THREE-PHASE DISCRETE FLOW NETWORK SIMULATION MATCHES VERTICAL AND HORIZONTAL COMPLETION EFFICIENCY

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Abstract
An innovative approach has been used to model flow through discrete fracture networks in a massive carbonate reservoir in order to understand and predict performance of vertical and horizontal well completions. This approach focuses on completion effectiveness and the influences that fractures have in a three-phase gravity influenced flow system. The model is set up as a dual porosity, dual permeability simulation of a discrete fracture network of high permeability grid blocks capable of modeling three-phase flow. This model reveals the dominant factors controlling well life cycle performance demonstrated in the Yates Field Unit

Natural fracture networks dominate flow throughout the reservoir with added economic significance to completion efficiency. Therefore 3D discrete fracture network (DFN) models based on connected-fracture orientation from FMI logs and flow surveys have been used as a basis for constructing the 3-phase simulation grid. The differences in mobility between the three phases result in abnormally shaped gas-oil and water-oil contacts as drawdown is applied. As the fracture oil column depletes, oil mobility reduces with the decrease in effective fracture connection to the outlying oil column. This loss of oil mobility through phase dis-connection in flow conduits has not been the focus of prior studies. The simulator has successfully generated production profiles similar to those observed in field performance data. This wellbore simulation has been used to develop a strategy for optimal completion performance and placement.

Introduction
Many reservoirs throughout the world reside as unconfined oil columns in massive naturally fractured carbonate formations. Field management may encourage the oil column to either move up or down in the reservoir. Engineers have typically designed completions that maximized oil production while minimizing associated fluids under a homogenous reservoir assumption. There are two things that amplify the complexity of this process for the engineer. The first is understanding the homogenous nature of the reservoir and the complex flow connections within the reservoir. The second thing that needs to be understood is how the reservoir's heterogeneous nature effects fluid flow from the reservoir into the wellbore.

Flow feature identification in a massive carbonate reservoir as described by Fitzsimmons[1] provides insight on the assessment of in situ heterogeneities and determination of which features provided the best connection between the wellbore and the formation. This characterization involved assessment of both resistive imaging logs (FMI and EMI) and high-resolution flow surveys to determine which features were acting as flow conduits into the wellbore.

Fluid flow in the near wellbore area and the strategies to optimize completions to take advantage of coning forces were discussed by Wadleigh[2]. Simulation and field results indicated deep completions provided cost effective oil rate increases in a massive carbonate reservoir while lowering gas-oil ratios.

This treatment will incorporate discrete fracture network concepts into the near wellbore simulation. This approach focuses on the completion's effectiveness at recovering oil. Value maximization will be targeted through high oil rate completions with minimum associated fluid cost per barrel of oil. This is achieved by focusing on the DFN impact on the well's production and the local oil column shape.

DFN Concepts
This discussion will not reveal a new technique that provides the correct answer for each well, but will describe an approach for quantifying and projecting the contrast in performance that can be extended to statistical solutions for completion planning and economics. These techniques incorporate available geologic and engineering data to reasonably constrain projections. Application of DFN concepts can improve understanding and solution of anomalous well

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performance in massive carbonates. A discrete fracture network model is a model providing realistic individual fracture interconnection (relative varying length, orientation, relative spacing, intersection styles and flow properties.) (The more generic discrete feature network may include fractures, bedding surfaces and other porous or tight reservoir bodies.) These concepts are more fully described by La Pointe[3].

Carbonates present an assessment challenge due to extremes in porosity and permeability. These extremes result from a combination of depositional contrast, fabric selective solution enhancement, and natural fracturing coupled with cementation or solution enhancement. At the Yates Field Unit differential compaction encouraged extensional fracturing near perpendicular to bedding at several orientations. These near-planar high-flow-capacity features can interconnect to span distances far exceeding developed well spacing (660 ft). Snell[4] reports the rapid movement of injected chemical tracer across significant reservoir distance. Figure 1 illustrates a composite of the type of data generally available at wellbores for assessment. This includes the productivity distribution, injection or production profiles showing locations of connection, and the orientation of fractures or other planar features intersecting the wellbore as determined from wellbore imaging logs. Once these permeability extremes are recognized in a formation the assessment objectives should shift from deterministic to probabilistic.

The geotechnical team (geoscientists and engineers) first must establish appropriate assessment criteria for the fractured reservoir project. Often management only asks for an estimate of project outcome. Technical response often includes a qualified projection of an uncertainty range and some risk estimates. For fields where there are limited completion opportunities this should extend to the probability of success on each completion and the improved probability of project success as the number of completions increase. Individual completion prognosis may be off dramatically while the outcome of an adequately sized project may closely match the probabilistic projection. The value of this approach will become obvious in discussing several examples. This study first focuses on a range of connectivity and then shifts to the dynamic loss of connectivity during depletion or displacement.

On the one extreme, the DFN model includes realistic distribution of the large fractures that significantly impact flow and well performance. The short, low flow capacity fractures are excluded from the model, but are recognized as aiding the transfer of fluids between the formation matrix pores and the network of larger fractures that dominate flow. The width of specific fractures can dictate the potential flow along a fracture; however, this potential is seldom met unless the fracture has specific connectivity along a significant flow network (conduit). Fracture connectivity dictates whether fluid flows around or through matrix.

The value of connectivity is illustrated by Figure 2a which provides a plan view of three large fracture sets in a slab model of 1,000 X 1,000 X 125 foot formation. Two fracture sets are oriented in a northwest to southeast direction with dispersion around N65W. The thud fracture set is roughly orthogonal to the first two sets.

Visually one can appreciate that about half of the potential completion locations within this model would not encounter a significant length fracture. Over 90% of the potential locations would intersect minimal fracture productivity. The other 10% of the potential locations would intersect a highly productive well-connected fracture cluster (as extracted in Figure 2b). Wellbore image data could appear statistically and orientationally similar in the variably connected wells.

This contrast in completion-to-DFN connectivity can be observed at every scale as illustrated by "zooming in" to the smaller scale connectivity of Figure 3a and 3b. Here a completion is placed into a 25-foot thick slab of fractured formation where it encounters a single fracture that connects to a cluster. The fracture intersecting the well happens to be oriented almost perpendicular to the trend of the cluster. In this case, the 25-foot interval has been modeled to consider the probability of fracture connection for a projected oil column thickness. It is easy to visualize loss of oil productivity as the oil column thins, cutting oil-phase connections to the remainder of the cluster. The typical loss in oil connections across a depleting DFN results in dramatic changes in vertical and horizontal well performance as observed in field data and three-phase simulation.

Field Data and Completion Life

Maximum value oil completions in a massive carbonate reservoir must connect with flow features in order to produce sustainable oil rates. This must be accomplished while thinning the oil column to maximize reserves. The completion must be strategically positioned relative to fracture connections and the oil column in order to optimize the individual well performance.

Performance can change rapidly in wells producing from an unconfined oil column. As the oil column thins or changes shape in the near wellbore area the effective mobility of each phase changes. This leads to a wide variety of results from very similar completions. As the oil column thins or moves with respect to a completion the oil mobility within the fractures changes. This loss in oil mobility is not a smooth function but is heavily influenced by the flow feature or a

fracture connection.

