1 of 2

Simulation Studies to Evaluate the Effect of
Fracture Closure on the Performance of
Fractured Reservoirs

Final Report

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ABSTRACT

A three-year research program to evaluate the effect of fracture closure on the recovery of oil and gas from naturally fractured reservoirs has been completed. The overall objectives of the study were to: (1) evaluate the reservoir conditions for which fracture closure is significant, and (2) evaluate innovative fluid injection techniques capable of maintaining pressure within the reservoir.

The evaluations of reservoir performance were made by a modern dual porosity simulator, TETRAD. This simulator treats both porosity and permeability as functions of pore pressure. Simulated well bores can assume any orientation from vertical to horizontal.

The Austin Chalk in the Pearsall Field in of South Texas was selected as the prototype fractured reservoir for this work. Availability of published data was the principal basis for this selection. Consequently, the simulation models were initialized with properties typical of the Pearsall Field, Austin Chalk reservoir.

During the first year, simulations of vertical and horizontal well performance were made assuming that fracture permeability was insensitive to pressure change. Sensitivity runs indicated that the simulator was predicting the effects of critical reservoir parameters in a logical and consistent manner. The results confirmed that horizontal wells could increase both rate of oil recovery and total oil recovery from naturally fractured reservoirs.

In the second year, the performance of the same vertical and horizontal wells was reevaluated with fracture permeability treated as a function of reservoir pressure. To investigate sensitivity to in situ stress, differing loading conditions were assumed. The highest condition assumed all principal stress components equalled the overburden stress. The lower stress cases assumed the horizontal stress components were unequal and less than the overburden stress.

Simulated natural depletions confirm that pressure sensitive fractures degrade well performance. The severity of degradation worsens when the initial reservoir pressure approaches the average stress condition of the reservoir, such as occurs in over pressured reservoirs. Simulations with water injection indicate that degradation of permeability can be counteracted when reservoir pressure is maintained and oil recovery can be increased when reservoir properties are favorable.

EXECUTIVE SUMMARY

1.0 SUMMARY

Fractured reservoirs contain a significant part of the remaining hydrocarbon reserves of the United States. Moreover, oil production from fractured reservoirs is increasing due to the recently accelerated development drilling activity in such reservoirs.

The remarkable advances in horizontal drilling technology are of particular interest to operators with large holdings in known fractured reservoir trends, such as the Austin Chalk in Texas and the Bakken Shale in the Williston Basin. Horizontal well bores offer a practical means to exploit these difficult reservoirs and others like them. In many instances, horizontal well completions offer the only economically feasible exploitation method.

This study investigated the pressure sensitivity of fractured reservoir systems and its impact on hydrocarbon recovery. An important objective was to develop innovative techniques for counteracting the natural tendency of fractures to deform and reduce reservoir flow capacity as pressure is reduced by fluid withdrawals. The work was divided into three one-year tasks:

- Task 1: Select a candidate field, establish its reservoir properties, and initialize a mathematical simulator of a typical segment of the reservoir. Make performance forecasts assuming natural depletion and using both vertical and horizontal well bores. Forecast secondary recovery performance with gas or water injection assuming vertical well exploitation. Make sufficient runs for each forecast mode to establish the sensitivity of the forecasts to key reservoir properties. For these simulations, the fractures are assumed to have no pressure sensitivity.
- Task 2: Repeat the natural depletion and secondary recovery simulation forecasts of Task 1, but assume the fracture permeability to be stress dependent. Base the permeability-stress relationship on the most current published research findings.
- Task 3: Consider the production problems arising from fracture permeability reduction and identify the reservoir and operating conditions giving rise to the most severe hydrocarbon recovery degradation. Seek innovative approaches to resolving these problems including fluid injection and the use of horizontal wells or combinations of vertical and horizontal wells.

The Task 1 work was reported in the first Annual Report¹. The Austin Chalk reservoir in Pearsall Field, Texas was selected as the prototype for the study. Prototype simulators were initialized and sixty-eight simulations of natural depletion and secondary recovery were performed to investigate sensitivity to reservoir parameter variation and well bore orientation, vertical versus horizontal.

The Task 2 work was described in the second Annual Report². The reservoir simulator was revised to treat fracture permeability as a function of reservoir pressure and applied to determine how pressure sensitive fracture permeability impacts oil recovery. The reservoir parameter sensitivity simulations of

Year One were repeated for two types of operation, natural depletion and water injection pressure maintenance and for two conditions of reservoir rock stress. In total, ninety simulations were performed.

The Task 3 work was completed in this, the final contract year. Several recently published research papers concerning the nature of fracture flow and the interaction of rock matrix and fractures were found. The most interesting of these were tested by simulation. Some additional simulations were also performed to test the sensitivity of water flood performance to reservoir characteristics such as capillary pressure, relative permeability and in situ stress conditions.

This report presents the results of the entire study including Task 1, Task 2, and Task 3. It is a stand alone report and contains a complete record of all work and findings of the subject contract.

2.0 CONCLUSIONS

The conclusions arising from Task 1 were as follows:

1. The permeability of fissures in naturally fractured reservoirs is most likely to exhibit some degree of pressure dependence.
2. The Austin Chalk reservoir in Pearsall Field is currently the best documented fractured reservoir in the petroleum literature, thus it has been selected as the prototype reservoir for this study.
3. Horizontal well completions have proven to be particularly effective in Pearsall Field.
4. The Pearsall reservoir is horizontally compartmented by the tendency of the fractures to develop vertically in recurring bands or swarms. For this reason a long offset horizontal well can develop several fracture swarms. Development of the same reserves by vertical drilling would require appreciably more wells.
5. Task 1 simulations have demonstrated that certain reservoir parameters are more important in determining the performance of the prototype reservoir:
 - Natural depletion recovery was very sensitive to the contrast of permeability between fractures and matrix: lowered by contrast reduction and raised by contrast increase.
 - Natural depletion recovery was sensitive to the storage capacity of the fractures in relation to the matrix storage capacity: higher fracture capacity yielded better recovery efficiency.
 - Natural depletion recovery was highly dependent on dual permeability shape factor.
 - Natural depletion recovery was adversely affected by fracture spacings closer than one foot for cubic matrix blocks.
 - Natural depletion recovery was increased as fracture capillary pressure was increased.
 - Water injection recovery was sensitive to capillary pressure but insensitive to producing well completion interval (top versus middle).
 - Gas injection provided no recovery improvement for the base case reservoir description, e.g. closely spaced orthogonal fractures and cubic matrix blocks.
 - Combined injection of gas and water offered no recovery advantage over water injection.

The conclusions arising from the second year, or Task 2, studies were as follows:

1. Interpretations of production test data from a horizontal Austin Chalk Well in Pearsall Field revealed:
 - Support for the multiple fracture swarm conceptual model.

- Fracture permeability is in the range of 1 to 10 md.
 - Positive skin factor.
2. Published experimental data confirmed the suitability of the fracture deformation logic programmed in the TETRAD simulator.
 3. Simulations of natural depletion with and without fracture deformation indicated that:
 - Well productivity decline is exacerbated resulting in a prolongation of the recovery period by as little as 27 days to as much as 1.95 years.
 - Recovery factors are generally slightly reduced. The reductions were greatest if either the fracture porosity to matrix porosity ratio is quadrupled or if the ratio of matrix to fracture permeability is divided by 10. Both resulted in a maximum decrement of 2% of STOIP[†]. This is equivalent to 10 to 11% of the recovery factor realized when fracture deformation is ignored.
 4. Simulations of a 640-acre horizontal line drive water flood, first ignoring, then including fracture deformation effects, demonstrated that:
 - Reservoir pressure is maintained, and well productivity is stabilized prior to water breakthrough.
 - Productivity deterioration due to fracture deformation was greatly attenuated. The most severe case prolonged the recovery period only 0.9 years.
 - Recovery factors were essentially independent of fracture deformation.
 - The fractional recovery at water breakthrough was reduced as effective stress was increased. Most commonly, the recovery difference was $\leq 1\%$ of STOIP. Quadrupling the fracture porosity/matrix porosity ratio resulted in breakthrough recovery lowered as much as 6% of STOIP.
 - For the most part, the oil rate versus oil recovery profiles were little affected by deformation. Differences were principally exacerbations of producing rate decline, confined to the first 1 or 2% of recovery. The quadrupling of the fracture/matrix porosity ratio produced the widest producing rate divergences.
 5. The horizontal water flood simulations also demonstrated recovery factor sensitivity to reservoir parameters, as follows:
 - Recovery was sensitive to matrix permeability, k_m , and relatively insensitive to fracture permeability, k_f .

[†]Stock tank oil initially in place.

k_m , md	k_r , md	Recovery
.001	10	.554
.0001	10	.500
.00001	10	.393
.0001	1	.514
.0001	10	.500
.0001	100	.506

- Water flood recovery was more sensitive to increasing fracture/matrix porosity ratios, ϕ_f / ϕ_m , than to reducing ratios:

	ϕ_f , %	ϕ_m , %	Recovery
base case	.0984	3.36	.500
ϕ_f / ϕ_m	.3936	3.36	.552
increase	.0984	.834	.554
ϕ_f / ϕ_m	.0492	3.36	.487
decrease	.0984	6.72	.489

- Lowering matrix capillary pressure reduced recovery (from .500 to .446 for the cases simulated).
 - Increasing fracture capillary pressure from 0 to $\frac{1}{2}$ of matrix values reduced recovery by 1.3% of STOIP.
 - Increasing fracture residual oil saturation, S_{orw} from 0 to $\frac{1}{2}$ of matrix S_{orw} reduced recovery < 1% of STOIP.
 - Changing fracture relative permeability shape from linear to curved reduced recovery < $\frac{1}{2}$ % of STOIP.
6. Comparing horizontal water flood and natural depletion simulations shows that water flooding substantially improves recovery factors. Expressed as a multiple of depletion recovery, the range is from 2.3 to 5.5 times. Contrasting the two recovery methods for identical reservoir parameters reveals:
- Sensitivity to a 10 times k_m / k_r increase is reversed, *i.e.* depletion recovery is reduced but water flood recovery is increased, yielding a recovery improvement multiple (water flood/depletion) of 4.9 times without deformation. If fracture deformation is included the multiple increases to as much as 5.5 times.

- Sensitivity to a 0.1 times k_m decrease is also reversed viz. depletion recovery increases while water flood recovery reduces, reducing the recovery improvement multiple to 2.3 times. The multiple does not change with fracture deformation.
- Sensitivity to a 10 times k_f increase is noticeable for depletion but insignificant for water flood, yielding water flood recovery improvement multiples of 2.8 to 2.9 times.
- Reduced ϕ_f / ϕ_m ratios provided negligible sensitivity effects, depletion or water flood. Recovery multiples for water flooding over depletion varied from 3.0 to 3.1
- Depletion recovery was considerably more sensitive to ϕ_f / ϕ_m increases than was water flood. Recovery improvement multiples, neglecting deformation effects, were 3.2. Fracture deformation increased the multiple to as much as 3.6 times.
- Fracture capillary pressures > 0 had opposing recovery impact for depletion (progression), compared to a water flood (regression). Recovery improvement multiples varied insignificantly with deformation from 2.7 to 2.8 times.
- Matrix capillary pressure reduction also had opposing recovery implications but water flood degradation was about 5 times greater than depletion improvement. Deformation produced insignificant recovery improvement variations of 2.5 to 2.6 times.
- Inclusion of fracture $S_{orw} > 0$ reduced depletion and water flood recovery factors almost equally and deformation effects were negligible. Water flood recovery were 2.8 times depletion recovery.
- Changing fracture relative permeability shape from linear to curved slightly improved the water flood recovery multiple to 2.9 times.

INTRODUCTION

3.0 BACKGROUND

A significant fraction of the remaining domestic oil and gas reserves is contained in reservoirs wherein naturally occurring fractures provide the means of fluid flow. Increased attention is being given to such reservoirs because of the potential for improved productive capacity and ultimate recovery offered by the long horizontal well bores made possible by recent advances in horizontal drilling technology. Examples of naturally fractured reservoirs in the United States include: Elk Basin in Montana and Wyoming, Bakken formation in the Williston Basin, Lisburne in Alaska, and Spraberry and the Austin Chalk trend in Texas.

The global fluid flow in a fractured reservoir takes place within a system of intersecting fissures in the reservoir rock. The volume of the fracture-related voids is, however, very small in comparison to the bulk volume of the reservoir, usually less than 1% and often much less. The greatest part of the reservoir storage volume is contained in the intervening porous rock, commonly referred to as the "matrix." The matrix is usually of very low permeability, often in the microdarcy range, but has more typical porous media porosity. Matrix porosity varies from a few percent up to a few tens of percent.

Reduction of void volume in conventional porous media due to the increased stresses induced by fluid withdrawals is a known phenomenon. It is usually accounted for in reservoir engineering calculations by the pore volume compressibility. It is generally acknowledged that similar reductions must also take place in the fissure void network. Since shrinkage of fissure voids would be expected to reduce their permeability, perhaps more drastically than for conventional porous media, this could have serious well productivity and reservoir flow mechanics implications.

There is a rather large body of writings in the technical literature, particularly in the field of rock mechanics, dealing with the assessment of fissure permeability and the tendency of this type of permeability to be stress sensitive. Researchers in this field have performed rather extensive studies of fracture systems, mainly in the shallow subsurface and commonly related to large construction projects. These studies have included in situ measurements of principal rock stresses and fracture properties, such as fracture aperture, length, height and orientation, and the description of complex rock joint systems.

Although fissures are often referred to in terms implying that they are planar features, they really are not. The fracture surface is commonly rough and undulating. The surface roughness can be characterized by the distribution of individual asperity heights. The stresses causing rock to fracture will commonly have a shear component which induces some displacement along the fracture surface. Even a slight displacement can be sufficient to juxtapose higher than average asperities, thus preventing the rock from mating and the fracture from closing. Larger displacements can lead to a situation where the waviness of the fracture will play a role in keeping the fracture surfaces from mating perfectly. Thus, it is common that fractures do not completely heal as stress is increased and measurable permeability can be observed to extremely high stress levels.

The void spaces along the fracture surface between the points of contact will have a tendency to deform and reduce the aperture with increasing stress. The degree of deformation is dependent upon the mechanical properties of the rock and the equilibrium state stress conditions. In oil field operations, this equilibrium is disturbed by the withdrawal of reservoir fluids. As a consequence, the fluid pressure is

reduced and the rock is subjected to increased stress.

A fracture flow system, therefore, is seen to be a complex system of flattened flow channels that, due to their tortuosity, intersect other channels to form a complex network. In many respects, this network is not unlike a normal porous media, in that fracture permeability will be highly variable and flow will tend to be tortuous. It differs in the respect that the fractures do have a planar element that imparts a highly directional permeability to the reservoir.

Two phase flow in fractures was, until recently, assumed to occur as if the fluids were completely segregated and with no interference between phases. Furthermore, capillary pressure in the fractures was usually assumed to be negligible. Recent research has shown both assumptions to be invalid.^{3, 4, 5, 6, 7, 8, 9, 10, 11, 12} These findings have shown that fracture capillary pressures are significant and phase interference ($k_{ro} + k_{rw} < 1$) is common in fracture flow. Indeed, the fracture functions are similar to typical porous media properties. Moreover, stress induced fracture aperture reduction has been shown to increase residual oil saturation and capillary pressure.

4.0 OBJECTIVES

This study was proposed on the basis of two observations arising from prior research:

1. Horizontal wells improve oil recovery from reservoirs containing tectonic fractures. This improvement is due to the larger number of vertical fractures intersected by the well bore.
2. Oil recovery in these reservoirs suffers because the fractures are inclined to close as reservoir pressure depletes, thus exacerbating the well productivity decline. The tendency of natural water encroachment or fluid injection is to retard or arrest reservoir pressure decline and fracture closure, thus reducing well productivity decline and offering the possibility of improved recovery.

Neither observation has been systematically quantified or evaluated. The primary purpose of this study is to rectify these shortcomings; thus, the work has the following general objectives:

1. To evaluate the impact of fracture closure on hydrocarbon recovery from reservoirs having pressure sensitive, naturally occurring fractures.
2. To investigate innovative developmental and fluid injection methods for improving hydrocarbon recovery from such reservoirs.

The study has relied on state-of-the-art reservoir modelling techniques to provide reliable simulations of reservoir behavior. Analysis of these results was the basis for all observations and conclusions reported herein.

DISCUSSION

5.0 LITERATURE REVIEW

A review of the technical literature was undertaken to establish a basic core of reference material. The scope of the search was broadened as new information sources and subject titles were identified to minimize the possibility that any pertinent information was overlooked.

The primary reference indexes utilized were the following:

Petroleum Abstracts, 1965 through 1992
Society of Petroleum Engineers, 1961 through 1992
Association of Petroleum Geologists, 1961 through 1992

The search was conducted in three phases:

1. Preliminary Phase - Pertinent sections of each index were copied to provide a convenient way to scan and highlight titles requiring closer review. The subject list, as defined in the Petroleum Abstract index, was as follows:
 - fracture extension
 - fracture geometry
 - fracture mapping
 - fracture porosity
 - fracture (rock)
 - fractured reservoir
 - fractured shale reservoir
 - fracture width
 - fracturing
2. Secondary Phase - Abstracts of candidate title documents were copied and reviewed to determine if they merited inclusion in the hard copy reference base.
3. Final Phase - The source documents for all interesting abstracts were looked up and copied. There were a few documents which could not be located in the available reference library. Approximately 200 documents were copied and filed for reference during the study. Each document was cataloged in a database.

In broad terms, the search attempted to identify and copy all documents dealing with some aspect of fractured reservoir/rock characteristics and their physical behavior. Of particular interest were naturally fractured hydrocarbon productive fields in the United States. A complete list of all documents located and copied as part of this search effort to date is provided in the bibliography. The reference database was kept current as new documents are added.

6.0 CANDIDATE RESERVOIR SELECTION

An important consideration in the literature search was to identify a suitable fractured reservoir to use as a prototype for initializing the simulators to be used in this study. It was recognized from the outset that the ideal candidate (a mature, fully documented, domestic reservoir producing from pressure sensitive fractures) was unlikely to be found. To be ideal, the documented data would have to include everything needed to initialize a modern dual porosity reservoir simulator, and sufficient diagnostic well production data, including some for horizontal wells, to provide a test case for the simulation approach. In this context, the test case simulations could be regarded as a form of history matching, even though history matching in the customary reservoir simulation sense was not intended in the scope of the present study.

Potential candidate fields included known fractured reservoirs like Bakken Shale, Elk Basin, Spraberry, Lisburne, Yates and the Austin Chalk. As the search progressed it became increasingly apparent that one of the Austin Chalk fields, Pearsall or Giddings, would have the most comprehensive set of published data. This was attributable to the current high level of horizontal drilling activity in these fields.

The Austin Chalk is an important reservoir rock in South Texas, the two most prolific oil producing areas being the Giddings and Pearsall Fields. Both fields have undergone several cycles of development, the most recent employing horizontal drilling.

The prototype reservoir chosen for the subject study was Pearsall. The main reason for this choice was that more published data was found for Pearsall than for Giddings. Secondary considerations favoring Pearsall were: fracture pervasiveness, horizontal well successes, and the performance data provided by a prominent field operator.

It was never intended that this study should necessarily simulate a particular field, nor indeed, that a single model would have to be used for all simulations. Thus, while Pearsall was the prototype for model initialization, the models would not be used to simulate its performance in the usual sense. Nonetheless, the use of actual field data should impart a reasonable degree of reality to the simulations.

7.0 RESERVOIR DESCRIPTION

Production from the Pearsall Austin Chalk reservoir began in 1936. Development drilling in this first cycle of activity ended sometime in 1941 and resulted in the drilling of approximately 30 wells.¹³ These wells were completed open hole and usually shot with nitroglycerin. The average per well oil recovery for this group of wells was about 85,000 STB¹⁴.

A second cycle of development occurred between 1948 and 1956. These were also open hole completions and most wells were stimulated with acid. The average per well recovery was disappointing, about 30,000 STB. As a result, a few wells were hydraulically fractured. The fractured well recoveries approached that of the nitroglycerin-shot wells¹³.

The third development cycle began in the latter part of 1974, peaked in 1978, and continued through 1980. During this period more than 1,000 wells were drilled in the field. The wells were cased through the Chalk and selectively perforated. Common stimulation treatments were large acid jobs and proppant fracturing jobs. Per well recoveries from this group of wells are difficult to ascertain as production in the public record is reported on a lease basis. By the end of 1985, most of these wells had been abandoned and average per well production for the remaining active wells had fallen to 5 STB/day.

The current development cycle with horizontal wells began in earnest in 1987 when ORYX Energy Company tested 338 STB/day from J.B. Baggett No. 9 through a redrilled 950-foot horizontal lateral. Drilling activity intensified significantly in 1989 after ORYX released information about their horizontal drilling experience.

7.1 Geology

Deposition of the Austin Chalk in the Pearsall vicinity was strongly influenced by the San Marcos Arch which created a shallow-marine environment¹⁵. The shallowest water occurred in the present day Austin-San Antonio vicinity. Water depths increased to the southeast, south, and southwest. This depositional setting is illustrated by Figure 7.1.1.

While deposition of chalks was common during the Cretaceous, the Austin Chalk differed with respect to the relative abundance of shallow-marine benthonic skeletal remains. These remains were deposited in the shallower waters on and surrounding the San Marcos Arch. Periodically, some of these remains were swept downdip into a deeper water marine setting, resulting in higher concentrations of metastable carbonates like high-magnesium calcite and aragonite. The presence of these minerals profoundly affected diagenesis. As a consequence, the Austin Chalk porosity in Pearsall Field has been reduced to the range of 3 percent to 7 percent, and permeability is usually less than 0.01 millidarcies.

