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A Practical Method For Determining The Productivity of Multi-Fractured Horizontal Wells

by

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled "A Practical Method for Determining the Productivity of Multi-Fractured Horizontal Wells" submitted by Frank Conrad Kuppe in partial fulfilment of the requirements for the degree of Master of Engineering.

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ABSTRACT

This work investigates the productivity of different configurations of fractured horizontal wells by means of numerical simulation. Model results have been compared to a number of analytical solutions available for estimating the productivity of unfractured horizontal wells under various boundary conditions. The simulation model was expanded to include varying lengths of one, three, five and seven, infinite conductivity, vertical hydraulic fracture configurations. In this work, infinite (high) fracture conductivity was used, although the model can also be used to investigate the effect of finite conductivity. Based on the numerical results, a third order polynomial correction to the linear flow equation was developed to yield more accurate productivity index predictions without the limitations of analytical solutions.

The empirical formula, generated from this work, can be used easily for accurate predictions of multi-fractured horizontal well productivity and project economics, under a variety of reservoir and boundary conditions.

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TABLE OF CONTENTS

TABLE OF CONTENTS (cont'd)

TABLE OF CONTENTS (cont'd)

LIST OF TABLES

Page

LIST OF FIGURES

NOMENCLATURE

a	large half-axis of elliptical drainage area (Joshi's equation)
b	reciprocal formation volume factor (STB/Bbl)
b'	derivative of reciprocal formation volume factor
b_f	fracture width (ft.)
B	formation volume factor (Bbl/STB)
B_o	oil formation volume factor (Bbl/STB)
c	conversion factor in well index equation
C	correction factor applied to fracture flow equation
C_A	Dietz shape factor
C_H	geometric factor as defined by Babu & Odeh[21]
C_R	constant compressibility
d	depth (ft.)
D	polynomial correction term
F_{cd}	dimensionless conductivity = $k_f b_f / k X_f$
h	reservoir pay thickness (ft.)
k	permeability of the medium (md)
k_f	permeability of the fracture (md)
k_H	permeability in the horizontal direction (md)
k_v	permeability in the vertical direction (md)
$k_{x,y,z}$	permeability in the x,y and z direction, respectively (md)
L	well length (ft.)
L_x	drainage width orthogonal to horizontal well (ft.)
L_y	drainage width parallel to horizontal well (ft.)
$L_{1/2}$	well half length (ft.)
N	Fourier transform variable in Goode & Kuchuk's solution
n	current time level
n+1	advanced time level
P	phase pressure (psia)
P_r	reference pressure (psia)

P_w	bottom hole flowing pressure (psia)
P_{wD}	dimensionless bottom hole flowing pressure (psia)
P_{limit}	modeled well pressure constraint (psia)
ΔP_s	pressure loss due to skin (psia)
PI_h	productivity index of the horizontal well
PI_{nf}	productivity index of horizontal well with no fractures
PI_v	productivity index of the vertical well
q	$\hat{q}/\rho_o$
$\hat{q}$	source density
Q	rate at standard conditions = qv (STB/d)
Q_{limit}	modeled well production constraint
r_b	effective grid block radius (ft.)
r_e	drainage radius (ft.)
r_w	wellbore radius (ft.)
S	skin factor
S_d	skin from change in formation permeability around wellbore
S_m	van Everdingen mechanical skin
S_p	skin due to partial penetration of vertical well
S_R	skin resulting from partial penetration of horizontal well
$T_{x,y,z}$	transmissibility in x, y and z directions, respectively
TXF	transmissibility of fracture gridblock
TXR	transmissibility of reservoir gridblock
TXT	total transmissibility
$\vec{u}$	velocity field of the reservoir fluid (ft./s)
V	reservoir volume element (ft.^{3})
WI	well index
x	distance between fracture and no-flow boundary
x_w	wellbore coordinate in x direction
x_0	coordinate measuring well center in x direction
X_f	fracture half length
X_{fd}	dimensionless fracture half length
y_w	wellbore coordinate in y direction

NOMENCLATURE (cont'd)

z_w	wellbore coordinate in z direction
z_0	coordinate measuring well center in z direction

Greek symbols

β	anisotropy indicator = $\sqrt{k_h/k_v}$
δ	vertical distance between horizontal well and reservoir midpoint
$\eta, \alpha, \theta, \lambda$	coefficients of the polynomial correction term D
μ	viscosity (cp)
γ	pressure gradient (psi/ft.)
ρ	phase density
ρ_o	phase density at standard conditions
ϕ	porosity of the medium
ϕ_r	porosity at the reference pressure

Chapter 1

1. Introduction

The productivity and hydrocarbon recovery benefits of horizontal wells, compared to their vertical counterparts are, by now, well established concepts. The unstimulated horizontal well can generate production rates of two to five times that of an unstimulated vertical well at similar pressure drawdowns. In addition, horizontal wells that intersect natural fractures dramatically increases reservoir contact area and, consequently, further increases the productivity and drainage efficiency.

Historically, horizontal wells have been less effective in thicker reservoirs (with thicknesses in the order of 500 ft. or more), reservoirs with low vertical permeability (relative to horizontal permeability) and in stratified reservoirs with impermeable shale barriers. The improvement of well completion and stimulation technology, however, is renewing enthusiasm for horizontal well applications in areas that were previously considered unqualified. In reservoirs of thick pay intervals, low permeability, having an overlying gas cap or perhaps underlying water, the exposure of the horizontal well can be increased substantially by inducing one or more hydraulic fractures. The horizontal well essentially acts as a production conduit, connecting multiple vertical fractures but, in some cases, can also contribute to production.

Giger et al[1] mentioned that productivity improvements of a horizontal well over a vertical well "will rarely be more than a factor of 5 except, of-course, in the case of fractured reservoirs". One year later Giger[2] stated that hydraulic fracturing would be "a way of synthetically creating heterogeneity in a reservoir. Therefore, as soon as reliable methods of cementing horizontal wells are industrially available, the idea of hydraulically fracturing such wells will arise". The timing of this somewhat prophetic prediction is testament to how rapidly technology has developed.

With the advent of fractured horizontal wells, or unstimulated horizontal wells, for that matter, has come a host of analytical solutions, developed to predict the productivity of these wells, although too few include fractures. Unfortunately analytical solutions are not very versatile or even accurate, in many cases, for predicting the productivity of multi-fractured horizontal wells. The derivation of analytical solutions requires simplifying assumptions to make the task possible. The three dimensional flow problem is usually simplified by combining two dimensional flow patterns, generated from mapping functions with or without comparisons to electrical analogs. Much discussion and research is focused on drainage patterns, the effect of boundary conditions, anisotropy and even the effective wellbore shape (elliptical or circular) when introducing anisotropy. When analytical solutions do match or are modified to match results from electrical analogs, other analytical solutions or "production history", they invariably break down when considering sensitivities to input parameters or boundary conditions.

This may be an over simplification, however, regardless of how the analytical solutions were derived, prerequisites for their development are the underlying assumptions of reservoir parameters, wellbore and fracture configurations and boundary conditions. This increases the complexity of analytical solution derivations which is challenging and interesting from an academic standpoint but very rigid for the practicing reservoir engineer. Suffice it to say, the mathematical basis of most analytical solutions developed to date is the topic of much conjecture and debate that leaves abundant room for improvement or perhaps alternatives.

Fortunately, along with horizontal well and stimulation technology, improvements have also been made in the area of reservoir simulation. The power and resolution enhancements made to the reservoir simulator allow for larger and more refined simulation models. The dynamics of fracture propagation, filtrate leak-off and even heat transfer can be modeled in the fracture and subsequently combined with the larger reservoir model. Simulation models are being used as the basis against which analytical solutions are tested. Rather than modifying an analytical solution that remains confined to particular assumptions, this study will endeavor to show how the simulation model can be used to generate a practical, versatile empirical solution that can be adapted to any conditions or reservoir parameters.

The derived empirical solution has been developed for the more common, no-flow boundary conditions. The method of development, however, can be applied to any boundary conditions. Simulation results of non-fractured horizontal wells are compared to some of the more commonly used analytical solutions. The simulation model is then extended to include increasing lengths of multiple fractures yielding productivity data as a function of increasing fracture length. The analytical solution for linear flow into a fracture, combined with third order polynomial "correction factors" can then be fit to the productivity curves to yield a more exact empirical relationship.

Chapter 2

2. Literature Review

2.1 Application of Fracturing in Horizontal Wells

Some of the earlier applications of multiple fractures in a horizontal wellbore involved extending the already existing natural fractures as well as inducing additional fractures. Stimulation work performed by Overbey et al[3] on the RET #1 well, penetrating the Devonian Shale formation, in West Virginia, reveals how multiple-oriented, multiple fractures can be induced from an open hole, horizontal wellbore. Natural fractures were stimulated by inflating them with non-damaging fluid and then propping these fractures to maintain the enhanced flow capacity (i.e. standard fracturing procedure). Additional fractures were induced by subsequently increasing the injection rate.

Two important features can be learned from the work. First, use of a video camera survey and radioactive isotopes provided conclusive evidence of multiple fracture orientations that showed relative deviations of ± 15°. Secondly, multiple fractures were induced between external casing packers, placed in an open hole wellbore. For modeling purposes, this case study would introduce complications with the multi-oriented fractures and would also require special considerations for a wellbore that not only connected fractures but also contributed production.

A large percentage of technical and economic successes (Chevron recorded a 93% success rate at the 1995 SPE technical conference in Banff), for horizontal wells, occurs in applications trying to avoid coning of an overlying gas cap or underlying aquifer, into the production interval. The reduced pressure drawdown of the horizontal well, compared to it's vertical counterpart, required to achieve comparable production rates, prevents or at least delays coning of gas and/or water. Thus, not only can productivity be increased but sweep efficiency is enhanced. The general idea in these applications is to keep the horizontal wellbore as far as possible from the two phase contacts. Hydraulic fracturing of these wells was therefore usually avoided.

Maersk Oil and Gas Co[4]., however, proved that multiple fractured horizontal (MFH) wells can also be applied in these cases. They design hydraulic fracture jobs for their horizontal wells in the North Sea Dan Field, so that fractures are confined within the oil column, between the gas cap and the 50% water saturation level of a long transition zone. Their horizontal well sections range in length from 1000 ft. to 3000 ft. and incorporate up to seven hydraulic fractures. At the time of presentation (Oct. 1990), the six MFH wells contributed 45% of the field's oil production. This field is also penetrated by 42 conventional deviated wells.

The Dan structure containing almost 2 billion barrels of oil in place, is located some 200 km west of the coast of Jutland, in the North Sea. Prior to the drilling of horizontal wells the anticipated recovery factor, of 30° API oil, in this 1.0 md permeability reservoir, was less than 7%. Although revised predictions of the recovery factor were not indicated, the application of multi-fractured horizontal wells was proven to be economically successful and technically practical (i.e. optimum method of increasing reservoir exposure from an offshore drilling platform).

Tight gas reservoirs are becoming increasingly popular candidates for multi-fractured horizontal wells. Accelerated production accompanied with more moderate recovery increases, pays for the initial capital expense, especially as horizontal drilling and stimulation costs continue to decline. Multi-fractured horizontal well technology has recently been applied to enhance productivity from a tight gas field located offshore from the Netherlands[5]. A horizontal well with two hydraulic fractures was completed in the tight (permeability = 0.2-1.0 md) Ameland East reservoir.

The Ameland East reservoir is a classic example of how a poor candidate for horizontal wells can yield substantially improved production when produced from a multi-fractured horizontal wellbore. The reservoir exhibits a "low ratio" of vertical to horizontal permeability rendering the non-stimulated horizontal well uneconomic. Simulation of vertical infill wells and various combinations of multi-fractured horizontal wells, combined with economic evaluations showed that the case of a horizontal well with two hydraulic fractures provided the best economic return. The actual productivity improvement of this well, over the horizontal well with no fractures, is estimated to be a factor of four with only a 30% higher cost.

2.2 Methods for Predicting Productivity

With the increasing use of fractured and multi-fractured horizontal wells it seems appropriate to expect a more accurate method of determining the potential productivity index enhancement of these wells. How a productivity index is calculated, with consideration for a range of variables (i.e. fracture height and length, well length, reservoir and fracture permeability, etc.), could influence the size of hydraulic fractures, the number of fractures in the horizontal wellbore or if in fact a horizontal well should be drilled. As mentioned previously, use of the available analytical solutions, for fractured or unfractured horizontal wells, could lead to errors if the limiting assumptions are not taken into consideration or overlooked.

There is a growing trend to marry numerical simulation technology with analytical solutions. Improvements can be made to existing analytical solutions by comparing their predictions to numerical simulation results. Economides et al[6] used a simulator with a "flexible grid scheme" (i.e. does not follow standard cartesian orthogonality) to modify Joshi's solution in anisotropic permeability conditions. The original form, of one version, of Joshi's equation was:

$$q_H = \frac{2\pi k_h h \Delta P}{\mu B[\ln(\frac{a+\sqrt{a^2-(L/2)^2}}{L/2})] + \frac{\beta h}{L}\ln(\frac{\beta h}{2r_w})} \qquad \text{for } L \rangle \beta h$$

where: L = well length,
a = large half-axis of elliptical drainage area,
$\beta = \sqrt{k_h/k_v}$,
All other variables are defined in the nomenclature.

Economides et al changed the second logarithmic expression in the denominator of this equation, replacing $\beta h/2r_w$ with $\beta h/r_w(\beta+1)$. The rationale for this change was based on Peaceman's equivalent wellbore radius (discussed in Chapter 4) in an anisotropic formation. Recognition of the need to modify the analytical solution, however, was based on numerical simulation results. Economides et al ran a number of cases showing deviations between numerical results and analytical solution predictions. Once the cause of the deviation was identified, modifications to the existing analytical solution provided results that were closer to the simulation results. It is interesting to note that simulation results were also used, in the same paper, as the basis for development of a new analytical solution (providing even closer approximations of the numerical results).

In some cases it becomes impossible to apply a "quick fix" to an existing analytical solution. For example, non-symmetrical spacing of fractures, between no-flow boundaries, was modeled by Walker et al[7]. The assumption of symmetrically spaced fractures is usually not practical due to either mechanical conditions in the well or reservoir conditions. The study was carried out to optimize the configuration of a multi-fractured well in Mobil's tight gas Sohlingen field (northwest Germany). It was found that non-symmetrical distances to no-flow boundaries can create "dynamic drainage areas". Figure 2.1 shows how a horizontal well with evenly spaced fractures can create non-symmetrical no-flow boundaries. Addressing this behavior with analytical solutions or type curves would be very difficult if not impossible. For accurate production forecasting this multi-fractured well would require an empirical formula based on simulation results or at least a simulation model.

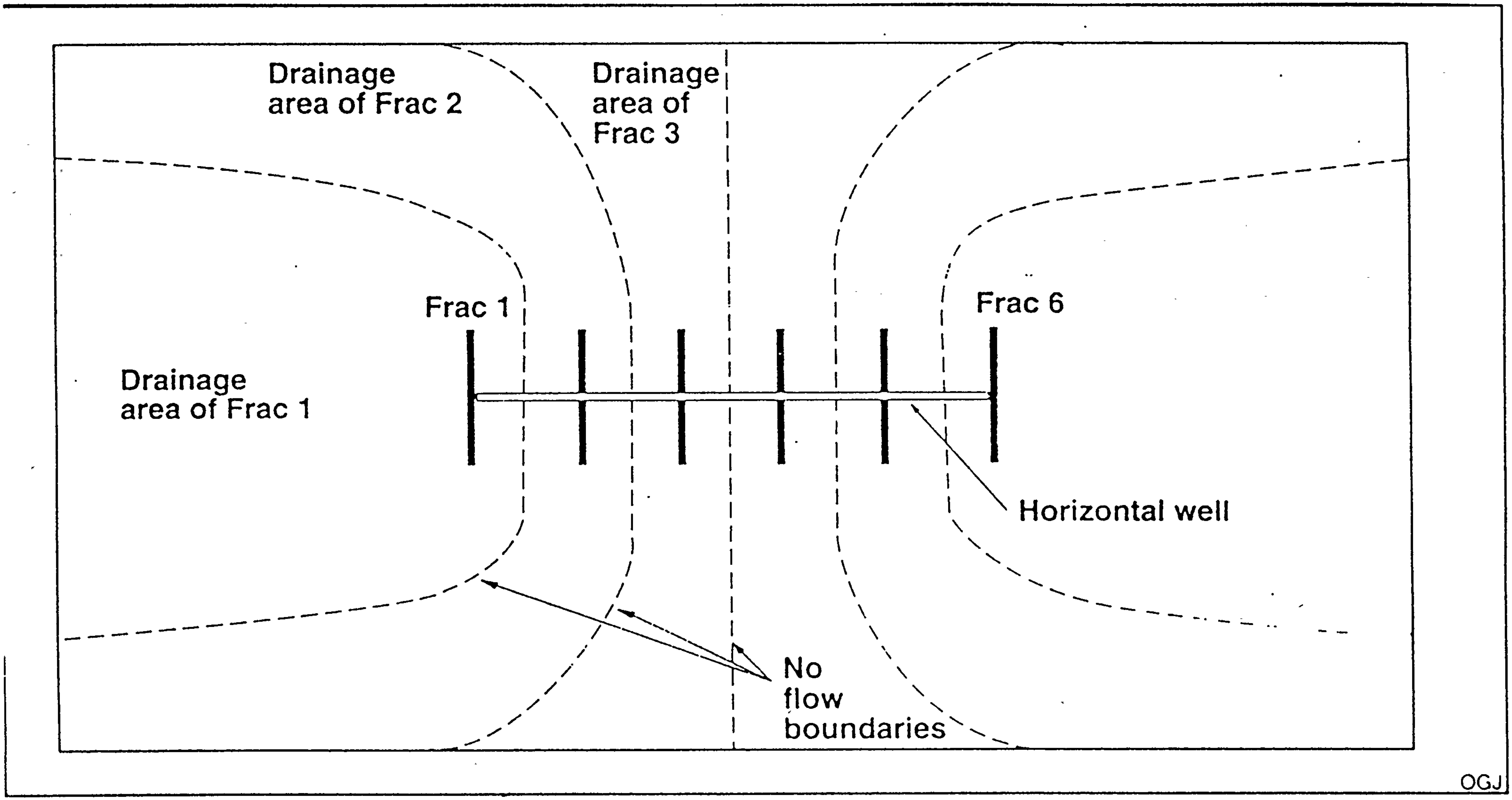


Fig. 2.1 Dynamic Drainage Areas - Horizontal Well with Six Fractures

2.3 Scope of this Work

This work models multiple transverse, hydraulic fractures, intersecting an open hole horizontal wellbore. The rationale for both of these features shall be explained currently. Recent model developments suggest that productivity improvements can be realized by selectively perforating the wellbore between fractures. The development of a mathematical model by Raghaven et al.[8] shows how the effective conductivity of a multi-fractured well can be improved by these perforations. In the extreme case (i.e. complete open hole), it has already been shown how multiple fractures were implemented in open hole wells in West Virginia. This study will show how the modeling of a multiple fractured open hole wellbore allows for productivity predictions of any type of horizontal well completion, whether it be open hole, perforated liner or cased liner.