In the Yates Field Unit the completion strategy has been to locate both vertical and horizontal completions below the oil column and produce oil by sumping oil down into the completions. (Referred to by Haug[5] as reverse coning.) As contacts move with respect to the completion the production characteristics of the well change. Production wells within the Yates Field Unit typically follow a signature life cycle that is a result of oil column movement and changing mobility within the fracture connection. Recent completions typically follow a cycle where the initial production is mostly water at relatively low gas and oil rates. Wells "oil in" as water is depleted from the near-well fracture connections. Water rate decreases and solution gas rate increases with the oil increases. Mature completions deplete both water and oil from the fracture connections allowing free gas to be produced from the completion. As more connections become gas filled and liquid head is lost the completions are deepened to restore liquid penetration. Both horizontal and vertical wells are positioned and operated to maximize the shift of water connections to oil connections while slowly adding gas connections.

Figure 4 is a production performance plot from a vertical well in the Yates Field Unit. This plot is a good example of the typical well lifecycle that is seen in the Yates Field Unit. In February 1996 the well was deepened and stimulated with acid. Immediately after this workover the water and oil rates stabilized at 1000 BWPD and 230 BOPD respectively. Over the next three years the completion progressed through its complete life cycle. The oil rate began to decline almost immediately as the connection to the oil column in the well diminished. The water and gas production rates began to increase as the oil production rate dropped off. During this time the oil connections were shifting to gas and water connections. (See Figure 5 for an illustration of how the fracture connections change from one phase to another and the properties that control this transition.) In December 1998 the well began to produce large amounts of free gas around the tubing tail; during the next three months the gas rate grew from 300 MSCFD to 880 MSCFD. At the same time as the gas rate stated to increase the liquid rates fell off dramatically. (Oil drops from 126 BOPD to 94 BOPD and water drops from 1565 BWPD to 1190 BWPD). Eventually the gas connections will increase to a point where the fluid connections are lost entirely.

Figure 6 is a good example of the life cycle of a horizontal well in the Yates Field Unit. The picture combines the production history of a well through its completion life as a vertical completion, through its first completion as a horizontal and finally as a re-drilled horizontal completion. Also in the figure is representation of the contacts in a twin observation well. The period from January 1996 through October 1999 shows the best representation of a recent horizontal completion in Yates. Production is initiated with relatively high water rates and low oil and gas rates. The oil increases as both the gas and water rates drop off as the well is produced. The well then begins to lose connection to the oil column as the gas cone reaches the wellbore. As the gas rate starts to increase with more free gas production the water rate also begins to increase. The reason for this is again that the oil connections were shifting to gas and water connections. This well will eventually lose all connection to the oil column as the mobility of the fluids continue to change with time. As the well life cycle matures it is interesting to see the effects on the oil column thickness in the near wellbore area. As the second horizontal completion is produced the oil column in the near wellbore region thins dramatically from 80 feet to only 10 feet.

Simulation Models

Dual-porosity, dual-permeability simulation demonstrates the loss in connectivity to individual phases and determines optimal completion practices. The focus of this study is on the DFN that provides an approximation of the high deliverability flow features found within the field. The emphasis of this model was to determine how flow through a discrete fracture network effects wellbore performance and the mobility of fluids in the near wellbore area. A series of high permeability cells were used to model a discrete flow feature. These cells are capable of thee-phase flow and reasonably predict fluid flow in massive carbonate reservoir.

Vertical Well Model

Figure 7 provides an illustration of the radial model grid with the fracture permeability and rock properties. The model is 133 feet thick and is divided into 25 layers (doubled for dual porosity). The ring radius (r) is a modified expansion constructed to allow for an approximation of a discrete fracture network and resolve fluid contact shape. The model contains 11 rings as a 17-acre column. The rings are divided into four theta (θ) divisions; the two offsetting 60 degree divisions contain the major discrete fractures and secondary fractures, the remaining two 120 degree theta divisions contain only the secondary fractures. Porosity in the model is set to 20% and 2% of bulk volume for matrix cells and the fracture cells, respectively. The permeability contrasts in the model are extreme; matrix permeability is 50 md, secondary fracture permeability is 550 md, and the discrete fracture permeability ranges from 22,000 md to 25,000 md.

As the production well is activated the oil column is transformed from a thick flat lying oil column to one that is locally thinned and irregular shaped. The high permeability flow feature has a definite influence on the shape of the oil column. As the oil is produced out of the high permeability blocks the more mobile gas and water replace it faster than oil can be mobilized from the matrix or the secondary fracture system. The irregular oil column shape is caused by fluid coning to different heights in the reservoir due to different pressure gradients and relative permeabilities. This phenomenon would be different in a homogeneous system where the cone would be limited to the very near wellbore area where the majority of the pressure drop is experienced. In a fractured reservoir the pressure drop is irregularly spread out across more of the formation, specifically along the intersection of the discrete fracture network flow channel with the matrix or secondary fractures.

Figure 8 illustrates the early time gas and water cone development as the well is started on production. The initial cone development that occurs is in the immediate wellbore area and is not heavily influenced by the discrete fracture network. The reservoir has not yet reached pseudo-steady state flow so the majority of the pressure drop is in the near well bore area.

Figure 9 illustrates the fracture oil column's shape at an intermediate stage in the wells life cycle. The shape of the oil column is beginning to be influenced by the discrete fracture network. The gas-oil contact starts to follow the portion of the discrete fracture network that extends upward in the reservoir. At the same time the water-oil contact starts to conform to the shape of the discrete fracture network in the lower portion of the model as well as extending up toward the well connection to the fracture network. The outlying oil column begins to loose connection to the wellbore through the discrete fracture network. This happens as the oil in the high permeability fracture system is produced and is replaced by either gas or water.

In Figure 10 a mature completion is illustrated. As the completion reaches maturity the gas-oil contact and the water-oil contact are becoming extremely undulated and are heavily influenced by the shape of the discrete fracture network. The outlying oil column has lost most of its initial connection to the wellbore at this time. The WOR and GOR have increased dramatically since the well was initially produced. The shape of the undulation are influenced by several things: (1) the viscosity differences between the fluid, (2) the shape of the discrete fracture network, (3) the permeability of both the secondary fracture system and the matrix, (4) the magnitude of the drawdown applied to the system, and (5) location in the reservoir where the greatest pressure change occurs.

Horizontal Well Model

The horizontal well model is a Cartesian model built to understand the inflow performance of a horizontal well that is connected to a discrete fracture network. This is an 11 by 18 model that contains 20 layers (doubled for dual porosity). The model was built to resemble half symmetry of an actual well to cut down the model size and get small enough grid blocks to resolve connection flow behavior in the reservoir. The discrete fracture network is modeled by placing three very small cells together and giving them extremely high permeability of 25000 md. This configuration was done so that harmonic averaging of the permeability with in the simulation program would not negate the flow capacity of a single high permeability grid block. The geometry of the rest of the grid blocks was designed to give as much definition to the near wellbore area as possible to clearly see the production impact on the oil column shape. The permeability of the matrix rock is 100 md and the permeability of the secondary fractures is 550 md. The porosity in the model is at 25% and 2% of bulk volume for the matrix and fracture cells, respectively. (See Figure 11 for fracture properties.)