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Figure 7.1.1
Depositional Environments for the
Upper Cretaceous Austin Chalk Formation¹⁵

Three diagenetic processes contributed to the porosity evolution: (1) early physical compaction, (2) cementation due to stabilization of metastable carbonates, and (3) pressure solution. The first two processes acted during burial and before the advent of pressure solution. In some cases the lithification associated with the stabilization of the aragonitic sediments was sufficient to resist the effects of pressure solution which is generally more dominant with increasing depth of burial. Thus, while there is a general trend of porosity decrease with depth, there are localized anomalies of better porosity development. Figure 7.1.2 illustrates the porosity variation with depth for the Austin Chalk in comparison to typical North Sea chalk reservoirs.

On the western flank of the San Marcos platform, the Austin Chalk thickens in a southwesterly direction as much as 700 feet in the Pearsall Field vicinity. Figure 7.1.3 is a representative well log illustrating the current field stratigraphic nomenclature and a possible correlation to outcrop studies in central Texas¹⁶. The lower Chalk is comprised of the basal "E" and overlying "D" members. Two pyroclastic clay beds bracket

the "C" member of the middle Chalk. The upper "B" and "A" members are separated by a persistent bentonite bed. An uppermost marl unit occurs in the northwestern part of the field, thickening to as much as 90 feet. This stratigraphic sequence is capped by the Upson Clay.

Figure 7.1.2
Porosity Versus Depth of Burial

Within Pearsall Field, the lower Chalk thickens while the upper Chalk thins toward the Pearsall anticline and shows evidence of growth fault thickening into the Charlotte Graben. The structural features in this area are shown on Figure 7.1.4. Westward, into the Rio Grande Embayment, the upper Chalk thickens rapidly and becomes marly. These features are illustrated by stratigraphic section X-Y, Figure 7.1.5.

The role of fractures in controlling productivity and recoverable reserves of Chalk wells is undisputed. There is also general agreement that the fractures are of tensional origin, near vertical dip and strike parallel to the basin margin. The fractures more commonly dip steeply to the southeast, although northwestwardly dipping fractures are not uncommon. The trend of the fractures is NE-SW $\pm 15^\circ$ (approximate) but some variation with structure has been observed in some of the longer horizontal wells. Schafer¹⁷ reports that 33 fracture strike observations in 28 Pearsall wells ranged from N13°E to N57°E with a mean of N39.5°E, a mode of N39°E, and a standard deviation of 10.7°.

There is less agreement on the vertical and lateral extent of individual fractures and the spacing between fracture "swarms;" i.e., zones of intense fracturing separated by relatively non-fractured rock containing little or no oil saturation. These factors are of obvious importance for development planning and reserve assessment.

Figure 7.1.3
Typical Log From Pearsall Field Well¹⁶

The spacing between fracture swarms varies widely from being almost continuous at frequencies up to several fractures per foot for several hundred lateral feet, to undetectable in dry holes. A periodicity of fracture development has been postulated on the basis of core, log, and drilling observations^{18, 19}. These data suggest that the intra-swarm, non-fractured rock is practically devoid of hydrocarbons. This interpretation suggests

that the hydrocarbons migrated into the Chalk along fracture planes, eventually saturating the low permeability matrix rock adjacent to the fractures. The Chalk and the underlying Eagleford Shale are possible source rocks.

The vertical continuity of fractures is also uncertain. Obviously, fractures do not always extend from top to base of the Chalk because development drilling has proven the existence of vertical isolation in some areas of the reservoir, at least. On the other hand, fractures in core and outcrop have been observed to cut across marly and shaley intervals. Also, marly intervals are prevalent in most productive intervals to the extent that the produced oil volumes could not be explained unless the bulk of the interval was fractured.

There is also general agreement that there is practically no communication from swarm to swarm normal to the fracture trend. The extent of communication along the fracture trend is obviously much better. The magnitude of oil recovery from many wells requires large (i.e., long) drainage areas. There is disagreement on how persistent communication is along a single fracture swarm. Production experience is reported to have shown very good communication along trend for a mile or more¹⁹.

Figure 7.1.4
Major Structural Features in Southwest Texas¹⁶

Figure 7.1.5
Subsurface Stratigraphic Cross-Section¹⁶

Fracture studies of the Austin Chalk outcrops have provided some important observations²⁰:

1. The pattern of fracture development suggests a very brittle deformation response.
2. Closely spaced parallel fractures often pass and curve toward each other to join up at right angles to the fracture strike suggesting that fracturing took place at low differential stress, i.e., shallow burial depth.
3. Fractures tend to be contained by marly bed thicknesses exceeding four inches.
4. Fracture spacing averages three to four inches, normal to the local structural strike. This is about half the along-strike fracture spacing.
5. The distribution of fracture spacing is highly skewed towards low values (less than eight inches). The distributions are reasonably fitted by exponential functions of the type:

$$y = ax^{-b}$$

6. Many fractures are filled with sparry calcite, most probably precipitated at temperatures exceeding 150°C.
7. The matrix rock is commonly diagenetically colored and banded parallel to each fracture, clearly indicating cross-flow from fracture to matrix.

The same study identified four structural styles which resulted in increased fracture intensity. Figure 7.1.6 (page 21), reproduced from Corbett²⁰, schematically depicts each fracture system type.

Plunging Anticlinal Fold - Two well-ordered and one poorly ordered fracture sets were observed. The major set was nearly vertical and parallel to the anticlinal axis with lengths up to 50 feet along strike and 15 feet downdip. The secondary set intersected the major set at 70° with dips varying 30° either side of vertical and averaging 10° from vertical. Spacing of this set was less regular, varying from 4 to 60 inches (26-inch average). Their length along strike was limited by major set spacing to about 40 inches and dip lengths averaged 14 inches. The third fracture set lacked order, was highly variable in strike and dip length, and was only developed along the anticlinal crest.

Monoclinial Fold - These structures possess nearly horizontal upper and lower limbs and a gently dipping (5° to 8°) intervening slope. They run parallel to and about one-half mile distant from northwest-dipping faults in the Balcones System. Four sets of fractures are observed in this structure type (Figure 7.1.6-b). The most dominant two form a steeply dipping conjugate pair, striking parallel to the fold axis, N20°E. Each dip at about 60°, but the northwest-dipping set is more abundant by a factor of two. These are actually small displacement faults of offsets ranging from 4 to 80 inches. They are localized by calcite and clay-filled veins and occur most abundantly in the slope and the synclinal axis. The remaining two sets have the same strike as the conjugate pair and one of these also develops into small faults dipping from 10° NW to 30°SE with shear displacements of up to a foot.

Figure 7.1.6
Schematic Illustrations of Structural Types
and Associated Fractures²⁰

PLUNGING ANTICLINE

a.

MONOCLINAL FLEXURE

b.

LISTRIC NORMAL FAULT

c.

**GRABEN-IN-GRABEN
NORMAL FAULTS**

d.

Listric Normal Faults - A system composed of a master fault accounting for most of the displacement and several small throw subsidiary faults in the foot and hanging walls. The foot wall subsidiary faults all strike parallel to and lie within 16 feet of the master fault with spacings of three to seven feet and are truncated by the master fault sole. The spacing of hanging wall subsidiary faults increases with distance from the master fault, continuing as far as 115 feet from the master fault. The dip lengths of the master and foot wall subsidiary faults exceeded the outcrop exposure of 100 feet. The hanging wall subsidiary faults decreased in dip length with distance from the master fault from 40 feet to six feet. Extension fractures occur in both fault walls but are 1.5 times as frequent in the hanging wall. The hanging wall fractures have the same length trend as the faults. In the foot wall the fracture length is generally constrained to bed thickness.

Graben-In-Graben Normal Faults - Develop into orthogonal striking faults and related fracture sets. Conjugate faults of the Balcones system are the dominant set with the southeast dipping faults having the greater throws. Contained within and striking perpendicular to the dominant set are a second set of conjugate faults. This results in a keystone block within a Balcones graben having 1.5 times the fracture intensity of the remainder of the graben and 2.5 times that of the adjacent horsts.

On the basis of these observations and studies of core recovered from Austin Chalk wells, the authors conclude that most of the fracture mechanisms observed in the surface outcrops can be extrapolated to predict fracture occurrence in the subsurface. They concede, however, that subsurface fracture spacing may be wider by some unknown factor.

7.2 Reservoir Properties

The properties of the Austin Chalk reservoir rock and fluids are discussed in this section. This information provided the basis for the reservoir simulator initialization data described in Section 9.2.

Porosity and Permeability - The Pearsall Austin Chalk reservoir is conceptualized as a lateral series of vertical compartments of varying width comprised of zones of intense fracture development^{18,21}. The term "fracture swarm" is used to denote such a compartment. The swarms are parallel to each other and of uniform strike over long distances. Each swarm is separated from neighboring swarms by varying width intervals of impermeable, unfractured, and water-saturated or dense chalk.

Within each swarm, vertical fractures, paralleling the swarm strike are predominant. A secondary set of steeply dipping fractures are postulated to intersect the principal set at nearly right angles. Microfracturing is extensive within the fracture swarms but almost absent in the inter-swarm rock¹⁸. Fracture spacing as close as three per foot and maximum fracture porosity of 0.001 as a fraction of core bulk volume is reported by the same source. The presence of secondary fractures would increase the total fracture porosity to some degree. The spacing of the secondary fractures is unknown, but is thought to be wider than the principal set.

The chalk matrix within a fracture swarm is known to be oil-saturated from log response and limited core observations in horizontal well bores. Conversely, the inter-swarm rock is known by these same means to be devoid of hydrocarbons. Although the core permeability of the chalk matrix is in the microdarcy range, it is probable that oil from the matrix is finding its way into the fractures through the microfractures observed in cores. It is extremely difficult to reconcile known recovered oil volumes unless some portion of the matrix hydrocarbon pore volume is regarded as effective and contributing to overall oil recovery.

The fractured chalk forms what is commonly referred to as a dual porosity reservoir system. The concept of dual porosity is a low pore volume, high transmissibility fracture network connecting discrete matrix blocks of higher pore volume and much lower permeability so that virtually all the reservoir flow takes place in the fractures while the matrix provides most of the reservoir storage capacity. The parameter ranges cited for the effective reservoir rock; i.e., in a fracture swarm, are given below¹⁸:

matrix porosity, ϕ_m , fraction	0.02	-	0.05
fracture porosity, ϕ_f , fraction	0.0005	-	0.001
matrix permeability, k_m , microdarcies	0.01	-	0.1
fracture permeability, k_f , millidarcies	3.0	-	10.0

These parameters fit the concept of dual porosity, although the matrix values are uncommonly low.

Reservoir Thickness - The gross thickness of the Chalk varies from about 400 feet to more than 700 feet. Using a porosity cut-off of 3 percent to determine net pay and core data from a vertical well, ORYX Energy Company computed a net thickness to gross thickness ratio of 0.321²². The same source presents average porosity for the net rock of 3.90 percent using the same porosity cutoff and core data from two wells having an aggregate net porous thickness of just 203 feet. Since the average porosity of the net rock is so close to the cut-off, it is likely that the net thickness computation would be very sensitive to the cut-off chosen.

Fluid Properties - The gravity of the Austin Chalk oil varies over an extremely wide range, 21° through 43° API, and oils from adjacent wells can have very different gravities, viscosities, gas in solution and color²³. In Pearsall Field, the range is somewhat narrower, from 29° to 37° API, but this is still unusually wide.

The experimental results for one bottom-hole sample were reported as follows¹⁸: bubble point pressure 2350 psig, solution gas-oil ratio of 825 scf/STB, oil formation volume factor 1.5, and oil viscosity of 0.6 cp. The author acknowledges that oil composition "varies from well to well," but most wells in his experience have producing gas-oil ratios in the 500-600 scf/STB range. In his view, this supports a lower bubble point value around 1650 psig compared to a virgin reservoir pressure of approximately 2600 psig.

The following Pearsall Field fluid data were provided in a 1990 spacing unit submission to the Texas Railroad Commission²²:

stock tank oil gravity, °API	32	-	37
solution gas-oil ratio, scf/STB	280	-	615
separator gas specific gravity (air = 1)	0.93	-	0.95
oil formation volume factor, v/v	1.382	-	1.183
reservoir temperature, °F	190		

Rock-Fluid Properties - Included in this category are capillary pressure, wettability, relative permeability, and pore volume compressibility. Pearsall data is almost completely lacking in the public data realm. Indeed, the only parameter found was an assumed value of matrix irreducible water saturation of 0.3 which was further assumed to be the initial water saturation¹⁸. This was contradictory to the 0.65 value used in the reserves computations found in the spacing unit submission²².

7.3 Well Performance Data

Horizontal well performance data, fluid production rates, bottom-hole measured pressures and wellhead pressures were provided by a Pearsall Field operator. Two of the Well B-1 and Well B-2, are in the same lease while Well A-1, Well A-2 and Well P-1 are single well leases.

The data spanned a time frame of up to two and one half years from the time of first production in each well until April 1991. Bottom hole pressures were provided for Well B-1 and Well B-2 essentially on a daily basis during much of the first half of this period.

The daily production data were often highly variable making recognition of trends difficult. For this reason the data, excluding pressures, were smoothed by filtering in the frequency domain using a fast Fourier transform. The smoothed production data for Well A-1, Well A-2, Well B-1, Well B-2 and Well P-1 are shown on Figure 7.3.1 through Figure 7.3.5, respectively. The raw, unfiltered data can be found in the first Annual Report under the same figure numbers.

7.3.1 Well Test Analysis

Well B-1 was placed on continuous production on October 24, 1987. From that time through March 1, 1988, the production and pressure data show three cycles of drawdown followed by build-up. The chronology of the test during the stated time interval is summarized in Table 7.3.1.

Table 7.3.1
Well B-1 Well Test Chronology

Beginning Date	Ending Date	Well Activity
10/24/87	12/17/87	drawdown
12/18/87	12/29/87	shut-in
12/30/87	1/17/88	drawdown
1/18/88	1/29/88	shut-in
1/30/88	2/19/88	drawdown
2/20/88	3/01/88	shut-in

Figure 7.3.6 displays the production and pressure data for this time period on an expanded time scale. It clearly shows the three drawdown-build-up cycles. If the pressures are assumed to be rigorously periodic, that is, recorded at fixed 24-hour time increments, they should be amenable to conventional well test analysis.

The Automate II[†] computer-aided well test analysis software was used to match the observed pressure

[†] © by Garrett Computing Systems, Inc.

response by non-linear multiple regression. Four models of increasing complexity were tried to see which would best reproduce the observed pressure behavior:

- a) single porosity, storage and skin, vertical well
- b) single porosity with storage and skin, horizontal well with infinite conductivity well bore
- c) dual porosity, transient, storage and skin, vertical well
- d) dual porosity, transient, storage and skin, horizontal well with infinite conductivity well bore

Unfortunately, the pressure response was not sufficiently diagnostic to clearly indicate dual porosity behavior. The results of the Automate II regression computed pressures are compared to the measured data in Miller-Dyes-Hutchinson (MDH) format on Figure 7.3.7 (model a), Figure 7.3.8 (model b), Figure 7.3.9 (model c) and Figure 7.3.10 (model d). A visual inspection of these four plots reveals that there is little difference in the quality of the computed pressure matches. There are, however, significant differences in the matching parameters of interest: skin factor (S) and permeability (k) as are common to all models; transmissivity (λ) and storativity (ω) ratios rendered by the dual porosity models; and the vertical to horizontal permeability ratio (k_v / k_h) defined by the horizontal well models. Table 7.3.2 summarizes the parameters used for the illustrated pressure matches.

Figure 7.3.1
Well A-1 Smoothed Test Data

K&A Energy Consultants, Inc

Figure 7.3.2
Well A-2 Smoothed Test Data

K&A Energy Consultants, Inc

Figure 7.3.3
Well B-1 Smoothed Test Data

K&A Energy Consultants, Inc

Figure 7.3.4
Well B-2 Smoothed Test Data

K&A Energy Consultants, Inc

Figure 7.3.5
Well P-1 Smoothed Test Data

K&A Energy Consultants, Inc.

Figure 7.3.6
Well B-1 Multi-Rate Test

K&A Energy Consultants, Inc

Figure 7.3.7
Well B-1 Multi-Rate
Miller-Dyes-Hutchinson Plot
Dbl Por (Transient) Model

Figure 7.3.8
Well B-1 Multi-Rate
Miller-Dyes-Hutchinson Plot
HorizWell(InfCond) Model

Figure 7.3.9
Well B-1 Multi-Rate
Miller-Dyes-Hutchinson Plot
Storage & Skin Model

Figure 7.3.10
Well B-1 Multi-Rate
Miller-Dyes-Hutchinson Plot
HorWell-InC-D-Tm Model

Table 7.3.2
Well B-1 Well Test Analysis Results

Parameter	Model a	Model b	Model c	Model d
C, stb/psi	0.128 $\pm$.075	0.538 $\pm$.056	0.287 $\pm$.087	0.647 $\pm$.058
S	-4.33 $\pm$.099	0.960 $\pm$.040	-7.17 $\pm$.039	.0023 $\pm$.171
kh, md-ft	101.8	164.1	57.6	147.0
6k, md	0.585 $\pm$.020	0.547 $\pm$.002	0.192 $\pm$.008	0.490 $\pm$.002
k_v / k_h	n.a.	0.033 $\pm$.003	n.a.	0.258 $\pm$.072
λ	n.a.	n.a.	8.5E-8 $\pm$ 3E-10	7.6E-6 $\pm$ 3E-7
ω	n.a.	n.a.	7.1E-6 $\pm$ 3E-7	2.6E-4 $\pm$ 4E-5

The table includes the regression determined confidence interval for each parameter. Since a smaller confidence interval relative to the magnitude of the parameter implies a better determined result, one could conclude that permeability is best determined by either of the horizontal well models, b or d. Note, however, that model b assumes a single porosity medium, whereas, model d assumes the medium to be dual porosity. Skin factor is clearly best defined by model c which assumes a vertical well in a dual porosity medium, while permeability ratio, k_v / k_h , is better defined by the single porosity model b than the dual porosity model d. As to the dual porosity parameters, model c is superior for both transmissivity ratio (λ) and storativity ratio (ω).

Knowing that the well bore to be horizontal and the medium to be fractured, one would anticipate that model d should best fit the data. The comparison shows this to be insupportable.

On the basis of the number of parameters best defined, model c scores points for S, λ and ω , model b for k and k_v / k_h and model d for k only. Taken at face value, this scoring would favor model c as being most applicable with model b as a close second.

Upon inspection, the model c dual porosity parameters (λ and ω) seemed unreasonably small. Reasonable first estimates of fracture and matrix permeability, porosity and compressibility might be as follows:

$$\begin{aligned}
 k_f &= 0.5 \text{ md} \\
 k_m &= 0.00001 \text{ md} \\
 \phi_f &= .001 \\
 \phi_m &= .03 \\
 c_f &= 10^{-5} \text{ psi}^{-1} \\
 c_m &= .5 \times 10^{-5} \text{ psi}^{-1}
 \end{aligned}$$

By definition, transmissivity ratio is defined as:

$$\lambda = \sigma \frac{k_m}{k_f} r_w^2 \dots\dots\dots (7.1)$$

Referring to Section 9.3.4 of the first Annual Report, the shape factor, σ , could have a value as low as $2 / L^2$. Assuming fracture spacing of one foot ($L = 1$) and a well bore radius (r_w) of .375 feet, λ could be as low as 2.8×10^{-4} . By contrast, the model λ is four orders of magnitude smaller.

The storativity ratio definition is:

$$\omega = \frac{\phi_f c_f}{(\phi_f c_f + \phi_m c_m)} \dots\dots\dots (7.2)$$

Therefore, a reasonable first estimate of ω would be 0.063. Again the model ω value is four orders of magnitude smaller.

The above observations bring into question the model c dual porosity parameters λ and ω . It would seem, therefore, that the observed pressure behavior is best represented by the b model, the homogeneous reservoir medium, horizontal well model. Thus, if it is assumed that the reservoir is actually of the dual porosity type and that the matrix permeability is very much less than the fracture permeability, it is reasonable to conclude that this test indicates a fracture permeability-thickness of about 160 md-ft and a skin factor of 1. No conclusion regarding k_f / k_b is drawn since this parameter is known to be very sensitive to placement of the horizontal well bore within the productive interval.

Attempts to make similar analyses of Well B-2 test data were unsuccessful due to data irregularities. Pressure data for Well A-1, Well A-2 and Well P-1 were too sparse to be analyzed.

7.3.2 Well Test Simulation

Well B-1 pressure matches were attempted using both prototype simulators, vertical well and horizontal well, and both deformation options for fracture properties, standard and deform[†]. It was hoped the potentially more rigorous treatment allowed by the simulators might reveal the data to be more diagnostic of fracture deformation and multi-fracture swarm horizontal well behavior.

The matches obtained with the vertical models are shown on Figure 7.3.11 for the standard option and on Figure 7.3.12 for the deform option. In terms of quality, they are about equal and neither is particularly good. To obtain these matches it was necessary to allocate 100% of the production to the simulated swarm. The matching parameters, k_r and S are displayed on each figure.

Figure 7.3.13 and Figure 7.3.14 show the horizontal model matches for the standard and deform option treatments, respectively. All production was withdrawn from two of the prototype fracture swarms via a 900-foot horizontal offset with an assumed flowing pressure gradient of 0.01 psi/ft. The build-up shapes are shown to be a slightly better matched but again, there is nothing to choose in the quality of the standard and

[†] With reference to fractures, "standard" infers $\partial k_r / \partial p = 0$, whereas "deform" infers $\partial k_r / \partial p \neq 0$.

deform option matches. A test match, assuming a single fracture swarm produced a pressure build up almost identical to the vertical well model match. It is concluded that the slightly improved matches of build-up shape provide qualitative validation of the multiple fracture swarm, horizontal well model. The indistinguishable standard and deform option matches frustrated any conclusion regarding fracture deformation.