Numerous papers in the literature discuss the benefits of horizontal wells with transverse fractures as opposed to longitudinal fractures.[6,8-13] Figure 2.2a and 2.2b shows the fracture orientation and stress distribution for transverse and longitudinal fractures respectively. Note that the vertical stress is usually greatest (hence the predominance of vertical fractures) and fracture orientation is always parallel to the maximum principal stress direction. Transverse fractures are generally preferred, allowing for multiple parallel fractures and affecting a larger drainage area. This type of fracture has a minimum contact area with the well bore and can therefore result in a large skin effect. Provided the fracture conductivity is high or matrix permeability is low, this skin effect is, however, minimal. Economides et al.[6] concluded that a single, large conductivity fracture ($k_f w/X_f k = F_{CD} > 20$) would yield little productivity improvements over the case of a fractured vertical well. For most applications the matrix permeability will rarely

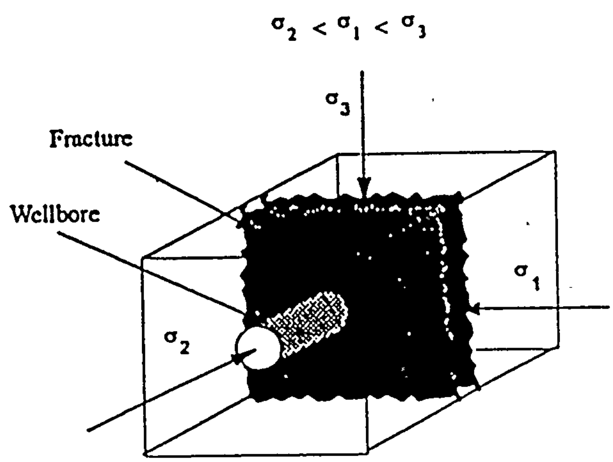


Fig. 2.2a Transverse Fracture in Horizontal Well

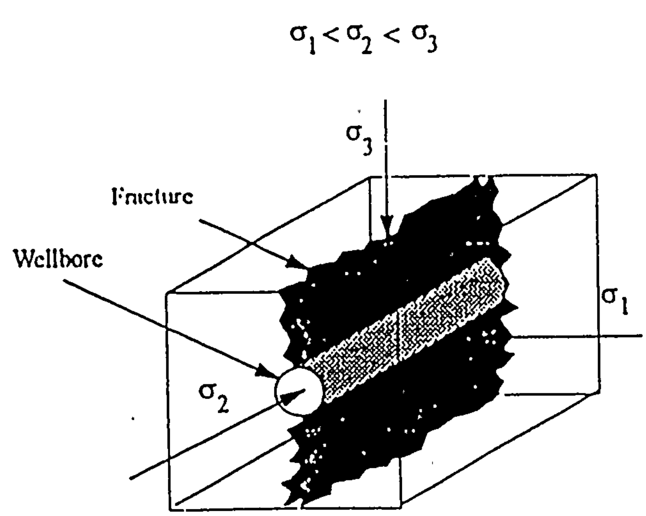


Fig. 2.2b Longitudinal Fracture in Horizontal Well

exceed 100 md, the maximum permeability modeled in this study. The type of fractures that have been modeled in this study are of infinite conductivity and are orthogonal to the wellbore, simulating the commonly sought after configuration.

Assuming the pay thickness and drainage area of any particular reservoir candidate, are established as well as can be expected and ideal fracture placement can be achieved (i.e. infinite conductivity), the parameters having the greatest influence on the economics of a multi-fractured horizontal well are 1) the number of fractures, 2) length of the fractures and 3) the in-situ reservoir permeability. This study will compare numerical results with analytical solutions for non-fractured horizontal wells after which the model will be expanded to include varying lengths of multiple fractures while also varying the permeability.

Chapter 3

3. Methodology

3.1 Preliminary Work

The methodology chosen to arrive at the final empirical solution for multi-fractured horizontal wells began with the duplication of previous work involving non- fractured horizontal wells. This preliminary work served the dual purpose of a) ensuring the model was set up correctly and was accurate (grid sizing, transmissibility multipliers, etc.) and b) revealing some subtleties that may have been overlooked or at least have not been noted in published analytical solutions.

More specifically, Gilman and Jargon[14] compared simulation results of non-fractured horizontal wells to some commonly used analytical solutions, which this study successfully reproduces. Boundary conditions and anisotropic conditions are varied for both numerical and analytical solutions to check accuracy and consistency of the analytical solutions.

To check productivity predictions of the fractured horizontal well, the work of Karcher et al[15] was duplicated. Fracture half lengths were varied revealing some interesting differences, in productivity predictions, between this work and that of Karcher et al's. Sensitivities were run on grid sizing to ensure these differences were duplicated when the grid resolution was increased. Once a "base case" and confidence in the simulation model was established, the model was expanded to include multi-fractured horizontal wells.

3.2 Development of Solutions for Fractured Horizontal Wells

The linear analytical solution for flow into a fracture, as presented by Mukerjee and Economides[16], is used as the basis which, with subsequent modifications, will yield an empirical solution that more accurately predicts the productivity of multi-fractured horizontal wells. The method applied to arrive at this solution can be suited to any reservoir conditions and well/fracture configuration.

For any given application the parameters having the greatest affect on well productivity are usually the reservoir permeability and the effective placement of some length of hydraulic fracture. Numerical methods were therefore applied to these two variables to achieve a match between numerical results and the modified analytical equation. Regression analyses, utilizing third order polynomials, were applied to these two variables. This technique could, however, be applied to other (or any number of) variables to generate an empirical solution for the desired conditions.

Using a typical oil drainage pattern of 2000 ft. x 2000 ft. and assuming a net pay thickness of 100 ft. a library of numerical solutions was created for 1,3,5 and 7 transverse hydraulic fractures in a horizontal well with a 1650 foot lateral. This library can be used to predict productivity for permeability ranging from 0 md to 100 md and any fracture half length within the given drainage area.

3.3 Testing and Applications

An empirical solution based on numerical results that have been generated at specific points along an interval (permeability range or dimensionless fracture half length, in this case) does not necessarily guarantee the solution to be applicable along the entire interval. Productivity predictions with the empirical solution were therefore plotted against numerical results. Methods to enhance prediction accuracy by modifying the data range used in the regression analysis, were explored and utilized.

The empirical solution is used in an example that evaluates the economics of various multi-fractured horizontal well options. Finally, the empirical solution can be used to investigate predictability of productivity indices with anisotropic conditions. An example application is analyzed to illustrate this.

Chapter 4

4. Numerical Model for Fractured Wells (FRACWELL)

This section provides a brief description of the simulation model used in this study, some of the basic equations that are similar in most models and also shows how certain model features or modifications affect this work.

4.1 Model Description

FRACWELL is the reservoir simulation module of the FRACANAL system developed by Simtech Consulting Services Ltd. This model can be used as a stand-alone reservoir simulator or with one of two available fracturing modules. When used with the fracturing modules, the fracture configuration is generated independently and subsequently combined with the standard reservoir description to simulate well performance with stimulated conditions. The fracturing modules also provide the user with the option of circumventing the dynamic fracture generation and specifying pre-determined fracture parameters. This second option was used for the purposes of this study.

The FRACWELL model operates under single phase, isothermal conditions with either oil or gas used as a reservoir fluid. These fluid properties are entered by means of tables. Anisotropic rock properties are permitted and all rock (and proppant) properties can vary with effective stress. The model is 3-dimensional and has several options for defining the grid. A cartesian, point centered, grid is used throughout this study. Any number of wells may be entered, subject only to dimension limits and can be completed in any set of vertically or horizontally contiguous grid blocks for vertical or horizontal wells respectively. Rate and/or pressure limitations can be specified for each well and cross-flow (through the wellbore or fracture) can be simulated. The time step control is automatic or manual.

The program requires the following input data:

1) Reservoir grid (radial or cartesian) and dimensions
2) Reservoir rock and fluid data
3) Initial conditions
4) Well locations with rate and/or pressure limitations
5) Production history data
6) Boundary conditions (i.e. constant pressure or no-flow)

Output generated from the program includes:

1) Reservoir initialization (pressures, initial volumes, etc.)
2) Time step and iteration summaries
3) Well performance summaries
4) Pressure distribution
5) Pre-frac/post-frac performance comparisons

The FRACANAL system utilizes the more precise and versatile partially-decoupled method of modeling hydraulic fractures, the details of which will be provided in section 4.8, "Theory of Coupling". This system is capable of modeling fracturing dynamics, fluid leakoff (and cleanup) or varying proppant density with rock properties that vary with the effective stress of the reservoir. This model not only provides the resolution required to generate the empirical relationships for this study but also provides a good basis for future work.

4.2 Model Formulation

4.2.1 Review of the Basic Equations

The equations which describe single phase flow are briefly reviewed in this section. A more detailed presentation may be found in Reference 17.

The flow equation in this, as in all reservoir models, is obtained by combining an equation of state and an equation for the velocity field with the mass conservation equation.

4.2.1.1 Mass Conservation

For a single component existing in one phase, the mass conservation is expressed by:

$$-\nabla \bullet (\rho\vec{u}) = \frac{\partial}{\partial t}(\rho\phi) - \hat{q}$$

where: ρ = phase density
$\vec{u}$ = velocity field of the fluid
ϕ = porosity of the medium
$\hat{q}$ = source density (+ve for source, -ve for sink).

4.2.1.2 Equation of State

The equation of state for a single phase isothermal system is simply the formation volume factor relation:

$$\rho = \rho_o / B = \rho_o b$$

where: B = formation volume factor (reservoir volume/ standard volume)
b = reciprocal formation volume factor
ρ_o = phase density at standard conditions.

4.2.1.3 Velocity Field

The velocity field, defined by Darcy's law, is given as:

$$\vec{u} = -\tfrac{k}{\mu}(\nabla P - \gamma \nabla d)$$

where: k = permeability of the medium
μ = phase viscosity
P = phase pressure
γ = pressure gradient
d = depth (where downward direction is positive).

The velocity field can be modified to accommodate pseudo pressures (for the more compressible gas reservoirs) or a non-Darcy flow (turbulence) coefficient which is also more prevalent in gas flow. For hydraulically fractured wells, two types of non-Darcy effects occur. One is associated with the reservoir and the other with the fracture with the difference typically being several orders of magnitude. A detailed formulation of the velocity field with inclusion of pseudo pressures and non-Darcy coefficients is beyond the scope of this study. The capability to model high compressibility, and/or turbulent flow environments is mentioned to note possible areas for further study.

4.2.1.4 Single Phase Flow Equation

Substituting the equation of state and the velocity field into the mass conservation equation and dividing through by the reference density, gives the standard single phase flow equation, namely:

$$\nabla \bullet \tfrac{kb}{\mu}(\nabla P - \gamma \nabla d) = \tfrac{\partial}{\partial t}(b\phi) - q$$

where: $q = \hat{q}/\rho_o$

Each term in this equation is now in terms of rate at standard conditions per unit of reservoir volume. The left side of the equation represents the difference between flow rates flowing into and out of a reservoir volume element. The right side of the equation represents the rate of mass accumulation in the volume element. The first term, on the right side, represents compressibility effects and the second term represents injection or production of mass.

4.2.2 Special Features

Aside from the previously mentioned pseudo pressure and turbulence features, the FRACANAL system is capable of modeling the dynamics of the fracture propagation, the stress dependency of fracture transmissibility (includes changing fracture geometry and proppant permeability) and finally the leak-off and subsequent cleanup of the fracture fluid filtrate.

A user defined fracture can also be implemented as has been for this study and is useful for determining the effect of various fracture properties and geometries on reservoir performance.

4.3 Finite Difference Formulation

The spatial discretization of the single phase flow equation in semi-discrete form (i.e. continuous in time but not in space) is simply stated as:

$$\Delta_x[T_x(\Delta_x P - \gamma\Delta_x d) + \Delta_y[T_y(\Delta_y P - \gamma\Delta_y d)] + \Delta_z[T_z(\Delta_z P - \gamma\Delta_z d)] = V\tfrac{\partial}{\partial t}(b\phi) - Q \qquad (4.1)$$

where: $V = \Delta X\Delta Y\Delta Z$ is a reservoir volume element
$Q = qV$ is the rate at standard conditions
$T_x = \frac{kb}{\mu}\frac{\Delta Y\Delta Z}{\Delta X}$ is the transmissibility in the x direction
$\Delta_x =$ the finite difference operator in the x direction (i.e. $\Delta_x d = d_{x+\Delta x} - d_x$) where the central-difference approximation is used in space

... and similarly for subscripts y and z.

All remaining equations pertain to the x direction however are identical in the y and z directions. To complete the discretization of the mass conservation equation, the time derivative must be discretized and the time level of various pressure dependent quantities must be specified. The current (known) time level is represented by the superscript n, while the advanced (next unknown) time level is superscript n+1.

The finite difference representation of the flow terms and compressibility term of equation 4.1 will be discussed presently while the representation of the rate term shall be introduced in the discussion on boundary conditions.

4.3.1 Flow Coefficient

The flow terms have the form:

$$\Delta_x[T_x(\Delta_x P - \gamma \Delta_x d)] \tag{4.2}$$

where γ, the pressure gradient, like density, is a function of pressure. The transmissibility, T_x, is the product of a geometric factor and the mobility, k/μ which is also a function of pressure. The pressure dependence of the flow terms causes the flow equation to be non-linear in pressure. The non-linearity which is not severe to begin with, is removed by evaluating all coefficients at the known time level and keeping them constant over the time step. Thus the flow terms have the form with time level shown as:

$$\Delta_x[T_x^n(\Delta_x P^{n+1} - \gamma^n \Delta_x d)] \tag{4.3}$$

4.3.2 Compressibility Term

The compressibility term;

$$V\frac{\partial}{\partial t}(b\phi), \tag{4.4}$$

can be expanded in finite difference form in many ways. Care must be taken to ensure that material balance is satisfied upon expansion (Reference 17). The appropriate expansion is:

$$V[(b\phi)^{n+1} - (b\phi)^{n}]/\Delta t. \tag{4.5}$$

By addition and subtraction of equal terms, this can be rewritten as:

$$\frac{V}{\Delta t}[b^{n+1}(\phi^{n+1} - \phi^{n}) + \phi^{n}(b^{n+1} - b^{n})] \tag{4.6}$$

The expansion of this equation, in terms of pressure derivatives of ϕ and b will be dealt with in Section 4.4.

4.3.3 Final Form of Discretized Flow Equation

The standard backward difference approximation for time discretization, more commonly referred to as the implicit method, is combined with gravity terms that are evaluated explicitly. Honoring material balance with a conservative expansion of the accumulation terms and combining with the gravity and rate terms yields the final form of the discretized flow equation in the x direction, namely:

$$\Delta_x[T_x(\Delta_x P^{n+1} - \gamma^n \Delta_x d)] = V[(b\phi)^{n+1} - (b\phi)^n]/\Delta t - Q \tag{4.7}$$

The spatial discretization is implemented with a point-centered grid, defined by distances between grid centers. Grid block boundaries are established as the mid-point between grid points. As an example, the point-centered grid with block boundaries for a 4 x 3 x 3 grid (i.e. 36 blocks) configuration is shown in Figure 4.1.

4.4 Expansion of the Accumulation Term

This section briefly introduces the discretization that was implemented into the FRACWELL model to ensure mass conservation properties.

The two differences of equation 4.6 must be expressed in terms of the pressure difference over the time step. For the porosity term, this is obtained from the usual assumption that the formation is only slightly compressible, i.e.,

$$\phi = \phi_r[1 + C_R(P - P_r)] \tag{4.8}$$

where:
ϕ_r = porosity at the reference pressure
P_r = reference pressure
C_R = constant compressibility

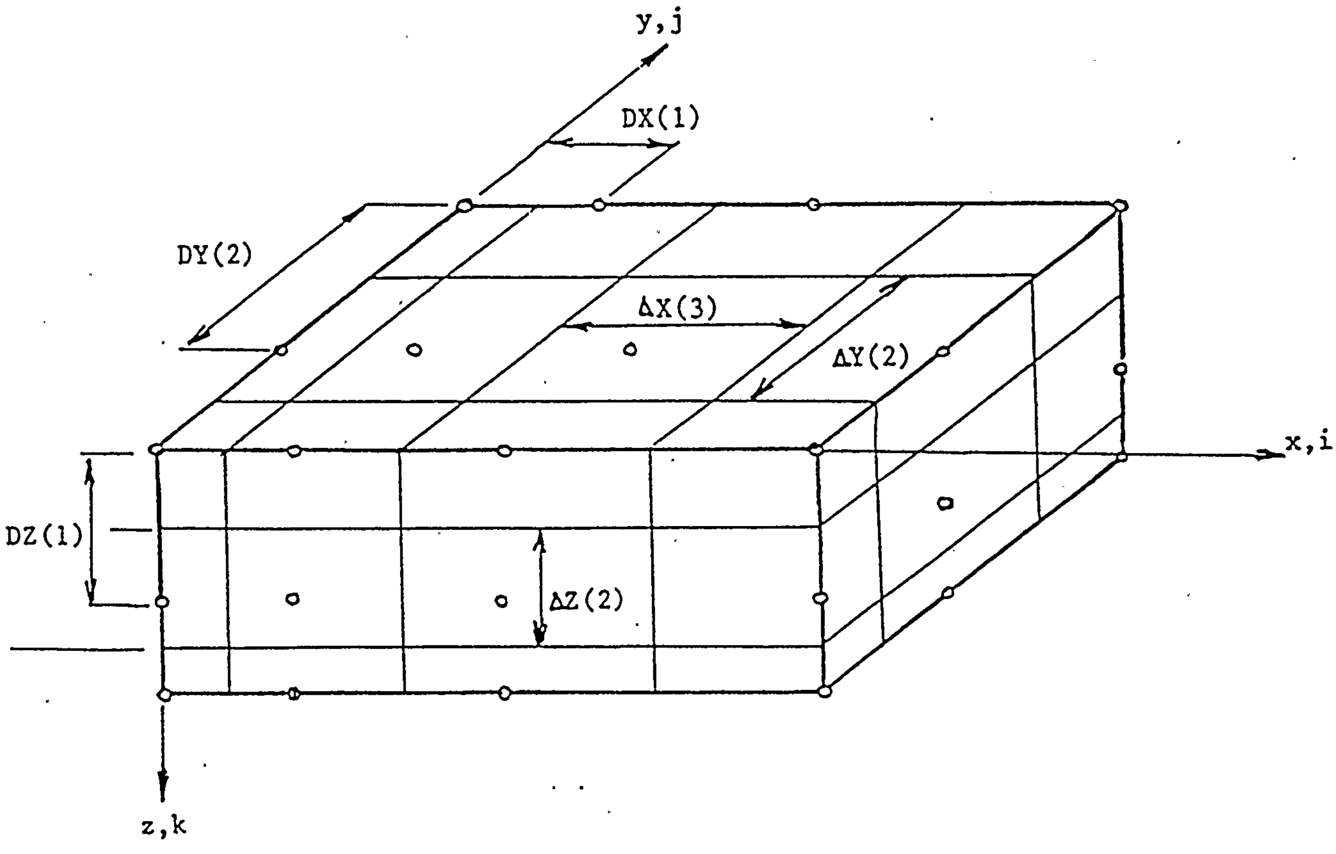


Fig. 4.1 Point Centered Grid and Block Boundaries

The pressure difference is accounted for in the density term, with the following expansion:

$$b^{n+1} - b^{n} = \tfrac{b^{n+1}-b^{n}}{P^{n+1}-P^{n}}(P^{n+1} - P^{n}) = b'^{n+1}(P^{n+1} - P^{n}) \tag{4.9}$$

where b'^{n+1} is the derivative of the reciprocal formation volume factor with respect to pressure at the advanced time level. The compressibility term of equation 4.6, can now be represented as:

$$\tfrac{V}{\Delta t}[\phi_r C_R b^{n+1} + \phi^{n} b'^{n+1}](P^{n+1} - P^{n}) \tag{4.10}$$

The reciprocal formation volume factor, b, is unknown at the n+1 timestep and because it is a function of pressure, is also non-linear. This term is linearized by using the latest iterate value (at υth iteration) for each of these quantities, i.e.,

$$\tfrac{V}{\Delta t}[\phi_r C_R b^{(\upsilon)} + \phi^{n} b'^{(\upsilon)}](P^{n+1} - P^{n}) \tag{4.11}$$

where:
$$b'^{(\upsilon)} = \tfrac{b^{(\upsilon)}-b^{n}}{P^{(\upsilon)}-P^{n}}$$
$$b^{(0)} = b^{n}$$
$$b'^{(0)} = b'^{n}$$

Upon convergence of the solution $\upsilon = \upsilon + 1 = n + 1$ so that equation 4.11 can be evaluated as:

$$[\phi_r C_R b^{n+1} + \phi^{n} \tfrac{b^{n+1}-b^{n}}{P^{n+1}-P^{n}}][P^{n+1} - P^{n}]$$

which reduces to:

$$[(\phi^{n+1}-\phi^{n})b^{n+1}+\phi^{n}(b^{n+1}-b^{n})] \quad = \quad [\phi^{n+1}b^{n+1}-\phi^{n}b^{n}]$$

This proves that mass conservation is maintained. It is this treatment of the accumulation term that allows for subsequent modifications (e.g., required for stress-dependent porosity treatment in the model).

4.5 Boundary Conditions

The rate at which fluid is produced or injected through the wellbore is a function of the grid block pressure. This pressure is included in the constant quantity expression known as the well index (WI). Fluid production is determined from:

$$Q=-\tfrac{b}{\mu}WI(P-P_w) \tag{4.12}$$

where P is the original reservoir pressure or pressure at the constant pressure boundary, under steady state flow conditions. The form of the equation assumes radial flow conditions with P_w representing the bottom hole flowing pressure and b and μ representing the reciprocal formation volume factor and viscosity of the fluid respectively. The well index, as represented in this equation, is comprised of the following constant parameters:

$$WI=c(2\pi)/\ln(\tfrac{r_b}{r_w})+S \tag{4.13}$$

An alternate form of this equation will be applied to the development of the modified analytical solution for productivity of a multi-fractured horizontal well. The constant c is 0.001127 in field units, r_w is the wellbore radius, S is the skin and r_b is the effective grid block radius. The effective well block radius in isotropic permeability conditions, as defined by Peaceman[18] is simply given as:

$$r_b = 0.14(\Delta x^2 + \Delta y^2)^{0.5} \tag{4.14}$$

When anisotropic permeability conditions are introduced into the reservoir model the expression for effective wellbore radius is expanded to:

$$r_b = \frac{0.28[(\frac{k_y}{k_x})^{0.5}\Delta x^2 + (\frac{k_x}{k_y})^{0.5}\Delta y^2]^{0.5}}{(\frac{k_y}{k_x})^{0.25} + (\frac{k_x}{k_y})^{0.25}} \tag{4.15}$$

For horizontal wells the Δy and k_y terms are interchanged with Δz and k_z terms, respectively. Subsequent refinements to equation 4.15 (Ref. 18), to account for the close proximity of other wells and vertical or horizontal grid boundaries, were not necessary as the horizontal well modeled in this study is sufficiently isolated.