The horizontal model, like the vertical completion model, is initialized with flat oil and water contacts. Figure 11 illustrates the initial contact along with a copy of the grid in the YZ direction overlain. The same figure also shows the location of the horizontal well in reference to the oil columns location. Notice the horizontal well is completed about 5 ft below the oil water contact in order to cone oil down into the completion and avoid gas production. The completion below the water-oil contact is recommended by Haug in order to increase the recoverable reserves from a well and reduce gas cycling. (Haug 1991.)

Figure 12 is a picture of the fracture oil column as the well is put on production. The oil in the fracture network that is connected up to the well is quickly drawn down to the completion and is depleted from the fracture network. As the oil is depleted out of the fractures and is replaced by gas, the local reservoir is drawn down. At this time no free gas is produced from the completion. It is important to also note that the oil column away from the wellbore begins to move downward as large volumes of water are produced from the system. The oil column actually begins to settle below the completion in the outlying areas of the model.

As the well is produced for longer time periods the mobility of the oil in the system begins to decrease. With continued liquid depletion, the gas connections reach the completion and free gas production is established from the well. In this case the well actually has a better connection to the water and gas than it does to oil. The connection to oil is limited to the secondary less connected fractures and the matrix. Figure 13 shows this loss of connection to the oil column. The gas

cone has developed along the fracture network and has reached the wellbore. Within the discrete fracture network that is modeled in this case a gas water contact actually exists. The water is being coned up from below the completion as the majority of the oil column has settled below the completion in the outlying areas of the model.
Figure 14 is a production plot from the horizontal simulation. Two things should be noted on this plot. First is the initial "oiling in" of the well as oil connections are established to the completion. The oil rate grows from 0 BOPD to 200 BOPD during the first day. The second important thing to note is at approximately the 50-day point. The well shows initial gas break through. This signifies that gas conections in the DFN have reached the wellbore. Notice the inflection point in the oil production curve as the well looses connection to the oil column. The water rate also has an inflection at this point as more and more gas is produced the water mobility decrease in the same fashion as the oil mobility does. The difference in viscosity is the main driver in which phase has the highest mobility. The oil viscosity is 8 times higher in the model than the water viscosity, and the water viscosity is 75 times the gas viscosity for the pressure ranges seen in the model.

Conclusions

I. Discrete fracture networks dominate fluid flow in the near wellbore region.
2. Discrete fracture networks heavily influence the contacts in the near wellbore region. (The contacts may vary as much as 60 ft. in the near wellbore area.)
3. The product of effective permeability (K_{eff}) and height (h) is not a smooth function in a discrete fractured reservoir as it may be in a homogeneous reservoir. (The discrete fractures and other solution enhanced flow features have huge permeability and yet take up a very small percentage of the bulk volume of the reservoir.)
4. The oil rate may reduce in steps, as connections are lost to the outlying oil column.
5. The discrete fracture network size and connectivity along with the mobility of the different phases determine the productivity of the different phases.

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Nomenclature

K_{eff} = Effective Permeability, L^2, md
μ_o = Oil Viscosity, f i t , cp
μ_w = Water viscosity, m/Lt, cp
μ_g = Gas Viscosity, m/Lt, cp
ρ_o = Oil density, m/L^3, lb/ft^3
ρ_w = Water density, m/L^3, lb/ft^3
ρ_g = Gas density, m/L^3, lb/ft^3

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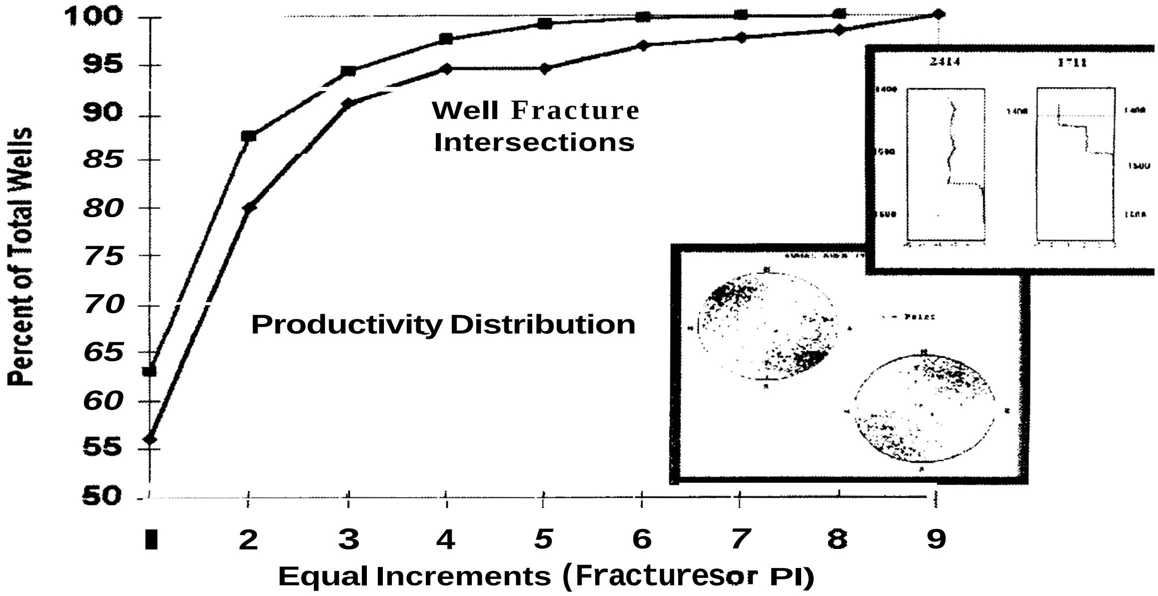


Figure 1 - Simulated wellbore facture intersections and field wells productivity distribution are compared to test reasonableness of the DFN of intersection with well-connected fractures. Also injection profile data from openhole completions tests the number of features offering the best connection, while stereonet plots of fracture orientation provide comparison to wellbore image data.

