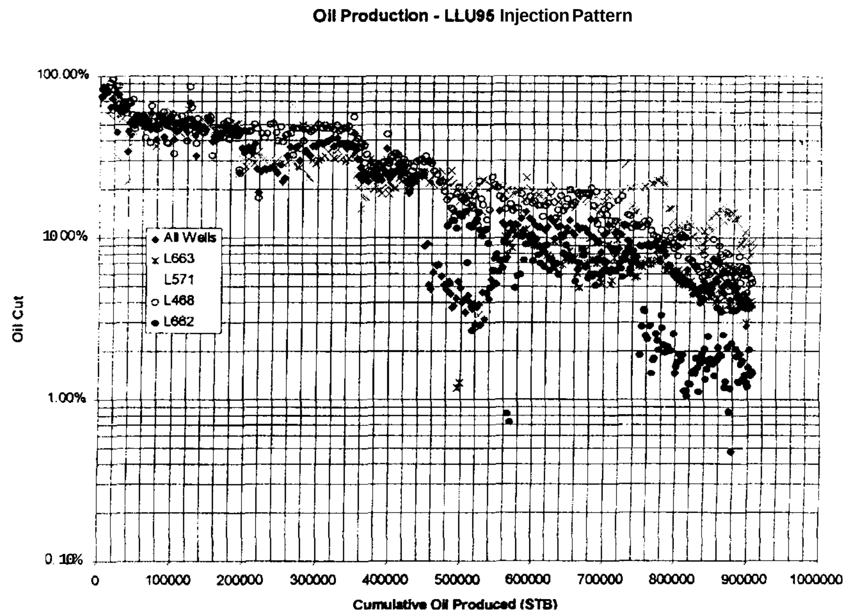


Figure 11 - Oil Cut for All Producers in LLU 95 (Southeast section) Waterflood Pattern. LLU 662 exhibits fracture behavior as identified in the model results.

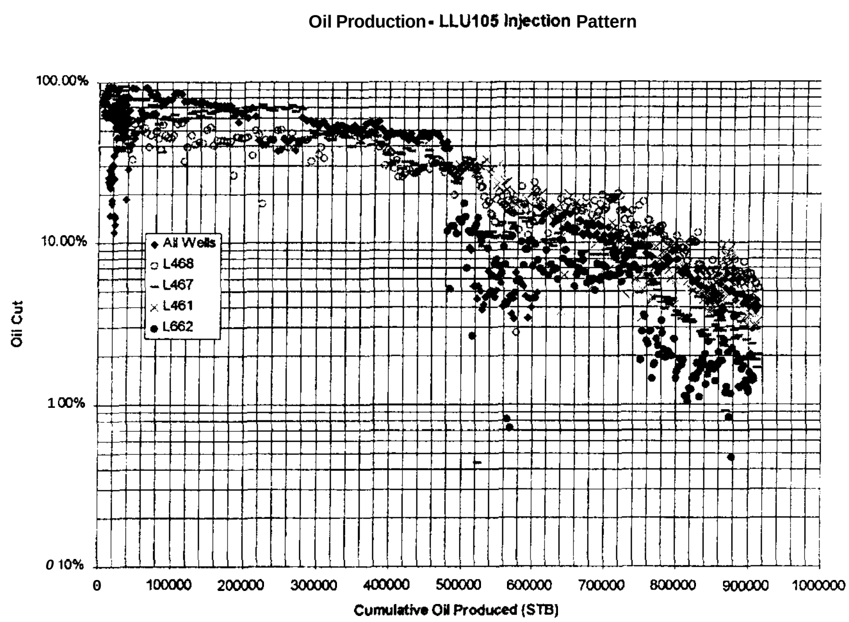


Figure 12 - Oil Cut for All Producers in LLU 05 (Southwest section) Waterflood Pattern. LLU 662 and LLU 467 exhibit fracture behavior as identified in th model results.