To model the production (or injection) history of a well and for forecasting, realistic production and/or pressure conditions, constraints must be specified at the wellbore. For a producing well;

$$Q \geq Q_{\lim it} \quad and \quad P_w \geq P_{\lim it} \tag{4.16}$$

The signs are reversed for an injection well. The value of Q is negative for production and positive for injection. Only one constraint prevails at any given time. In each of the simulation models used for this study a rate constraint was set at a level that would be violated (i.e. well not able to maintain set rate) early in the well's production history but not before pressure transients have reached the no-flow boundaries.

Violation of the rate constraint combined with a measurable pressure drop at the no-flow boundaries, ensures that unconstrained productivity of the well is being measured under pseudo-steady state flow conditions. Alternatively, a constant sandface pressure constraint could have been utilized with unconstrained well production beginning immediately. In either case, productivity indices can only be measured when the pressure transients have reached the no-flow boundaries.

At the reservoir edge, constant pressure boundaries can be implemented by setting the pressure in one row of grid cells and simply connecting the cells in the constant pressure plane with the appropriate (i.e. large) transmissibility multipliers. A transmissibility multiplier can also be applied to the contiguous grid blocks of the horizontal wellbore to ensure infinite wellbore conductivity is being modeled. The fracture model also provides for the inclusion of infinite conductivity.

4.6 Representation of Hydraulic Fractures

This section discusses the three "classical" methods that have been applied in the past for modeling hydraulic fractures which includes 1) modifying the well index in a given reservoir model, 2) refining the grid to model the true dimensions of the fracture or 3) representing the fracture with modified transmissibilities . The third method, the more rigorous coupling technique for fracture and reservoir models, shall be discussed in more detail. The discussion in this section assumes that the fracture dimensions are known. The methods for computing the dynamic fracture propagation, in the context of a reservoir simulator are discussed in Section 4.7.

4.6.1 Increasing the Well Index

The work of Cinco Ley and Samaniego[19] showed how the wellbore radius can be altered to model fractures in coarse grid blocks. The half length of an infinite conductivity fracture is equated to an "effective" wellbore radius by:

$$r_{we} = X_f/2 = r_w e^{-S} \tag{4.17}$$

In the case of finite conductivity fractures, the effective radius can be plotted against dimensionless fracture conductivity, defined as:

$$F_{cd} = k_f b_f / k X_f \tag{4.18}$$

where k_f is the fracture permeability, b_f is the fracture width and k is the permeability of the reservoir matrix. The relationship between r_{we}/X_f and F_{cd} is shown in Figure 4.2 and shows how rapidly the fracture effectiveness decreases below F_{cd} = 1.0. Infinite conductivity fractures are, effectively, those fractures with a dimensionless conductivity in excess of 30.0.

For large reservoir models with limited resolution, the fracture can be simulated by modifying the effective well radius (substituting r_{we} for r_w) or skin in the well index

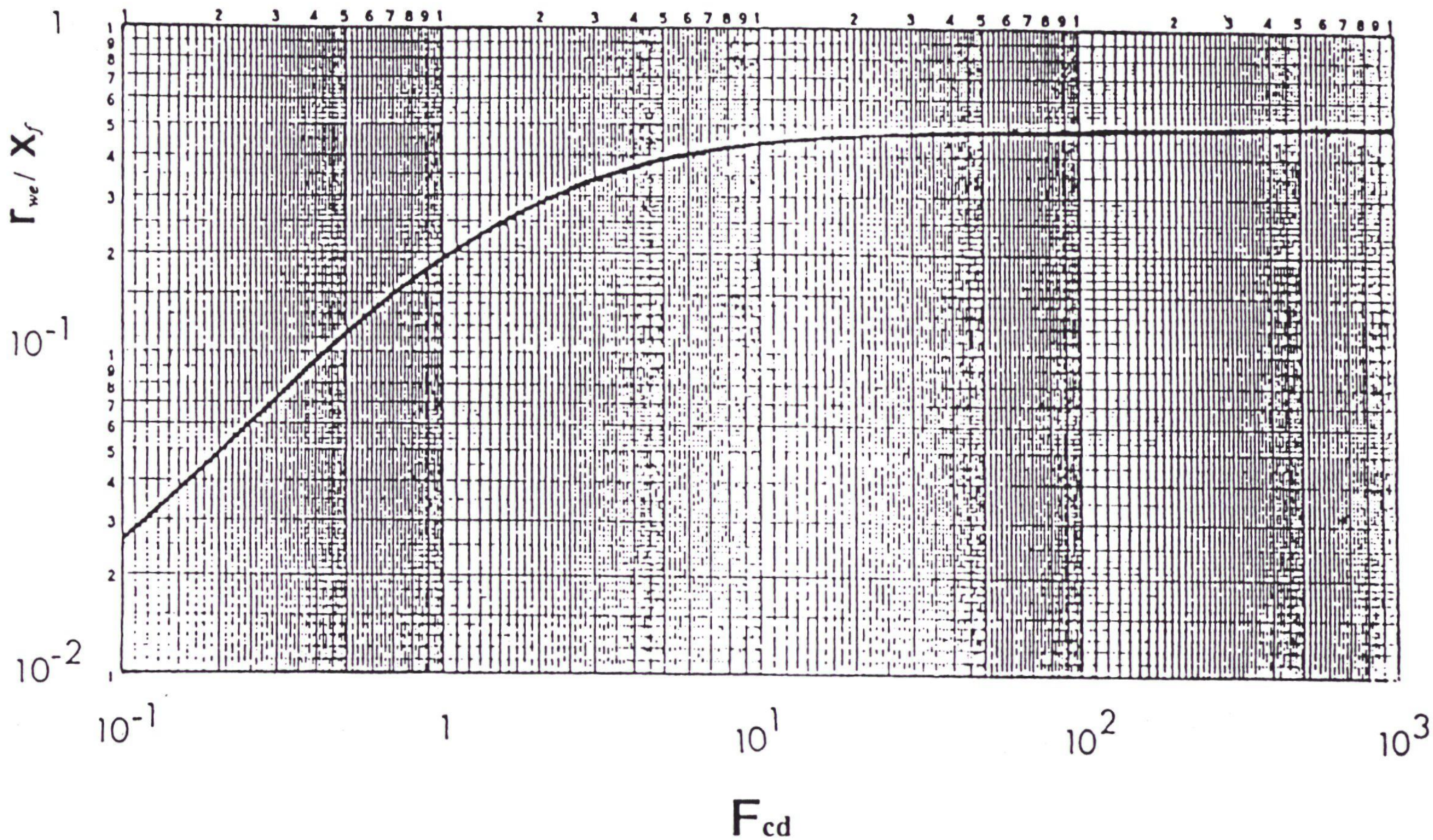


Fig. 4.2 Effective Wellbore Radius vs. Dimensionless Fracture Conductivity for Vertical Fracture

equation (Equation 4.13). If the fracture cannot be confined to the well block, additional source terms or "pseudo-wells" may be required in all blocks communicating with the fracture (Fig. 4.3a). In this case the linear transient flow regimes and perhaps the long term non-radial flow is poorly approximated by single or multiple radial flow source points. Another inherent assumption is that fracture storage and pressure drop are negligible.

4.6.2 Fracture in Separate Grid Blocks

A more rigorous approach would be to represent the fracture with actual dimensions, in a plane of grid blocks (Fig. 4.3b). Incorporating the real dimensions of the fracture into the model allows the user to specify intrinsic fracture permeability (k_f) and porosity (ϕ_f) and thereby model the early-time transients.

The degree of refinement, however, required for this approach is so large that numerical stability is a concern even for fully implicit, single well models. Most models incorporating this method must artificially increase the fracture width and compensate this with a reduction in fracture transmissibility. This negates the original objective of modeling the real fracture dimensions.

4.6.3 Modified Transmissibilities

A more practical approach for modeling fractures essentially combines independently generated fracture transmissibilities with the transmissibilities of the reservoir blocks in the fracture plane (Fig. 4.3c). The productivity enhancements

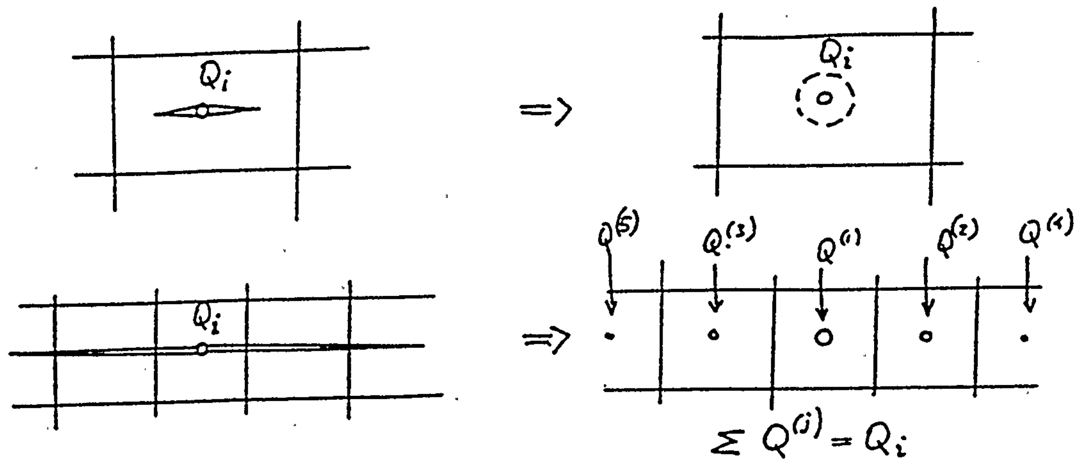


Fig. 4.3a Representation of a Fracture by a Well Index or by Source Terms

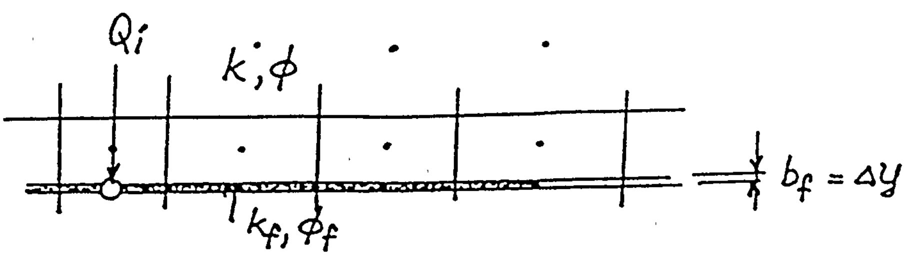


Fig. 4.3b Representation of a Fracture using True Dimensions and Properties

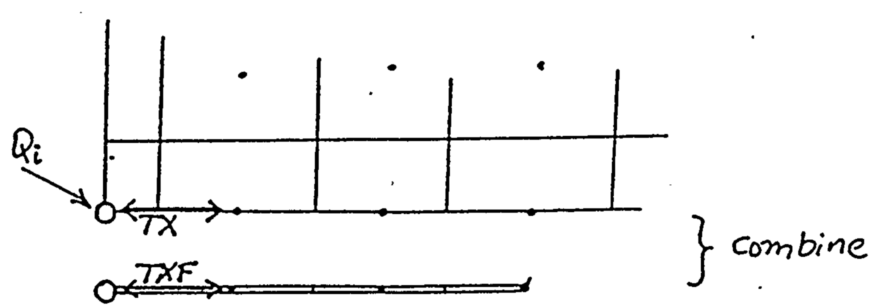


Fig. 4.3c Representation of a Fracture by Modified Transmissibilities

of the fracture are included while the negligible volume of the fracture is excluded. This approach has better stability when compared with the previous methods. The accuracy can be improved by decreasing the reservoir grid block size, which, when reduced to true fracture dimensions, represents the previous method of fracture representation.

One of the disadvantages of this method is in the necessity to interface the fracture model with the reservoir model. Aside from the various coupling (or partially- decoupled) methods, which will be discussed in the next section, combining these models introduces complications associated with the averaging of transmissibilities. On the other hand, this is also one of the main advantages of this approach.

The transmissibility of the fracture varies spatially to model the potentially different proppants and/or varying proppant concentrations. In most applications the fracture grid is finer than the reservoir grid. When the fracture grid is subdivided to include the proppant transport grid and subsequently combined with the reservoir grid, the resulting refined grid could appear as shown in Fig. 4.4. Transmissibilities from the subdivided fracture grid must then be combined with the reservoir grid using the appropriate averaging technique.

Referring to Fig. 4.5, the combining of fracture and reservoir transmissibilities in the FRACANAL system, can be described briefly as follows:

1) Any part of the reservoir grid completely covered by the fracture, such as the area between i and i+1 in Fig. 4.5a, has a transmissibility determined from the harmonic average of the refined grid transmissibilities:

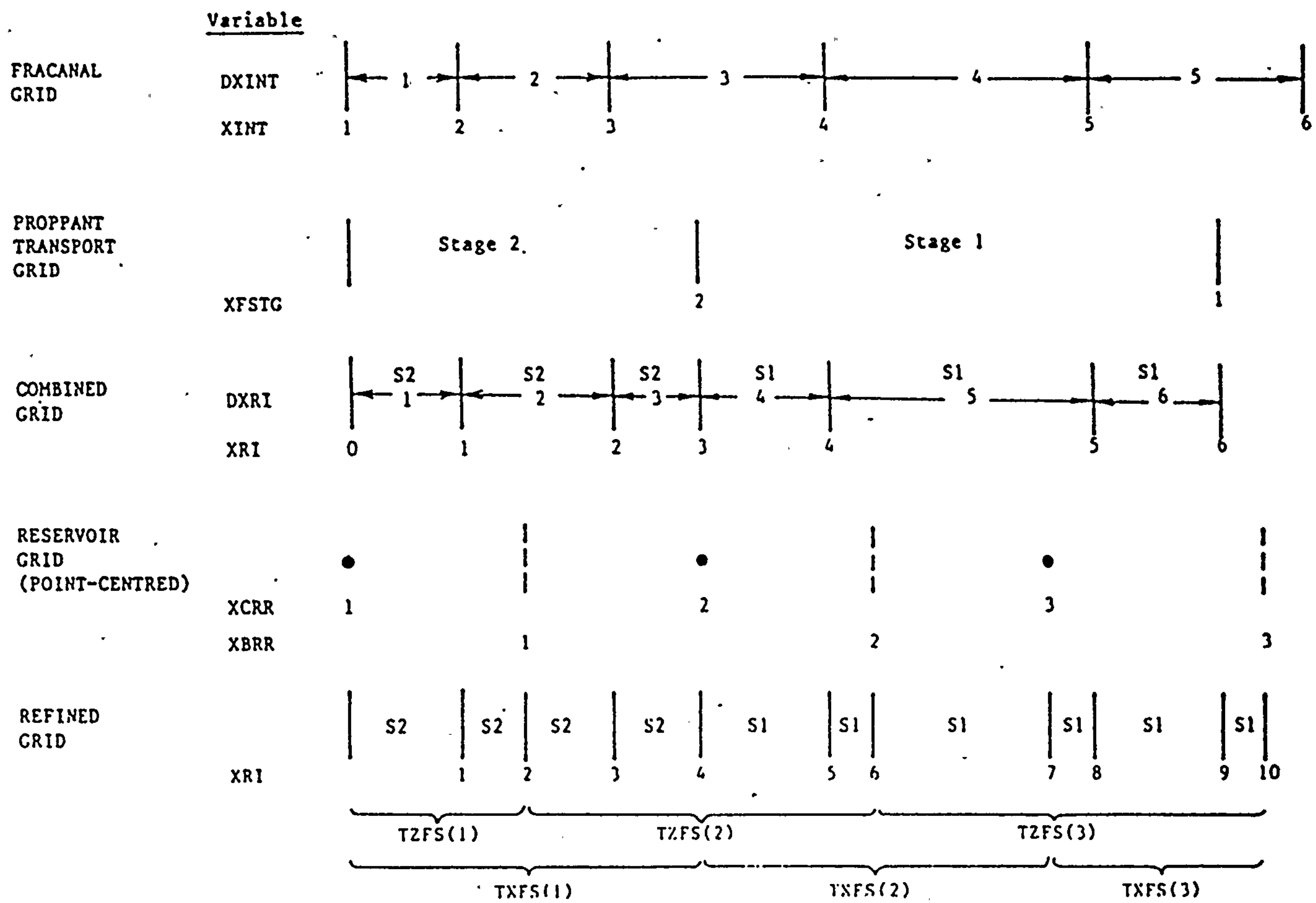


Fig. 4.4 Grid Refinement of the Fracture

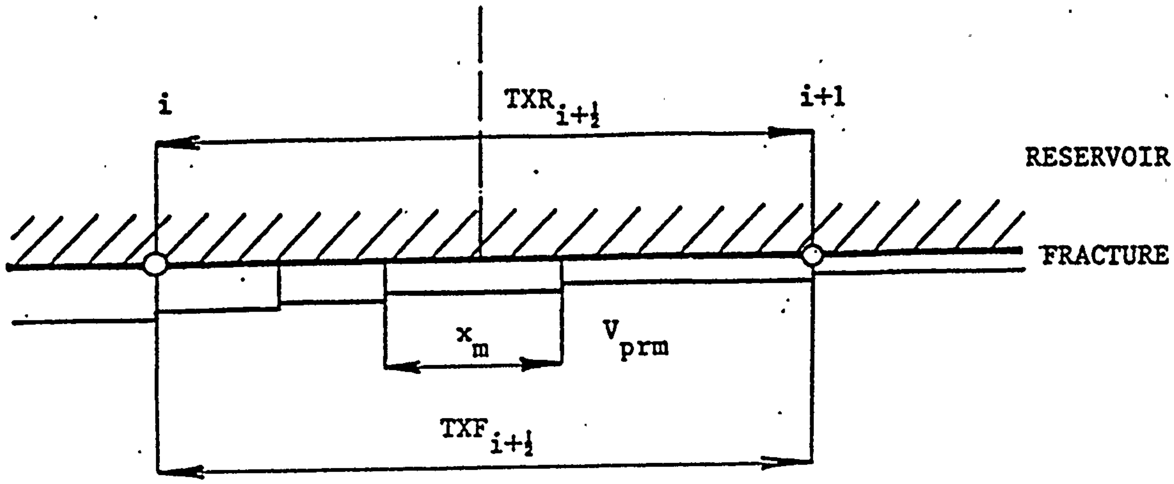


Fig. 4.5a Combining Transmissibilities for Interval Fully Penetrated by Fracture

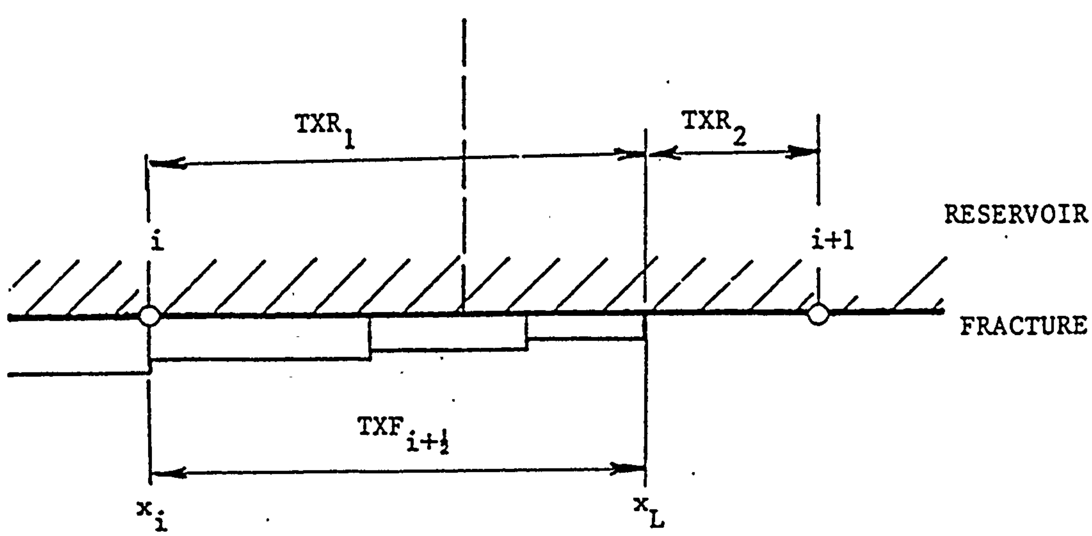


Fig. 4.5b Combining Transmissibilities for Interval Partially Penetrated by Fracture

$$TXF_{i+1/2} = 1/[1/\Sigma_m TXF_m], \tag{4.19}$$

after which the total transmissibility is determined by:

$$TXT_{i+1/2} = TXR_{i+1/2} + TXF_{i+1/2} \tag{4.20}$$

2) For the partially penetrating (i.e. into reservoir grid) fracture tip:

a) the same method applied in (1) is applied up to the fracture tip and
b) beyond the fracture tip only the reservoir transmissibility is present. The two parts (refer to Fig. 4.5b) are averaged harmonically:

$$TXT_{i+1/2} = 1/[1/(TXR_1 + TXF_{i+1/2}) + 1/TXR_2] \tag{4.21}$$

where: $$TXR_1 = TXR_{i+1/2}(x_{i+1} - x_i)/(x_L - x_i) \tag{4.22}$$
and $$TXR_2 = TXR_{i+1/2}(x_{i+1} - x_i)/(x_{i+1} - x_L) \tag{4.23}$$

The vertical transmissibilities are calculated the same way. Numerical errors associated with the tip block transmissibility calculation can be magnified in the vertical direction where the reservoir grid is often coarser than in the horizontal direction.