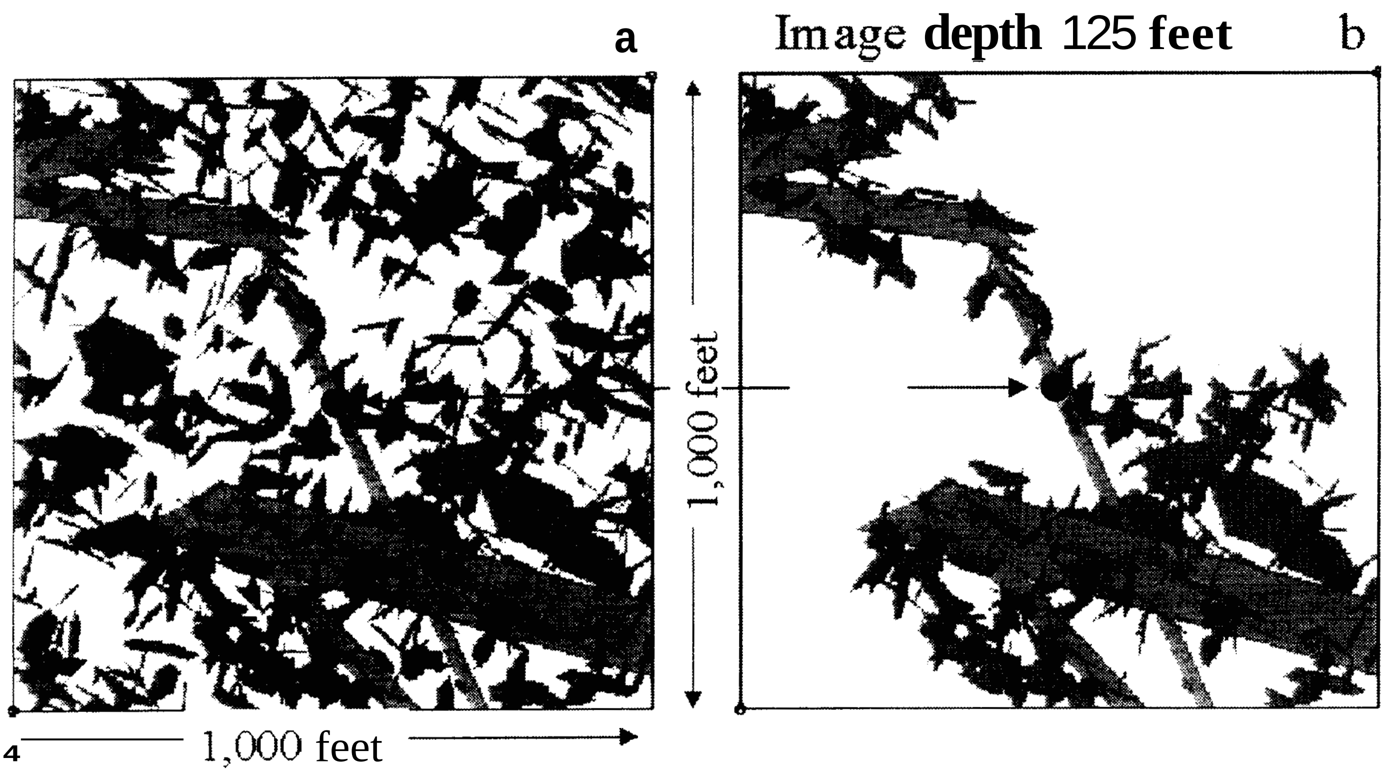


Figure 2 - The illustration on the left provides a conceptual view of DFN of three fracture sets, two oriented northwest to southeast and one oriented orthogonally to those. At the wellbore sampling level it may be impossible to discern the longest fractures from the more typical shorter fractures. On the right the largest cluster of interconnected fractures is presented to illustrate the irregular drainage shape that a wellbore might intersect.

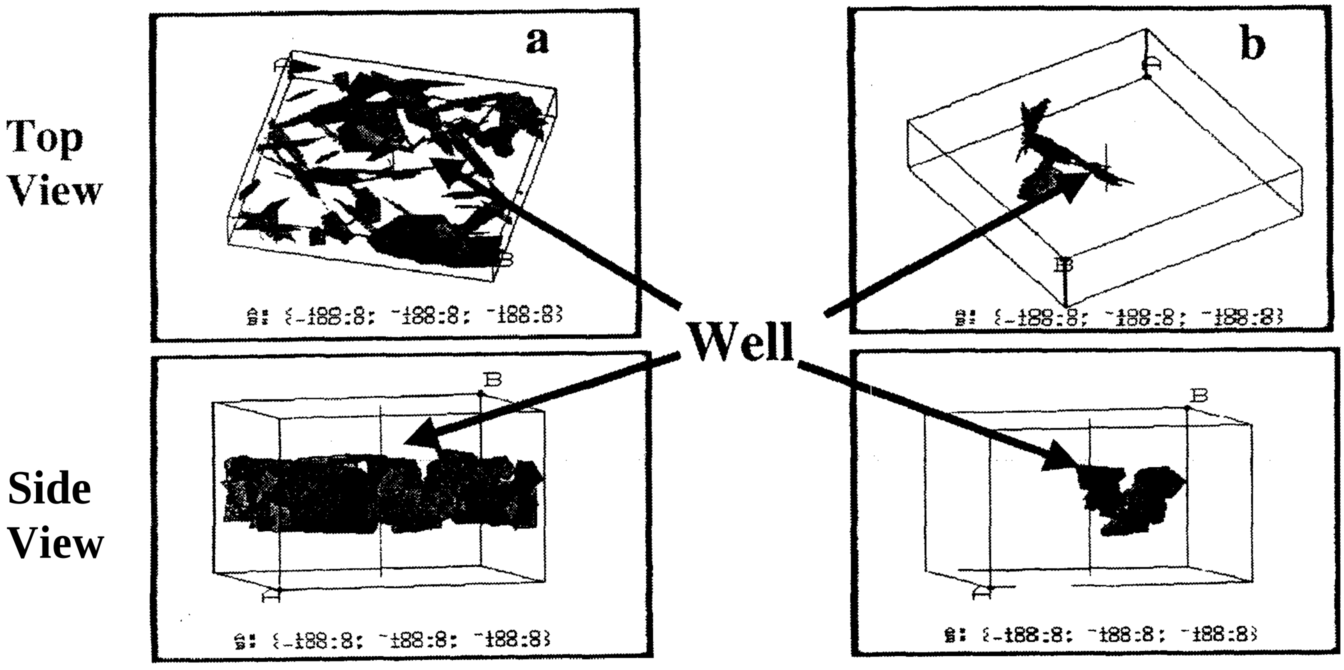


Figure 3 - Top and side views of the DFN model in a 200 foot cube are provided illustrating a wellbore intersection with the fracture network. On the right the wellbore is extracted with only the fractures that interconnect to the wellbore.