It is quite possible that the matches could be further improved if other reservoir data were changed, *e.g.* number of penetrated fracture swarms, swarm dimensions, well bore length, transmissivity ratio (λ), storativity ratio (ω) or k_v / k_h . This was not attempted because to have done so would not render the interpretation any more conclusive with regard to fracture deformation.

The k_f and S parameters used in each model to produce the matches are indicated on the appropriate illustration. The results for all four models are summarized in Table 7.3.3.

Table 7.3.3
Well B-1 Test Data Simulation Match Parameters

Parameter	Vertical Standard	Vertical Deform	Horizontal Standard	Horizontal Deform
S	15.2	10.4	3.55	2.53
kh, md-ft	870.	940.	371.	411.
k, md	25.0	27.0	5.80	6.42
k_v / k_h	0.1	0.1	0.1	0.1
λ	6.75E-6	6.25E-6	2.91E-5	2.63E-4
ω	0.314	0.335	0.314	0.335

Since the test well bore is known to be horizontal, the simulation matches suggest fracture permeability-thickness of about 400 md-ft and a skin factor around 3.

8.0 EXAMINATION OF VERTICAL AND HORIZONTAL WELL PERFORMANCE

An examination of Pearsall Field, Austin Chalk, vertical well and horizontal well performance was undertaken to provide guidelines for the simulation studies. In this context, several items were investigated, i.e.:

- Distribution of ultimate recovery for vertical wells.
- Distribution of ultimate recovery for horizontal wells.
- Distribution of the amount of displacement in pay for both vertical and horizontal wells.
- Nature of the relationship between ultimate recovery and its associated amount of displacement in pay.

These items were examined through analysis of historical performance data via engineering and statistical methods. This effort consisted of four steps: selection of a data sample, the determination of ultimate recoveries, statistical analysis of the data, and discussion of results.

8.1 Sample Selection

The well sample was chosen from Austin Chalk completions in Pearsall Field for consistency with the simulation study. All data were obtained from public records or from commercial sources which accumulate public sector data. Data in the public domain is limited, for most instances, to well completion information, initial well potential and monthly production reported by lease. In some instances, a lease contains either a single well or a single active well at any given time. A list of data item variable names with a brief description of each can be found in Appendix A.

Specific wells and leases were sought which would provide definitive production history trends for both horizontal and vertical well completions. Previous experience with horizontal completions indicated a minimum requirement of approximately 12 months of performance data. Thus, all leases containing at least one horizontal well completed prior to April, 1990 were selected. The leases found fell into two main groups: those with prior production from vertical wells and those with no prior vertical well production. Each lease was further categorized according to the number of horizontal completions it contained, as being either a single well lease or a multiple well lease. The first two columns of Table 8.1.1 show the number of wells in each category without regard to completion date and production data availability. These were the target group of wells. The final two columns show the numbers of wells on leases which satisfied the date and production data criteria.

The sample data are widely distributed across the field and do not represent a grouping of contiguous leases. The spatial distribution of the sample leases covers an area extending some 30 miles east, 20 miles west, 13 miles north and 10 miles south of the ORYX J.B. Baggett lease.

Table 8.1.1
Sample Categories and Numbers of Wells

Category	Original Search		Final Search	
	Horiz.	Vert.	Horiz.	Vert.
Leases Having Prior Vertical Production				
Leases with single horizontal wells	10	25	8	25
Leases with multiple horizontal wells	34	33	7	31
Leases Without Prior Vertical Production				
Leases with single horizontal wells	53	0	35	0
Leases with multiple horizontal wells	51	0	24	0
Totals	148	58	74	56

8.2 Determination of Ultimate Recovery

The production data were analyzed to determine an ultimate oil recovery for each completion. All leases were extrapolated to a common ending rate which was arbitrarily applied to all leases with no regard for the number or type of producing wells. The selection of a single final rate, simplified the determination of lease ultimate recovery but it probably does not reflect the average economic limit for these leases. Ultimate recovery was the summation of cumulative production to the end of the historical period and the extrapolated estimate of remaining reserves. Ultimates obtained from the sample data set were divided into subsets according to well type in order to obtain and compare results among the respective types.

The analyses were made with the assistance of commercial software which facilitated both diagnostic plot generation (log rate versus time and log rate versus log time) and application of dimensionless type-curves. In most instances, data which could not be extrapolated by semi-log analysis were amenable to type curve analysis of the log-log plots.

Ultimate recoveries were determined for all leases with definitive production rate trends. Leases containing horizontal completions were examined to see if the ultimate recovery of individual wells could be ascertained. This proved to be possible for some wells. Otherwise, multi-well ultimates were determined.

Regardless of how determined, the ultimate recoveries were the only interpretative data to be included in the statistical analysis. All other data used for statistical analysis such as displacement in pay was regarded as fixed and not subject to interpretation.

8.3 Statistical Analysis

The data described in Section 8.1 and the respective ultimate recoveries for a well or lease basis were processed through the use of SPSS/PC + statistical software. Descriptive statistics were performed on several

items and a test for relationship between ultimate recovery and displacement in pay[†] was performed.

Descriptive statistics for ultimate recovery, displacement in pay, and ultimate recovery divided by displacement in pay were calculated for various well groupings. The values computed for each grouping included mean, the median, and the 5 percent trimmed mean. Outlier and extreme data points can distort the mean computation, whereas, the trimmed mean tends to discount extreme points giving a better representation of the mean. The following discussions summarize the analysis of each well grouping. A box plot and descriptive statistics details for each well grouping can be found in Appendix B.

Table 8.3.1 summarizes the statistical computations for eight different groupings of wells. The first and second differentiate on the basis of well type, either vertical or horizontal. The next two grouping pairs apply only to the horizontal well data: grouping 3 and 4 differentiate leases with and without prior vertical well production and grouping 5 and 6 separate leases having multiple well and single well solutions. The last two groupings apply to horizontal wells with single well solutions and differentiate on the basis of the ability to flow upon initial completion.

The vertical well grouping includes all ultimate recovery values attributable to vertical completions on both single and multiple well leases. Similarly, the horizontal well grouping comprises recoverable values ascribed to horizontal completions, including both single and multiple well solutions.

Displacement in pay represents an estimate of the pay section contributing production to a given well bore. For a vertical well, the displacement was taken to be the total perforated interval (top to bottom). For a horizontal well, the well bore length within the reservoir interval was assumed. Table 8.3.2 summarizes the properties of the displacement in pay distribution.

The computed displacement values represent upper limits of effective thickness. The thickness that actually contributes the production, the net effective thickness, is expected to be somewhat lower. This would be particularly true of a horizontal well wherein effective pay is constrained to the fracture swarms, whereas displacement is taken as the entire borehole length within the reservoir section. Vertical wells on the other hand are cased and selectively perforated, presumably in the effective intervals, so the ratio of effective pay to displacement should be higher.

The displacements were paired with ultimate recovery for each well to determine values for recovery per foot of displacement. The mean values, grouped as presented in Table 8.3.1, are provided in Table 8.3.3. This variable was an attempt to normalize ultimate recovery to permit vertical and horizontal well comparison on a barrel per foot basis. The overstatement of displacement will tend towards understatement of the barrel per foot figures. For the reasons cited above, this understatement will tend to favor the vertical well values.

The ranges of values obtained, 3.7 to 234.4 STB/ft for vertical completions and 3.4 to 245.3 STB/ft for horizontal completions, suggest heterogeneity of the pay section across the area sampled. Well bores which penetrate thick intervals of high fracture density should yield high values of ultimate recovery per displacement in pay. Well bores which encounter infrequent fracturing would yield very low values. Although mapping of this variable might provide some indication of where fracturing is best developed, it was not attempted.

[†]Borehole length within the gross pay interval.

Table 8.3.1
Ultimate Recovery - Descriptive Summary
(Units are 1000 STB)

Groupings	Wells	Mean	Median	5% Trimmed Mean	Minimum Value	Maximum Value
Vertical Wells	56	29.3	17.1	27.8	2.1	81.9
Horizontal Wells	74	117.4	71.1	104.0	7.2	488.7
Well subtotal	130					
Horizontal Wells						
Leases - no prior vertical production	59	127.9	77.2	114.5	7.2	488.7
Leases - prior vertical production	15	76.3	43.3	72.2	19.4	207.0
Well subtotal	74					
Horizontal Wells						
Leases - multi-well solutions	25	152.6	114.4	141.2	22.2	488.7
Leases - single-well solutions	49	99.5	69.0	90.3	7.2	372.4
Well Subtotal	74					
Horizontal Wells on Leases With Single-Well Solutions						
Flowing initial completion wells	27	136.3	90.5	130.3	13.1	372.4
Non-flowing initial completion wells	22	54.4	37.7	50.4	7.2	179.1
Well Subtotal	49					

Table 8.3.2
Displacement In Pay - Descriptive Summary
(Units are feet)

	Wells	Mean	Median	5% Trimmed Mean	Minimum Value	Maximum Value
Vertical Wells	56	355.0	333.0	350.0	240.8	57.0
Horizontal Wells	74	2272.0	2182.0	2255.0	502.0	4133.0
Well subtotal	130					

A statistical test for the existence of a relationship between ultimate recovery and displacement in pay was performed using the single horizontal well lease data. These data were chosen because they should possess the least possible degree of ambiguity due to other well interference. This does not preclude, however, interference from wells on offsetting leases. The selected data are crossplotted on Figure 8.3.1. If it is hypothesized that the variables are completely unrelated, the χ^2 of the population would be zero. If this hypothesis can be disproved, it can be said that a relationship does indeed exist. If the hypothesis can not be disproved, it must be concluded that no relationship exists.

Table 8.3.3
Ultimate Recovery Per Displacement In Pay - Descriptive Summary
 (Units are STB/foot)

Groupings	Wells	Mean	Median	5% Trimmed Mean	Minimum Value	Maximum Value
Vertical Wells	56	82.4	53.9	78.2	3.7	234.3
Horizontal Wells	74	58.9	32.8	53.6	3.4	245.3
Well subtotal	130					
Horizontal Wells						
Leases - no prior vertical production	59	59.0	36.7	53.2	3.4	245.3
Leases - prior vertical production	15	58.2	21.3	56.2	7.6	145.7
Well subtotal	74					
Horizontal Wells						
Leases - multi-well solutions	25	68.3	43.9	66.3	10.2	163.4
Leases - single-well solutions	49	54.1	31.5	47.2	3.4	245.3
Well Subtotal	74					
Horizontal Wells on Leases With Single-Well Solutions						
Flowing initial completion wells	27	77.1	54.7	71.8	6.7	245.3
Non-flowing initial completion wells	22	25.7	19.1	23.6	3.4	88.6
Well Subtotal	49					

To enable the χ^2 calculation, each variable distribution was subdivided into three class intervals by visual examination. Thus, all ultimate recovery values in the range 0 to 49,999 STB were in reserves class one; values from 50,000 to 149,999 were class two; and values from 150,000 to 489,000 were class three. Similarly, displacement in pay values between 0 and 1,499 feet were displacement class one; 1,500 to 2,499 were class two; and 2,500 feet to 4,200 were class three. The class interval data and the χ^2 calculation are summarized in Table 8.3.4.

The significance of a χ^2 of 1.13173 is shown to be 0.88921. This means that approximately 88.9 percent of the time, a sample will yield a χ^2 of 1.13173 or larger from a population whose true χ^2 is assumed to be zero. This probability is much too large to reject the assumption; therefore, it is concluded that the variables are quite probably unrelated.

Table 8.3.4
Results of χ^2 Test for Ultimate Recovery (STB)
Versus Displacement (feet)

Class	Recovery Min. - Max.	Class	1	2	3	Row Total
		Min. Displacement: Max.	0 through 1,499	1,500 through 2,499	2,500 through 4,200	
1	0 through 49,999	Count	4	10	4	18
		Expected	4.4	8.8	4.8	-
		Row %	22.2	55.6	22.2	-
		Column %	33.3	41.7	30.8	-
		Total %	8.2	20.4	8.2	36.7
		Residual	-.4	1.2	-.8	-
2	50,000 through 129,999	Count	4	9	6	19
		Expected	4.7	9.3	5.0	-
		Row %	21.1	47.4	31.6	-
		Column %	33.3	37.5	46.2	-
		Total %	8.2	18.4	12.2	38.8
		Residual	-.7	-.3	1.0	-
3	130,000 through 489,000	Count	4	5	3	12
		Expected	2.9	5.9	3.2	-
		Row %	33.3	41.7	25.0	-
		Column %	33.3	20.8	23.1	-
		Total %	8.2	10.2	6.1	24.5
		Residual	1.1	-.9	-.2	-
Column Total		Count Total %	12 24.5	24 49.0	13 26.5	49 100

Statistical Property	Value
χ^2 (Pearson)	1.13173
Degrees of Freedom	4
Significance	0.88921
Phi	0.15198
Cramer's V	0.10746
Contingency Coefficient	0.15025

Figure 8.3.1
Horizontal Wells With Single-Well Solution

8.4 Interpretation

Comparison of the data presented in Table 8.3.1 through Table 8.3.3 allows several observations to be made. The results are compared on an average basis as represented by the 5% trimmed mean value. Comparisons are made for: (1) vertical versus horizontal completions, (2) horizontal wells on leases with prior vertical well production versus horizontal wells on single well leases, and (3) horizontal well completions which initially flowed versus those artificially lifted.

The 104.0 mSTB average ultimate recovery for a horizontal completion is significantly larger than the vertical completion value of 27.8 mSTB (Table 8.3.1). This difference seems to confirm the higher probability that horizontal wells encounter more fracture swarms than do vertical wells. Vertical well bores are probably limited to a single fracture swarm, whereas, horizontal boreholes may penetrate several fracture swarms. Even for dissimilar ratios of productive section to total displacement in pay, a horizontal well may be drilled so that it encounters more reservoir quality rock than a vertical well.

The average vertical completion ultimate recovery per foot of displacement in pay of 78.2 STB is greater than the comparable average of 53.6 STB/ft for horizontal completions (Table 8.3.3). In this instance, the difference is most likely due to the overstatement of horizontal displacement as compared to the vertical displacement, as was explained in the discussion of Table 8.3.2. If the displacement values could be brought

more in line with the net effective thickness contributing the reserves, it is considered likely that the comparison would be tipped in favor of the horizontal wells.

Referring again to Table 8.3.1, comparison of the 114.5 mSTB average recovery from horizontal completions on undeveloped leases (no prior vertical well production) against the 72.2 mSTB average for horizontal completions on leases with prior vertical production, appears to indicate that horizontal well recovery is reduced by prior vertical well production. This observation is not unexpected since the fracture swarms partially depleted by prior vertical well production will most likely be also penetrated by the horizontal borehole.

In contrast to the preceding observation, the corresponding per foot recoveries given in Table 8.3.3, 53.2 STB/ft versus 56.2 STB/ft, suggest that prior vertical production has little impact on ultimate recovery when it is related to horizontal displacement. This observation is probably incorrect or at best incomplete. The comparison of the median values supports the expected result that prior production does impact the recovery per foot.

Distinguishing horizontal wells according to their ability to flow at initial completion (last two rows of Table 8.3.1) shows that flowing wells have an average ultimate recovery of 130.3 mSTB as compared to 50.4 mSTB for non-flowing completions. A similar comparison is provided by Table 8.3.3 in terms of recovery per foot of displacement in pay: 71.8 STB/ft for flowing completions and 23.6 STB/ft for non-flowing completions. Both observations are consistent with the expectation that higher reservoir energy environments, as evidenced by the flowing initial completions, should yield larger recovery values.

The χ^2 test (Table 8.3.4) indicated that horizontal well ultimate recovery and displacement in pay are not correlated. The variability of the key unknowns, like fracture swarm frequency and oil in place per swarm may preclude such a simple relationship. Nonetheless, it seems highly likely that ultimate recovery is dependent on one or more variables which are somehow related to displacement length. No other explanation exists for the observation that the average ultimate recovery for a horizontal completion is larger than that for a vertical completion.

9.0 SIMULATOR DESCRIPTION

A mathematical model for single-phase flow in a dual porosity system was first solved by Barenblatt²⁴ and later refined by Warren and Root²⁵. The Warren and Root model assumes that the fractures are orthogonal and parallel to one of the three permeability axes. The fractures subdivide the matrix rock into a regular array of identical homogeneous rectilinear blocks. Along each axis, the fractures are assumed to be evenly spaced and of constant aperture. Flow can occur between matrix and fracture, but matrix-matrix flow cannot occur. Matrix-fracture flow is governed by a shape factor which is a function of the matrix block geometry.

Other workers incorporated the Warren and Root model in existing black-oil reservoir simulators and extended the mathematics to describe three-phase flow^{26, 27, 28, 29, 30, 31, 32}. The more recent workers have dealt with methods to more accurately treat gravity segregation and capillary imbibition.

The program used for the simulations described in this report is TETRAD, an updated version of the TRIAD simulator. It is a state-of-the-art, general purpose reservoir simulator which provides dual-porosity treatment as an option. The simulator allows implicit treatment of horizontal wells and deformation of the porous media; i.e., both porosity and permeability are functions of pore pressure. A description of the features of TETRAD can be found in Appendix C.

The program was extensively tested following modification to ensure that it was performing correctly. The problems posed in the Sixth SPE Comparative Solution Project for dual-porosity simulators provided one source of test problems³³. The waterflood test problems published by Kazemi²⁶ were also simulated. The TETRAD solutions agreed with the published solutions of Kazemi and compared very favorably with those of the Comparative Solution Project participants.

9.1 Reservoir Model Segments

The conceptual Austin Chalk model presented in Section 7.2 was emulated by four differently configured simulation models, each designed to satisfy a particular aspect of the total work scope. These were: (1) the horizontal well natural depletion model (horizontal depletion), (2) the vertical well natural depletion model (vertical depletion), (3) the horizontal well secondary recovery model (horizontal injection) and, (4) the vertical well secondary recovery model (vertical injection).

All four models considered a rectangular segment of the reservoir corresponding to a 640-acre well spacing unit. All fracture swarms were assumed to extend beyond the segment and to be of identical strike, paralleling the Y-axis (long axis) of the reservoir segment. Thus, a horizontal well drilled parallel to the X-axis of the segment would penetrate all fracture swarms. Conversely, a vertical well could only penetrate one fracture swarm.

The horizontal depletion model further assumed the presence of a single horizontal well bore, drilled through the reservoir segment parallel to its X-axis (horizontal length; 3,733.5 feet). Communication between fracture swarms was non-existent in the reservoir but permissible through the well bore. Figure 9.1.1 is a schematic representation of the spacing unit for the horizontal depletion model.

The vertical depletion model described an individual fracture swarm within the basic reservoir segment. Thus, it has a reduced X-direction length equal to the width of one fracture swarm but the same Y-direction

length as the horizontal model. This model is depicted in Figure 9.1.2.

The horizontal injection model additionally assumed the existence of a horizontal injection well along both Y-direction boundaries of the reservoir segment and equidistant from the centrally located producing well, as illustrated by Figure 9.1.3.

The vertical injection model was basically the vertical depletion model with the addition of a vertical injection well at each Y-direction boundary, as seen on Figure 9.1.4.

9.2 Simulator Initialization

The data used to initialize the simulators for these four models is discussed according to one of the four basic categories: grid definition, reservoir properties, reservoir fluids, initial conditions, and well data.

Figure 9.1.1
Horizontal Depletion

Figure 9.1.2
Vertical Depletion

Figure 9.1.3
Horizontal Injection

Figure 9.1.4
Vertical Injection

9.2.1 Simulation Grid

All four simulators covered an assumed 640-acre rectangular spacing unit with dimensions 3,733.52 by 7,467.05 feet. Wells, either vertical or horizontal, were assumed to be drilled along the short central axis of the spacing unit, thus creating an axis of symmetry. The horizontal well segments were assumed to be properly oriented and of sufficient length to develop all fracture swarms occurring within the spacing unit while the vertical wells are assumed to develop only a single fracture swarm.

The grid for the horizontal well natural depletion cases had dimensions: NX by NY by NZ of 21 by 9 by 5. The grid was oriented with the X-axis perpendicular to the major fracture set strike and with the Y-Z plane parallel to the fracture strike-dip plane.

The assumed gross thickness of the reservoir was a constant 544 feet. This total was equally distributed across the five model layers, making the layer thickness 108.8 feet in the Z direction.

The model included seven identical fracture swarms, each 100 feet wide, but excluded the intervening dense rock. Thus, each fracture swarm was three grid blocks wide in X and each block was 33.33 feet long in X direction. The excluded dense rock was assumed to be equally distributed between swarms; i.e., 433.34 feet of dense rock between each swarm. The horizontal well flowing pressure gradient was adjusted to compensate for omission of the dense intervals. Communication between fracture swarms was prevented by explicitly setting the X direction transmissibility of every third grid block to zero.

Table 9.2.1
Horizontal Depletion Model
Y Direction Grid Sizes (feet)

J	ΔY
1	33.33
2	43.72
3	72.39
4	119.87
5	198.48
6	328.64
7	544.16
8	901.02
9	1,491.91
Total	3,733.52

The Y direction grid spacing varied logarithmically from 33.33 feet at the well cell to 1,491.91 feet at the spacing unit boundary. Table 9.2.1 lists the Y direction grid block sizes.

The injection case horizontal well model dimensions in the X and Z directions were identical to the natural depletion model. However, the Y direction grid was refined at both ends (Table 9.2.2) to better define conditions in the vicinities of the production and injection well bores. This model has two axes of symmetry, one at the producing well and another at the injection well, making each a half well.