These discretization errors can be reduced by applying the appropriate weighting technique (modifying Equation 4.21) and by reducing Δx. It should be noted that further "smoothing" of the discretization error, in multiphase applications, can be achieved by also incorporating a mobility weighting (different in the fracture) to the geometric portion of the transmissibility calculation.

These "fracture tip oscillations" are more prevalent in fully coupled simulation models and can be eliminated in the partially-decoupled model (used for this study) when applying dynamic gridding techniques. In any case, care was taken during this study to ensure fracture tips closely coincided with the point centers of the reservoir grid thereby minimizing this discretization error.

4.7 Theory of Coupling

This section briefly discusses the theory as well as advantages and disadvantages of fully coupled and partially de-coupled models. The latter model is utilized in the FRACANAL system used in this study.

4.7.1 Fully Coupled Models

Models combining or coupling a reservoir simulator with a fracture simulator were originally developed for waterflood induced fractures[20] and subsequently extended to include hydraulic fracturing[21]. In a fully coupled model, fracture variables and dimensions are solved simultaneously with the reservoir variables.

Advantages of a fully coupled model include:

1) Rigorous coupling (communicating) of the two models.
2) Representing the fracture with separate blocks.
3) Accurate prediction of leak-off (i.e. multi-dimensional).

The associated disadvantages are:

1) Numerical problems associated with the coupling of a fine fracture grid with the coarser reservoir grid. The flow normal to the fracture face requires finer detail in the grid dimensions.

2) Multiphase flow in the fracture causes stability problems.

3) Models are large and CPU intensive.

4) Another problem is associated with partial penetration of the fracture tip. This causes oscillations in injectivity and consequently in the fracture growth rate.

Because of the size limitations and numerical problems, fully coupled models are not commonly used.

4.7.2 Partially-Decoupled Models

The time required to generate a fracture is relatively short compared to the productive life of a well and can therefore be treated as an instantaneous event. The end result or static fracture can then be incorporated into the reservoir model where the combined transmissibilities are determined as described in section 4.6.3.

Modeling the dynamics of the fracturing process is achieved in a similar fashion. The complete simulation of the fracture growth is generated from the fracturing model with timesteps that are unique to the fracture model. These timesteps are subsequently interpolated with reservoir model timesteps using a "fracture interface" module. Transmissibilities are intermittently calculated in the same manner as with the static fracture case. A schematic representation of how the fracture model is coupled with the reservoir model is shown in Fig. 4.6. Details of the dynamic fracturing technique are provided in Reference 22.

Advantages of the partially-decoupled models include:

1) Maximizing efficiency by applying the appropriate spatial and time scales to fracture mechanics and reservoir flow.

2) The varying of fracture or reservoir characteristics can be readily achieved.

3) Fracture model can utilize a dynamic grid which eliminates the previously described fracture tip problems.

The disadvantages of this approach include:

1) A one dimensional representation of leak-off and possibly heat transfer is usually required.

2) Fracture is lumped with adjacent reservoir gridblocks.

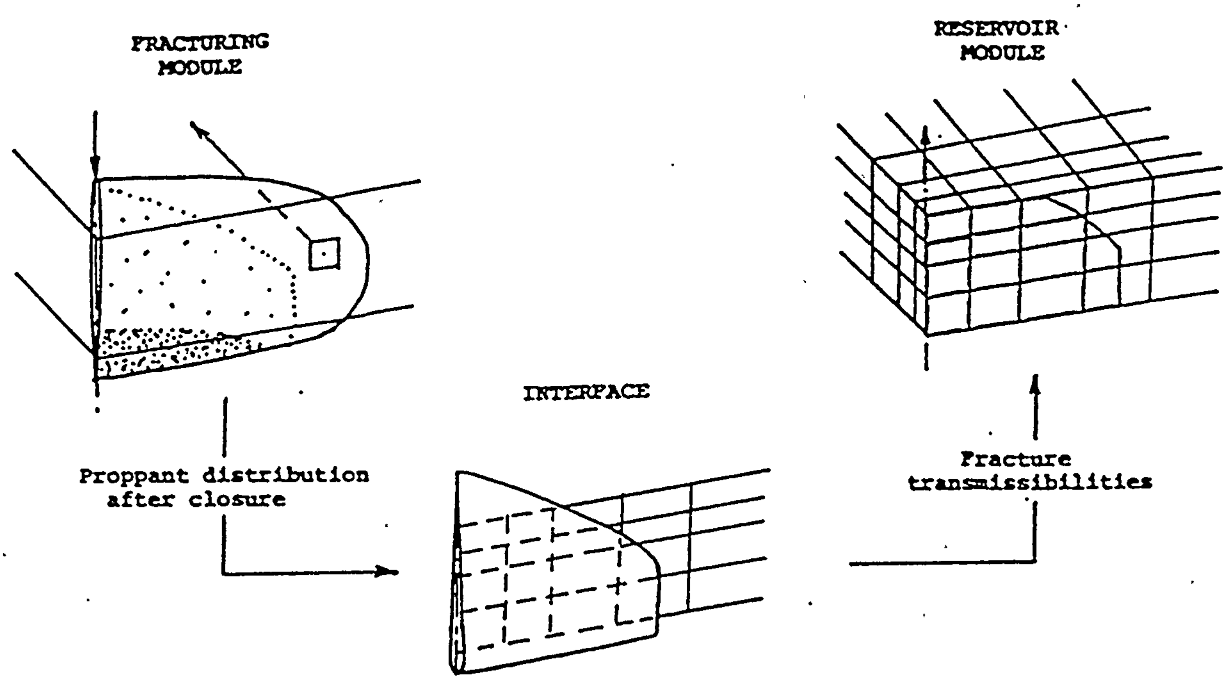


Fig. 4.6 Schematic of a Partially-Decoupled Model for Hydraulic Fracturing

3) The productivity enhancement of the fracture is uncertain and therefore may not satisfy pre-specified well conditions.

The enhanced stability and versatility of the partially-decoupled model, especially for static fracture applications, makes this model a practical tool for detailed predictions of multi-fractured horizontal well performance. This work deals with propped fractures and therefore the assumption of static fractures is justified.

Chapter 5

5. Productivity Indices: Simulation Model versus Analytical Solutions

Productivity indices of unfractured horizontal and vertical wells, generated from a numerical simulation model, are compared to analytical solutions in this chapter. The purpose here is to approximate, as closely as possible, Table 1 of the work published by Gilman and Jargon[14], comparing horizontal well productivity indices (non-fractured), from the simulator, to productivity indices predicted from the commonly used analytical solutions of Babu & Odeh[23], Goode & Kuchuk[24] and Joshi[25]. A "base" is established after running sensitivities on the number of grid blocks, size of grid blocks, transmissibility multipliers, etc., required to yield results approximating these analytical solutions and simulation work by Gilman and Jargon. This work assesses the reliability of the simulation model in general, and establishes a basis from which specific empirical solutions can be generated for multi-fractured horizontal well configurations.

5.1 The Analytical Solutions

The three equations considered and conditions governing their use, are as follows:

5.1.1 Babu & Odeh's Solution

Babu & Odeh[23] presented the following equation for pseudo-steady state conditions:

$$PI_h = \frac{0.00708\, L_y \sqrt{k_x k_y}}{\mu B[\ln(\sqrt{L_x h}/r_w) + \ln(C_h) - 0.75 + S_R + S_d}$$

where:

$$\ln(C_h) = 6.28 L_x/h \sqrt{k_z/k_x}\,[\tfrac{1}{3} - \tfrac{x_o}{L_x} + (\tfrac{x_o}{L_x})^2] - \ln(\sin 180^o z_0/h) - 0.5 \ln[(L_x/h)\sqrt{k_x/k_x}\,] - 1.088$$

with x_o and z_o as coordinates measuring the center of the well in the vertical plane, L_x and L_y as dimensions of the drainage area, orthogonal and parallel, respectively, to the horizontal well. The procedure for calculating the skin S_R is simple but long. Two different methods are described for calculating this skin depending on whether;

$$L_x/\sqrt{k_x} \;\geq\; 0.75b/\sqrt{k_y} \;\geq\; 0.75h/\sqrt{k_z} \quad \text{or} \quad L_y\sqrt{k_y} \;\rangle\; 1.33a/\sqrt{k_x} \;\geq\; h/\sqrt{k_z}$$

The skin calculation, for either case, is comprised of two to three components that consider the degree of penetration and location of the well on the x-y plane. Sample calculations of S_R can be found in Babu & Odeh's paper.[23]

Conditions:

$L_x \geq 0.75h\sqrt{k_x/k_z}$

a minimum distance between the well and boundaries must be maintained:

$\min(x_0, L_x - x_0) \geq 0.75\sqrt{k_x k_z}$

5.1.2 Goode & Kuchuk's Solution

Goode and Kuchuk[24] provide methods for evaluating inflow performance of a horizontal well bounded by no flow boundaries on all sides or with a constant pressure upper boundary (e.g. gas cap). Using normalized pressure, to provide a measure of the pressure drawdown required to flow a unit of volume per unit of time, the productivity index is expressed as;

$$\mathrm{PI} = 7.08x10^{-3} k_h h/\mu B_o(p_{wD} + S_m^*)$$

where: $S_m^* = (h/2L_{1/2})\sqrt{k_x k_z}\, S_m$ and S_m is the van Everdingen mechanical skin, described by

$$S_m = [2\pi L_{1/2}\sqrt{k_y k_z}/\mu Q]\Delta p_s$$

5.1.2.1 Pseudo-Steady State (PSS)

The general solution for the PSS pressure drop for no flow boundaries is as follows:

$$p_{wD} = \frac{2\pi L_y}{L_x}\sqrt{\frac{k_x}{k_y}}\left(\frac{1}{3} - \frac{y_w}{L_y} + \frac{y_w^2}{L_y^2}\right) + \frac{2L_x^2}{\pi^2 L_{1/2}^2}\sum_{N=1}^{\infty}\frac{1}{N}\Xi_x^2(1+\xi) + S_{zD}$$

where: $S_{zD} = -\frac{h}{2L_{1/2}}\sqrt{\frac{k_x}{k_z}}\{\ln[\frac{\pi r'_w}{h}2\sin(\frac{\pi z_w}{h})] + \sqrt{\frac{k_x}{k_z}}\frac{h}{L_{1/2}}(\frac{1}{3} - \frac{z_w}{h} + \frac{z_w^2}{h^2})\}$,

$r'_w = (r_w/2)(1 + \sqrt{k_z/k_y}$,

$\xi = 2e^{\alpha L_y} + e^{\alpha(L_y - y_w)} + e^{\alpha y_w}/1 - e^{\alpha L_y}$,

$\alpha = -\frac{2n\pi}{L_x}\sqrt{\frac{k_x}{k_y}}$, N = Fourier transform variable

and $\Xi_x = \frac{1}{N}\sin(N\pi\frac{L_{1/2}}{L_x})\cos(N\pi\frac{x_w}{L_x})$.

Conditions:

The skin expression, S_{zD} is valid for $\sqrt{k_x/k_z}\,(h/L_{1/2}) \angle 5$. When this is not the case, additional terms must be included (see Ref. 24) and are solved with reference to the provided table. If the well's length does not greatly exceed $h\sqrt{k_x/k_z}$, distances to the lateral boundaries must be large relative to distances to the vertical boundaries (usually the case).

5.1.2.2 Constant Pressure Boundary

For the constant pressure boundary case the solution is:

$$p_{wD} = \frac{h}{2L_{1/2}}\sqrt{\frac{k_x}{k_z}}\,\{\ln[\frac{8h}{\pi r_w}\cot(\frac{\pi z_w}{2h})] + \frac{z_w-h}{L_{1/2}}\sqrt{\frac{k_x}{k_z}}$$

Conditions:

The equation for constant pressure boundary conditions is valid when $\sqrt{k_x/k_z}\,(h/L_{1/2}) \angle 2.5$. If this condition is not satisfied, an extended version of this equation (Ref. 24) must be applied.

5.1.3 Joshi's Solution

Joshi (Ref. 25) presented the following equation for steady-state conditions:

$$\mathrm{PI} = \frac{0.00708 k_h h}{B\mu[\ln(\frac{a+\sqrt{a^2-0.25L_w^2}}{0.5L_w}) + \frac{\beta h}{L_w}(\ln(\frac{0.5(\beta h)^2+2(\beta\delta)^2}{\beta h r_w}) + S_d)]}$$

where: $\beta = \sqrt{k_h/k_v}$ = measure of the reservoir permeability anisotropy,

δ = vertical distance between the horizontal well and vertical mid-point of the reservoir,

and $a = 0.5L_w[0.5 + \sqrt{0.25 + (2r_e/L_w)^4}\,]^{0.5} =$ the large half-axis of the elliptical drainage area.

This equation applies for steady-state flow conditions and is valid only for $\beta h \angle L_w$ and $L_w \angle 1.8r_e$

5.1.4 Vertical Well Solution

The analytical solution for the productivity index of a vertical well is also required for comparisons between vertical well and horizontal well productivities. The solution, as indicated by Gilman and Jargon, is given as:

$$\mathrm{PI}_v = \frac{0.00708 k_h h}{B\mu[\ln(3.1725\frac{\sqrt{L_x L_y / C_A}}{r_w}) + S_p + S_d - 0.75]}$$

There the shape factor, C_A is 30.883 and the skin effect due to partial penetration, S_p, is given by:

$$S_p = (\frac{h}{h_p} - 1)[\ln(\frac{h}{r_w}\beta) - 2]$$

5.2 Comparison of Analytical and Numerical Solution

5.2.1 Setup of Numerical Model

The horizontal well cases without hydraulic fractures were simulated with half elements of symmetry utilizing cartesian, point centered grids. Prior to running quarter elements of symmetry, required for the multi-fractured well cases, half element and quarter element solutions were compared to ensure consistency (i.e. ensure flux distribution along well is symmetrical which is indicative of infinite conductivity). For fractured horizontal wells the (single) fracture is placed on the x-z plane while the wellbore is placed parallel to the y-z plane. The well and fracture intersect at the origin of the x and y plane and the desired gridblock in the z direction, depending on the vertical placement of the wellbore (as shown of Fig. 5.1).

For an infinite row of equally spaced fractures, the mult-fractured well can simply be modeled with the appropriate element of symmetry including only one fracture. A realistic placement of a multi-fractured well however, is not usually symmetrical about the center of any convenient "element" of the drainage area. In fact, due to mechanical or reservoir conditions, spacing between fractures is rarely consistent. These configurations (simulated in this study) require transmissibility multipliers that are generated from the single fracture run and incorporated in the reservoir model at the desired fracture spacings. Care was taken to ensure transmissibility multipliers were modified to suit the different grid dimensions in which they were placed. If this is not done, erroneous production enhancement results and is readily detected.

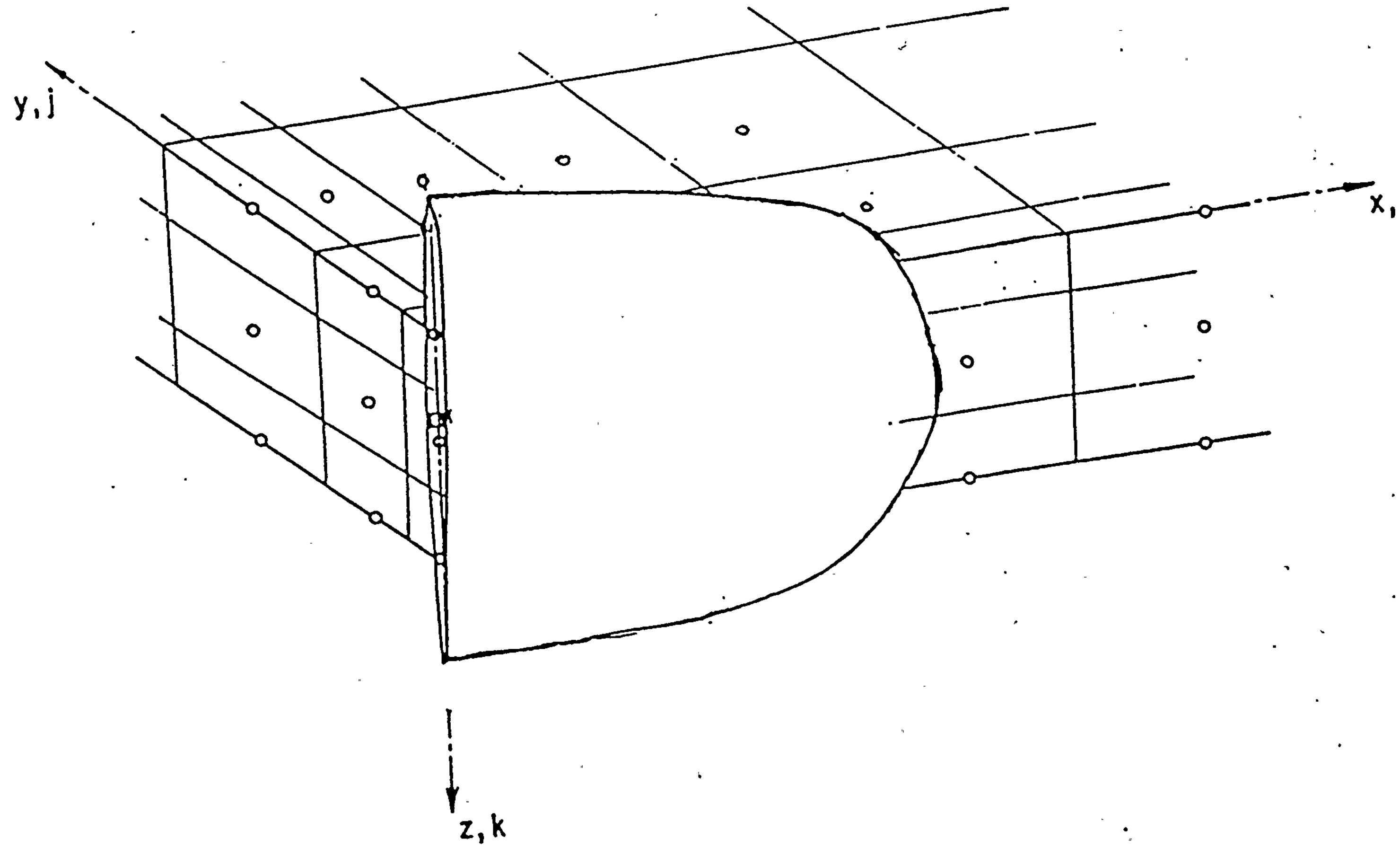


Fig. 5.1 Placement of a Fracture Relative to the Reservoir Grid

Reservoir and wellbore dimensions are provided with each case in the discussion on the empirical formula derivation. For the most part the modeled drainage area is slightly less than a 1/4 section drilling spacing unit (i.e. 2000 ft. x 2000 ft.). Grid spacing along the y axis is uniform (50 ft./grid block) while spacing in the x direction progresses from smaller dimensions near the wellbore, for better resolution, and increases away from the wellbore. Grid block sizing in the x direction was implemented so that block centers of the reservoir model, coincided with fracture half lengths to avoid numerical oscillations at the fracture tip as previously discussed. Grid dimensions for the nine layers are also spaced with smaller grid dimensions near the centrally located wellbore and larger dimensions towards the top and bottom of the reservoir. Grid spacing and transmissibility multipliers can be found in the example data file in Appendix A, printed from the three fracture case. The corresponding "static" fracture properties, found in the interface template, are provided in Appendix B.