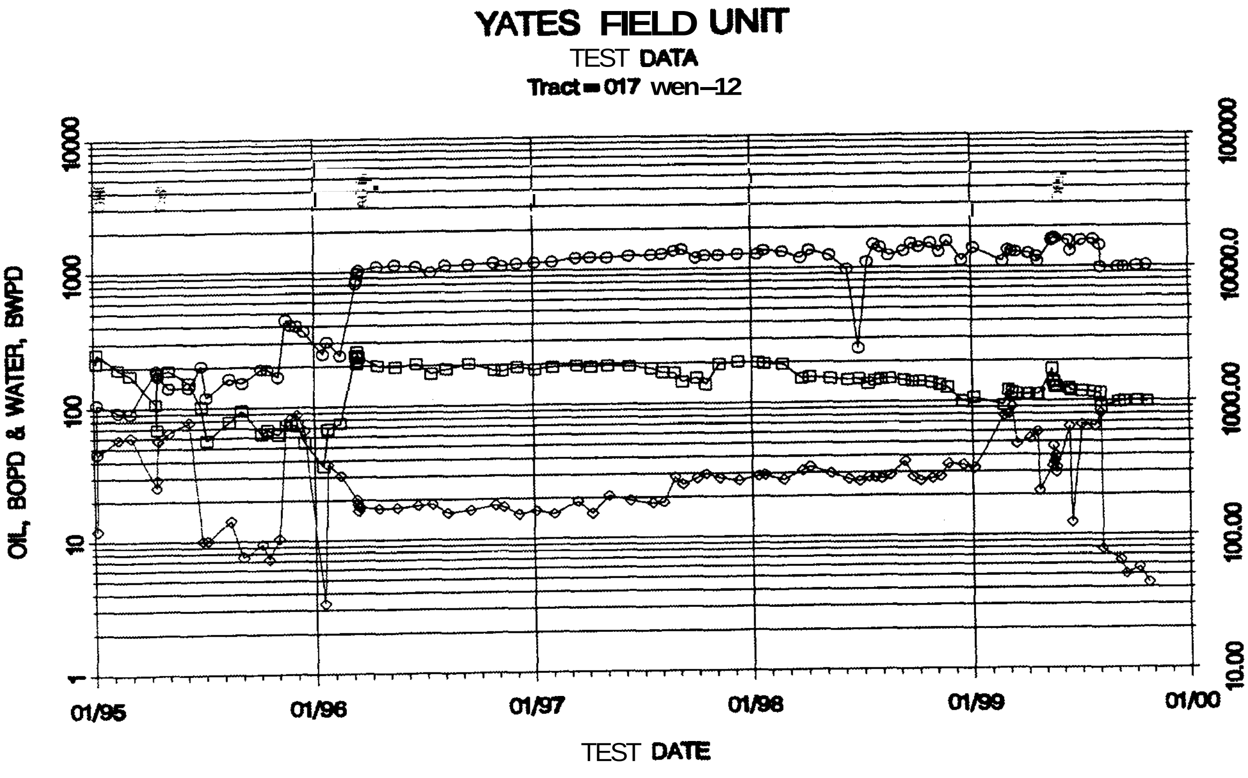


Figure 4 - Vertical Well Production Performance Plot from Yates Field Unit.

Three-Phase DFN Schematic

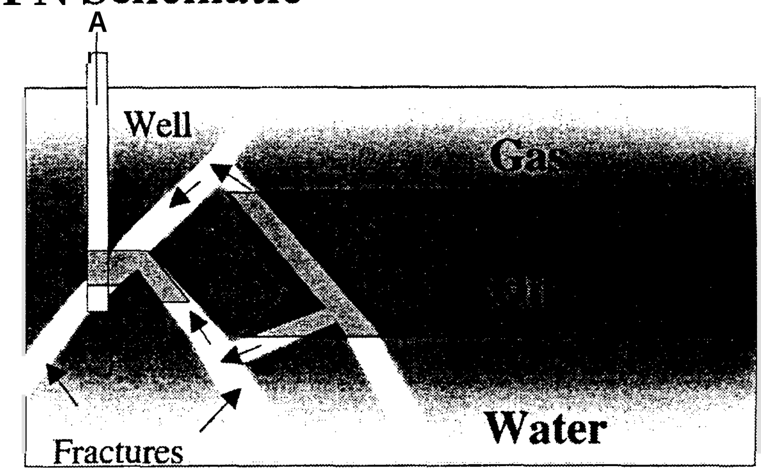
$\mu o/\mu g = 500$ (high)

$\rho o - \rho g$ (high)

Compare

$\mu o/\mu w = 9$ (low)

pw-po (low)



Oil can go under a matrix obstruction easier than over the obstruction

Figure 5-Illustration of Fracture Connection to the Oil Column and the Factors that Control How the Connections Change

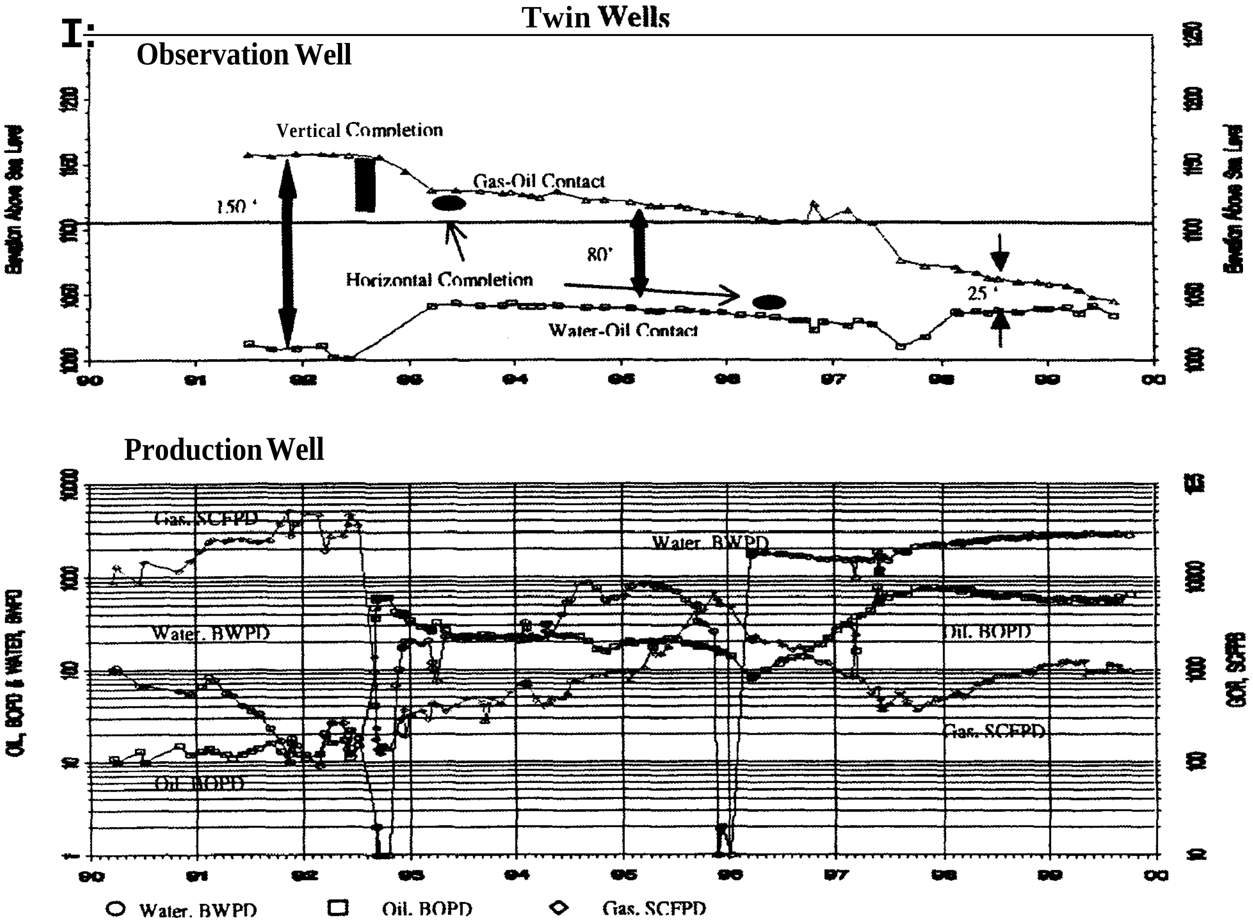
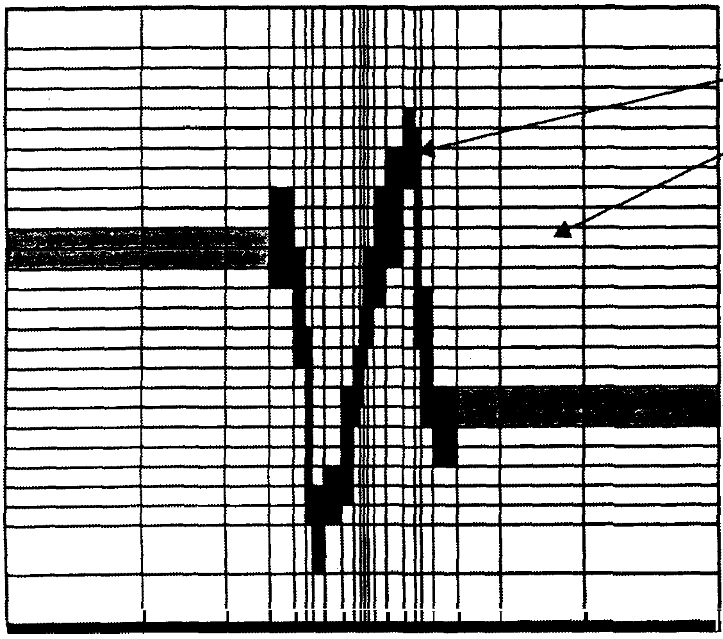