Table 9.2.2
Horizontal Injection Model
Y Direction Grid Sizes (feet)

J	ΔY
1	38.53
2	96.13
3	263.56
4	722.59
5	1,491.92
6	722.59
7	263.56
8	96.13
9	38.53
Total	3,733.52

It is emphasized that both horizontal well models, the natural depletion model and the injection model, were identical in area and volume. Schematic representations of the two grids can be seen in Figure 9.2.1 and Figure 9.2.2.

9.2.2 Grid Node Data

The input data items described in this section apply to both horizontal and vertical models and both depletion and injection configurations.

Net Thickness - The assumed total net reservoir thickness of 174 feet was equally subdivided among the five model layers. Thus, the effective ratio of net thickness to gross thickness was 0.32.

Depth - The depth of each grid node was computed assuming a monoclinial structure, dipping 88.3 feet/mile (1°) parallel to the X axis. A minimum top of reservoir depth of 6,290 feet was assumed along the first column of grid blocks ($I = 1, J = 1, NY$). The tops for columns $I = 2$ through $I = 21$ were computed from this depth, the dip angle, and the cumulative X departure, including the 433.34 feet of dense rock assumed to separate each fracture swarm (refer to Section 9.3.1).

Porosity - Uniform matrix and fracture porosities of 3.36 and 0.0984 percent were assumed for all grid blocks in the model. The fracture value was computed by assuming a constant fracture aperture of 0.1 millimeters and three intersecting fracture sets, dividing the matrix into one-foot cubic blocks.

Permeability - Matrix and fracture permeabilities were also assumed to be uniform and isotropic. The assumed values were 10 millidarcies for the fractures and 0.100 microdarcies for the matrix.

Figure 1 is a perspective view of a rectangular plate with a grid pattern, showing a series of vertical fractures. The fractures are labeled 1 through 19. The plate is divided into sections by these fractures. The width of the plate is 100 inches. The distance between fractures 1 and 2 is 433.34 inches. The distance between fractures 2 and 3 is 100 inches. The distance between fractures 3 and 4 is 100 inches. The distance between fractures 4 and 5 is 100 inches. The distance between fractures 5 and 6 is 100 inches. The distance between fractures 6 and 7 is 100 inches. The distance between fractures 7 and 8 is 100 inches. The distance between fractures 8 and 9 is 100 inches. The distance between fractures 9 and 10 is 100 inches. The distance between fractures 10 and 11 is 100 inches. The distance between fractures 11 and 12 is 100 inches. The distance between fractures 12 and 13 is 100 inches. The distance between fractures 13 and 14 is 100 inches. The distance between fractures 14 and 15 is 100 inches. The distance between fractures 15 and 16 is 100 inches. The distance between fractures 16 and 17 is 100 inches. The distance between fractures 17 and 18 is 100 inches. The distance between fractures 18 and 19 is 100 inches. A coordinate system is shown in the top right corner with axes I, J, and K.

Figure 9.2.2
Schematic of Grid for
Horizontal Injection Model

9.2.3 Rock-Fluid Properties

The properties considered in this category are relative permeability, capillary pressure, and pore compressibility of the matrix and fracture systems.

Relative Permeability - Matrix relative permeability was developed from the empirical correlations of Honarpour³⁴. These correlations define relative permeability as functions of porosity, permeability, wettability, lithology, and endpoint fluid saturations. The correlating parameters used to evaluate the correlations are given below:

Rock Type: Carbonate Wettability: Water Wet	
Irreducible water saturation, S_{wi}	0.30
Residual oil saturation, water, S_{orw}	0.28
Water relative permeability @ S_{orw}	0.35
Residual oil saturation, gas, S_{org}	0.16
Gas relative permeability, @ S_{org}	0.62

The resulting relative permeability curves are shown on Figure 9.2.3 for the oil-water system and by Figure 9.2.4 for the gas-oil system.

Fracture relative permeabilities were assumed to be linear functions of phase saturations with zero residual saturation values.

Capillary Pressure - Matrix capillary pressure was computed assuming capillary pressure endpoints of 1.99 psia when completely water saturated ($S_w = 1.0$) and 59.7 psia at irreducible water saturation, S_{wi} of 0.3. Between these extremes it was assumed that the reciprocal of capillary pressure was a linear function of water saturation.

Gas-oil capillary pressure was computed from the oil-water capillary pressures using the familiar relationship:

$$p_{cgo} = p_{cow} \frac{\sigma_{go}}{\sigma_{ow}} \quad \dots \dots \dots (9.1)$$

Gas-oil interfacial tension in dynes/cm, σ_{go} , was computed from the phase densities as suggested by the work of Van Dijk³⁵ and Offerlinga³⁶:

$$\sigma_{go} = 43.36 (\rho_o - \rho_g)^4 \quad \dots \dots \dots (9.2)$$

Oil-water interfacial tension of 23.33 dynes/cm was assumed.

The computed oil-water and gas-oil capillary pressure functions are displayed on Figure 9.2.5. Each curve is also depicted on the relative permeability plots, Figure 9.2.3 for oil-water and Figure 9.2.4 for gas-oil.

Figure 9.2.3
Oil-Water Relative Permeability After Honarpour³⁴
Water Wet Carbonate Rocks

Figure 9.2.4
Gas-Oil Relative Permeability After Honarpour³⁴
Water Wet Carbonate Rocks

Figure 9.2.5
Capillary Pressure Versus Wetting Phase Saturation

9.2.4 Initial Reservoir Conditions

Initial values of reservoir temperature and pressure typical of virgin conditions in Pearsall Field were chosen to initialize the models. The values selected were 190° Fahrenheit for temperature and 3,000 psi for reservoir pressure at datum depth (6,592 feet).

9.2.5 Reservoir Fluid Properties

The PVT properties of the reservoir gas and oil phases were computed from published correlations.^{37, 38, 39, 40} The unknown parameter values, such as separator temperature, pressure, and produced gas gravity, were allowed to vary until known fluid properties were reasonably matched. Known values were: stock tank oil gravity, 37° API, saturation pressure, p_b of 2350 psig and solution gas-oil ratio, R_s of 730 scf/STB. The unknown parameters yielding the best agreement were as follows:

produced gas specific gravity, air = 1	0.95
separator temperature, °F	120
separator pressure, psig	250

The resulting PVT property functions are shown on Figure 9.2.6 and Figure 9.2.7. The data set depicted has the following additional properties:

oil formation factor, B_o @ p_b , psia	1.393
slope of B_o above p_b , $10^6 v/v/psia$	-16.30
oil viscosity @ p_b , cp	0.452
slope of oil viscosity above p_b , $cp \cdot 10^3/psi$	5.46

Figure 9.2.6
Reservoir Oil PVT Properties Versus Pressure

Figure 9.2.7
Reservoir Gas PVT Properties Versus Pressure

9.2.6 Well Productivity and Injectivity

Well productivity/injectivity parameters were defined using the Peaceman equivalent drainage radius concept, modified as suggested by the author for wells on the edge of the computing grid or wells near an upper or lower boundary^{41, 42, 43, 44}. This was necessary since all model wells are edge wells and in some cases they are located near the top or bottom boundary. The method employs a model with refined grid in the the well block vicinity. The author demonstrated that radial flow conditions are satisfied if the well block is centered in a uniform grid and surrounded by five empty grid nodes.

Given the assumed isotropic permeability condition ($k_x = k_y = k_z = k$), the equations defining flowing bottom-hole pressure, p_{wf} for the vertical models are:

$$p_{wf} = p_0 - \frac{qB_o\mu\ln(r_0/r_w)}{k_o2\pi k\Delta z} \quad \dots\dots\dots (9.3)$$

where:

$$r_o = 0.14\sqrt{\Delta x^2 + \Delta y^2} \quad \dots\dots\dots (9.4)$$

and for horizontal models:

$$p_{wf} = p_0 - \frac{qB_o\mu\ln(r_0/r_w)}{k_o2\pi k\Delta y} \quad \dots\dots\dots (9.5)$$

where:

$$r_o = 0.14\sqrt{\Delta x^2 + \Delta y^2} \quad \dots\dots\dots (9.6)$$

Inspection of the equations reveals that the equivalent well block radius, r_o is a function of the grid block dimensions, Δx and Δy or Δz . Furthermore, the well block pressure, p_0 will be grid block size-dependent. Therefore, without correction, the bottom-hole pressures computed by the field scale models would be significantly different than that computed by the fine grid. To avoid this problem a correction factor, ϵ , is applied in the coarser grid, field scale model so that the p_{wf} equation becomes:

$$p_{wf} = p_0 - \frac{q_o\mu\ln(\epsilon r_o/r_w)}{k_o2\pi k\Delta z} \quad \dots\dots\dots (9.7)$$

for the vertical well case and,

$$p_{wf} = p_0 - \frac{qB_o\mu\ln(\epsilon r_o/r_w)}{k_o2\pi k\Delta y} \quad \dots\dots\dots (9.8)$$

for the horizontal well case.

Referring to Equation 9.7 and Equation 9.8, the terms $\ln(\epsilon r_o/r_w)/2\pi k\Delta z$ and $\ln(\epsilon r_o/r_w)/2\pi k\Delta y$ enclosed in brackets are independent of pressure and saturation. In the TETRAD simulator this term is given the variable name PICIW. Thus, the problem reduces to defining a PICIW value for the field scale model which will yield

the same p_{wf} as the fine grid model. This can readily be done by making a field scale test run assuming $\beta = 1$ to determine the uncorrected pressure drawdown, $p_o - p_{wf}$. Since the pressure drawdown is directly proportional to PICIW, the PICIW scaling factor is simply the ratio of this drawdown to the drawdown needed to match the fine grid p_{wf} .

9.3 Deformable Fracture Properties

The central thesis of this study is that naturally fractured petroleum reservoirs will experience permeability reduction during primary depletion operation. The permeability reduction arises from fracture deformation caused by the increasing net confining stress, that is, less of the external geostatic stress is offset by internal fluid pressure as fluids are withdrawn and fluid pressure is reduced. The definition of these properties in the current simulation studies is the subject of this section.

9.3.1 Background

Laminar, isothermal, steady-state single phase fluid flow in planar, constant aperture fractures is commonly expressed by the so called "cubic law." Several workers including Lomize⁴⁵, Snow⁴⁶, Louis⁴⁷ and Witherspoon *et al*⁴⁸ have developed the relationship. It is reproduced here as presented by Jones⁴⁹:

$$Q = 5.11 \times 10^6 \frac{H \delta p^3}{L \mu} \dots \dots \dots (9.9)$$

where:

Q	=	flow rate (reservoir barrels/day)
H	=	height of fracture face (feet)
Δp	=	pressure differential (psi)
w	=	fracture aperture (inches)
L	=	length of fracture face (feet)
μ	=	fluid viscosity

Equation 9.9 applies to flow in smooth walled fractures. By analogy to pipe flow, the friction created by flow between rough-walled fractures would be expected to cause a deviation, expressible by a friction factor, f , of the form:

$$f = \frac{4 \Delta p_w H^2 C}{L Q^2 \rho} \dots \dots \dots (9.10)$$

where:

ρ	=	fluid density (pounds per cubic foot)
C	=	unit conversion constant
	=	6.35×10^8 for the units of this discussion

Lomize⁴⁸ studied flow in rough fractures fabricated by cementing quartz grains to smooth plates and found that the cubic law did not always apply. He correlated the deviation through friction factors, one for the laminar flow regime and another for the turbulent flow regime:

laminar

$$f = \frac{96}{N_{re}} \left[1 + 6.0 \left(\frac{e}{w} \right)^{1.5} \right] \dots \dots \dots (9.11)$$

turbulent

$$\sqrt{f} = \frac{1}{2.55 \log \left[\frac{2.48w}{e} \right]} \dots \dots \dots (9.12)$$

where:

e = fracture surface roughness (inches)

and Reynolds Number, N_{re} is a dimensionless group defined as:

$$N_{re} = \frac{496R_h \rho V}{\mu} \dots \dots \dots (9.13)$$

where:

R_h = hydraulic radius, $w/2$ for fractures (inches)

V = fluid flow velocity (feet/second)

Louis, working with rough-walled fractures created from concrete slabs, developed similar friction factor relationships:

laminar

$$f = \frac{96}{N_{re}} \left[1 + 3.1 \left(\frac{e}{w} \right)^{1.5} \right] \dots \dots \dots (9.14)$$

turbulent

$$\sqrt{f} = \frac{1}{2 \log \left[\frac{3.8w}{e} \right]} \dots \dots \dots (9.15)$$

Jones⁴⁹ attributed the coefficient differences to the authors' dissimilar treatment of roughness geometry. Figure 9.3.1, reproduced from the Jones paper, shows that the Lomize fractures are idealized while those of Louis are more realistic. It also illustrates the fundamental problem of how to determine fracture aperture

and roughness for real fracture systems.

Jones⁴⁹ used the pipe flow analogy to develop an equation for fracture flow using the friction factor to correct the pressure drop for the increase caused by fracture roughness.

$$Q = 5.06 \times 10^4 H \left[\frac{\Delta P w^3}{f L \rho} \right]^{\frac{1}{3}} \dots \dots \dots (9.16)$$

Noting that flow velocity, V is Q/wH and adjusting for units, Jones⁴⁹ showed that Equation 9.16 reduces to the cubic law equation (Equation 9.9) in the case of flow in smooth walled, planar fractures for which the friction factor is $96 / N_{re}$.

Reiss⁵⁰ used Darcy's law to define fracture permeability:

$$k_f = \frac{10.65 Q L \mu}{H w \Delta P} \dots \dots \dots (9.17)$$

where k_f is fracture permeability in Darcies.

Thus, the permeability of a rough walled fracture becomes:

$$k_f = 5.39 \times 10^3 \mu \left[\frac{w L}{f \Delta P \rho} \right]^{\frac{1}{3}} \dots \dots \dots (9.18)$$

Jones' experimental studies of naturally fractured sandstone concluded that the Cubic Law governs flow in large aperture fractures ($b > 0.0253$ inches) and that deviation increases as the aperture is diminished.

While the equations discussed thus far provide the basics of fracture fluid flow, their application requires a knowledge of fracture aperture and surface roughness. In practical cases these parameters are difficult, if not impossible to define. Furthermore, the effect of increasing confining stress has not yet been addressed.

Walsh⁵¹ developed a useful model relating fracture conductivity (e.g. Darcy-feet) and confining stress. Warpinski *et al*⁵² have expressed the Walsh model as:

$$K_f^n = A + B \ln \sigma_e \dots \dots \dots (9.19)$$

where A and B are constants, n is $\frac{1}{3}$ and σ_e is the effective stress as defined by the effective stress law:

$$\sigma_e = \sigma - \alpha p \dots \dots \dots (9.20)$$

where:

- σ = confining stress (psi)
- α = poroelastic parameter
- p = pore pressure, psi

Figure 9.3.1
Lomize⁴⁶ and Louis⁴⁷ Models
of Fracture Roughness
(reproduced from Jones⁴⁹)

(a) Lomize

(b) Louis

The main parameters controlling fracture conductivity at any pore pressure are B which controls the conductivity reduction and α which defines the stress law influence including the effect of hysteresis observed when the fracture is alternately loaded (increasing effective stress) and unloaded (reducing effective stress).

9.3.2 Fracture Permeability versus Pore Pressure

The experimental results published by Warpinski *et al* for North Sea fractured chalks provided the basis for the fracture permeability versus pore pressure function used in these simulation studies. The authors measured the conductivity of a core plug containing an axial fracture during repeated loading (increasing confining stress) and unloading (diminishing confining stress) cycles until a reproducible cycle was achieved. This process "seasoned" the sample and rendered the data suitable for interpretation. The authors point out that the in situ condition of the rock and fracture may differ from the "seasoned" sample condition. The procedure was performed at four levels of pore pressure.

The chalk fracture apertures were very small and permeabilities were in the microdarcy range. As a result inertial/turbulence effects were quite noticeable, requiring all conductivity measurements to be corrected for turbulence. To make the correction, conductivities were measured at several flow rates and for selected levels of net stress. Flow rates were varied by adjusting upstream and downstream pressures such that average pore pressure remained constant. The intrinsic conductivity at each net stress point was computed by fitting the data to a modified form of the Forcheimer equation:

$$\frac{1}{K_f} = \frac{1}{K_i} + bQ_{aim} \quad \dots\dots\dots (9.21)$$

where K_i , the intrinsic conductivity is defined by the intercept of $1 / K_f$ as a function of gas flow rate at atmospheric conditions, Q_{aim} . The slope, b is related to the turbulence factor, β as follows:

$$\beta = b \frac{\mu h w^2}{\rho_{aim}} \quad \dots\dots\dots (9.22)$$

The computed b values were surface fitted as functions of confining stress, σ and pore pressure p , thus enabling conversion of measured conductivity, K_f to intrinsic conductivity, K_i at any stress condition.

The corrected conductivity was transformed and fitted to a three dimensional surface of the form:

$$K_f = X_1 + X_2\sigma + X_3p + X_4\sigma^2 + X_5\sigma p + X_6p^2 \quad \dots\dots\dots (9.23)$$

where X_n are the fit coefficients and K_f' is the transformed conductivity:

$$K_f' = \left[\frac{K_f}{K_{fo}} \right]^\lambda \quad \dots\dots\dots (9.24)$$

and

$$\begin{aligned} K_{fo} &= \text{maximum } K_f \\ \lambda &= \text{transform parameter } (-3 < \lambda < +3) \end{aligned}$$

The poroelastic parameter (alpha, α) was evaluated from the coefficients of the $K_f' - \sigma - P$ surface as follows:

$$\alpha = - \frac{\left[\frac{\partial K_f'}{\partial p} \right]}{\left[\frac{\partial K_f'}{\partial \sigma} \right]} \quad \dots\dots\dots (9.25)$$

$$\alpha = \frac{X_3 + X_5\sigma + 2X_6p}{X_2 + 2X_4\sigma + X_5p} \quad \dots\dots\dots (9.26)$$

A simulator option allows both porosity and permeability to be deformable, *i.e.* functions of pore pressure. Porosity is treated as a function of pore pressure and permeability is expressed as a function of porosity.

$$\phi_f = \phi_{fo} \exp[c_f(p - p_o)] \quad \dots\dots\dots (9.27)$$

$$k_f = k_{fo} \exp \left[\eta \frac{\phi_f - \phi_{fo}}{1 - \phi_{fo}} \right] \quad \dots\dots\dots (9.28)$$

where, c_f is fracture compressibility and, η is a fitting parameter.

The problem is reduced, therefore, to choosing values of c_f and η which best fit the computed fracture porosity versus pore pressure and permeability versus fracture porosity functions, respectively. These parameters were developed using the Warpinski *et al*⁵² coefficients, X_n . The procedure was as follows:

- a. Compute alpha (α) from Equation 9.26 for stress conditions representative of the prototype reservoir.
- b. Fit the Walsh equation (Equation 9.19) to the Warpinski *et al* data assuming the cubic form, *i.e.* $n = 1/3$. Use the fitted Walsh equation to compute fracture conductivity, K_f for the prototype reservoir stress conditions.
- c. Compute fracture permeability assuming that the conductivity ratio K_f/K_{fo} for the derived function is equivalent to the permeability ratio, k_f/k_{fo} for the scaled function. Thus,

$$\phi_f = \phi_{fo} \left[\frac{K_f}{K_{fo}} \right]^{1/3} \quad \dots\dots\dots (9.29)$$

where k_{fo} is the model fracture permeability at initial pore pressure (10 md).

- d. Compute fracture porosity, ϕ_f assuming that the cubic law pertains. Thus,

$$k_f = k_{fo} \frac{K_f}{K_{fo}} \quad \dots\dots\dots (9.30)$$

where ϕ_{fo} is the model fracture porosity at initial pore pressure (.000984).

- e. Compute the average fracture compressibility, c_f by fitting Equation 6.17 to porosity versus pore pressure.
- f. Determine the simulator input parameter, η by fitting Equation 6.18 to the calculated permeability versus porosity function.

The fitting parameters were determined for two assumed stress conditions. The base case assumption was that the rock was lithostatically loaded, making all three components of the confining stress equal, *i.e.* $\sigma_x = \sigma_y = \sigma_z = \gamma Z$ and

$$\sigma = \frac{(\sigma_{xx} + \sigma_{yy} + \sigma_{zz})}{3} \dots \dots \dots (9.31)$$

where,

γ_o = assumed overburden gradient = 1.0 psi/foot
 Z = average reservoir depth = 6592 feet

This resulted in a base case confining stress of 6592 psig.

The alternative confining stress case assumptions were: $\sigma_{xx} = 0.9Z$; $\sigma_{yy} = 0.75\sigma_{xx}$ and $\sigma_{zz} = 1.1p_o$. Substitution of these values in Equation 9.31 gave an alternate confining stress of 4560.8 psig.

The base case computed fracture porosity and permeability values are shown as functions of pore pressure on Figure 9.3.2. The basic assumed parameters were: confining stress of 6592 psi, initial pore pressure of 3000 psi, porosity at initial pore pressure of .000984 and permeability at initial pore pressure of 10 md. The points are the values derived from the Warpinski *et al*⁵² experimental data and the solid lines show the fitted form of equations 9.27 and 9.28. Figure 9.3.3 displays the same information for the alternate assumed confining stress of 4560.8 psi.

Figure 9.3.3
 Fracture Properties Versus Pore Pressure
 for $\sigma = 6592.0$ psi
 Basis: Warpinski *et al*⁵² Experimental Data

Figure 9.3.4
Fracture Properties versus Pore Pressure
for $\sigma = 4560.8$ psi
Basis: Warpinski et al 52 Experimental Data

10.0 SIMULATION RESULTS

A large number of simulations have been performed in the course of this project. In this section they are presented with reference to depletion method, primary depletion or fluid injection pressure maintenance, and exploitation method, vertical wells or horizontal wells.