The PVT properties, applied to most simulation runs, represents a single phase fluid with small compressibility. The variation of the formation volume factor (~ 1.0 Bbl/STB) with pressure is recorded in the attached data file (Appendix A). Viscosity is 1.0 cp when modeling runs for the empirical formulation work and is changed to 4.0 cp when duplicating the work of Gilman and Jargon.

Infinite conductivity in the wellbore and fractures was implemented with transmissibility multipliers. The fractures are orthogonal to the wellbore. Reservoir petrophysical parameters remained consistent, applying a 10% porosity, 10% connate water saturation and 30% residual oil saturation at a reservoir pressure of 1500 psia.

As mentioned previously, in Chapter 4, most simulation runs, in this study, were run with pseudo-steady state (PSS) boundary conditions. To ensure these conditions prevailed when measuring the productivity index, boundaries were checked for measurable pressure drops at the corresponding timesteps. The productivity index is determined by subtracting sandface (bottom hole pressure) from the average reservoir pressure and dividing into the production rate. Measurements were taken one timestep after violation of the rate constraint (i.e. when rate is not constrained).

5.2.2 Re-Generating the Work of Gilman and Jargon

Table 5.1 compares productivity indices between a 400 ft horizontal and a vertical well with the indicated boundary conditions and anisotropies. Model dimensions and viscosity, duplicate those used by Gilman and Jargon and are as follows:

$\mu = 4$ cp	$L_x = 2000$ ft (reservoir width)
$r_w = 0.1875$ ft	$L_y = 2000$ ft (reservoir length)
$h = 100$ ft	Centered well

The simulation results of this work show that productivity indices predicted by the horizontal well model closely approximate those predicted by the analytical solution. Productivity indices predicted by Goode & Kuchuk's equation are quite comparable to indices from the simulation model. Indices predicted by the Babu & Odeh equation are slightly less accurate and indices predicted by Joshi's equation were either too low or too high depending on anisotropy. As noted by Gilman and Jargon, Joshi's equation is for steady state flow and isotropic conditions and therefore yields less accurate results in anisotropic reservoir conditions. Determining a representative horizontal permeability in anisotropic conditons was not attempted, in this work, for productivity calculations using Joshi's pseudo-steady state solution. This solution[24] was, however, applied to isotropic conditions to yield a comparable productivity index of 5.21 Bbls/day/psi in the 100 md case.

Table 5.1 - Comparisons of Simulator and Analytical Productivities

					Analytical Solutions				Simulation Results	
Lw (ft)	Horizontal well direction	kx (md)	ky (md)	Boundary Condition	PIv	Babu & Odeh	Goode& Kuchuk	Joshi	PIv	PIh
400		100	100	no flow	2.22	4.82	5.18	3.92	1.99	4.87
400		100	100	const press	2.83		7.13		2.97	7.36
400	x	10	100	no flow	0.70	2.21	2.49	1.60	0.67	2.37
400	y	10	100	no flow	0.70	1.22	1.30	1.60	0.67	1.31
400	x	1	100	no flow	0.22	0.42	0.47	0.60	0.21	0.48
400	y	1	100	no flow	0.22	0.22	0.23	0.60	0.21	0.27

In any case, the horizontal well configurations dealt with thus far yield results that support the general observations made by Gilman and Jargon and, for this work, establishes a "base" from which hydraulic fractures may be initiated.

Chapter 6

6. Productivity Enhancement with Fractures

6.1 Single Fracture

Productivity enhancements of a horizontal well with increasing fracture half length has been investigated by Karcher et al.[15], whose work is also referred to in Joshi's book.[25] Using a numerical finite difference model Karcher et al. compared the productivity of fractured and unfractured horizontal wells using steady state boundary conditions. They used a model of 1000 ft. by 1000 ft. area with a 125 ft. thickness and a centralized 400 ft. horizontal well. Our work, using the same configuration yields productivity index ratios that are similar to Karcher et al's when the dimensionless fracture length ($2X_f$/drainage width) is greater than 0.5 as shown on Fig. 6.1. The work of Karcher et al. yields an almost linear relationship of productivity enhancement with frac length. As indicated on Figure 6.1, our work shows that larger productivity enhancements, for a horizontal well with one orthogonal fracture, occur at the beginning of fracture initiation (i.e. up to a dimensionless fracture length of 0.05). This feature is enhanced as the reservoir thickness is increased. For example, for a 250 ft. thick reservoir, the productivity can improve two fold when the hydraulic fracture half length is less than 50 feet (in the 1000 ft. by 1000 ft. reservoir) and must extend some 300 feet from the center of the 400 foot horizontal well before the productivity is increased four fold. This feature becomes important when designing proppant amounts for the stimulation treatment required to achieve the desired fracture length.

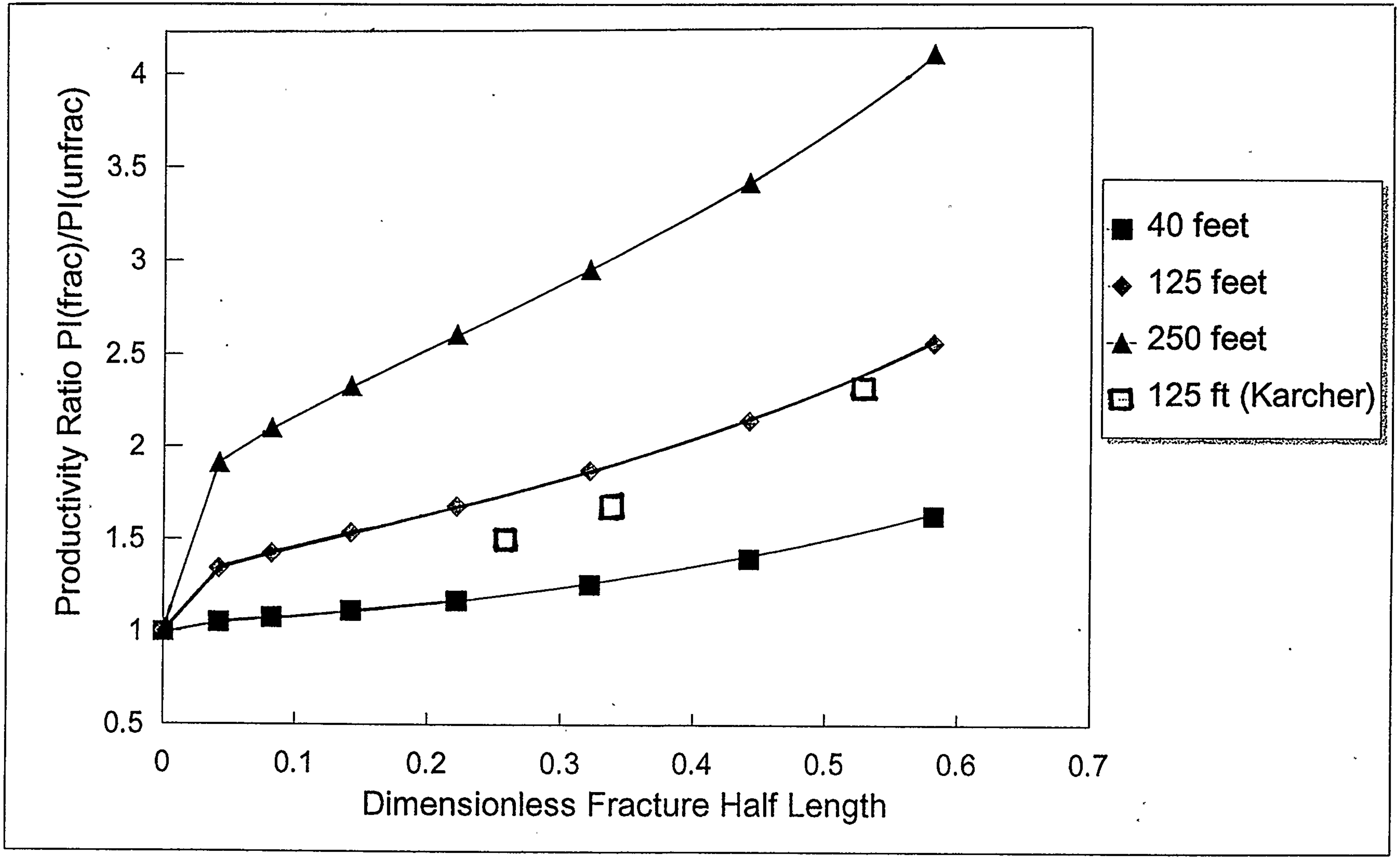


Fig. 6.1 Productivity Enhancement of Fractured Horizontal Well

These results were duplicated when running sensitivities on the grid block sizes. Figure 6.2 shows the relationship of productivity with increasing fracture half length holds when the number of grid blocks is increased almost three-fold. Note that this feature is not necessarily in contradiction with the work of Karcher et al. since they apparently did not simulate cases with small fracture lengths.

Before considering multiple fractures, sensitivities on horizontal well length were modeled for a well with a single fracture in a 2000 ft. by 2000 ft. drainage area with a 100 foot pay thickness and permeability of 100 md. The results of this example, plotted on Figure 6.3, reveal that a horizontal well with 700 feet of lateral length has three times the productivity of a horizontal well with 100 feet of lateral, when neither well has a fracture (i.e. $X_{fd} = 0$). However the same 700 foot well has less than a 15% productivity improvement over its' 100 foot counterpart when each well has a single fracture with a fracture half length of 550 feet. This example illustrates three points:

1) Horizontal wells in a homogeneous reservoir, having one fracture of reasonable length, need not be very long (i.e. fractured vertical well may be more cost effective).

2) For fractured horizontal wells, any additional length of the wellbore achieves real returns in productivity only when the length is fully utilized to space multiple fractures (rather than from the wellbore itself).

3) Pseudo-steady state boundary conditions change the shape of the productivity vs. X_{fd} curve such that the slope begins to decline at $X_{fd} \cong 0.3$ (compare with steady state conditions modeled in Fig. 6.1).

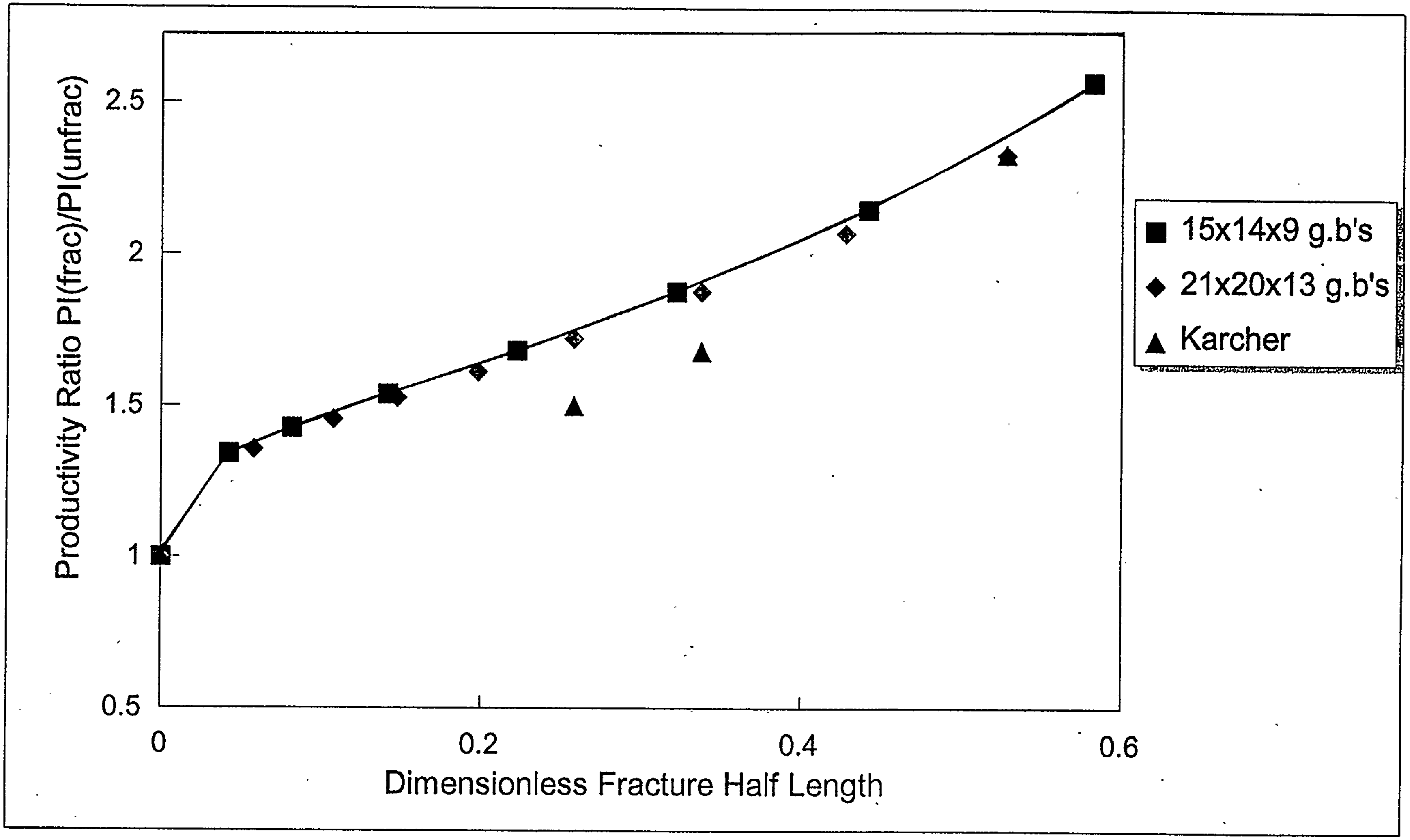


Fig. 6.2 Productivity vs. Fracture Half Length with Refined Grids

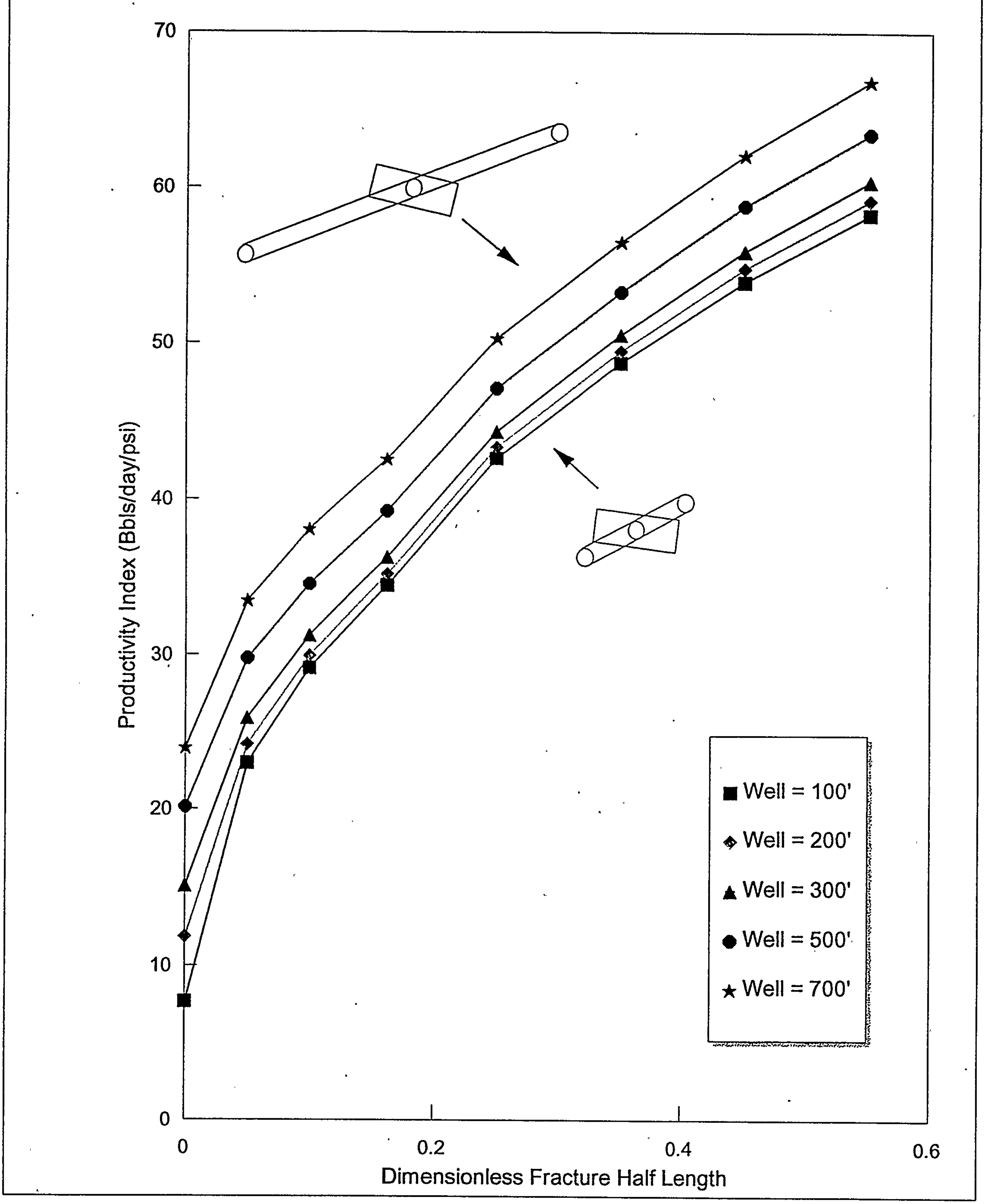


Fig. 6.3 Varying Horizontal Lateral Length and Fracture Half Length

6.2 Multiple Fractures - General Approach

The empirical relationship, determining productivity enhancement from fractures in horizontal wells, developed in this work, begins with the linear flow equation of a horizontal well with a row of infinite conductivity fractures, as proposed by Mukerjee and Economides.[16] Assuming a spacing of 2x between fractures, the flow into each fracture is given by:

$$Q/\Delta P = 0.00127(2K_h)(2X_f h)/\mu Bx \qquad [Bbls/day/psi] \qquad (6.1)$$

where: Q = flow rate
ΔP = pressure drawdown
K_h = horizontal permeability
h = net pay thickness
μ = viscosity of reservoir fluid
B = formation volume factor
and x = distance to no-flow boundary = 1/2 the distance between fractures.

The inaccuracy of this equation originates with the condition that only linear flow occurs in the formation producing to the fracture(s). Simulation work reveals that productivity, when plotted against the fracture half length is in fact curvilinear with productivity at fracture ends (origin at the wellbore and tip at reservoir edge) established by the linear equation. All points on a straight line between these two end points is, at best, a line of best fit and usually a rough approximation. These observations hold for both constant pressure boundary conditions, for which this equation was intended and PSS conditions, for which this equation can be used as a basis. For most reservoirs with pay thickness' of 100 feet or less and wells having only one orthogonal fracture, spanning half the reservoir width or less, this equation probably has the required accuracy.

The primary focus of this work is the development of a relationship between productivity index and fracture length for multi-fractured wells. The results of the simulation model show that the non-linearity of this relationship can be extreme. An empirical relationship has therefore been developed by modifying the straight line, linear flow relationship with third order polynomials that are a function of fracture half length and matrix permeability, within any given well/fracture configuration.

Simulation model dimensions, used in this study, are consistent for all multi-frac cases. The quarter element of symmetry used to model the single frac, three frac, five frac and seven frac well configurations are illustrated in Figure 6.4. To illustrate the versatility of the derived empirical equation, fractures are not necessarily spaced evenly throughout the drainage area. The simulation model, fortunately, can accommodate any demands placed upon it to mimic real configurations. The fracture spacing, for example, may be influenced by isolated heterogeneities (while not greatly affecting the overall homogeneous assumption), reservoir parameters such as permeability deterioration near the spacing edge, rock properties that offer less fracture containment, down structure water and/or a host of other considerations.

A convenient feature of the empirical equation, derived from simulation runs, is that consistent fracture spacing is not required. The empirical relationship is based on simulation output and can therefore be determined from any well/fracture configuration. Conversely, once established, the empirical relationship will not hold if considering a change in fracture spacing for the same number of fractures.