Figure 6 - Horizontal Well Production Performance and Twin Observation Well Contact Performance in the Yates Field Unit

Vertical Well Model with Fracture Permeability



Vertical Well Model **Properties**	
DFN Permeability K (md)	20,000 to 25,000
Secondary Fracture Permeability K (md)	550
Matrix Permeability K (md)	50
Fracture Porosity (% of bulk volume)	20
Matrix Porosity (% of bulk volume)	2

Figure 7 - Vertical Well Model Fracture Grid with Fracture Permeability, Model Dimensions and Rock Properties

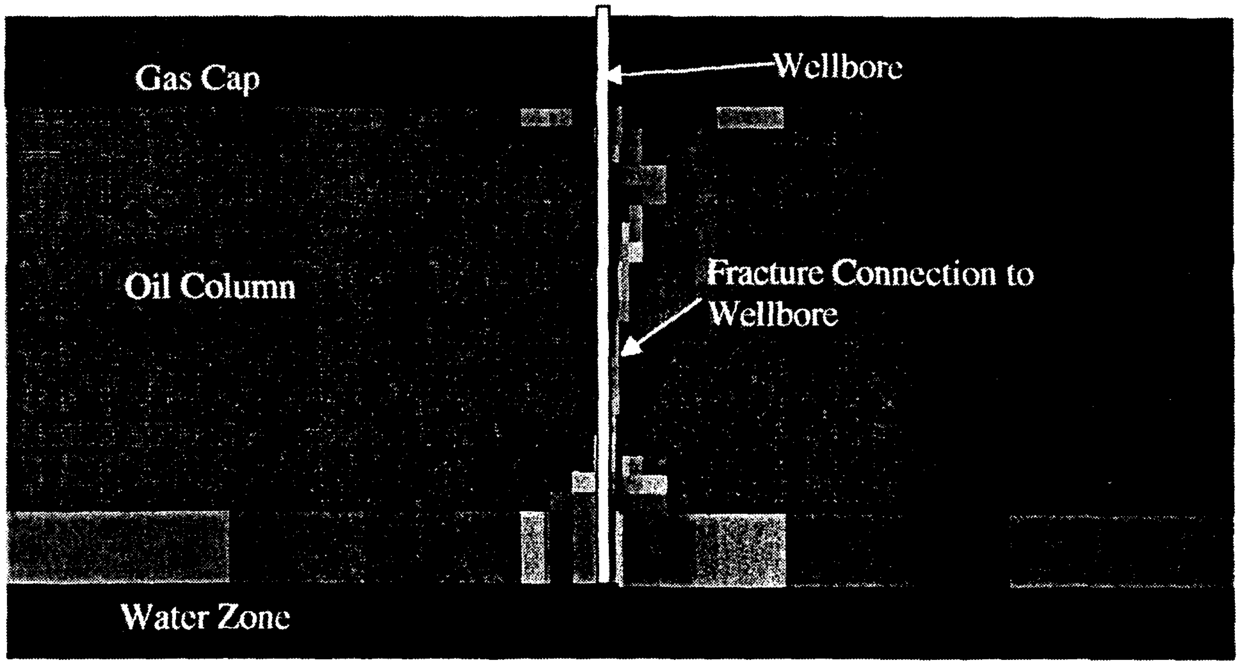


Figure 8. Initial connection change and cone development in a vertical well connected *to* a discrete fracture network. Wabr and gas coning in the near wellbore area only

Figure 8 - Initial Connection Change and Cone Development in a Vertical Well Connected to a Discrete Fracture Network Water and gas coning in the near wellbore area only.

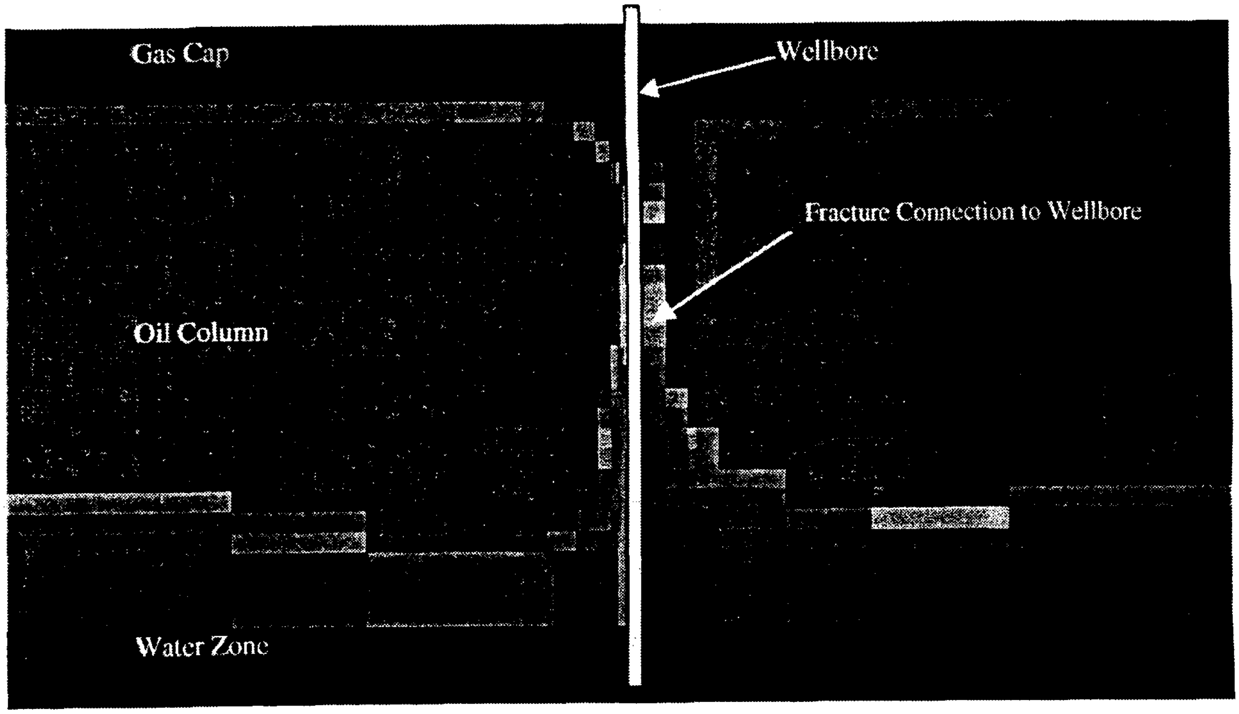


Figure 9 - Intermediate Connection Change in a Vertical Well Connected to a Discrete Fracture Network
The connection to the oil column begins to change as more mobile water and gas replace oil in the fracture system.