In most instances the number of cases was compounded by the need to consider the stress sensitivity of the fracture properties. For discussion purposes, the term *standard option* is used when the case under discussion considered fracture permeability to be independent of pore pressure. Conversely, the term *deform option* is used to distinguish a case in which fracture permeability varied with pressure.

The essential difference between the two options was in the treatment of fracture permeability and porosity, the basis of which has been described in Section 9.3.2. The tabulation below contrasts the standard and deform option treatments of fracture properties as used in this study. For convenience, the use of the subscript f to denote fractures has been omitted.

	Standard Option	Deform Option
Permeability	constant	$k = k_0 \exp \left[\eta \frac{\phi - \phi_0}{1 - \phi_0} \right]$
Exponent, η	not used	$\eta = f(\sigma)$
Porosity	$\phi = \phi_0 [1 + c(p - p_0)]$	$\phi = \phi_0 \exp [c(p - p_0)]$
Compressibility	7.821×10^{-5}	$c = f(\sigma)$

The discussion following Equation 9.27 and Equation 9.28 in Section 9.3.2 explains that η and c_f were determined for two conditions of confining stress, 6592 and 4560.8 psia. The values best fitting the data are tabulated below.

σ , psig	η	c_f
6592.0	3260.5	8.614E-5
4560.8	3545.8	1.299E-4

The greatest majority of the cases simulated were to test for sensitivity to reservoir parameter variation away from the base case parameters. As in the base case models, the reservoir segment was regarded as being comprised of seven isolated and identical fracture swarms. The vertical well models each treated a single fracture swarm containing a single well. As such they contained only 135 grid cells ($NX = 3$ by $NY = 9$

by $NZ = 5$). On the other hand, the horizontal well models included all seven fracture swarms, contained seven times as many grid nodes and ran seven times as long. Because of the running time advantage, sensitivities were tested first in the vertical well model. In most instances, the vertical and horizontal models performed so similarly that detailed discussion of both would have been completely redundant. For the sake of conciseness, the discussions of sensitivity which follow generally reference the vertical model results.

10.1 Base Case Forecasts

The presentation begins with the base case simulations, so called because each simulator was initialized with basic reservoir data as described in Section 9.2.2 through Section 9.2.6. The cases were simulated on one of the four basic models described in Section 9.1, the model selected depending on the method of operation: a depletion model for a natural depletion case, an injection model for a water injection case, and so on.

Each case actually had three variants differentiated by the degree of fracture sensitivity to stress. In the least sensitive, or standard option variant, only fracture porosity was stress sensitive as determined from fracture compressibility. The second and third variations assumed that both fracture porosity and fracture permeability were increasingly stress sensitive. This stress sensitivity was invoked through the deform option as described in section 9.3.2.

The variant type is distinguished by the name prefix **DPCK** to signify Dual Porosity Constant K, or **DPVK** to indicate Dual Porosity Variable K. A unique name for each case was composed by combining a 3 or 4 character suffix with the appropriate prefix. For example the vertical well model base cases were named DPCK_V1A, DPVK_V1A and DPVK_V1B while the horizontal well model base cases were named DPCK_H1A, DPVK_H1A and DPVK_H1B. The appearance of a V or a H in the name suffix is used to denote the vertical well model or the horizontal well model, respectively.

10.1.1 Primary Depletion

Depletion of the reservoir segment by primary recovery was simulated with the vertical depletion model and the horizontal depletion model. The layer of completion was the middle layer or layer three. This meant that the vertical model had a single completion block, whereas, the horizontal model had 21 completion blocks.

Three conditions of stress sensitivity were simulated with each model. The case names and assumed conditions are tabulated below. Note that stress condition *none* is used to signify that fracture permeability was insensitive to stress.

Stress σ , psia	Vertical Well	Horizontal Well
none	DPCK_V1A	DPCK_H1A
6592.0	DPVK_V1A	DPVK_H1A
4560.8	DPVK_V1B	DPVK_H1B

The oil producing rate was allowed to decline until it first fell below a limiting minimum rate at which point the case was terminated. The limiting rates were 1 STB/day for the vertical model and 25 STB/day for the horizontal model.

The effect of stress on the rate of recovery and ultimate recovery factor is illustrated on Figure 10.1.1. Comparing the performance of the vertical well (upper panel) to the horizontal well (lower panel) it is seen that the ultimate oil recovery fraction is about the same but the horizontal well produces the oil at a higher rate. This is entirely consistent with the basic assumptions underlying the two models.

The numerical comparison of the vertical and horizontal model results offered in Table 10.1.1 confirms the visual impression provided by Figure 10.1.1. The recovery factors (the fraction of in-place oil produced during the recovery period) of comparable cases are almost identical. The vertical model required a noticeably longer time to recover the reserves than did the horizontal model. Furthermore, the recovery time divergence increased as the stress state increased: from plus 17% for the standard option, to plus 32% with the deform option when σ was 6592 psia and plus 37% when σ was 4560.8 psia.

Table 10.1.1
Oil Recovery Sensitivity to Confining Stress
Natural Depletion, Base Case Reservoir Definition

Case	σ psig	Recovery period, days	Recovery Factor, %
DPCK_V1A	n.a.	627.1	16.5
DPVK_V1A	6592.0	1040.6	15.4
DPVK_V1B	4560.8	1298.9	14.5
DPCK_H1A	n.a.	535.2	16.4
DPVK_H1A	6592.0	789.5	15.3
DPVK_H1B	4560.8	946.8	14.6

10.1.2 Water Injection

Depletion of the reservoir segment by water flooding such that pressure was maintained from the initiation of production, was simulated using the vertical injection and horizontal injection models. In both model types, the producing well was completed in the top model layer and the injection well was completed in the bottom model layer. Thus, the vertical wells were each completed in a single model block, whereas, the horizontal wells each had 21 completion blocks (refer to Figure 9.1.3).

The oil water capillary pressures used in these simulations were revised to approximate the imbibition nature of the water displacing oil process. These data are shown on Figure 10.3.8.

The same three conditions of stress sensitivity simulated by the natural depletion models were simulated with the two water injection models (horizontal and vertical well models). The case names followed the same conventions as the depletion model. Note again that stress condition *none* is used to signify that fracture

permeability was insensitive to stress.

The oil producing rate limit for the vertical producing well was raised to 5 STB/day but the horizontal producing well limit was the same as the natural depletion cases, 25 STB/day. In all simulated cases, well production was allowed to decline until it first fell below the limiting rate, at which point the case was terminated.

Reservoir pressure was maintained by specifying suitable bottom hole pressures in the producing and injecting well bores. These were determined by monitoring the pressure in the reservoir away from the producing block. The objective was to keep these pressures from declining, thereby arresting fracture permeability decline when the deform option was invoked.

The objective was very successfully achieved: reservoir pressures were maintained and fracture permeability decline was arrested as evidenced by the ultimate recovery factors shown in Table 10.2.1 and the performance plots provided in Figure 10.2.1. Furthermore, the favorable oil-water relative permeability and capillary pressure provided efficient imbibition driven recovery of the matrix oil. Table 10.1.2 shows the vertical model ultimate recovery by water flooding was about 42% and little affected by stress (*c.f.* cases DPCK_IV3, DPVK_IV3 and DPVK_BV3). The horizontal well model recovery numbers (cases DPCK_IH3, DPVK_IH3 and DPVK_BH3) were one-half to one percent higher.

Table 10.1.2
Oil Recovery Sensitivity to Confining Stress
Water Injection, Base Case Reservoir Definition

Case	σ psig	Recovery period, days	Recovery Factor, %
DPCK_IV3	n.a.	2388.5	42.1
DPVK_IV3	6592.0	2331.8	41.7
DPVK_BV3	4560.8	2477.9	41.8
DPCK_IH3	n.a.	2826.0	42.8
DPVK_IH3	6592.0	3114.4	42.6
DPVK_BH3	4560.8	3128.2	42.3

Figure 10.1.1
Oil Recovery Sensitivity to Confining Stress
Natural Depletion, Base Case Reservoir Definition

(a) Vertical Depletion Model

(b) Horizontal Depletion Model

While the effect of stress on ultimate recovery was almost negligible, Figure 10.1.2 shows that stress augmentation caused water breakthrough to occur at progressively lower recoveries. There was also a progressive increase in the time required to recover the reserves. The time increase was much greater for the horizontal well model (302.2 days) than for the vertical model (89.4 days). (See Table 10.1.2 Case IH3 versus Case BH3 as compared to Case IV3 versus Case BV3).

These same two simulators, the vertical injection model and the horizontal injection model, were also employed for the sensitivity studies discussed in section 10.3.

Figure 10.1.2
Oil Recovery Sensitivity to Confining Stress
Water Injection, Base Case Reservoir Definition

(a) Vertical Injection Model

(b) Horizontal Injection Model

10.1.3 Gas Injection

The use of injected produced gas to supplement the natural reservoir energy and reduce the rate of pressure decline was explored in this series of cases using only the vertical injection model. The well completion interval was changed to take advantage of gravity forces such that oil was withdrawn from the lowermost layer at the producing well while gas was introduced in the uppermost layer at the injection well. The fraction of produced gas re-injected was varied by case: 100 percent for cases gV2, 75 percent for Case fV2, and 66 percent for Case eV2.

Figure 10.1.3, panel (a) offers a comparison of these three cases against Case V2A, the similarly completed natural depletion case. The figure clearly shows that gas re-injection, at best, offers no real recovery benefit over natural depletion, and if all of the produced gas is recycled, as in Case eV2, the recovery was actually reduced. This observation is borne out by the recovery factors given in Table 10.1.3.

The same series of recycled gas fractions was repeated using the lower, more "L-shaped" capillary pressure curves discussed in Section 10.2.10 (Case V1R). These were cases were numbered hV2, iV2, and jV2. To provide a comparable case, the base case natural depletion alternative, completed in the bottom layer and using the revised capillary pressures was rerun as Case V2R. The performance comparison for this suite of cases is shown by Figure 10.1.3(b). The performance pattern is much the same, showing gas recycling recovery to be no better than natural depletion; however, the more favorable capillary pressures did provide a modest recovery improvement over the eV3, fV3 and gV3 cases (Table 10.1.3).

Table 10.1.3
Oil Recovery Sensitivity to Recycled Gas Volume and p_{cm}
Vertical Gas Injection Model

Case	Recycle fraction	p_{cm} shape	Recovery period, days	Recovery factor, %
V2A	none	$p_c^{-1} \text{ lin } f(s_w)$	435.9	16.2
eV2	0.66 * Gp	$p_c^{-1} \text{ lin } f(s_w)$	488.2	16.4
fV2	0.80 * Gp	$p_c^{-1} \text{ lin } f(s_w)$	518.8	16.3
gV2	1.00 * Gp	$p_c^{-1} \text{ lin } f(s_w)$	311.6	10.6
V2R	none	$p_c^{-2} \text{ lin } f(s_w)$	488.0	17.1
hV2	0.66 * Gp	$p_c^{-2} \text{ lin } f(s_w)$	565.2	17.7
iV2	0.80 * Gp	$p_c^{-2} \text{ lin } f(s_w)$	612.1	17.7
jV2	1.00 * Gp	$p_c^{-2} \text{ lin } f(s_w)$	365.2	11.3

The failure of gas re-injection to improve recovery over the natural depletion case indicates the lack of potential for injection gas to enter the matrix. This is largely due to the dual porosity formulation which regards every matrix block to be separated from its neighbors by a capillary discontinuity, thus limiting gravity potential for oil to drain from the matrix to that imposed by the assumed block size. Recent studies by Firoozabadi et al have demonstrated that capillary continuity most probably does exist across block boundaries such that a vertical assemblage of matrix blocks experiences gravity drainage much as it would if the fractures were non-existent.

Figure 10.1.3
Oil Recovery Sensitivity to Recycled Gas Volume and p_{cm}
Vertical Injection Model, Gas Injection

(a) Base Case Capillary Pressure

(b) Reduced Capillary Pressure

Furthermore, the voidage replacement afforded by the injected gas tends to maintain matrix pressures above bubble point, thus retard the evolution of dissolved gas and expulsion of oil into the fractures. Evidently, this reduction of matrix oil expulsion is compensated by reduced shrinkage of oil in the fractures, since the ultimate recoveries of the best injection cases (eV2 or fV2) are comparable to the depletion cases, (V2A or V2R). Figure 10.1.4 which compares the evolution of average matrix values of gas saturation and pressure for injection Case eV2 to depletion Case V2A, supports this reasoning.

Given the poor results obtained with produced gas recycling, the use of gas injection at rates sufficient to maintain pressure was ruled out.

10.1.4 Combined Injection of Gas and Water

The possibility of recovery improvement with gas injection into the top model layer, water injection into the bottom model layer, and production from the middle model layer was investigated in a series of three runs. The imbibition water-oil capillary pressure functions were used for the water displacing oil process as was done for the water injection only cases.

The assumed volumes of recycled gas were 90 percent of those used for the gas injection cases. In all three cases, gas injection was supplemented by water injection sufficient to maintain the reservoir pressure. Water injection was regulated by monitoring reservoir pressure, just as it was for the water injection cases (Section 10.1.2).

Table 10.1 4 summarizes the oil recovery data for these cases and provides a convenient reference for the recycled gas fraction. The recoveries realized for all recycling rates were some two percent lower than the water flood recoveries discussed in Section 10.1.2.

Table 10.1.4
Oil Recovery Sensitivity to Recycled Gas Volume
Vertical Gas and Water Injection Model

Case	Recycle fraction	Recovery period, days	Recovery factor, %
cV1	$0.900 * G_p$	1826.2	39.8
dV1	$0.720 * G_p$	1579.5	39.6
eV1	$0.594 * G_p$	1552.7	39.6

Figure 10.1.5 presents the results for these cases versus recovery factor: panel (a) shows oil production rate and gas-oil ratio and panel (b) shows oil production rate and water cut. Following an initial decline, all three cases show a levelling of production rate which continues until about one-third of the oil has been recovered. During this period, the gas-oil ratio, after an initial build-up which mirrors the production decline, also flattens at a gas-oil ratio level dependent on the recycle fraction. The water cut (Panel (b) shows that water breakthrough occurred at after one-quarter of the oil had been recovered and that the oil production rate plateau extended until the water cut reached about 10 percent. Thereafter, the production rate began an almost log-linear decline and the water cut continued to increase, eventually exceeding 90 percent.

10.1.5
Oil Recovery Sensitivity to Recycled Gas Volume
Gas and Water Injection, Vertical Injection Model
Base Case Capillary Pressure

(a) Oil Rate and Gas-Oil-Ratio

(b) Oil Rate and Water Cut

10.2 Primary Recovery Sensitivity

The sensitivity of the simulated natural depletion performance to reservoir parameter variation was tested by the series of cases described below. Each run was made with some variation of one of the base case depletion

models. Taking the series of runs for shape factor as an example, the base case (Case V1A) assumed one-foot cubic matrix blocks, Case V6 assumed one-foot square columnar blocks, and Case V7 assumed one-foot wide tabular blocks.

Most of the cases were run on both models: the vertical depletion model and the horizontal well model. Most often the results of the two models were very similar in character so the discussion herein focuses on the vertical model. Discussion of the horizontal model will be introduced whenever there is some departure from this general case. The performance plots in Appendix D do, however, include all of the horizontal depletion cases. The same plot format was used for both vertical and horizontal model results in order to facilitate comparison and verification of their similarity.

The sensitivity testing was begun in Task 1 and continued into Task 2; however, the treatment of fracture permeability differed, being independent of pressure for Task 1 and variable with pressure for Task 2. Forty-one different reservoir parameter variations were simulated in Task 1. Many of the same parameter variations were also simulated in Task 2.

All simulations were terminated when the oil producing rate first fell below a specified limit. For Task 1, the terminal rates were 10 STB/day for a vertical well and 25 STB/day for a horizontal well. In order to make meaningful ultimate recovery comparisons for some of the Task 2 vertical well cases, it was necessary to reduce the terminal rate to 1 STB/day. This being the case, all Task 2 vertical well cases were continued to the lower, 1 STB/day terminal rate.

10.2.1 Completion Layer

The base cases, V1A and H1A, assumed the well to be completed in the middle of the reservoir, *i.e.* in model layer three. Cases V2A and H2A considered the well to be completed near the base of the reservoir in model Layer 5, as it might be to take advantage of gravity segregation and delay gas production. The last cases in this series, V3A and H3A, had the wells completed near the top of the reservoir in model Layer 1.

The results of these runs are compared to the base case in Figure 10.2.1 in terms of oil production rate and gas-oil ratio versus cumulative oil recovery as a fraction of oil initially in place. The comparison shows that the mid-point completion depth (Case H1A) gives the most favorable rate of recovery, while the bottom completion interval (Case H2A) provides the highest ultimate recovery. The top completion interval (Case H3A) yields the least desirable results. The cases are compared in terms of cumulative oil produced and recovery as a fraction of oil initially in place in the simulated reservoir segment in the following table. These figures show that recovery is relatively insensitive to positioning of the completion interval.

Table 10.2.1
Oil Recovery Sensitivity to Depth of Completion
Horizontal Depletion Model

Case/Interval	Recovery period, days	Recovery factor, %
H1A, middle	535.2	0.164
H2A, base	594.6	0.166
H3A, top	547.9	0.160

Figure 10.2.1
Oil Recovery Sensitivity to Depth of Completion
Horizontal Depletion Model

10.2.2 Distribution of Swarm Oil-In-Place

The oil-in-place of a given fracture swarm would be determined by the distributions of the volumetric parameters: porosity, oil saturation (matrix and fracture), swarm dimensions (width, length, height), net to gross ratio and formation volume factor. The oil-in-place distribution was simulated by Monte Carlo simulation, using reported data or assumptions, and assuming either triangular distribution or constant values for all parameters, as appropriate. The oil-in-place values at the first through seventh octiles provided the fracture swarm oil-in-place volumes for this series of cases. These volumes were randomly assigned to the fracture swarms of the Case H18 model. The same volumes were assigned in ascending order to the fracture swarms of the Case H19 model and in descending order for the Case H20 model, the ordering being with reference to the well bore outlet. Thus, all three models had the same total oil-in-place and the same statistical distribution but in differing arrangements. To get a base case comparison, the H1A model was re-initialized with this same total volume, equally distributed among all seven fracture swarms. To avoid confusion the re-initialized base case was named H1X. The two models differ only in respect to oil-in-place: 1,546,154 STB for Case H1X and 1,435,502 STB for Case H1A.

The results of the variable oil-in-place cases were quite similar to each other and to the uniform distribution case. Some differences in oil rate and gas-oil ratio profiles indicated a modest sensitivity in this respect. Figure 10.2.2, comparing Cases H18 and H1X illustrates the fullest extent of the observed differences. Table 10.2.2 shows that while all four cases achieved the same oil recovery, the recovery period was longer for the non-uniform distribution cases.

Figure 10.2.2
Oil Recovery Sensitivity to Fracture Swarm OOIP Distribution
Horizontal Depletion Model

Table 10.2.2
Oil Recovery Sensitivity to Fracture Swarm OOIP Distribution
Horizontal Depletion Model

Case/distribution	Recovery period, years	Recovery factor, %
H18, random	617.8	16.4
H19, ascending	672.8	16.4
H20, descending	673.2	16.4
H1X, uniform	581.5	16.4

10.2.3 Shape Factor

The dual porosity formulation uses a shape factor in the definition of the matrix-fracture fluid transfer term. Warren and Root¹² originally defined the shape factor, σ for the assumption of single-phase, quasi-steady state flow as,

$$\sigma = \frac{4N}{L^2}(N + 2) \quad \dots \dots \dots (10.1)$$

where:

- N = number of sets of fractures
- L = block dimension (fracture spacing)

For cubic block cases, Equation 10.1 reduces to:

$$\sigma = \frac{60}{L^2}$$

Kazemi²⁶, still assuming pseudo steady state matrix-fracture flow but working with a multi-phase, unsteady state reservoir simulator revised the shape factor definition as follows:

$$\sigma = 4 \left[\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2} \right] \dots \dots \dots (10.2)$$

where:

- L_x = block dimension in X-direction
- L_y = block dimension in Y-direction
- L_z = block dimension in Z-direction

Again, for the cubic block case, Equation 10.2 reduces to:

$$\sigma = \frac{12}{L^2}$$

Thomas²⁷ re-defined the shape factor by adding the terms total fracture block face area, A and fracture block volume, V_b as follows:

$$\sigma = \frac{A}{L_f V_b} \dots \dots \dots (10.3)$$

where:

L_f = a characteristic flow path length

Setting L_f to the distance from a block face to the centroid of the pyramid having the block face as its base and a volume, $L^3/6$, the author suggested a shape factor as follows:

$$\begin{aligned} A &= 6L^2 \\ V_b &= L^3 \\ L_f &= L/6.1 \end{aligned}$$

therefore,

$$\sigma = \frac{36.6}{L^2}$$

Taking the simple cubic block case ($L_r = L$), the Thomas definition then becomes:

$$\sigma = \frac{6}{L^2}$$

The effect of shape factor was tested in a suite of six runs, three using the Kazemi definition (Equation 10.2) and three using the Thomas definition (Equation 10.3). All cases used a characteristic matrix block dimension of one foot. Table 10.2.3 compares the cumulative production and recovery fraction of these six cases.