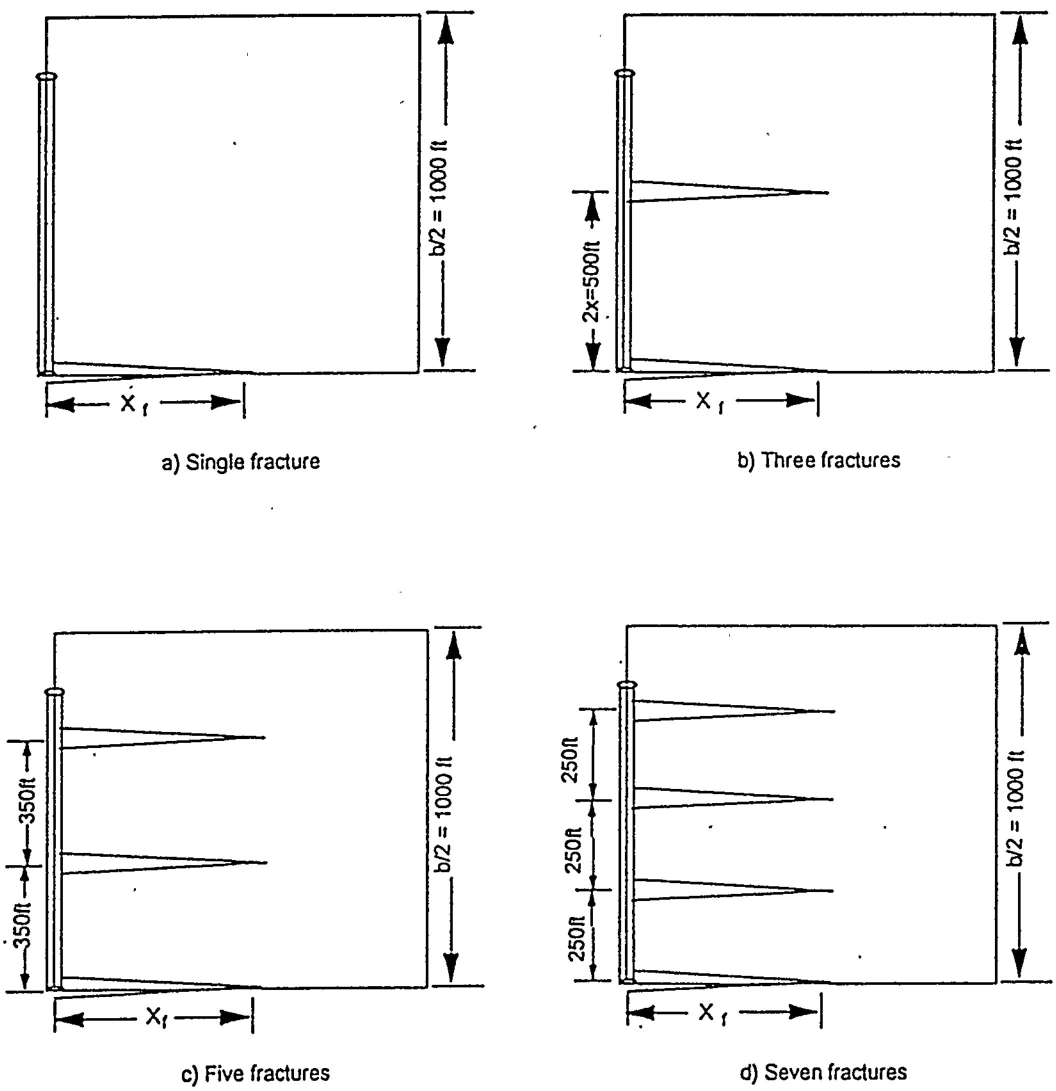


Fig. 6.4 Multi-Fractured Well Configurations in Quarter Element of Symmetry

Simulation runs would have to be repeated to develop a new empirical relationship.

6.2.1 Errors of the Analytical Solution for Fracture Flow

The underlying assumption of the equation (6.1) used to determine flow into a fracture, presented by Economides and Mukherjee, is that fluid flows normal to the fracture face and is linear. Therefore the actual productivity should be higher. Although end effects may provide minimal contributions to the productivity of the fracture in tight reservoirs, the understatement of this equation is dramatic in even a 10 md reservoir. This feature can be illustrated using the reservoir model shown in Figure 6.4a with the same boundary conditions for which this equation is intended (i.e. constant pressure). As indicated in Figure 6.5, the productivity indices of the analytical and simulation models compare at fracture initiation and when the fracture fully penetrates the reservoir, however they can be almost an order of magnitude different in between. The productivity index at $X_{fd} = 0.05$ is shown to be 1.51 bbls/ psi from simulation results yet it is anticipated to be only 0.23 bbls/psi from the analytical solution. This example shows how the linear flow assumption greatly underestimates fracture end effects, especially for shorter fracture lengths when pseudo-radial flow predominates.

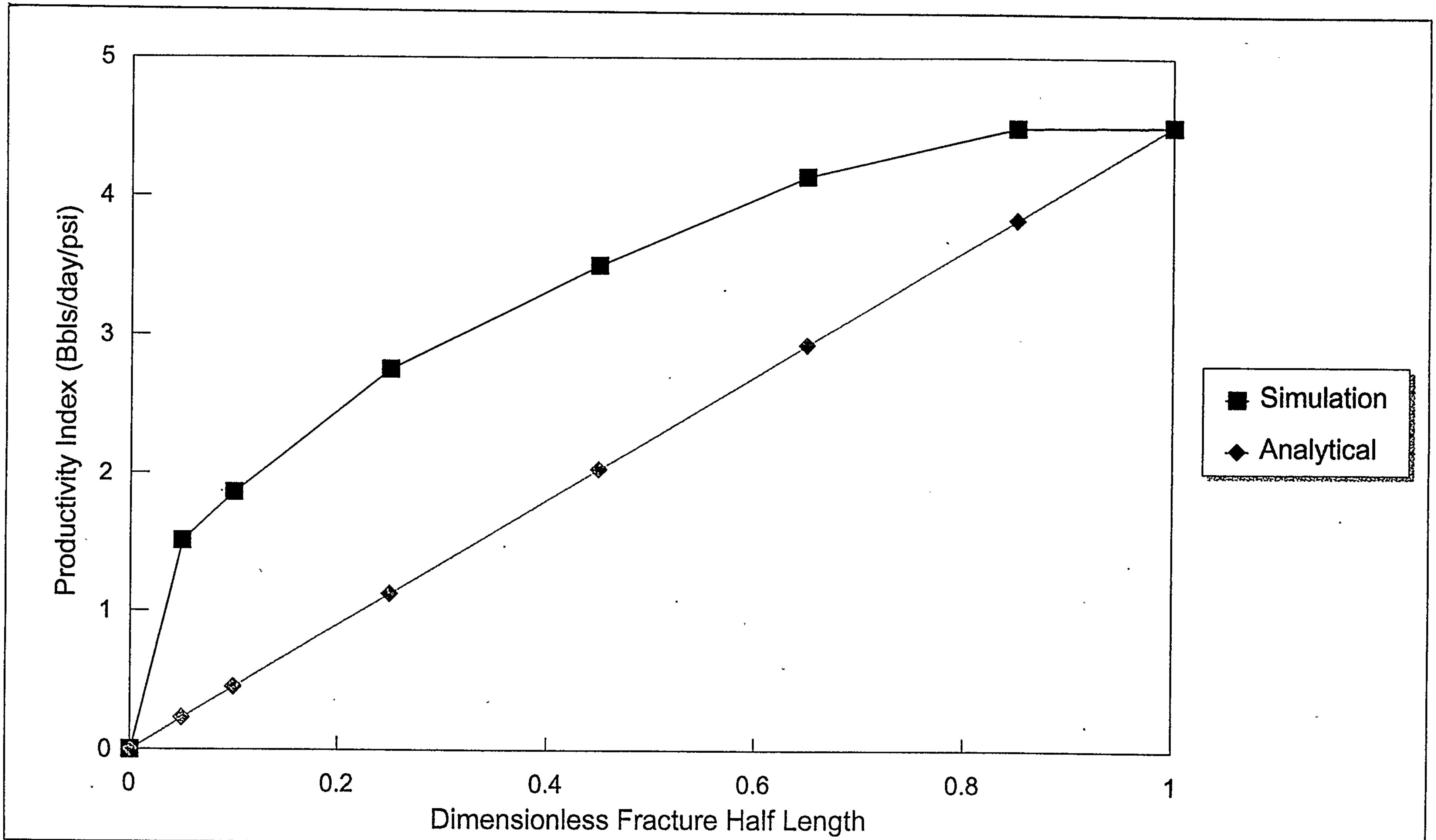


Fig. 6.5 Analytical vs. Simulation Results under Constant Boundary Pressure Conditions

6.2.2 First Order Correction of the Analytical Model

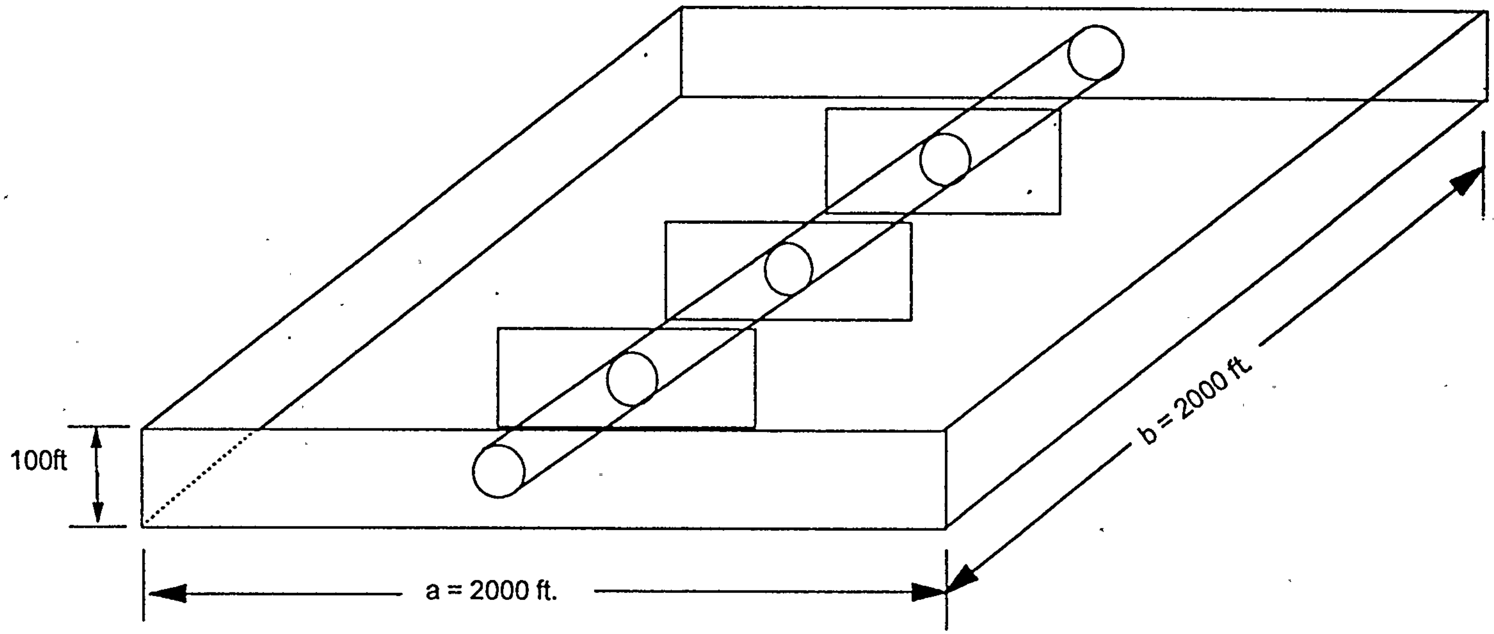
The remainder of this study will focus on no-flow boundary conditions with a wellbore, open to the reservoir, connecting multiple fractures, as depicted in Figure 6.6. The various fracture spacings are as previously mentioned and illustrated in Figure 6.4. The proposed model is representative of an open hole completion intercepting natural fractures or could be a perforated, cemented liner with multiple hydraulic fractures. Deviations, from the linear analytical solution become more complicated when applying this model. The reduced pressure support resulting from the omission of the constant pressure boundary magnifies the wellbore interference, especially when applying short fracture lengths. As an example, the productivity index plotted against fracture half length, for the 100 md case, yields the results illustrated on Figure 6.7. Note that for each multi-frac configuration, the analytical solution (modified for PSS conditions) is compared to simulation output. Based on these results the original equation (6.1) is modified as follows:

a) The straight line linear flow equation is modified by assigning the productivity index in the non-fractured well case, as the intercept on the ordinate.

b) The slope is then modified to match the end point (i.e. PI at $X_{fd} = 1.0$) of the curve generated from simulation results.

The linear flow equation, proposed by Economides and Mukherjee then becomes;

$$Q_{fh}/\Delta P = \left(\frac{0.001127(2K_h)(2X_f h)C}{\mu B x} + PI_{nf}\right) \qquad [Bbls/day/psi] \qquad (6.2)$$



kxy = 1, 10, 50, 100 md
kz = 0.5 kxy
h = 100 ft.
a = b = 2000 ft.

u = 1cp
rw = 0.25 ft.
Horizontal Well Length = 1650 ft.
Centered Well (vertically & horizontally)

Fig. 6.6: Orthogonal Fractures in Horizontal well

where PI_{nf} is the productivity index of the non-fractured well and C is the correction factor applied to the slope to account for PSS conditions. The correction factor will always be greater than 1.0 by virtue of the way productivity indices are calculated for PSS conditions. Under these conditions the bottom hole flowing pressure is subtracted from the average reservoir pressure to determine ΔP. The average reservoir pressure will always be less than the pressure at the spacing boundary, even under constant pressure boundary conditions, for which this equation was intended. The productivity index, calculated for PSS conditions, using this analytical solution, will therefore always be greater than for constant pressure boundary conditions (for early flow period).

Numerical simulation results, forming the basis of the empirical solution, is modeled using a open horizontal wellbore. If the wellbore were not contributing production as would be the case with a cemented liner, this model can still be adopted. Sensitivity runs show a maximum error of less than 5% when using the open wellbore configuration to model cemented liner applications. The procedure being developed to determine the productivity of multi- fractured horizontal wells can therefore be applied to any type of wellbore completion.

For the single fracture case the dimension "x" from the fracture to the nearest no-flow boundary, is the distance to the spacing boundary. For multiple fracture cases, this value has been arbitrarily chosen to represent the arithmetic average of the two distances to no-flow boundaries on either side of the given fracture. So, for example, in the three fracture case, depicted in Figure 6.4(b), the productivity index as a function of frac half length, under PSS flow conditions, would be calculated as follows:

$$q_{fh}/\Delta P = 1.23015 \times [\frac{2(100md)(2X_f(100ft))}{1.0cp(250ft)} + (\frac{2(100md)(2X_f(100ft)}{1.0cp(375ft)}) \times 2]/3 + PI_{nf}$$

The 375 foot distance in the denominator of the second term represents the arithmetic average of 250 feet and 500 feet, the distance to no-flow boundaries for the two outer fractures. The correction factor, in this case, is 1.23015 and has the same order of magnitude regardless of the number of fractures. Subtle differences in correction factors are to be expected for inconsistent fracture spacing between the mult-frac cases. Note that the equation determines the average contribution of each fracture by dividing by the number of fractures. The productivity gains as well as recognition of the varied spacing, for each fracture is accounted for with the aforementioned average distance to no-flow boundaries.

6.2.3 Final Empirical Solution

The above form of the modified Analytical equation (6.2) only represents, at best, a rough approximation of a "line of best fit". This is illustrated in Figure 6.7 where the modified analytical solution varies from a poor best fit, in the seven frac case, to an understatement of productivity for all other multi-frac cases. Here we develop a much more accurate representation by introducing higher order correction terms.

6.2.3.1 Third Order Polynomial Correction

The next step in developing a more "exact" empirical relationship is to multiply the current representation of the modified equation by an additional term, "D", that represents a third order polynomial and is a function of the fracture half length. This term is in the following form:

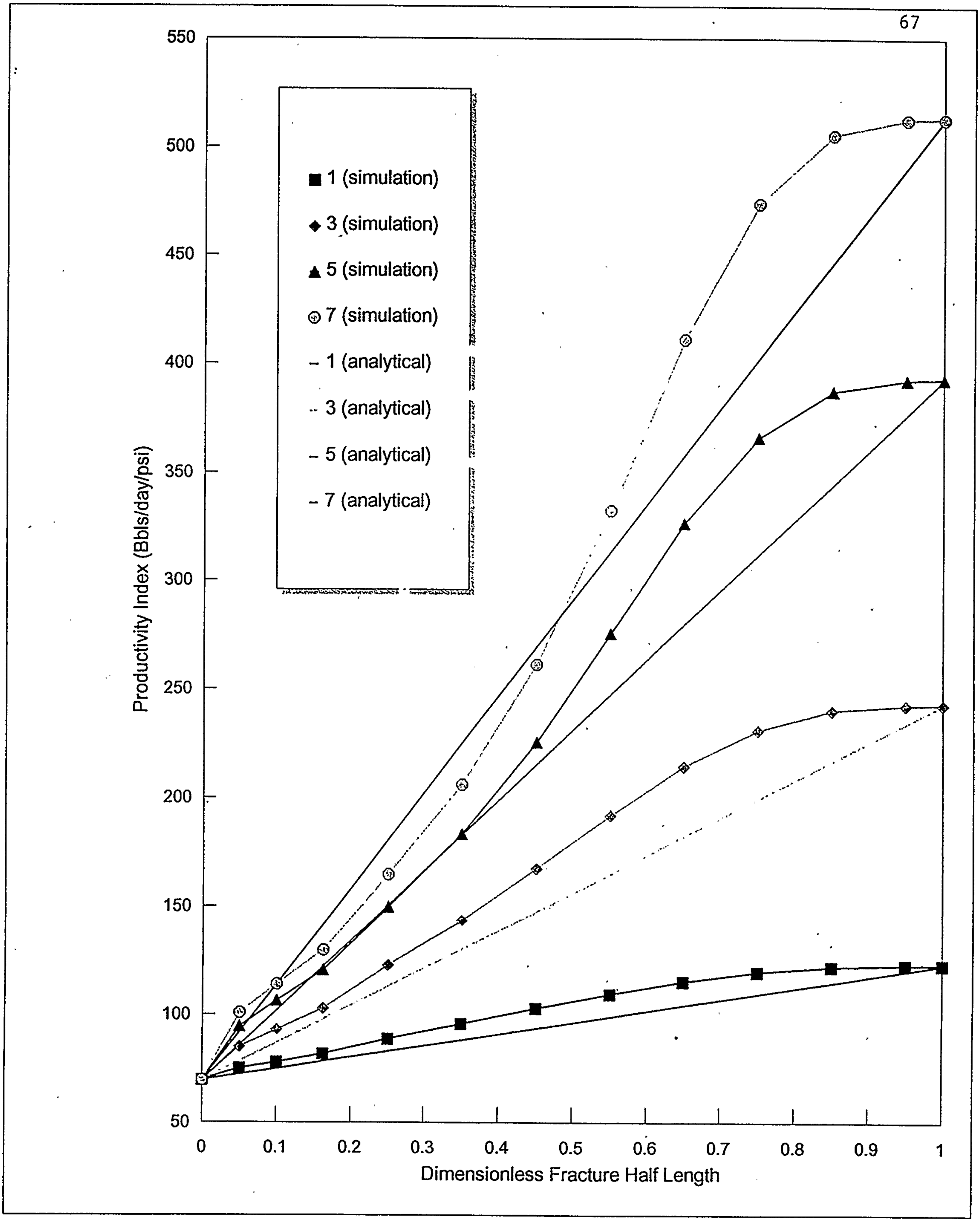


Fig. 6.7 Slope Adjusted Analytical Solution vs. Simulation Results

$$D = \eta + \alpha X_{fd} + \theta X_{fd}^2 + \lambda X_{fd}^3, \tag{6.3}$$

where η is unity in the non-fractured case and a constant for the fractured cases, regardless of fracture length and α, θ, and λ are coefficients which are a function of the matrix permeability. The value of η anchors the intercept on the productivity axis (ordinate) and depending on the developer's choice of methods for polynomial regression, should not deviate much from unity. In fact, for higher order polynomials this coefficient approaches unity. A third order polynomial was, however, chosen for the regression analysis for simplicity and the required accuracy. Also the initial "hump" ($X_{fd} \leq 0.05$) was omitted from the regression data to yield a better representation of the S shaped curve. When the regression analysis excludes the ordinate intercept, the curve is smoothed in a manner that yields a much closer fit to productivity index variations with fracture half length in the area of interest ($X_{fd} \rangle 0.05$).