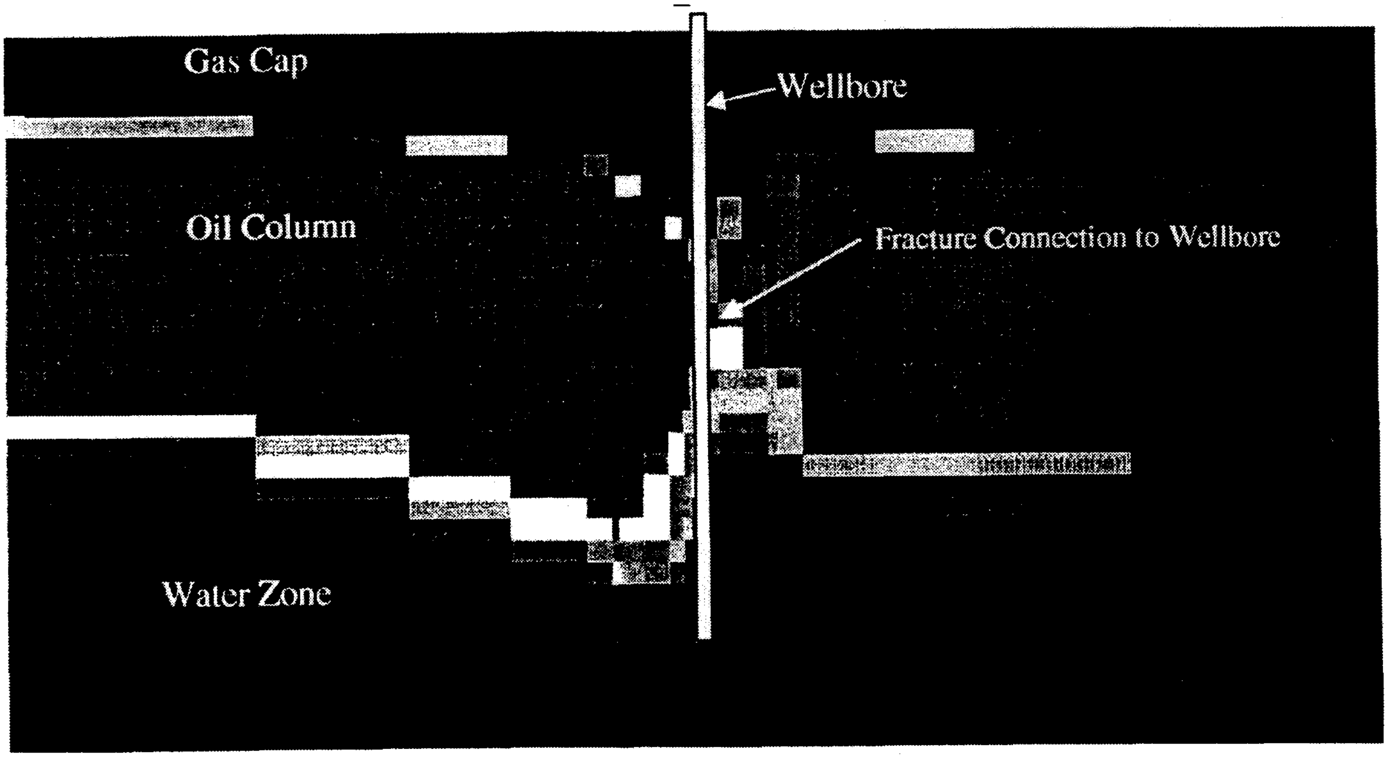


Figure 10 - Mature Connection Shifting in a Vertical Well Connected to a Discrete Fracture Network
The oil connections to the wellbore have been transformed into gas and water connections to the DFN.
Notice the shape of the DFN controls the shape of the gas-oil and water-oil contacts.

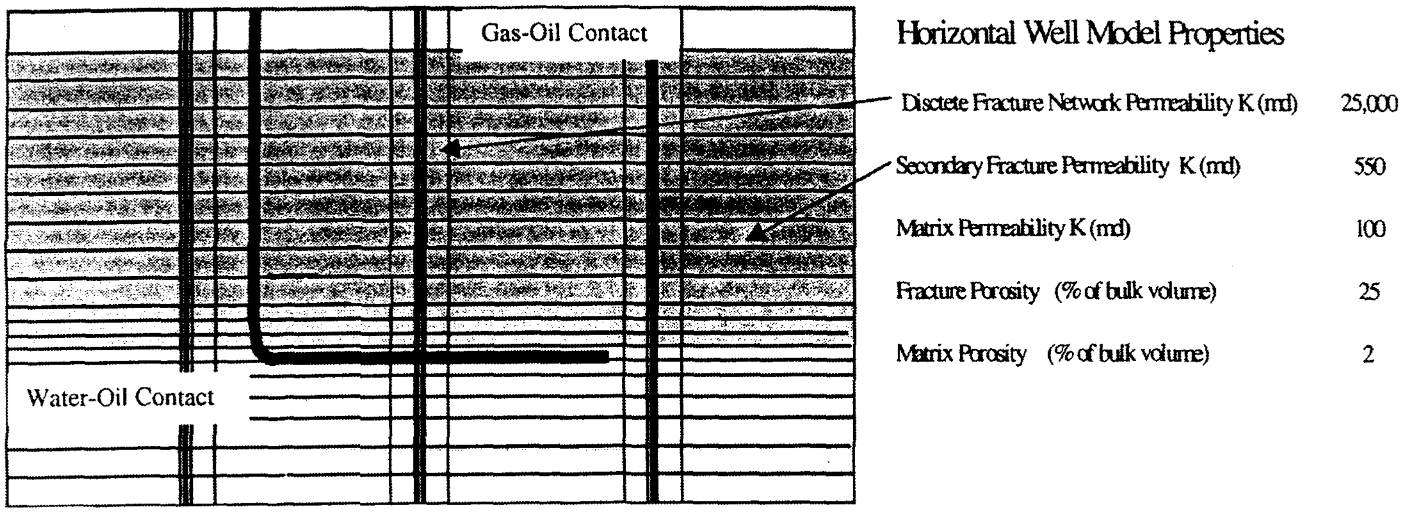


Figure 11 - Horizontal Model Grid with Intial Fracture Oil Colunm and Rock Properties