Table 10.2.3
Oil Recovery Sensitivity to Dual Porosity Shape Factor
Horizontal Depletion Model

Case/Shape	σ , 1/ft ²	Recovery period, days	Recovery factor, %
V1A, cube	12.0	627.1	16.5
V6K, column	8.0	421.8	16.4
V7K, slab	4.0	436.7	16.7
V1T, cube	36.6	334.5	14.5
V6T, column	4.0	437.0	16.7
V7T, slab	2.0	451.1	16.9

With the exception of the base case which used the Kazemi definition, the case names differentiate the shape factor calculation method by letter: K for the Kazemi method and T for the Thomas method. The results show a logical progression, in that recovery increases as the shape factor is reduced, under either method of computation. Further, the Thomas method yields somewhat higher recoveries for the column and slab geometries.

The recovery performance of the shape factor sensitivity cases is compared in Figure 10.2.3. The panel labelled (a) shows the Kazemi method results while the (b) panel gives Thomas method results. The visual impression gained from these plots agrees with the observations in the paragraph above.

Figure 10.2.3
Oil Recovery Sensitivity to Dual Porosity Shape Factor
Horizontal Depletion Model

(a) Kazemi

(b) Thomas

10.2.4 Fracture Spacing

Fracture spacings varying from one-half to ten times the base case spacing were simulated in a series of nine vertical model cases. A narrower range of spacings (one-half to four times) were simulated with the horizontal model. The matrix blocks were assumed to be cubic in all cases. Table 10.2.4 summarizes the results of this series of runs.

The oil recovery factors suggest that there is an optimum block size[†]. The recovery is seen to rise sharply as block size is increased from 0.5 feet, remain fairly constant for spacings ranging from 2 to 4 feet and eventually to drop slightly at the widest, 8 foot spacing. These observations are clearly evident on Figure 10.2.4 which displays recovery factor as a function of block size. The similarity of the horizontal and vertical well results strongly suggests that the Case H9A recovery is a maximum for the cubic block shape assumed for the prototype reservoir.

10.2.5 Relative Conductivity (matrix/fracture)

Relative conductivity, or the ratio of matrix permeability to fracture permeability, was 10^{-5} in the base case model. This series of runs looked at the recovery implications of increasing the ratio to 10^{-4} , and of reducing the ratio to 10^{-6} . The changes were accomplished in either of two ways: keep the base case fracture permeability and change the matrix values (Cases V12/H12 and VC13/H13), or keep the base case matrix permeability and revise fracture permeability (Cases V1F/H1F Case V1K/H1K).

Table 10.2.4
Oil Recovery Sensitivity to Fracture Spacing
Horizontal Depletion Model

Case & spacing, feet		Recovery period, days	Recovery factor, %
<u>Vertical</u>			
V8	0.50	349.3	14.3
V8A	0.75	388.1	15.6
V1A	1.00	414.6 ^{††}	16.1
V9	2.00	413.0	16.5
V9A	4.00	412.1	16.5
V9B	8.00	442.0	16.3
<u>Horizontal</u>			
H8	0.5	434.0	14.5
H1A	1.0	535.2	16.4
H9	2.0	566.1	16.9
H9A	4.0	577.8	16.9

The oil recovery factors suggest that there is an optimum block size^{†††}. The recovery is seen to rise sharply as block size is increased from 0.5 feet, remain fairly constant for spacings ranging from 2 to 4 feet and eventually to drop slightly at the widest, 8 foot spacing. These observations are clearly evident on

[†] The terms block size and fracture spacing are synonymous in the context of this report.

^{††} Recovery data for is to a minimum rate of 10 STB/day.

^{†††} The terms block size and fracture spacing are synonymous in the context of this report.

Figure 10.2.4 which displays recovery factor as a function of block size. The similarity of the horizontal and vertical well results strongly suggests that the Case H9A recovery is a maximum for the cubic block shape assumed for the prototype reservoir.

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The performance plot comparing the changed matrix permeability cases, V12 and V13 to the base case, V1A is shown on Figure 10.2.5(a). It shows that oil recovery varied inversely with matrix permeability, reducing as permeability was increased (Case V12) and increasing as permeability was reduced (Case V13). Also, the recovery changes were disproportionate: the reduction being much greater than was the improvement. This observation is borne out by the recovery factors shown in Table 10.2.5 for these same standard option cases. Furthermore, the recovery period is seen to have increased much more rapidly than did the recovery factor.

The last two panels of Figure 10.2.5 and the last two groupings of in Table 10.2.5 depict how cases of similar matrix permeability are affected by increasing fracture deformation. In terms of recovery factor, the increased matrix permeability cases, V12 and V1G are seen to be most sensitive, whereas the reduced permeability cases, V13 and V1H are little affected (Table 10.2.5). The picture is reversed, however, in respect to recovery period. The prolongation of the recovery period caused by increasing fracture deformation is much greater for the reduced permeability cases than it is for the increased permeability cases.

Figure 10.2.5
Oil Recovery Sensitivity to Relative Conductivity and Stress
Matrix Permeability Varied, Vertical Depletion Model

(a) $k_r = 10$ md & insensitive to stress

(b) Stress sensitivity for $k_m/k_r = 0.001/10$

(c) Stress sensitivity for $k_m/k_r = 0.00001/10$

Table 10.2.5
Oil Recovery Sensitivity to Relative Conductivity and Stress
Matrix Permeability Varied, Vertical Depletion Model

Case	σ , psia	k_m , μD	k_m/k_f	Recovery period, days	Recovery factor, %
DPCCK_V12	n.a.	1.0	10^{-4}	282.3	11.5
DPCCK_V1A	n.a.	0.1	10^{-5}	627.1	16.5
DPCCK_V13	n.a.	0.01	10^{-6}	845.9	17.6
DPCCK_V12	n.a.	1.0	10^{-4}	282.3	11.5
DPVK_V12	6592.0	1.0	10^{-4}	408.2	9.4
DPVK_V1G	4560.8	1.0	10^{-4}	483.8	8.5
DPCCK_V13	n.a.	0.01	10^{-6}	845.9	17.6
DPVK_V13	6592.0	0.01	10^{-6}	1599.4	17.4
DPVK_V1H	4560.8	0.01	10^{-6}	2207.8	17.3

Parallel comparisons can be made for the changed fracture permeability alternative results displayed in Figure 10.2.6 and Table 10.2.6. Comparing Figure 10.2.6(a) to Figure 10.2.5(a), it is obvious that changing the fracture permeability profoundly affected the rate of oil recovery (Figure 10.2.6); however, the fractional recovery for a comparable k_m/k_f ratio was about the same regardless of which permeability was changed (Table 10.2.6 versus Table 10.2.5).

Table 10.2.6
Oil Recovery Sensitivity to Relative Conductivity and Stress
Fracture Permeability Varied, Vertical Depletion Model

Case	σ , psia	k_f , mD	k_m/k_f	Recovery period, days	Recovery factor, %
DPCCK_V1F	n.a.	1	10^{-4}	2311.1	11.3
DPCCK_V1A	n.a.	10	10^{-5}	627.1	16.5
DPCCK_V1K	n.a.	100	10^{-6}	119.4	17.7
DPCCK_V1F	n.a.	1	10^{-4}	2311.1	11.3
DPVK_V1F	6592.0	1	10^{-4}	3002.7	9.2
DPVK_V1D	4560.8	1	10^{-4}	3446.1	8.2
DPCCK_V1K	n.a.	100	10^{-6}	119.4	17.7
DPVK_V1K	6592.0	100	10^{-6}	252.6	17.6
DPVK_V1E	4560.8	100	10^{-6}	398.7	17.5

Figure 10.2.8
Oil Recovery Sensitivity to Relative Conductivity and Stress
Fracture Permeability Varied, Vertical Depletion Model

(a) $k_m = 0.0001$ md, k_f insensitive to stress

(b) Stress sensitivity for $k_m/k_f = 0.0001/1$

(c) Stress sensitivity for $k_m/k_f = 0.0001/100$

Thus, it would appear that ultimate oil recovery principally depends on the ratio of matrix to fracture permeability, increasing as the ratio is reduced and reducing as the ratio is increased. Furthermore, the impact of fracture deformation on oil recovery is exacerbated when the permeability ratio is increased but the prolongation of the recovery period is proportionately greater when the permeability ratio is reduced.

10.2.6 Relative Storativity (fracture/matrix)

The base case fracture porosity was computed assuming a uniform fracture aperture of 0.1 mm and one-foot cubic matrix blocks. This provided a fracture porosity of 0.000984. In the series of cases discussed in this section, the ratio of fracture pore volume to matrix pore volume (relative storativity) was altered to either of one-half or four times the base case ratio ($0.000984/0.0336 = 0.0293$). Again, there were two ways to accomplish these changes: either keep matrix porosity constant and change fracture porosity, or keep fracture porosity constant and change matrix porosity. Both means were explored.

Matrix porosity was kept constant and fracture porosity was changed to 0.000492 ($0.5\times$) for Case H14 and to 0.003936 ($4\times$) for Case H15. These values correspond to one-foot cubic matrix blocks surrounded by constant aperture fractures of 0.05 mm and 0.4 mm, respectively. Although fracture aperture modification would also impact fracture permeability, only porosity was changed for these runs.

For cubic blocks, the functional relationship of fracture porosity, ϕ_f to fracture aperture, w_f and block size, L is:

$$\phi_f = \frac{(L + w_f)^3 - L^3}{(L + w_f)^3} \dots \dots \dots (10.4)$$

Fracture aperture also enters into the computation of flow from one matrix block to the surrounding fractures in two ways. First in the computation of harmonic mean permeability, $\bar{k}$:

$$\bar{k} = \frac{(w_f k_m + L k_f)(L + w_f)}{k_f k_m} \dots \dots \dots (10.5)$$

and secondly, the potential gradient:

$$\frac{\Delta \Phi}{\Delta L} = \frac{2(\Phi_f + \Phi_m)}{(L + w_f)} \dots \dots \dots (10.6)$$

where Φ_f and Φ_m refer to the potential of the fractures and matrix, respectively.

Equation 10.5 indicates that fracture aperture should have a negligible effect on $\bar{k}$ since the product, $w_f k_m$ approaches zero and fracture aperture is insignificant in relation to the block dimension, with w_f in comparison to L . This reasoning applies to Equation 10.6 as well. Thus, it seems safe to conclude that the sensitivity shown by Case V14 and Case V15 in comparison to the base case, V1A, is a valid reflection of the relative storativity effect.

Figure 10.2.7(a) shows the sensitivity of oil recovery and gas-oil ratio to fracture porosity under standard option conditions. The differences in recovery were small, but recovery did consistently increase as fracture porosity was increased (Table 10.2.7, DPCK prefix cases).

The sensitivity of the reduced fracture porosity cases to increasing deformation is shown in Figure 10.2.7(b). The trend of reduced recovery as deformation is increased is clear but the final recovery factor reductions were small (Table 10.2.7, second grouping). The time required to recover the oil was considerably more sensitive (from 562.8 days to 837.5 days).

Figure 10.2.7(c) and the last grouping of cases in Table 10.2.7 show that increasing fracture porosity greatly increased sensitivity to increased deformation. The larger fraction of fracture oil, the higher compressibility of the fracture pore volume and the deformation induced permeability reduction all tended to act in the same direction in these cases.

The relative storativities of Case VIP and Case VIM were the same as those of Case V14 and Case V15, respectively, but the ratios were achieved by changing matrix porosity while keeping fracture porosity constant. As this change alone would have resulted in unacceptably large oil-in-place changes, net thickness was adjusted to compensate so that oil-in-place was effectively unchanged. The modification of net thickness required a reciprocal modification of permeability to retain the same transmissibility from case to case.

The effect of matrix porosity variation (Case VIM and Case VIP) is displayed in Figure 10.2.8 and quantified in Table 10.2.8. Figure 10.2.8(a) shows that reducing matrix porosity increased the recovery fraction more rapidly than raising matrix porosity reduced recovery. Comparing this illustration to Figure 10.2.7(a), it is also evident that this sensitivity depended only on the ratio of fracture to matrix porosity. This observation is certainly borne out by the identical recovery factors and similar recovery periods of the standard option cases, Table 10.2.8, as compared to Table 10.2.7 (DPCK name prefixes).

Comparing Figure 10.2.8(b) to Figure 10.2.7(b) it is evident that if storativity ratio is reduced through matrix porosity revision, the results were more sensitive to deformation. Conversely the (c) panels of these same illustrations show that increasing the storativity ratio through matrix porosity reduction showed reduced sensitivity to deformation.

2 of 2

Figure 10.2.7
Oil Recovery Sensitivity to Relative Storativity and Stress
Fracture Porosity Varied, Vertical Depletion Model

(a) $\phi_m = 3.36\%$, k_r insensitive to stress

(b) Stress sensitivity for $\phi_f/\phi_m = 0.0492/3.36$

(c) Stress sensitivity for $\phi_f/\phi_m = 0.3927/3.36$

Table 10.2.7
Oil Recovery Sensitivity to Relative Storativity and Stress
Fracture Porosity Varied, Vertical Depletion Model

Case	σ , psia	ϕ_f , %	ϕ_f/ϕ_m	Recovery period, days	Recovery factor, %
DPCK_V14	n.a.	.0492	.01464	562.8	16.2
DPCK_V1A	n.a.	.0984	.02929	627.1	16.5
DPCK_V15	n.a.	.3936	.11714	915.4	17.6
DPCK_V14	n.a.	.0492	.01464	562.8	16.2
DPVK_V14	6592.0	.0492	.01464	728.3	15.7
DPVK_V1J	4560.8	.0492	.01464	837.5	15.4
DPCK_V15	n.a.	.3936	.11714	915.4	17.6
DPVK_V15	6592.0	.3936	.11714	3303.3	10.6
DPVK_V1I	4560.8	.3936	.11714	5885.7	8.0

Table 10.2.8
Oil Recovery Sensitivity to Relative Storativity and Stress
Matrix Porosity Varied, Vertical Depletion Model

Case	σ , psia	ϕ_m , %	ϕ_f/ϕ_m	Recovery period, days	Recovery factor, %
DPCK_V1P	n.a.	6.72	.01464	572.6	16.2
DPCK_V1A	n.a.	3.36	.02929	627.1	16.5
DPCK_V1M	n.a.	0.84	.11714	813.4	17.6
DPCK_V1P	n.a.	6.72	.01464	572.6	16.2
DPVK_V1P	6592.0	6.72	.01464	948.5	15.0
DPVK_V1L	4560.8	6.72	.01464	1331.1	16.8
DPCK_V1M	n.a.	0.84	.11714	813.4	17.6
DPVK_V1M	6592.0	0.84	.11714	1199.3	14.0
DPVK_V1N	4560.8	0.84	.11714	1708.6	16.3

Figure 10.2.8
Oil Recovery Sensitivity to Relative Storativity and Stress
Matrix Porosity Varied, Vertical Depletion Model

(a) $\phi_r = 0.0984\%$, k_r insensitive to stress

(b) Stress sensitivity for $\phi_r/\phi_m = 0.0984/6.72$

(c) Stress sensitivity for $\phi_r/\phi_m = 0.984/0.84$

10.2.7 Fracture Capillary Pressure

Capillary pressure was assumed to be nonexistent in the fractures of the base case model. Case H16 and Case H17 considered the effects of non-zero fracture capillary pressures. Fracture oil-water and gas-oil capillary pressure were assumed to be simple fractions of matrix capillary pressure values: one-half for Case H16 and two-tenths for Case H17. The same fractions were applied to irreducible water saturation, reducing the Case H16 value to 0.15 and Case H17 to 0.06.

Figure 10.2.9(a) displays oil rate and gas-oil ratio for these cases in comparison to the base case (V1A). The results clearly show that oil recovery increased with increasing fracture capillary pressure but that the recovery increases are realized at an advanced stage of depletion. A numerical comparison of recovery fractions and times for these standard option cases are given in the first grouping on Table 10.2.9.

Figure 10.2.9, parts (b) and (c) show that fracture deformation impacted recovery time much more than it did the recovery fraction. For the most severe deformation cases (V23 or V24) the prolongation was some 2.5 times the timings for standard option cases of similar fracture capillary pressure (last two grouping of Table 10.2.9).

10.2.8 Fracture Relative Permeability

A series of four runs was made to test the base case assumptions of linear relative permeability and zero or unity endpoint values for the fracture system. The Case V30 model used linear relative permeabilities, but with endpoints of two-tenths of the corresponding matrix values. This introduced an irreducible water saturation of 0.06 and residual oil saturations of 0.032 (gas displacement) and 0.056 (water displacement) to the fracture system. Fracture capillary pressure was as described in the preceding section, commensurate with irreducible water saturation. Linear relative permeabilities were also used for Case V31, but the ratio of fracture to matrix endpoints was increased to one-half. Case V32 and Case V33 used curvilinear relative permeabilities and endpoints as for Case V30 and Case V31, respectively. The curvature was introduced by equating relative permeability to the square of the normalized saturation of the flowing phase. Thus, for the two-phase, oil-water system:

$$k_{rw} = S_w^{*2} \dots \dots \dots (10.7)$$

where:

$$S_w^* = \frac{S_w - S_{wi}}{1 - S_{wi}} \dots \dots \dots (10.8)$$

and

$$k_{row} = S_{ow}^{*2} \dots \dots \dots (10.9)$$

where:

$$S_{ow}^* = \frac{S_o - S_{orw}}{1 - S_{wi} - S_{orw}} \dots \dots \dots (10.10)$$

and for the gas-oil system

$$k_{rg} = S_g^{*2} \dots \dots \dots (10.11)$$

where:

$$S_g^* = \frac{S_g - S_{gc}}{1 - S_{wi} - S_{gc}} \dots \dots \dots (10.12)$$

and

$$k_{rog} = S_{og}^{*2} \dots \dots \dots (10.13)$$

where:

$$S_{og}^* = \frac{S_o - S_{org}}{1 - S_{wi} - S_{org}} \dots \dots \dots (10.14)$$

The fracture-relative permeabilities and capillary pressures corresponding to the 0.2 endpoint assumption, Case V30 (linear) and Case V32 (curvilinear), are displayed in Figure 10.2.10 (oil-water) and Figure 10.2.11 (gas-oil). Figure 10.2.12 (oil-water) and Figure 10.2.13 (gas-oil) depict the 0.5 endpoint assumption data as used for Case V31 (linear) and Case V32 (curvilinear).

Figure 10.2.9
Oil Recovery Sensitivity to Fracture Capillary Pressure and Stress
Vertical Depletion Model

(a) $\phi_m = 3.36\%$, k_r insensitive to stress

(b) Stress sensitivity for $p_{cf}/p_{cm} = 0.5$

(c) Stress sensitivity for $p_{cf}/p_{cm} = 0.2$

Figure 10.2.10
Fracture Oil-Water Relative Permeability
(s_{wi} , s_{orw} , p_{cow}) = 0.2 of Matrix Values

Figure 10.2.11
Fracture Gas-Oil Relative Permeability
(s_{wi} , s_{org} , p_{cgo}) = 0.2 of Matrix Values

Figure 10.2.12
Fracture Oil-Water Relative Permeability
(s_{wi} , s_{orw} , p_{cow}) = 0.5 of Matrix Values

Figure 10.2.13
Fracture Gas-Oil Relative Permeability
(s_{wi} , s_{org} , p_{cgo}) = 0.5 of Matrix Values

Table 10.2.9
Oil Recovery Sensitivity to Fracture Capillary Pressure and Stress
Vertical Depletion Model

Case	σ , psia	p_{cr}/p_{cm}	Recovery period, days	Recovery factor, %
DPCK_V16	n.a.	0.5	949.9	17.9
DPCK_V17	n.a.	0.2	728.4	17.0
DPCK_V1A	n.a.	0.0	627.1	16.5
DPCK_V16	n.a.	0.5	949.9	17.9
DPVK_V16	6592.0	0.5	1694.9	17.7
DPVK_V23	4560.8	0.5	2338.0	16.3
DPCK_V17	n.a.	0.2	728.4	17.0
DPVK_V17	6592.0	0.2	1291.4	17.3
DPVK_V24	4560.8	0.2	1718.5	15.6

The linear fracture relative permeability cases are compared graphically on Figure 10.2.14 and numerically in Table 10.2.10. Cases V1A, V30 and V31 (Figure 10.2.14(a)) all used linear fracture relative permeability but with differing endpoint assumptions. The simulated production rate and gas-oil ratio trended slightly more favorably as the endpoint level was increased, but the differences materialized late in the recovery life, so that ultimate recovery was little affected. These observations are supported by trend of recovery factors and time periods shown in Table 10.2.10 (first grouping).

Figure 10.2.14 (b) and (c) show that the recovery rate was impacted by increasing deformation. The recovery factors of the 0.2 end point cases (V30 and V34) were most affected by increasing deformation. The prolongation of recovery time was most severe for the 0.5 end point cases (Table 10.2.10 last two groupings).

Figure 10.2.15(a) compares the curvilinear Case V32 and Case V33 to the linear fracture relative permeability base case. The rate of oil recovery for both curvilinear cases was less favorable, but the final recovery of all three cases was quite similar. The recovery factor and timing data shown in Table 10.2.11 for these cases provide confirmation.

The (b) and (c) portions of Figure 10.2.15 illustrate the deformation sensitivity for the two end point assumptions. If Figure 10.2.15 is compared to Figure 10.2.14, it is seen that the linear fracture permeability assumption yielded more optimistic results overall. The same conclusion is reached if Table 10.2.11 is compared to Table 10.2.10.