6.2.3.2 Optimizing Regression Analysis

Applying regression analysis to selective portions of the curve (or any curve) will require some form of accomodation to portions of the curve that were omitted. In this case the area of the curve between $X_{fd} = 0.0$ and $X_{fd} = 0.05$ requires a function in the following form:

$$\eta = \left(\frac{\eta_{0.05} - 1}{0.05}\right) X_{fd} + 1 \qquad \text{for } X_{fd} \leq 0.05 \tag{6.4}$$

where: $\eta_{0.05}$ is the η value at $X_{fd} \geq 0.05$

Note that the form of this function is simply a straight line between 0.0 and 0.05 dimensionless fracture half length. The productivity of fracture lengths in this range would require a finer resolution (i.e. $X_{fd} < 0.05$).

Each of the coefficients, α, θ and λ in the D term, also represents a third order polynomial that is a function of the matrix permeability for each fracture configuration. For example, the case of seven fractures the coefficients are as follows:

$$\eta = 1.01445$$
$$\alpha = -2.7873 + 0.003921 * k \ - 2.0695E-5 * k^2 + 5.79E-8 * k^3$$
$$\theta = 7.1272 - 0.018051 * k \ + 2.3149E-4 * k^2 - 1.2394E-6 * k^3$$
$$\lambda = -4.5551 + 0.013063 * k \ - 1.87085E-4 * k^2 + 1.0356E-6 * k^3$$

The number of significant digits, used in the various coefficients preceding the matrix permeability terms, becomes important when dealing with reservoirs of higher permeability. The final form of the modified empirical equation is as follows:

$$q_{fh}/\Delta P = \left(\frac{0.001127(2K_h)(2X_fh)C}{\mu Bx} + PI_{nf}\right) * D \qquad [Bbls/day/psi] \qquad (6.5)$$

where: $D = \eta + \alpha X_{fd} + \theta X_{fd}^2 + \lambda X_{fd}^3$

and $\eta = \left(\frac{\eta_{0.05}-1}{0.05}\right)X_{fd} + 1$ for $X_{fd} \leq 0.05$, $\quad \eta = \eta_{0.05}$ for $X_{fd} > 0.05$

A summary of all coefficients comprising the "D" and "C" terms, for each of the four multi-frac cases (one, three, five and seven), are provided in Table 6.1.

Table 6.1: Coefficients for Empirical Solution:

Term	Single frac	Three fracs	Five fracs	Seven fracs
"C" *poly*	2.3316-0.024836k+0.00026062k^2-1.2829e-6k^3	1.5514-0.011630k+0.00021149k^2-1.2734e-6k^3	1.6721-0.015495k+0.00035024k^2-2.2240e-6k^3	1.5433-0.007390k+0.00013432k^2-7.885e-7k^3
α *poly*	-0.1000+0.006324k+1.6595e-5k^2-5.725e-7k^3	-0.6300+0.018444k-0.00043036k^2+2.7348e-6k^3	-2.0236+0.027019k-0.00065918k^2+4.2812e-6k^3	-2.7873+0.003921k-2.0695e-5k^2+5.79e-8k^3
θ *poly*	1.6787-0.024161k+0.00016310k^2-6.078e-7k^3	2.5276-0.044078k+0.00093111k^2-5.7816e-6k^3	5.4892-0.063846k+0.00146191k^2-9.3269e-6k^3	7.1272-0.018051k-2.3149e-4k^2-1.2394e-6k^3
λ *poly*	-1.3556+0.017561k-0.00015199k^2+6.836e-7k^3	-1.9785+0.026139k-0.00051766k^2+3.1575e-6k^3	-3.6679+0.035429k-0.00076575k^2+4.8053e-6k^3	-4.5551+0.013063k-1.87085e-4k^2+1.0356e-6k^3
η	1.01445	1.0768	1.14853	1.17907
perm = 1 md	$PI_{nf} = 0.7$			
C	2.307	1.54	1.657	1.536
α	-0.3402	-0.6257	-1.9972	-2.78339
θ	1.6547	2.4844	5.42678	7.10939
λ	-1.3382	-1.9529	-3.63325	-4.54225
k = 10 md	$PI_{nf} = 7.0$			
C	2.108	1.455	1.55	1.482
α	-0.28198	-0.49958	-1.81501	-2.75009
θ	1.45279	2.1741	4.98758	6.96861
λ	-1.19452	-1.76574	-3.3854	-4.44217
k = 50 md	$PI_{nf} = 35.0$			
C	1.580995	1.339498	1.495005	1.410995
α	-0.03134	-0.45557	-1.7854	-2.63573
θ	0.80242	1.92872	4.78581	6.64846
λ	-0.7721	-1.57103	-3.2102	-4.24024
k = 100 md	$PI_{nf} = 69.7$			
C	1.171358	1.229986	1.401043	1.358963
α	0.11185	-0.36811	-1.63222	-2.54422
θ	0.28579	1.64924	4.39683	6.39763
λ	-0.43585	-1.38373	-2.97726	-4.08407

Comparisons of multi-frac well configurations are shown in figures 6.8 through 6.11 for the 1 md, 10 md, 50 md and 100 md cases, respectively. In all cases, curves generated from the derived empirical relationship very closely approximates the productivity versus fracture half length relationship from simulation output. Note that when the slope of the empirical relationship reduced to a value equal to or less than zero, a zero slope was manually input. This would usually occur at a dimensionless fracture half length of 0.8 or greater for the 3, 5 and 7 frac cases. A more complex set of constraints (i.e. do not allow the derivative of the polynomial to be negative) could have been included in the derivation of the empirical equation. Considering that the solution would only improve in an area of lesser practical significance (i.e. $X_{fd} \geq 0.8$) where increasing the frac length provides minimal increases in productivity, the additional refinement of the correlation was not included.

6.3 Example Calculation

The following example will illustrate how readily the empirical relationship can be applied to predict productivity and economics of various well/fracture configurations. Suppose we are given spacing and reservoir parameters upon which the derived empirical relationship is based, i.e.:

$\mu = 1.0$ cp	a = 2000 ft (reservoir width)
$r_w = 0.1875$ ft	b = 2000 ft (reservoir length)
h = 100 ft	Centered horizontal well of length 1650'
$B_o = 0.966$	

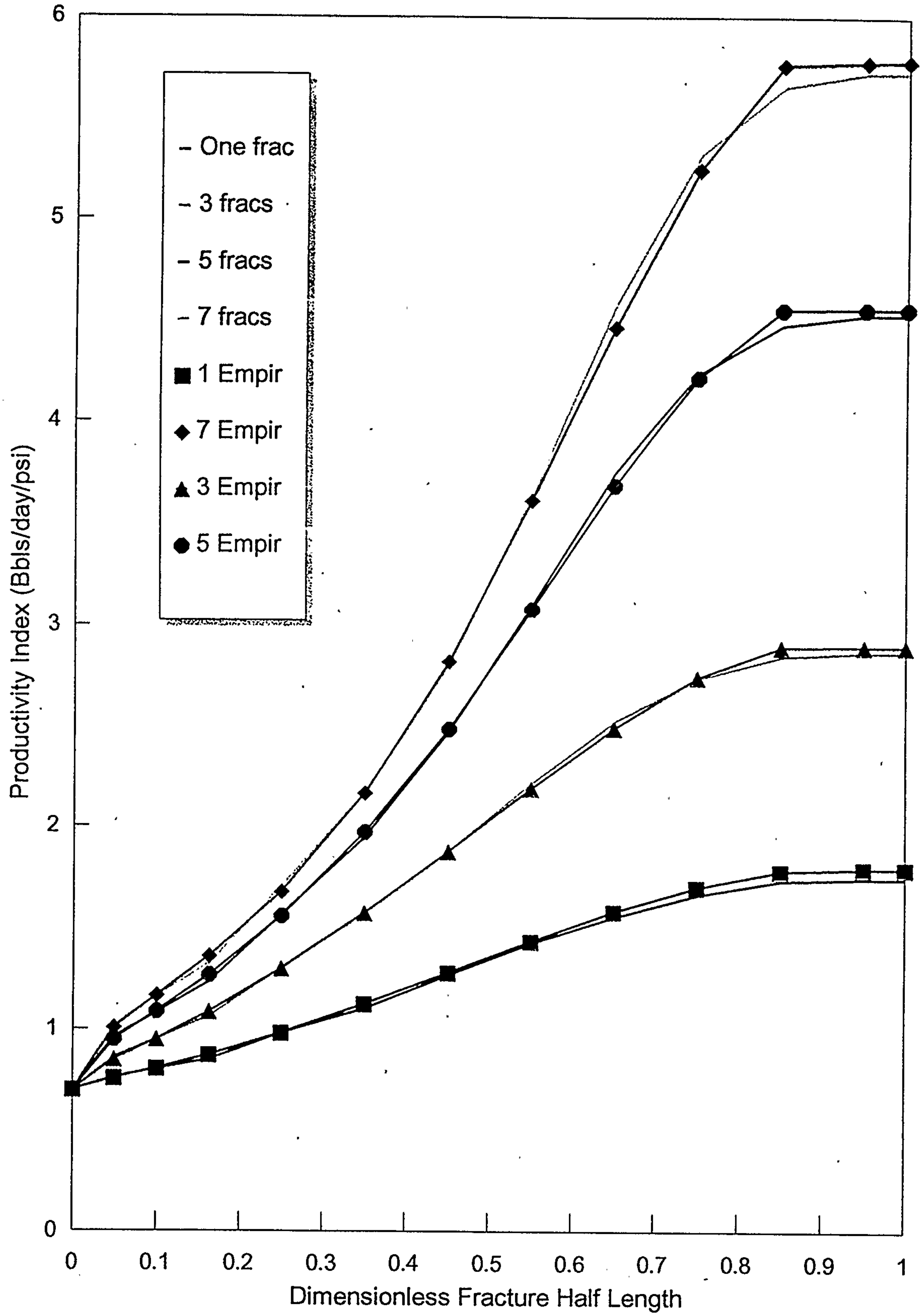


Fig. 6.8 Empirical Solution vs. Simulation Results for 1.0 md Case

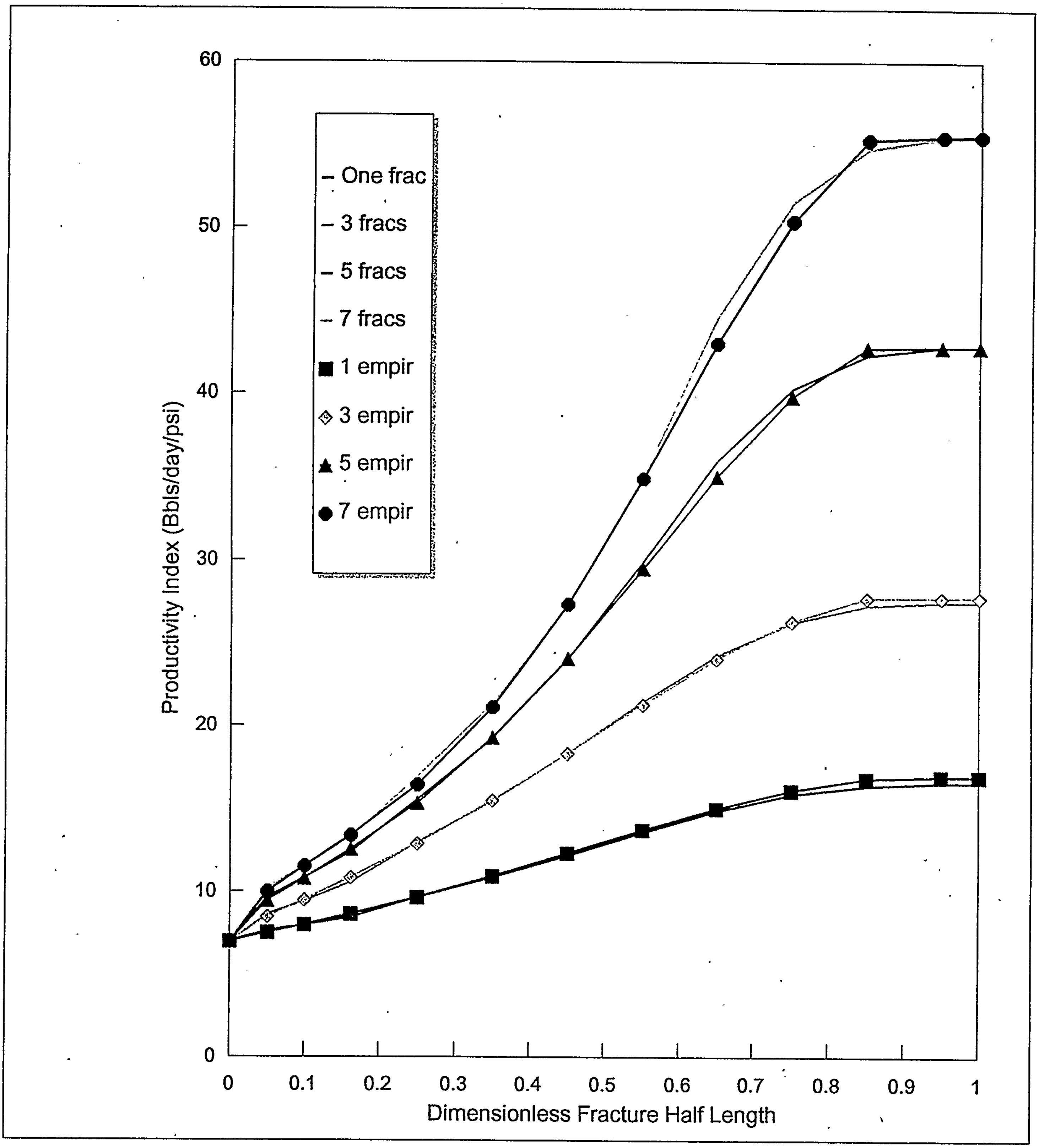


Fig. 6.9 Empirical Solution vs. Simulation Results for 10.0 md Case

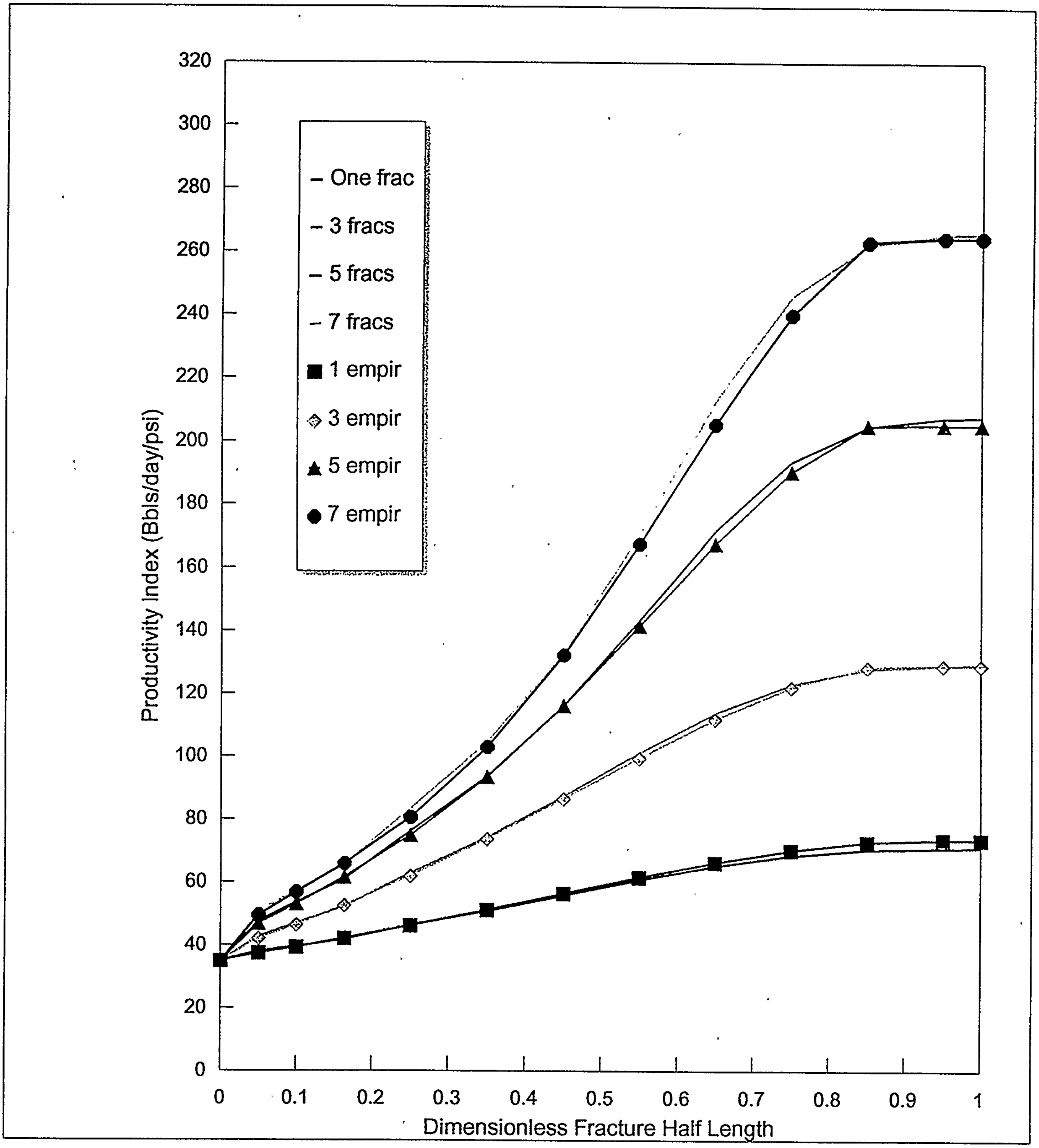


Fig. 6.10 Empirical Solution vs. Simulation Results for 50.0 md Case

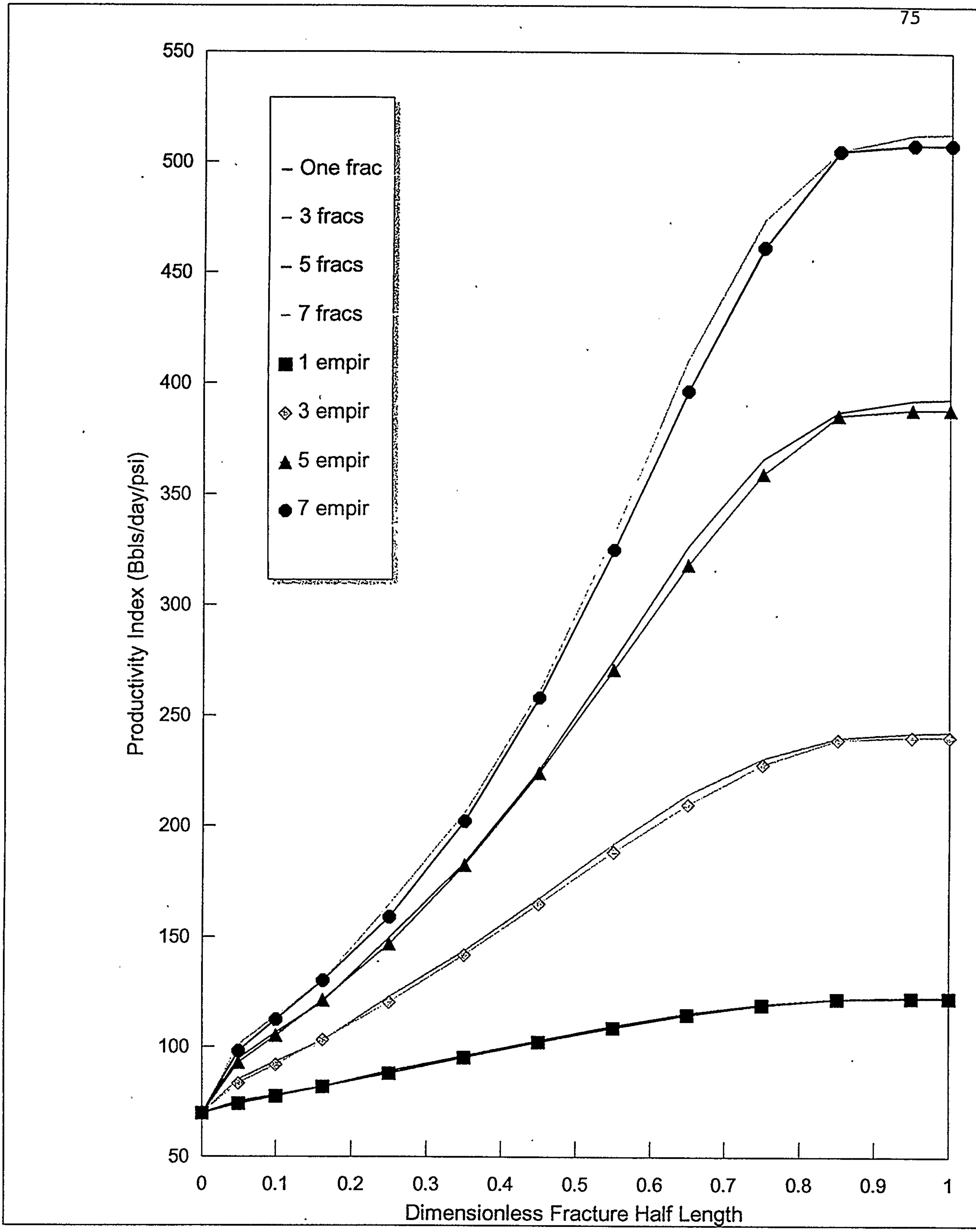


Fig. 6.11 Empirical vs. Simulation Results for 100.0 md Case

Suppose also that a buildup test suggested the reservoir is homogeneous with in-situ permeability in the order of 10 md ($k_v / k_h = 0.5$) and that the containing stresses, above and below the formation of interest, are such that a hydraulic fracture half length of 700 feet ($X_{fd} = 0.7$) can be readily achieved. The well is to be completed with a cemented liner and management is inquiring as to what productivity improvements can be realized, over the open hole completion scenario, with one, three or five fractures. Management already suspects that implementing more than 5 fractures is too costly! Assume that the various fracture configurations are as depicted in Figure 6.4(a,b & c).