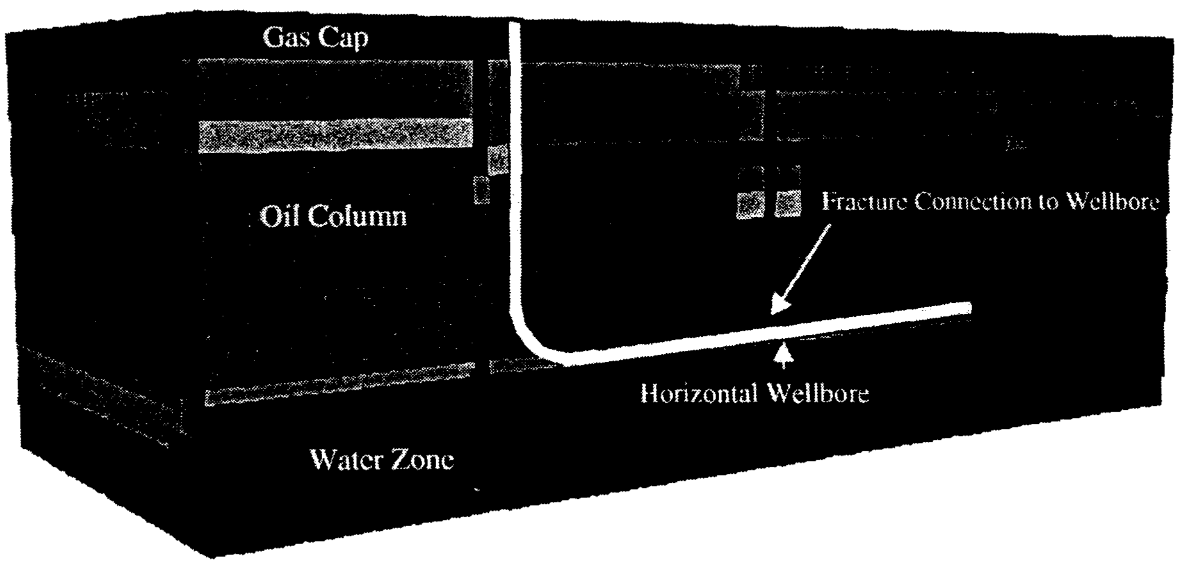


Figure 12 - Initial Connection Change and Cone Development in a Horizontal Well Connected to a Discrete Fracture Network
The oil connection to the DFN begins to transform into gas connection in the upper section of the oil column.

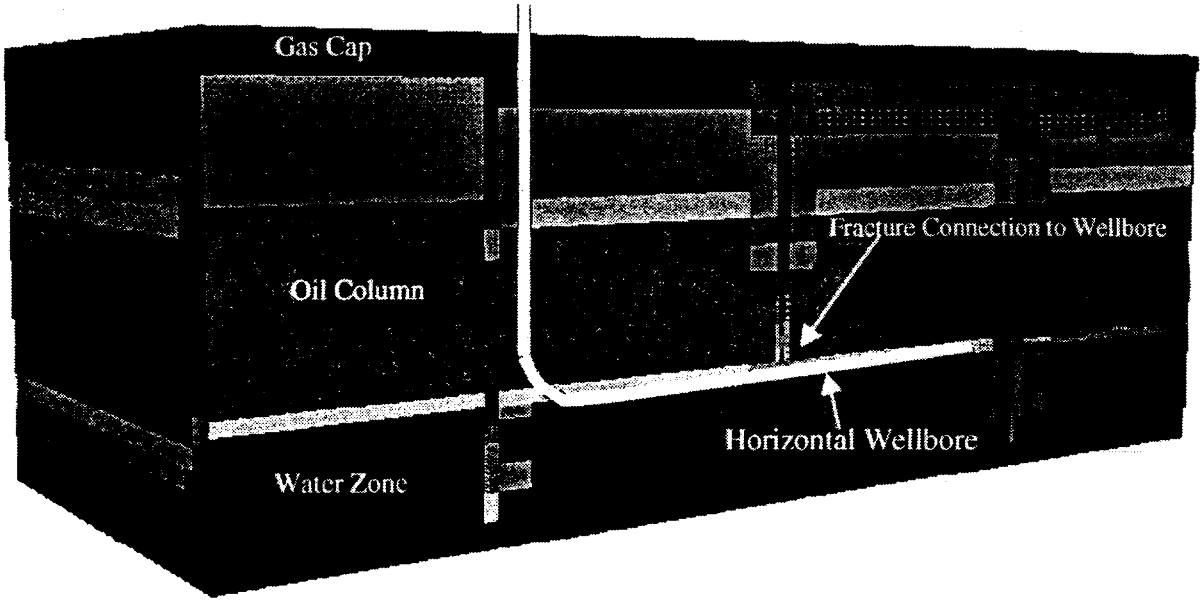


Figure 13 - Mature Connection Change and Cone Development in a Horizontal Well Connected to a Discrete Fracture Network
The oil connections in the DFN are transformed into water and gas connections.
Oil connections exists only in the secondary fracture system at this point.

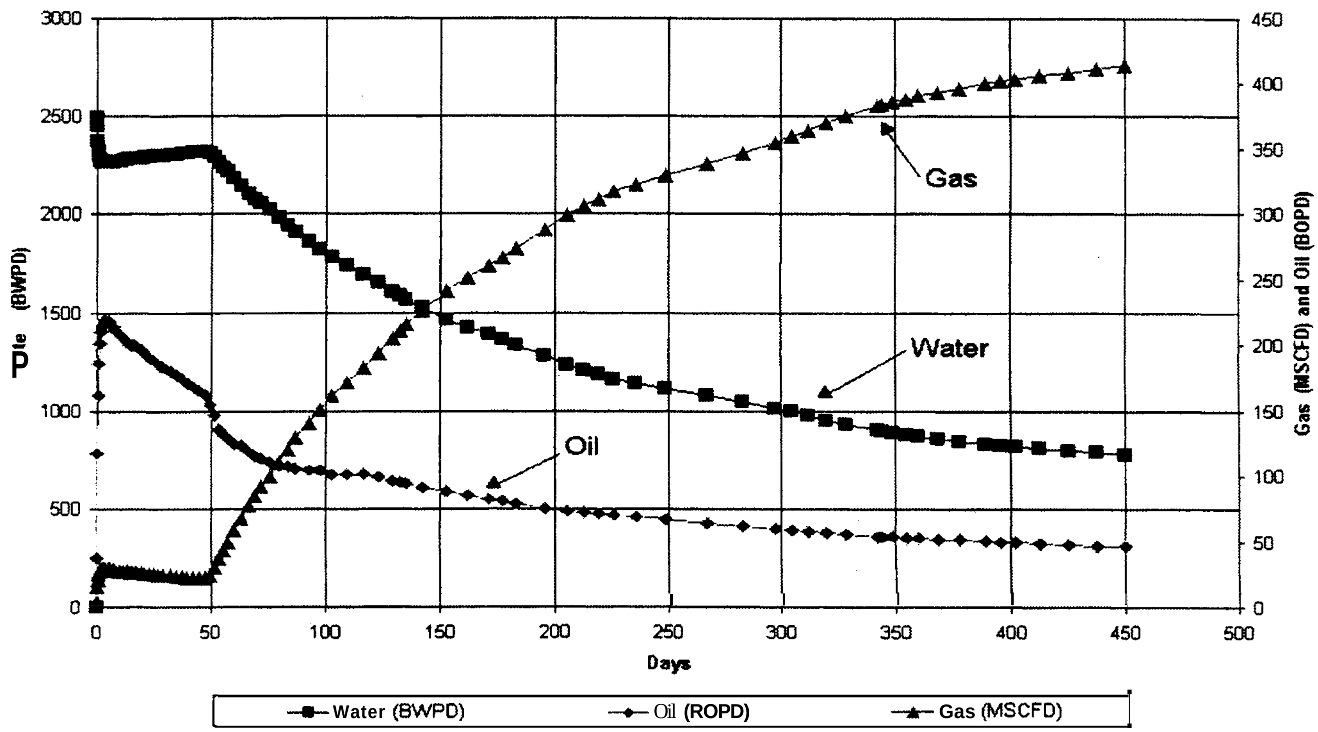


Figure 14 - Production Plot from Horizontal Well Model Showing Life Cycle to Typical Horizontal Well