Figure 10.2.14
Oil Recovery Sensitivity to Linear Fracture Relative Permeability
Vertical Depletion Model

(a) k_i insensitive to stress

(b) Stress sensitivity for 0.2 endpoint values

(c) Stress sensitivity for 0.5 endpoint values

Table 10.2.10
Oil Recovery Sensitivity to Linear Fracture Relative Permeability
Vertical Depletion Model

Case	σ , psia	shape	$s_{\text{orf}}/s_{\text{orm}}$	Recovery period, days	Recovery factor, %
DPCK_V1A	n.a.	lin.	0.0	627.1	16.5
DPCK_V30	n.a.	lin.	0.2	675.8	16.8
DPCK_V31	n.a.	lin.	0.5	786.6	17.2
DPCK_V30	n.a.	lin.	0.2	675.8	16.8
DPVK_V30	6592.0	lin.	0.2	1168.2	15.9
DPVK_V34	4560.8	lin.	0.2	1531.0	15.2
DPCK_V31	n.a.	lin.	0.5	786.6	17.2
DPVK_V31	6592.0	lin.	0.5	1429.0	16.8
DPVK_V35	4560.8	lin.	0.5	1960.8	16.4

10.2.9 Matrix Capillary Pressure

The base case matrix capillary pressure data assumed threshold capillary pressures (at 100 percent wetting phase saturation) of 1.99 psia for oil-water and 0.154 psia for gas-oil systems. These thresholds were removed for Case H1Q to see how sensitive the recovery performance was to this parameter.

Table 10.2.11
Oil Recovery Sensitivity to Curvilinear Fracture Relative Permeability
Vertical Depletion Model

Case	σ , psia	shape	$s_{\text{orf}}/s_{\text{orm}}$	Recovery period, days	Recovery factor, %
DPCK_V1A	n.a.	lin.	0.0	627.1	16.5
DPCK_V32	n.a.	curv.	0.2	822.1	16.5
DPCK_V33	n.a.	curv.	0.5	977.0	16.9
DPCK_V32	n.a.	curv.	0.2	822.2	16.5
DPVK_V32	6592.0	curv.	0.2	1367.9	15.3
DPVK_V36	4560.8	curv.	0.2	1704.0	14.3
DPCK_V33	n.a.	curv.	0.5	977.0	16.9
DPVK_V33	6592.0	curv.	0.5	1710.6	16.2
DPVK_V37	4560.8	curv.	0.5	2227.2	15.6

Figure 10.2.15
Oil Recovery Sensitivity to Curvilinear Fracture Relative Permeability
Vertical Depletion Model

(a) k_r insensitive to stress

(b) Stress sensitivity for 0.2 endpoint values

(c) Stress sensitivity for 0.5 endpoint values

Figure 10.2.16
Oil-Water Capillary Pressure Versus Water Saturation
Case V1R and Case H1R Versus Base Case

(a) Oil-Water

(b) Gas-Oil

Figure 10.2.17
Oil Recovery Sensitivity to Matrix Capillary Pressure
Vertical Depletion Model

(a) k_r insensitive to stress

(b) Stress sensitivity for: $p_c^{-1} = f(s_w)$, $p_{cowl} = 0.00$

(c) Stress sensitivity for: $p_c^{-2} = f(s_w)$, $p_{cowl} = 0.00$

Table 10.2.12
Oil Recovery Sensitivity to Matrix Capillary Pressure
Vertical Depletion Model

Case	σ , psia	p_c thresh.	p_c shape	Recovery period, days	Recovery factor, %
DPCCK_V1A	n.a.	yes	$p_c^{-1} \text{ lin } i(s_w)$	627.1	16.5
DPCCK_V1Q	n.a.	no	$p_c^{-1} \text{ lin } f(s_w)$	714.4	17.1
DPCCK_V1R	n.a.	no	$p_c^{-2} \text{ lin } f(s_w)$	844.0	17.6
DPCCK_V1Q	n.a.	no	$p_c^{-1} \text{ lin } f(s_w)$	714.4	17.1
DPVK_V1Q	6592.0	no	$p_c^{-1} \text{ lin } f(s_w)$	1484.0	17.2
DPVK_V1S	4560.8	no	$p_c^{-1} \text{ lin } f(s_w)$	2056.0	17.0
DPVK_V1R	n.a.	no	$p_c^{-2} \text{ lin } f(s_w)$	844.0	17.6
DPVK_V1R	6592.0	no	$p_c^{-2} \text{ lin } f(s_w)$	1581.1	17.5
DPVK_V1T	4560.8	no	$p_c^{-2} \text{ lin } f(s_w)$	2230.5	17.4

The shape of the assumed capillary pressure curves was altered for Cases V1R and H1R to the more "L-shaped" curves shown in Figure 10.2.16. The oil-water curve, (a) was developed by assuming that the reciprocal of the square of capillary pressure was a linear function of water saturation between the points (S_w , p_{cow}) (30%, 59.7 psia) and (100%, 0.0 psia). The base case curve assumed capillary pressure was a reciprocal linear function of S_w between the points (30%, 59.7 psia) and (100%, 1.99 psia). The gas-oil capillary pressure function shown in Panel (b) was computed from the oil-water function in proportion to ratio of interfacial tensions, as explained in Section 9.2.3.

Figure 10.2.17 shows the recovery performance improvement that occurred when the matrix capillary pressure threshold was removed, as in Case H1Q, and the further improvement when a more uniform pore size distribution was approximated, as in Case H1R. All cases behaved essentially the same over the first half of the oil recovery. The numerical comparison of cumulative oil production and fractional recovery for these cases (Table 10.2.12) show modest, roughly equal increments of oil recovery as capillary pressure was reduced.

The sensitivity of rate of oil recovery to increasing deformation was about the same for the matrix capillary pressure cases as the fracture capillary pressure cases (Figure 10.2.17(b) and (c) versus Figure 10.2.9(b) and (c)). The recovery factor was, for practical purposes, insensitive to deformation. The recovery periods show that these cases were significantly prolonged by deformation (Table 10.2.12).

10.3 Secondary Recovery Sensitivity

The base case simulations investigated the recovery improvement potential of three injection processes: water injection full pressure maintenance, gas recycling reservoir energy conservation, and full pressure maintenance by combined gas recycling and water injection. These simulations showed that water injection to be the most desirable alternative in terms of ultimate recovery factor and simplicity of operation. In view of these

findings, all subsequent secondary recovery investigations have utilized the water injection process.

The models used for the water flood sensitivity investigations were the base case vertical injection and horizontal injection models, as described in Section 10.1.2 and schematically represented in Figure 9.1.3 and Figure 9.1.4. The models represent a basic element of a line drive water flood pattern: bounded one end by a producing well completed in the top layer and at the other end by an injection well completed in the bottom layer. Since the models represent a symmetrical element, each well was regarded as a half-well for rate allocation.

The assumption of continuous fracture development within each fracture swarm was necessary to make the cases viable and is justifiable in the light of the nature of these studies. In real reservoirs the continuity of fractures is difficult to predict, thus proper injection well placement becomes highly problematic and particularly so if they are vertically drilled. Thus, while the horizontal injection model simulations offered no great advantage over the vertical injection model, it is highly probable in the real reservoir case that horizontal wells would offer a better chance of success and higher resultant recoveries.

The sensitivity of water injection behavior to reservoir parameter variation was investigated using these models. The list of parameters included most of those investigated by the same as natural depletion sensitivity cases described in Section 10.1.

All parameter sensitivities were tested in both models. The two sets of test results were found to be always in agreement and showed very similar character. Thus, the final investigations presented herein were all performed with the vertical injection model to take advantage of its shorter execution timings.

The following presentation of results includes the combined effect that reservoir parameter and fracture deformation has on water flood oil recovery. Typically, two variants were simulated for each reservoir property: the one higher than the base case, the second lower than the base case and for the deform option cases, two stress conditions were simulated for each parameter variant. Some parameters were found to be of little significance and are not included in the report discussions.

10.3.1 Relative Conductivity (matrix/fracture)

This series of runs investigated order of magnitude changes in the ratio of matrix permeability to fracture permeability. The permeability ratio changes were effected exactly as they were for natural depletion: first by changing the matrix permeability at constant fracture permeability and then by revising fracture permeability at constant matrix permeability.

The constant fracture permeability alternative results are presented on Figure 10.3.1 and Table 10.3.1. Comparing cases UV3 (increased permeability) and VV3 (reduced permeability) to IV3, the base case, the recovery factors and water breakthrough times are seen to have varied significantly with matrix permeability. The recovery times, not unexpectedly, varied inversely with matrix permeability (Table 10.3.1). Parts (b) and (c) of Figure 10.3.1 show how that fracture deformation effects were much reduced as compared to natural depletion, however, the water breakthrough timing was more sensitive for the higher matrix permeability cases.

Figure 10.3.1
Oil Recovery Sensitivity to Relative Conductivity and Stress
Matrix Permeability Varied, Vertical Injection Model

(a) $k_r = 10$ md and insensitive to stress

(b) stress sensitivity for $k_m/k_r = .001/10$

(c) Stress sensitivity for $k_m/k_r = 0.00001/10$

Table 10.3.1
Oil Recovery Sensitivity to Relative Conductivity and Stress
Matrix Permeability Varied, Vertical Injection Model

Case	σ , psia	k_m , μD	k_m/k_f	Recovery period, days	Recovery factor, %
DPCK_UV3	n.a.	1.0	10^{-4}	1076.7	45.8
DPCK_IV3	n.a.	0.1	10^{-5}	2388.8	42.1
DPCK_VV3	n.a.	0.01	10^{-6}	3402.8	31.3
DPCK_UV3	n.a.	1.0	10^{-4}	1076.7	45.8
DPVK_UV3	6592.0	1.0	10^{-4}	1123.8	45.9
DPVK_GV3	4560.8	1.0	10^{-4}	1165.2	45.8
DPCK_VV3	n.a.	0.01	10^{-6}	3402.8	31.3
DPVK_VV3	6592.0	0.01	10^{-6}	3266.4	30.4
DPVK_HV3	4560.8	0.01	10^{-6}	3240.9	30.0

The constant matrix permeability results are plotted on Figure 10.3.2. Part (a) shows that performance is strongly affected by fracture permeability, although the recovery factors of all three cases differed only slightly. Parts (b) and (c) show how the deform option influenced performance. The initial rate decline and water breakthrough were both exacerbated, but overall, the production rates were fairly independent of deformation. The low permeability cases, FV3 and DV3 reached a production plateau which continued until water breakthrough at around 25-30% recovery. Thereafter, water cut increased and oil rate declined until the minimum rate constraint was reached.

Table 10.3.2
Oil Recovery Sensitivity to Relative Conductivity and Stress
Fracture Permeability Varied, Vertical Injection Model

Case	σ , psia	k_f , mD	k_m/k_f	Recovery period, days	Recovery factor, %
DPCK_FV3	n.a.	1	10^{-4}	6009.5	41.9
DPCK_IV3	n.a.	10	10^{-5}	2388.8	42.1
DPCK_KV3	n.a.	100	10^{-6}	1587.6	39.3
DPCK_FV3	n.a.	1	10^{-4}	6009.5	41.9
DPVK_FV3	6592.0	1	10^{-4}	5979.5	42.0
DPVK_DV3	4560.8	1	10^{-4}	5861.8	41.5
DPCK_KV3	n.a.	100	10^{-6}	1587.6	39.3
DPVK_KV3	6592.0	100	10^{-6}	1886.1	40.9
DPVK_EV3	4560.8	100	10^{-6}	2001.5	41.6

Figure 10.3.2
Oil Recovery Sensitivity to Relative Conductivity and Stress
Fracture Permeability Varied, Vertical Injection Model

(a) $k_m = 0.0001$ md, k_r insensitive to stress

(b) Stress sensitivity for $k_m/k_r = 0.0001/1$

(c) Stress sensitivity for $k_m/k_r = 0.0001/100$

Table 10.3.2 gives the numerical comparisons of recovery times and factors for the different fracture permeability cases. The most noticeable feature is the recovery time reduction as permeability is improved. Also, the low permeability cases are influenced much more by deformation than are the high permeability cases.

The following observations arise when these cases are compared to the base cases.

1. Given fixed k_f of 10 md, an order of magnitude k_m increase (Case UV3), yielded a 5% recovery increment. Conversely, an order of magnitude k_m decrease (Case VV3) resulted in a recovery decrement of 11%.
2. Given fixed k_m of .0001 md, an order of magnitude k_f increase reduced recovery 3% recovery. Conversely, an order of magnitude k_f decrease had no effect on recovery.
3. Raising the ratio of k_m to k_f by one order of magnitude by increasing k_m improved oil recovery 4% (UV3). Recovery was unchanged when the same order of magnitude change was effected by reducing k_f (FV3).
4. Reducing the k_m / k_f ratio one order of magnitude by reducing k_m (VV3) recovered 11% less oil. When the ratio was changed by increasing k_f (KV3), recovery was decreased by 3%.

Expressed another way, the last two observations indicate that reducing the contrast between matrix and fracture permeability results in modest oil recovery improvement, whereas, increasing the contrast results in a recovery reduction. These results are contrary to the correlative natural depletion cases.

10.3.2 Relative Storativity (fracture/matrix)

This series of cases undertook to determine how waterflood recovery would be impacted when the ϕ_f / ϕ_m was halved or quadrupled. The combinations of ϕ_f and ϕ_m and compensating net thickness and permeability changes were identical to those described in Section 10.2.7 for natural depletion.

Table 10.3.3 and Figure 10.3.3 give the results for the varied fracture porosity alternative. The standard option cases show that oil recovery changed almost in direct proportion to the porosity change but the recovery time was not affected. When porosity is lowered, Figure 10.3.3(b) shows little sensitivity to fracture deformation, whereas, if fracture porosity is raised Figure 10.3.3(c) shows the early time behavior to be very sensitive. The latter observation is to be expected given the higher fraction of oil in place in the fractures and their assumed deformable nature. Ultimate recovery was clearly not affected in any of these cases.

Figure 10.3.3
Oil Recovery Sensitivity to Relative Storativity and Stress
Fracture Porosity Varied, Vertical Injection Model

(a) $\phi_m = 3.36\%$, k_r insensitive to stress

(b) Stress sensitivity for $\phi_r/\phi_m = 0.0492/3.36$

(c) Stress sensitivity for $\phi_r/\phi_m = 0.3927/3.36$

Table 10.3.3
Oil Recovery Sensitivity to Relative Storativity and Stress
Fracture Porosity Varied, Vertical Injection Model

Case	σ , psia	ϕ_f , %	ϕ_f/ϕ_m	Recovery period, days	Recovery factor, %
DPCK_WV3	n.a.	.0492	.01464	2366.4	40.5
DPCK_IV3	n.a.	.0984	.02929	2388.8	42.1
DPCK_XV3	n.a.	.3936	.11714	2384.2	48.0
DPCK_WV3	n.a.	.0492	.01464	2366.4	40.5
DPVK_WV3	6592.0	.0492	.01464	2215.8	40.4
DPVK_YV3	4560.8	.0492	.01464	2227.4	40.4
DPCK_XV3	n.a.	.3936	.11714	2384.2	48.0
DPVK_XV3	6592.0	.3936	.11714	2499.4	47.5
DPVK_JV3	4560.8	.3936	.11714	2392.3	47.2

The next comparisons, given in Figure 10.3.4 and Table 10.3.4 are for the cases in which matrix porosity was varied at constant fracture porosity. A notable feature is that the standard option cases show almost exactly the same sensitivity to relative storativity as did the varied fracture porosity cases. The deform option comparisons given in panels (b) and (c) show negligible rate sensitivity and similar water breakthrough sensitivity to stress level.

The oil recovery data provided in the preceding two tables show that ultimate oil recovery was sensitive to the ratio of fracture to matrix porosity: reduced by 1.6% of STOIP when ϕ_f/ϕ_m is halved and increased about 6% of STOIP when ϕ_f/ϕ_m is quadrupled.

10.3.3 Fracture Capillary Pressure

The effect of fracture capillary pressure greater than zero was tested in Cases OV3 and AV3 for which fracture capillary pressure was assumed to equal one half of the low matrix capillary pressures shown on Figure 10.3.5 and in Cases 40V3 and ZvV3 for which the pressure was assumed to equal one half of the high matrix function (Figure 10.3.5).

Figure 10.3.4
Oil Recovery Sensitivity to Relative Storativity and Stress
Matrix Porosity Varied, Vertical Injection Model

(a) $\phi_m = 3.36\%$, k_r insensitive to stress

(b) Stress sensitivity for $\phi_r/\phi_m = 0.0984/6.72$

(c) Stress sensitivity for $\phi_r/\phi_m = 0.0984/0.84$

Table 10.3.4
Oil Recovery Sensitivity to Relative Storativity and Stress
Matrix Porosity Varied, Vertical Injection Model

Case	σ , psia	ϕ_m , %	ϕ_r/ϕ_m	Recovery period, days	Recovery factor, %
DPCK_PV3	n.a.	6.72	.01464	2286.7	40.6
DPCK_IV3	n.a.	3.36	.02929	2388.8	42.1
DPCK_MV3	n.a.	0.84	.11714	2191.8	48.2
DPCK_PV3	n.a.	6.72	.01464	2286.7	40.6
DPVK_PV3	6592.0	6.72	.01464	2286.0	40.4
DPVK_LV3	4560.8	6.72	.01464	2515.2	40.7
DPCK_MV3	n.a.	0.84	.11714	2191.8	48.2
DPVK_MV3	6592.0	0.84	.11714	2225.4	47.9
DPVK_NV3	4560.8	0.84	.11714	2326.1	48.0

Figure 10.3.6 shows the recovery performance of these cases. The inclusion of p_{cr} significantly improved the oil recovery by as much as 10% of STOIP for the lower capillary pressure Case OV3 as compared to the base Case IV3, slightly retarded water breakthrough and made the early water cut build-up less steep. The deform option (Figure 10.3.6 (b) and (c)) had little effect on oil-producing rate. The rate-stress sensitivity pattern was similar to the base case plot, Figure 10.1.2.

Figure 10.3.5
Oil-Water Capillary Pressure
Water Injection Models

Figure 10.3.6
Oil Recovery Sensitivity to Fracture Capillary Pressure and Stress
Vertical Injection Model

(a) k_f insensitive to stress

(b) Stress sensitivity for $p_{cf} = 0.5 * \text{low } p_{cm}$

(c) Stress sensitivity for $p_{cf} = 0.5 * \text{High } p_{cm}$

Table 10.3.5
Oil Recovery Sensitivity to Fracture Capillary Pressure and Stress
Vertical Injection Model

Case	σ , psia	$p_{cr} = f(p_{cm})$	Recovery period, days	Recovery factor, %
DPCK_OV3	n.a.	.5*p _c low	2592.8	52.8
DPCK_IV3	n.a.	0.0	2388.8	42.1
DPCK40V3	n.a.	.5*p _c high	2958.2	46.2
DPCK_OV3	n.a.	.5*p _c low	2592.8	52.8
DPVK_OV3	6592.0	.5*p _c low	2636.5	53.5
DPVK_AV3	4560.8	.5*p _c low	2749.6	53.9
DPCK40V3	n.a.	.5*p _c high	2958.2	46.2
DPVK40V3	6592.0	.5*p _c high	3330.2	47.0
DPVK_ZV3	4560.8	.5*p _c high	3279.3	46.8

10.3.4 Matrix Capillary Pressure

Water flood oil recovery sensitivity to matrix capillary pressure was investigated using the high and low imbibition data shown in Figure 10.3.5. The terms high and low are with reference to the imbibition data used for the base water injection case, DPCK_IV3.

Figure 10.3.7 and Table 10.3.6 summarize the results obtained for these cases. The standard option cases comparison shows that oil recovery and water breakthrough timing are sensitive to matrix capillary pressure, as would be expected. Reducing p_{cm} significantly reduced recovery factor, some 13% while increasing p_{cm} raised recovery only 4% (Table 10.3.6).

10.3.5 Fracture Relative Permeability

Two of the four fracture relative permeability data sets used in the natural depletion cases were chosen for water injection simulation. Those were the Case V31 linear functions and the Case V33 curvilinear functions. These data sets are described in Section 10.2.10 and illustrated on Figure 10.2.12 and Figure 10.2.13. Water injection Case 31V3 and Case 35V3 used the Case V31 data, and Case 33V3 and Case 37V3 used the Case V33 data. The following table summarizes key features of these functions in comparison to the base water injection Case IV3 and Case BV3.

Case	Shape	S_{wi}	S_{orw}	S_{org}
IV3,BV3	linear	0.30	0.00	0.00
31V3,35V3	linear	0.15	0.14	0.08
33V3,37V3	curved	0.15	0.14	0.08

Referring to Figure 10.3.7 (b) and (c), and Table 10.3.6, deformation is shown to have very little effect on rate of recovery or recovery factor, but water breakthrough is advanced somewhat as confining stress is reduced.

Table 10.3.6
Oil Recovery Sensitivity to Matrix Capillary Pressure and Stress
Vertical Injection Model

Case	σ , psia	Capillary pressure function	Recovery period, days	Recovery factor, %
DPCK_RV3	n.a.	p_c high	2321.8	46.1
DPCK_IV3	n.a.	p_c base	2388.8	42.1
DPCK_SV3	n.a.	p_c low	1389.1	29.3
DPCK_RV3	n.a.	p_c high	2321.8	46.1
DPVK_RV3	6592.0	p_c high	2662.0	46.7
DPVK_TV3	4560.8	p_c high	2725.4	46.7
DPCK_SV3	n.a.	p_c low	1389.1	29.3
DPVK_SV3	6592.0	p_c low	1477.6	29.0
DPVK_QV3	4560.8	p_c low	1459.1	28.7

The results of these simulations are displayed on Figure 10.3.8 and numerical comparisons can be found in Table 10.3.7.

The comparison of the standard option cases (Figure 10.3.8(a)) shows that recovery factor was sensitive to shape of the k_r functions, as were water breakthrough timing and water cut buildup. The early production rate plateau was some 200 STB/d lower and water breakthrough is delayed about 4 recovery percentage points for the curvilinear k_r cases 33V3 and 37V3. Further, the linear k_r cases displayed a nearly linear water cut build-up following breakthrough.

Neither the linear (31V3 and 35V3) or curvilinear (33V3 and 37V3) cases showed much sensitivity to stress level (Figure 10.3.8(b) and (c)). Table 10.3.7 also shows that ultimate recovery was quite independent of both stress and relative permeability curve shape. The recoveries were, nonetheless, about 2% of STOIP lower than the base cases. This difference can be largely attributed to the differing treatment of fracture capillary pressure.

Figure 10.3.7
Oil Recovery Sensitivity to Matrix Capillary Pressure and Stress
Vertical Injection Model

(a) k_r insensitive to stress

(b) Stress sensitivity for high imbibition p_{cm}

(c) Stress sensitivity for low imbibition p_{cm}

Figure 10.3.8
Oil Recovery Sensitivity Fracture Relative Permeability and Stress
Vertical Injection Model

(a) k_r insensitive to stress

(b) Stress sensitivity, linear functions

(c) Stress sensitivity, curvilinear functions

Table 10.3.7
Oil Recovery Sensitivity to Fracture Relative Permeability and Stress
Vertical Injection Model

Case	σ , psia	K _r shape	Endpt sats, s_{rf}/s_{rm}	Recovery period, days	Recovery factor, %
DPCK_IV3	n.a.	lin.	0.0	2388.8	41.7
DPCK31V3	n.a.	lin.	0.5	2397.8	52.8
DPCK33V3	n.a.	curv.	0.5	3021.7	50.0
DPCK31V3	n.a.	lin.	0.5	2397.8	52.8
DPVK31V3	6592.0	lin.	0.5	2514.5	53.8
DPVK35V3	4560.8	lin.	0.5	2542.1	54.0
DPCK33V3	n.a.	curv.	0.5	3021.7	50.0
DPVK33V3	6592.0	curv.	0.5	1412.7	41.9
DPVK37V3	4560.8	curv.	0.5	3138.8	50.4

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APPENDIX A

NOMENCLATURE

A	- Block face area
°API	- Oil gravity
B	- Formation volume factor
c	- Compressibility
e	- Fracture surface roughness
f	- Friction factor
°F	- Temperature, degrees Fahrenheit
F	- Well block radius correction factor
Gp	- Gas produced
h	- Thickness
H	- Height of fracture face
k	- Permeability
$\bar{k}$	- Harmonic mean permeability
k_r	- Relative permeability
K	- Conductivity, kh
L	- Block dimension (fracture spacing)
L_f	- Characteristic flow path length
mSTB	- Thousand stock tank barrels
N	- Number of sets of fractures
NX, NY, NZ	- Number of grid blocks along given axis
p	- Pressure
p_b	- Saturation pressure
p_c	- Capillary pressure
p_o	- Initial well block pressure
p_{wf}	- Flowing bottom-hole pressure
psi	- Pounds per square inch
q	- Volume rate, production or injection
Q	- Reservoir flow rate
R_h	- Hydraulic radius
r_o	- Well block radius
R_s	- Solution gas-oil ratio
r_w	- Well bore radius
S	- Phase saturation
S^*	- Normalized saturation
scf	- Standard cubic feet
STB	- Stock tank barrel(s)
STOIP	- Stock tank conditions
V	- Flow velocity
V_b	- Fracture block volume
w_f	- Fracture aperture
Z	- Depth

NOMENCLATURE (cont'd)

α	- Poroelastic parameter
γ	- Stress gradient
Δ	- Difference operator
η	- Fitting parameters for Eqn. 6.18
μ	- Phase viscosity
π	- 3.14159...
ρ	- Phase density
σ	- Shape factor or confining stress
σ_{go}	- Gas-oil interfacial tension
σ_{ow}	- Oil-water interfacial tension
ϕ	- Porosity
Φ	- Phase potential
λ	- Transmissivity ratio
ω	- Storativity ratio

SUBSCRIPTS

f	- Fracture
g	- Gas phase
i	- Irreducible or intrinsic
m	- Matrix
o	- Oil phase or at reference condition
r	- Residual
t	- Threshold
w	- Water phase
x,y,z	- Reference to given reservoir axis
xx,yy,zz	- Principal stress axis

APPENDIX B

BOXPLOT SUMMARIES

The following illustrations summarize the statistical analyses discussed in Section 8.0 of this report. These illustrations are in a statistical "Boxplot" format. The box limits indicate the range of the middle half of the data known as the inter-quartile range (IRQ). The asterisk (*) is positioned within the box at the median value. The "whiskers" extend beyond either box end up to 1.5 times the IRQ or to the last data point within 1.5 times the IRQ, whichever is the lesser. Outlier points, (O), are those falling beyond the whiskers and within 3.0 times the IRQ. An extreme outlier point, (E), is any data point outside of 3.0 times the IRQ.

Figure B.1
Ultimate Oil Recovery Per Well
Versus Wellbore Orientation

Horizontal Well Cases 74

Mean	117431.7	Std Err	13861.52	Min	7220.000	Skewness	1.6868
Median	71148.50	Variance	1.42E+10	Max	488670.0	S E Skew	.2792
5% Trim	104033.3	Std Dev	119241.3	Range	481450.0	Kurtosis	2.3016
				IQR	94283.75	S E Kurt	.5517

Vertical Well Cases 56

Mean	29273.18	Std Err	3136.999	Min	2108.000	Skewness	1.3193
Median	17060.00	Variance	5.51E+08	Max	81888.00	S E Skew	.3190
5% Trim	27798.88	Std Dev	23475.15	Range	79780.00	Kurtosis	.6007
				IQR	21888.75	S E Kurt	.6283

Symbol Keys:

* - Median

(O) - Outlier

(E) - Extreme

Figure B.2
Ultimate Oil Recovery Per Well
For Horizontal Wells
Based On Prior Production From
Vertical Well(s) On Same Lease

Figure B.3
Ultimate Oil Recovery Per Well
For Horizontal Wells
Based On Multiple Well Lease
Versus Single Well Lease

Figure B.4
Ultimate Oil Recovery Per Well For
Horizontal Wells On Single Well Leases
Based On Initial Production Method -
Flowing or Pumping

Figure B.5
Wellbore Displacement in Pay Zone
Versus Wellbore Orientation

Orientation		Horizontal		Vertical			
Number of Wells		74		56			
Horizontal Cases		74					
Mean	2271.514	Std Err	105.0794	Min	502.0000	Skewness	.3172
Median	2181.667	Variance	817084.7	Max	4133.000	S E Skew	.2792
5 % Trim	2254.943	Std Dev	903.9274	Range	3631.000	Kurtosis	-.5860
				IQR	1315.875	S E Kurt	.5517
Vertical Cases		56					
Mean	355.0536	Std Err	10.1024	Min	240.8000	Skewness	1.2257
Median	332.9022	Variance	5715.320	Max	570.0000	S E Skew	.3190
5 % Trim	350.0706	Std Dev	75.5997	Range	329.2000	Kurtosis	1.6497
				IQR	56.4457	S E Kurt	.6283

Symbol Key:

* - Median

(O) - Outlier

(E) - Extreme

* A.Krawetz -15- VERTICAL, F.J.Avant VERTICAL WELL, Hawkins VERTICAL WELL (1)

Figure B.6
Ultimate Oil Recovery Per Displacement
Versus Wellbore Orientation

Horizontal Cases 74

Mean	58.8797	Std Err	6.7841	Min	3.4000	Skewness	1.3460
Median	32.8000	Variance	3405.818	Max	245.3000	S E Skew	.2792
5% Trim	53.6080	Std Dev	58.3594	Range	241.9000	Kurtosis	1.1482
				IQR	75.1000	S E Kurt	.5517

Vertical Cases 56

Mean	82.4911	Std Err	8.2979	Min	3.7000	Skewness	1.5108
Median	53.9000	Variance	3855.927	Max	234.3000	S E Skew	.3190
5% Trim	78.2238	Std Dev	62.0961	Range	230.6000	Kurtosis	1.5709
				IQR	41.1250	S E Kurt	.6283

Symbol Key:

* - Median

(O) - Outlier

(E) - Extreme

Figure B.7
Ultimate Oil Recovery Per Displacement
For Horizontal Wells
Based On Prior Production From
Vertical Well(s) On Same Lease

Previous
Vertical Production
Number of Wells

No
59

Yes
15

No Prior Vertical Production Cases . . . 59

Mean	59.0475	Std Err	7.6442	Min	3.4000	Skewness	1.4983
Median	36.7000	Variance	3447.587	Max	245.3000	S E Skew	.3112
5% Trim	53.2035	Std Dev	58.7162	Range	241.9000	Kurtosis	1.7594
	IQR	68.6000	S E Kurt	.6133			

Prior Vertical Production Cases 15

Mean	58.2200	Std Err	15.2216	Min	7.6000	Skewness	.8054
Median	21.3000	Variance	3475.460	Max	145.7000	S E Skew	.5801
5% Trim	56.1722	Std Dev	58.9530	Range	138.1000	Kurtosis	-1.3181
	IQR	135.5000	S E Kurt	1.1209			

Symbol Key:

* - Median

(O) - Outlier

(E) - Extreme

Figure B.8
Ultimate Oil Recovery Per Displacement
For Horizontal Wells
Based On Multiple Well Lease
Versus Single Well Lease

Multiple-Well Solution Cases 25

Mean	68.3120	Std Err	12.1050	Min	10.2000	Skewness	.5396
Median	43.9000	Variance	3663.254	Max	163.4000	S E Skew	.4637
5% Trim	66.2578	Std Dev	60.5248	Range	153.2000	Kurtosis	-1.4647
				IQR	132.9000	S E Kurt	.9017

Single-Well Solution Cases 49

Mean	54.0673	Std Err	8.1792	Min	3.4000	Skewness	1.8664
Median	31.5000	Variance	3278.075	Max	245.3000	S E Skew	.3398
5% Trim	47.1577	Std Dev	57.2545	Range	241.9000	Kurtosis	3.3665
				IQR	54.4500	S E Kurt	.6681

Symbol Key:

* - Median

(O) - Outlier

(E) - Extreme

Figure B.9
Ultimate Oil Recovery Per Displacement For
Horizontal Wells On Single Well Leases
Based On Initial Production Method -
Flowing or Pumping

APPENDIX C

TETRAD

TETRAD is a state-of-the-art three-dimensional numerical reservoir simulator that can function in one of four modes:

Black Oil - Isothermal with three phases, water, gas, and oil and three component, also usually designated as water, gas, and oil. The gas component can dissolve in both the water and oil phases to represent solution gas. The oil component can be present in both the gas and water phases, to represent condensate or oil-in-water emulsion.

Multicomponent - Isothermal with three phases, water, gas, and oil. The hydrocarbon phases may each be multicomponent and hydrocarbon components may be present in any phase.

Thermal - Thermal with three phases, water, gas, and oil. All three phases may be multicomponent. Any component may be present in any phase.

Geothermal - Thermal with two phases, water and gas (no oil phase). The water and gas phases may be multicomponent. Any component may be present in any of the two phases.

The program has been extensively tested on a wide variety of problems in user environments ranging from major oil companies to independent consulting firms. It has been successfully installed on computers ranging from PC's to Cray supercomputers.

Program input is keyword driven and free format under the rules of FORTRAN 77. Default variables are extensively defined to facilitate problem set up.

The program has been efficiently interfaced to a front end gridding and data preparation package and a post processing mapping and graphics package to facilitate both data preparation and the presentation of results.

The grid algorithms will accept irregular and curvilinear grids and localized grid refinement. Any grid node may be coupled to any other grid node, to facilitate juxtaposition of non-conforming layers due to faulting and the irregular coupling of grid nodes due to grid refinement.

The initialization of saturations and pressures account for the presence of fluid contacts within a grid block. Contacts can either be sharp or with a transition zone as defined by the capillary pressure.

The simulator formulation provides a wide range of options for the degree of implicitness of the numerical solutions:

- fully implicit
- linearized implicit
- dynamically implicit
- sequentially implicit
- IMPES

Optional features of TETRAD include:

- Dual porosity/dual permeability can be treated in all four modes.

- Fully implicit treatment of flow in the well bore from the reservoir to the surface. Well bores can assume any inclination from horizontal to vertical.
- Control over the degree of numerical dispersion.
- Permeability can vary with reservoir pressure and temperature in a spatially dependent fashion.
- The input capillary pressure curves can be scaled to the porosity and permeability of each grid block according to the Leverett J function.
- Analytical aquifers can be tied to the model at any block. The aquifer options provided are:
 - steady-state
 - tank-type
 - infinite linear
 - semi-analytical aquifer options:
 - finite linear
 - infinite radial
 - finite radial
- Porosity and permeability hysteresis due to non-elastic deformation of the porous media.
- Controlled automatic switching of a well from injection to production and vice versa for cyclic "huff and puff" operation.
- Simulation of the electrical resistive heating method for enhanced recovery of heavy oils.
- Vectorised solver for use on vector computers.

TETRAD

TYPES OF PROBLEMS

TETRAD is applicable to an unusually broad spectrum of problems:

Reservoir Fluid Types

- Volatile oil
- Dry gas
- Gas condensate
- Geothermal
- Black oil

Recovery Processes

- Primary depletion.
- Water flooding
- Gas injection
- Aquifer influx
- Gas cycling
- Miscible flooding
- Steam flooding
- Electrical heating
- Horizontal wells

Single Well Studies

- Water and gas coning or cusping
- Steam "huff and puff"
- Pressure transient tests
- Fluid flow in well bore and pipes

Complex Porous Media

- Dual porosity/dual permeability
- Fractured systems
- Vugular
- Stress dependent porosity and permeability

Simulation of Laboratory Experiments

- Fluid displacement studies
- Fractured core studies
- Flash experiments

Special Applications

- Oil-in-water emulsions
- Tracer injection tracking
- Research into simulation techniques.
- Dissolved gas-in-water systems.
- Slug flow (reduced numerical dispersion required)
- Non-elastic deformation of porous media

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MODEL PERFORMANCE

The numbers of time steps and Newton iterations required to solve published SPE Comparative Solution Project Problems are given in the following tabulation. All simulations were performed on a 32 bit computer using double precision. The numbers required for a given installation may vary slightly from the tabulated values, depending on the accuracy of the machine.

Computational Effort Requirements SPE Comparative Solution Project Problems

Solution Project	Problem Description & Variations	Time Steps Required	Total Newton Iterations
First	3D Black Oil: fixed p_b variable p_b	17	72
		17	79
Second	2D Radial Coning	7	40
Fourth	Thermal, Steam Flooding:		
	2D radial huff & puff	85	282
	3D heavy oil	48	195
	3D volatile oil	35	200
Sixth	Dual Porosity, 2D Vert. water inj.	29	96

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MODEL FORMULATION BASICS

Phases and Components

Petroleum and natural gas reservoir systems are formulated as three phase, water, gas, and oil. Geothermal reservoirs have only two phases, gas and liquid.

Reservoir fluid systems have a total of n_t components, comprised of n_w water components, and $n_t - n_w$ hydrocarbon components.

Component 1 is generally the pure water component in the water phase. Components 2 through n_w are referred to as tracer components in the water phase and can only be present in a thermal or geothermal simulation. They can be used to model a tracer such as deuterium, tritium, or dissolved gas such as CO_2 , or dissolved salt.

Components $n_w + 1$ through n_t are the hydrocarbon components, in order of increasing molecular weight. They are not present in geothermal simulations.

Conservation Equations

In a black oil or multicomponent simulation, there are n_t conservation equations, one for each component. In a thermal or geothermal simulation, there are $n_t + 1$ conservation equations, the extra equation being the energy conservation equation.

Fundamental Variables

TETRAD regards the following as fundamental variables:

- pressure (P)
- saturations of oil, gas and water phases (S_o , S_g , S_w)
- temperature (T)
- component mole fractions in water, gas, oil phases (W,Y,X)

Primary Variables

The number of primary variables is always the same as the number of conservation equations; however, the choice of primary variables depends on the type of simulation, and the presence of phases. Variable substitution is used depending on the phase status. Possible primary variables are:

- P
- S_g , or X(2), or T
- S_o , or Y(n_t), except for geothermal
- W(2) through W(n_w) for thermal or geothermal
- X($n_w + 2$) through X($n_t - 1$) for multicomponent
- X($n_w + 1$) through X($n_t - 1$) for thermal

All other variables are secondary variables.

Constraint Equations

The constraining equations are as follows:

$$S_o + S_g + S_w = 1$$

$$\Sigma W = 1$$

$$\Sigma Y = 1$$

$$\Sigma X = 1$$

Equilibrium Constants

The mole fractions are related through the equilibrium constants (K and F values). Usually, the F values will be zero.

For the water components:

$$Y_i = K_i W_i \quad i = 1, n_w$$

$$X_i = F_i W_i \quad i = 1, n_w$$

For the hydrocarbon components:

$$Y_i = K_i X_i \quad i = n_w + 1, n_i$$

$$W_i = F_i X_i \quad i = n_w + 1, n_i - 1$$

$$W(n_i) = F(n_i) Y(n_i) \quad \text{black oil and multicomponent mode}$$

$$W(n_i) = F(n_i) X(n_i) \quad \text{thermal mode}$$

The equilibrium constants, K are functions of pressure and temperature.

As TETRAD always works with mole fractions, black oil PVT data are used internally to construct the equivalent K values for the phase equilibria.

Solution Procedure

In a *black oil* simulation, with all phases present, the primary variables are P, S_g , and S_o . If the gas phase disappears, $X(2)$ replaces S_g as a primary variable, (this is equivalent to solving for R_s , the solution gas-oil ratio). If the oil phase disappears, $Y(n_i)$, (n_i being 3 in this case) replaces S_o as a primary variable. This is equivalent to solving for the gas-condensate ratio. Once the primary variables have been found, the remaining fundamental variables can be determined from the constraint equations and equilibrium relationships. All other variables (densities, etc.) are functions of the fundamental variables.

In a *multicomponent* simulation when all phases are present, the primary variables are P, S_g , S_o , and $X(3)$ through $X(n_i - 1)$. Variable substitution is performed in exactly the same manner as for black oil.

In a *thermal* simulation with all phases present, the primary variables are P, S_g , S_o , $W(2)$ through $W(n_w)$ and $X(n_w + 1)$ through $X(n_i - 1)$. If the gas phase or the water phase disappear (e.g. superheated steam), T replaces S_g as a primary variable. The oil phase is not allowed to disappear in a thermal simulation, although the oil saturation can go to zero. This is done by means of a pseudo K value for the heavy oil component to prevent further evaporation as the oil saturation approaches zero.

In a *geothermal* simulation, the primary variables are P, S_g , and $W(2)$ through $W(n_w)$. Variable substitution is performed in the same manner as for thermal.

In constructing the Jacobian, the primary variables are aligned on the conservation equations to make

the resulting matrix as diagonally dominant as possible.

Dual Porosity

When invoked, the number of grid blocks is doubled and a dual grid is set up. The first $N/2$ grid blocks then represent the fracture system and the last $N/2$ the matrix system. The grid parameters, such as grid block sizes and formation tops are automatically dualled. Thus, the two grids occupy the same spatial positions. Each grid block in the fracture system is connected to the equivalent grid block in the matrix system by a special interaction, namely the fracture-matrix interaction.

Optionally, matrix-matrix interblock connection can be set up. These interactions then represent first degree couplings and are included as such in the inner LDU factorization and iterative inversion. However, if any of the matrix-matrix transmissibilities are specified as zero, the corresponding interblock connections are omitted to save storage. These interactions then represent third degree couplings in the inner LDU factorization, and are not included in the default second degree factorization. In this circumstance, the number of inner iterations can increase significantly, depending on the problem. The situation can be overcome by specifying either, low matrix-matrix transmissibilities, or third degree inner LDU factorization. Both alternatives increase the storage requirement.

Implicit Well bore Simulation

For implicit well bores, the flow in the well bore is modelled as part of the overall grid. This option allows the definition of additional grid blocks to represent the well bore. The well bore blocks will be automatically coupled to each other in the direction of the well bore, and to the reservoir grid blocks. Two sets of relative permeabilities will generally be required, one for the well bore blocks, another for the reservoir blocks.

Implicit well bore modelling may not be combined with local grid refinement or dual porosity.

Numerical Dispersion Control

Weighting options are provided for relative permeabilities and viscosity.

Relative permeability weighting parameters can be specified as follows:

A zero value to indicate no dispersion control resulting in single point upstream mobility weighting.

A value of 1.0 to define a strict second order method in space. Values between 0.0 and 1.0 give a mixture of single point upstream and the second order method.

Values greater than 1.0 can be used if more dispersion control is required. On slug type problems of near unit viscosity ratio, a well defined slug can be obtained by raising the weighting parameter to about 4. On Buckley-Leverett type problems, sharp shock fronts can be obtained using a parameter of about 2.

Viscosity weighting parameters can be assigned to each phase. A parameter of 0.5 yields a central difference while 1.0 gives single point upstream. Any value between 0.5 and 1.0 can be used.

Deformation Model

The basis of the deformation model is described in SPE paper 18752, published in *SPE Reservoir Engineering*, May 1991. The approach was specifically developed for application to the Cold Lake reservoir in northeastern Alberta. In an injection cycle, porosities are assumed to follow an elastic

compressibility curve until some deformation pressure is exceeded; thereafter, a dilation curve with a much greater compressibility is followed. During the subsequent production cycle, porosities follow the shifted (along dilation path) elastic curve until pressure falls below a recompaction pressure; thereafter, a recompaction curve of elevated compressibility is followed.

Permeability is treated as a function of the porosity change as follows:

$$k_n = k_0 e^C$$

where, $C = b(\phi_0 - \phi_n) / (1 - \phi_0)$

ϕ_0 = porosity at initial conditions

ϕ_n = porosity at n time level

and b = fitting coefficient

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