For the given configuration, the productivity index for the horizontal well, without fractures, is 7.0 Bbls/psi based on the reservoir model. This would be the productivity of the horizontal well with an open hole completion. The available analytical solutions yield a similar productivity, the calculation of which will currently be omitted for expediency.

6.3.1 Productivity Comparisons

Recall; $$q_{fh}/\Delta P = \left(\frac{0.001127(2K_h)(2X_f h)C}{\mu B x} + PI_{nf}\right)D$$

where: $$D = \eta + \alpha X_{fd} + \theta X_{fd}^2 + \lambda X_{fd}^2$$

...for the single frac case;

$$C = 2.3316 - 0.024836(10\text{md}) + 0.00026062(10\text{md})^2 - 1.2829\text{e-}6(10\text{md})^3$$
$$= 2.108$$

and $D = 1.01445 - 0.28198(0.7) + 1.45279(0.7)^2 - 1.19452(0.7)^3$
$= 1.119$

The productivity of a horizontal well with one fracture of half length equal to 700 feet in a cemented liner (i.e. $PI_{nf} = 0$) is:

$$q_{fh}/\Delta P = (\frac{0.001127(2*10)(2*700*100)2.108}{1.0*0.966*1000ft} + 0.0)1.119 = 7.71\ bbls/day/psi$$

We can see that the productivity of a single fracture is only slightly greater than that of the open hole horizontal wellbore (no frac case = 7.0 bbls/psi) and probably would not justify the cost of fracing, let alone the cemented liner completion.

... for the three frac case;

$C = 1.5514 - 0.011630(10md) + 0.00021149(10md)^2 - 1.2734e\text{-}6(10md)^3$
$= 1.455$

and $D = 1.0768 - 0.49958(0.7) + 2.17410(0.7)^2 - 1.76574(0.7)^3$
$= 1.187$

The productivity of a horizontal well with three fractures of half length equal to 700 feet is:

$$q_{fh}/\Delta P = (\frac{0.001127(2*10)(2*700*100)1.455}{1.0*0.966*333.3ft} + 0.0)1.187 = 16.93\ Bbls/day/psi$$

where the distance to no-flow boundaries, equal 333.3 ft, is an arithmetic average distance for the three fractures.

... for the five frac case;

$$C = 1.6721 - 0.015495(10md) + 0.00035024(10md)^2 - 2.2240e\text{-}6(10md)^3$$
$$= 1.550$$

and $$D = 1.14853 - 1.81501(0.7) + 4.98758(0.7)^2 - 3.38540(0.7)^3 = 1.161$$

The productivity of a horizontal well with five fractures of half length equal to 700 feet is;

$$q_{fh}/\Delta P = \left(\frac{0.001127(2*10)(2*700*100)1.550}{1.0*0.966*200.0ft} + 0.0\right)1.161 = 29.39\ bbls/day/psi$$

The horizontal well completed with cemented liner and five fractures is more than four times as productive than the horizontal well with an open hole completion, at time of PSS flow conditions.

6.3.2 Economic Evaluation

Economic evaluations have been made for the three multi-fractured well scenarios using the Petroleum Economics Evaluation Program (PEEP). To get a general perspective of the economic impact of the three cases, the following simplifying assumptions have been incorporated:

- Forecasting one year of production as the long term productivity is uncertain.
- Applying a 100 psi pressure drawdown to the well.
- Using a \$24 Cdn/Bbl oil price.

- Using capital costs of 2.0 MM$ for drilling, completion and tie-in costs of a horizontal well and 250 M$ per hydraulic fracture.

- Well operating costs = $7000/well/mth (not including fluid processing).

- Gas production and associated NGL's have been ignored. This more than pays for any gas or oil processing costs at the Plant.

- Water production and associated costs have been ignored.

- The above capital and operating costs are representative of a horizontal well with a 1,650 ft. long horizontal lateral in a 10,000 ft. deep reservoir (perhaps the Swan Hills or Leduc formation of northern Alberta).

The net present value (at a 15% discount rate) for the single fracture, three frac and five frac cases are 366 M$, 3.1 MM$ and 6.7 MM$. In case the productivity enhancement cannot be maintained for one year due to productivity decline, a more conservative six month period was also evaluated. For the one frac case, payout has not been achieved at the end of six months and 742 M$ is still owing on the initial 2.25MM$ investment. However, the three frac and five frac cases still yield net present values of 439 M$ and 2.0 MM$ respectively at the end of six months.

These evaluations show that fracture costs are relatively insignificant and can be recovered with accelerated production alone (i.e. enhanced recovery benefits have not been included). This assumes, of-course, that no fracture cost overruns occur and ideal fracture placement has been achieved. In other words, no skin damage of the fracture from filtrate invasion has occured, as per assumptions used throughout this study. Economic Summaries for the multi-frac example runs, in the one year production case, are included in Appendix D.

Chapter 7

7. Permeability Anisotropy

The generalized empirical solutions, developed in Chapter 6, apply to isotropic permeability (i.e. $k_x = k_y = k_z$). Some interesting features have been observed when introducing permeability anisotropy to the reservoir model. The empirical solution yields accurate predictions at the fracture end points (i.e. @ X_{fd} = 0.0 and X_{fd} = 1.0) but is poor in between. The changing productivity of the well and fracture, as the fracture length increases, is more extreme than the variations observed under isotropic conditions. A simple example will illustrate this point more clearly and also point out differences between the isotropic and anisotropic permeability cases.

7.1 Anisotropy Example

The reservoir model used is the same as the one modeled with isotropic conditions, i.e. a 1650 foot horizontal lateral centered in all directions with length and width dimensions of 2000 feet each and a thickness of 100 feet. The permeability in the i, j and k directions are 1 md, 100 md and 5 md respectively. When a horizontal well is drilled in anisotropic conditions with the intention of inducing multiple fractures, it is advantageous to place the well parallel to the high permeability direction (the direction of minimum horizontal stress). Thus the resulting orthogonal fractures, having more height than the wellbore, will maximize the area exposure normal to this high permeability direction. We have therefore assumed this orientation in the example.

7.1.1 Approximation of the Wellbore Productivity

Simulations for a single fracture case produced the results on Fig. 7.1. If we assume, for this example, that the unfractured wellbore behaves as a fracture, we can apply the correlation as follows:

The constants C and D, for a permeability of 1 md and frac half length of 825 feet is 2.307 and 1.086 respectively, yielding a productivity for the well of;

$$PI_{well} = \left(\frac{0.001127(2*1.0)(2*825*100)2.307}{1.0cp*0.966ft^3/ft^3*1000ft}\right)1.1086 = 0.99\ Bbls/day/psi$$

The productivity of the wellbore compares to simulation results (Figure 7.1) of 1.13 Bbls/psi. The wellbore, assumed to behave as a fracture, does not span the entire height of the reservoir and would therefore be expected to yield less production in the simulation model. The simulation model however shows higher productivity probably due to wellbore end effects and the fact that vertical permeability is still five times greater than the horizontal permeability (1 md), perpendicular to the wellbore thereby essentially emulating a vertical fracture.

7.1.2 Approximation of the Fracture Productivity

For the fully penetrating fracture case the constants C and D, for a permeability of 100 md and frac half length of 1000 feet is 1.1714 and 1.0866 respectively, yielding a total productivity of;

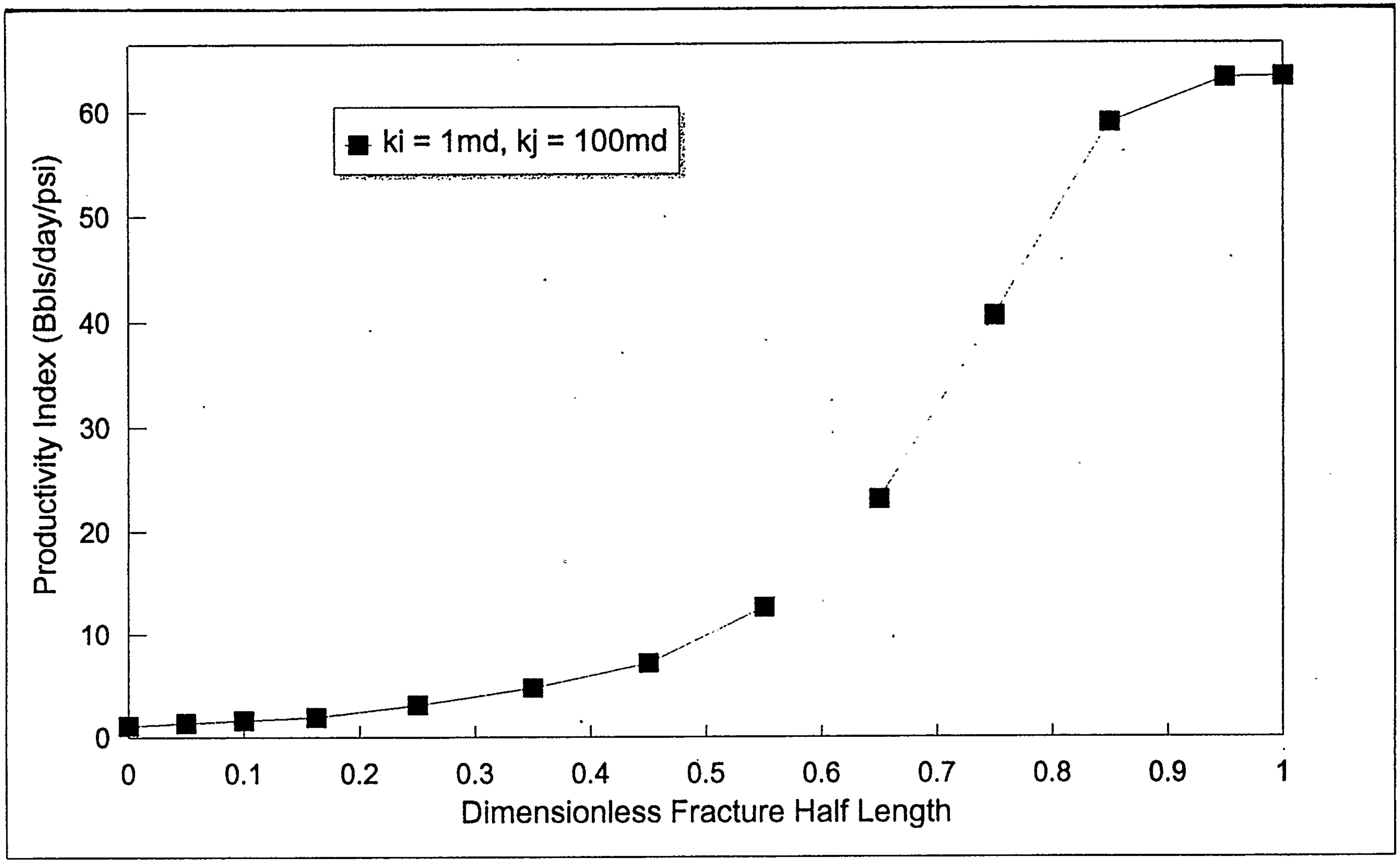


Fig. 7.1 Productivity vs. Xf in Anisotropic Permeability Conditions

$$PI_{total} = PI_{frac} + PI_{well}$$

$$= \left(\frac{0.001127(2*100md)(2*1000ft*100ft)1.1714}{1.0cp*0.966ft^3/ft^3*1000ft}\right)1.0866 + 0.99 = 60.4\,Bbls/day/psi$$

The simulation model yields a productivity of 63.5 Bbls/psi for this case and is now only 5% over empirical predictions (compared to 14% in the no frac case). The difference in productivity indices can be attributed to the fact that the empirical solution for the 100 md case was developed using a vertical permeability of 50 md.

7.2 Generalizing the Empirical Solution

The vertical permeability used in the previous example is 5 md which does not impede the linear flow into the fracture but does reduce the vertical component of radial flow into the wellbore. In any case, a close approximation of endpoints has been determined for this anisotropic case.

Productivity between dimensionless fracture length endpoints, requires some intuitive thought if not imagination. The initial hump, observed in isotropic conditions (Fig. 6.7), is not evident in anisotropic conditions as shown in Figure 7.1. The curve now shows productivity increasing slowly (shallow slope) until almost half the reservoir width is penetrated by the hydraulic fracture. Flow into the fracture tips is substantially reduced due to the low permeability parallel to the fracture face.

This suppressed productivity can best be illustrated with plan views of the spacing unit with 1) flow into a short fracture (Figure 7.2a) and 2) flow into a longer fracture (Figure 7.2b). These plan views show how a fractured horizontal well in anisotropic conditions not only displays distinct flow patterns but can generate altered pressure profiles. Pseudo-steady state conditions, identified with pressure drops at the boundaries, can still be readily detected however the "average" reservoir pressure used to calculate productivity indices now represents lumped interpretation of the more complex flow and pressure regimes. It is this method for determining the productivity index (i.e. using P_{avg}) that has the greatest influence on the productivity versus frac half length curve shape, in anisotropic conditions.

The short fracture produces from the small area, normal to the fracture face, more rapidly than from the larger area beyond the fracture tips. Upon reaching pseudo-steady state flow conditions, the bulk of the drainage area still maintains a high reservoir pressure since flow along the low permeability direction has yet to replace production removed from the area normal to the fracture face. The productivity index, in this case, may include an inordinately high reservoir pressure and therefore falsely understate actual productivity. In the case of the longer fracture length, the pressure regime more closely approximates one found in isotropic conditions where the drainage area is more uniformly depleted. The primary difference, is that the final "hump" on the productivity curve does not exceed the straight line relationship as much in anisotropic conditions as in the isotropic case due to reduced production contributions from the fracture tips.

To confirm the intuitive thought process depicted on Figures 7.2a and 7.2b the pressure distribution for anisotropic conditions at 0.1 days and 60.0 days (Fig. 7.3 & 7.4 respectively) was compared to the same reservoir configuration with isotropic conditions, at the same time (Fig. 7.5 & 7.6 respectively). It is interesting to note the pressure magnitudes as well as pressure distributions. Figure 7.4 clearly shows how the linear flow patterns in anisotropic conditions creates "blocked" pressure distributions. Also, the pressure near the wellbore is only half the pressure at the reservoir edge, after 60.0 days (of 200 Bbls/d production). The isotropic case, conversely, shows a pressure distribution that has a range of some 10 psia at 60.0 days. The average pressure used in the productivity index calculation is fairly representative of the pressure distribution for this case. The same cannot be said for the anisotropic case.

These anisotropic examples illustrate how caution must be exercised when attempting to generalize empirical solutions, based on a specific set of parameters and conditions.

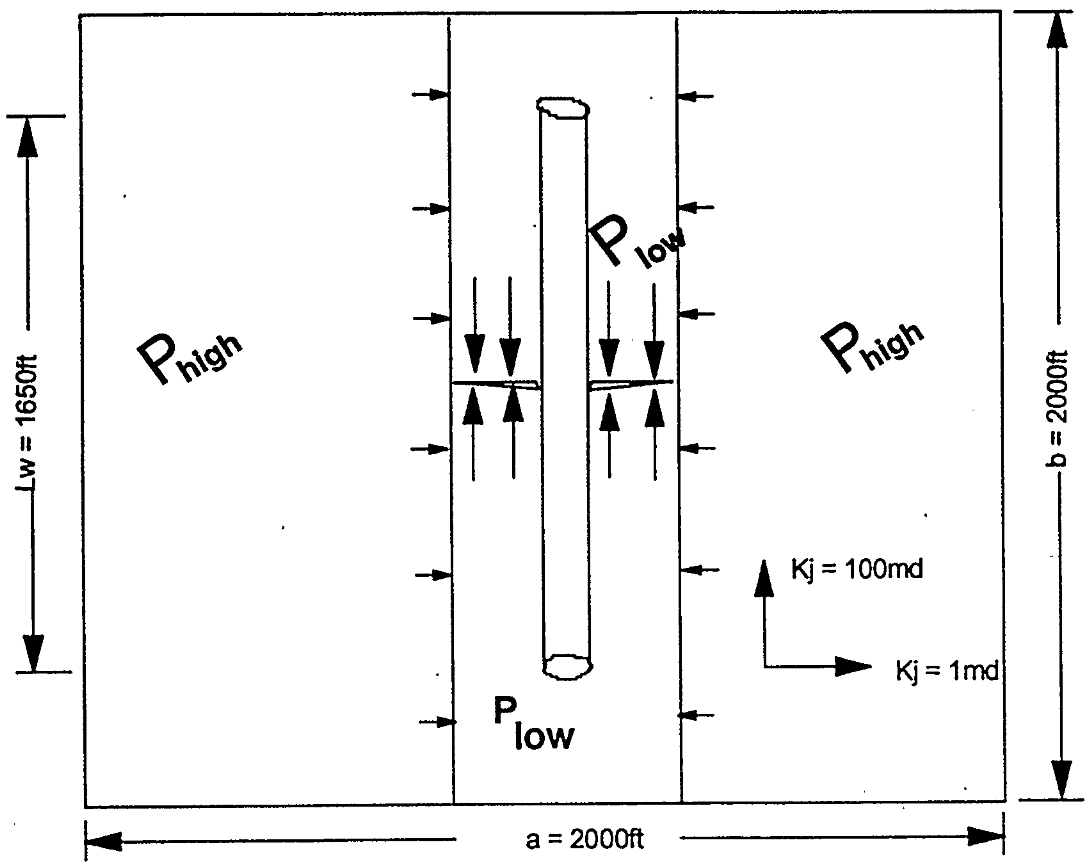


Fig. 7.2a: Pressure Distribution with Small Fracture and Permeability Anisotropy

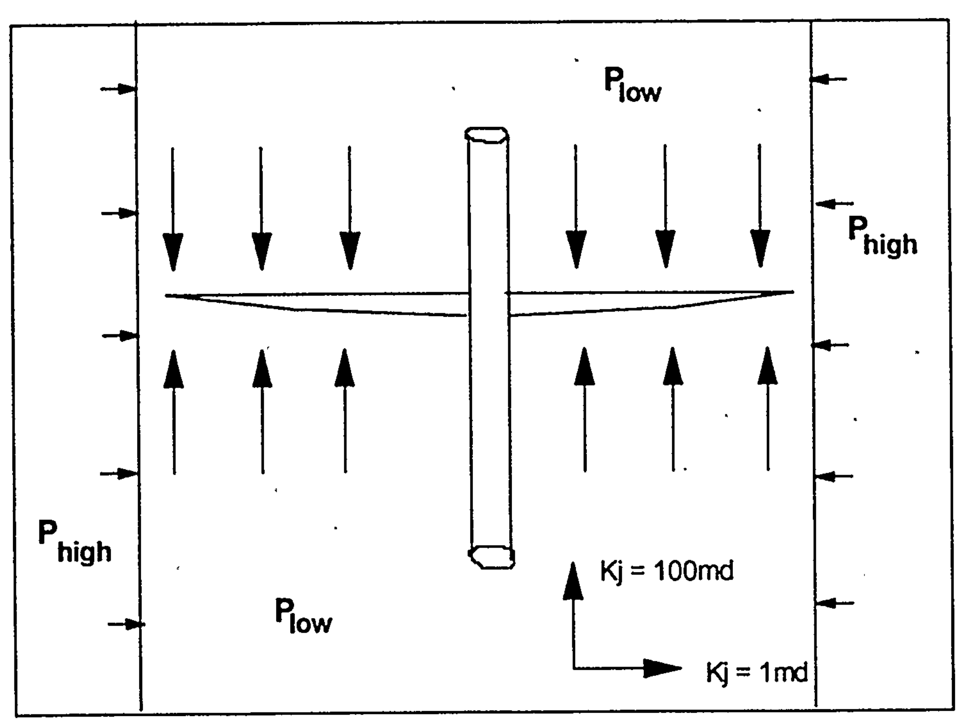
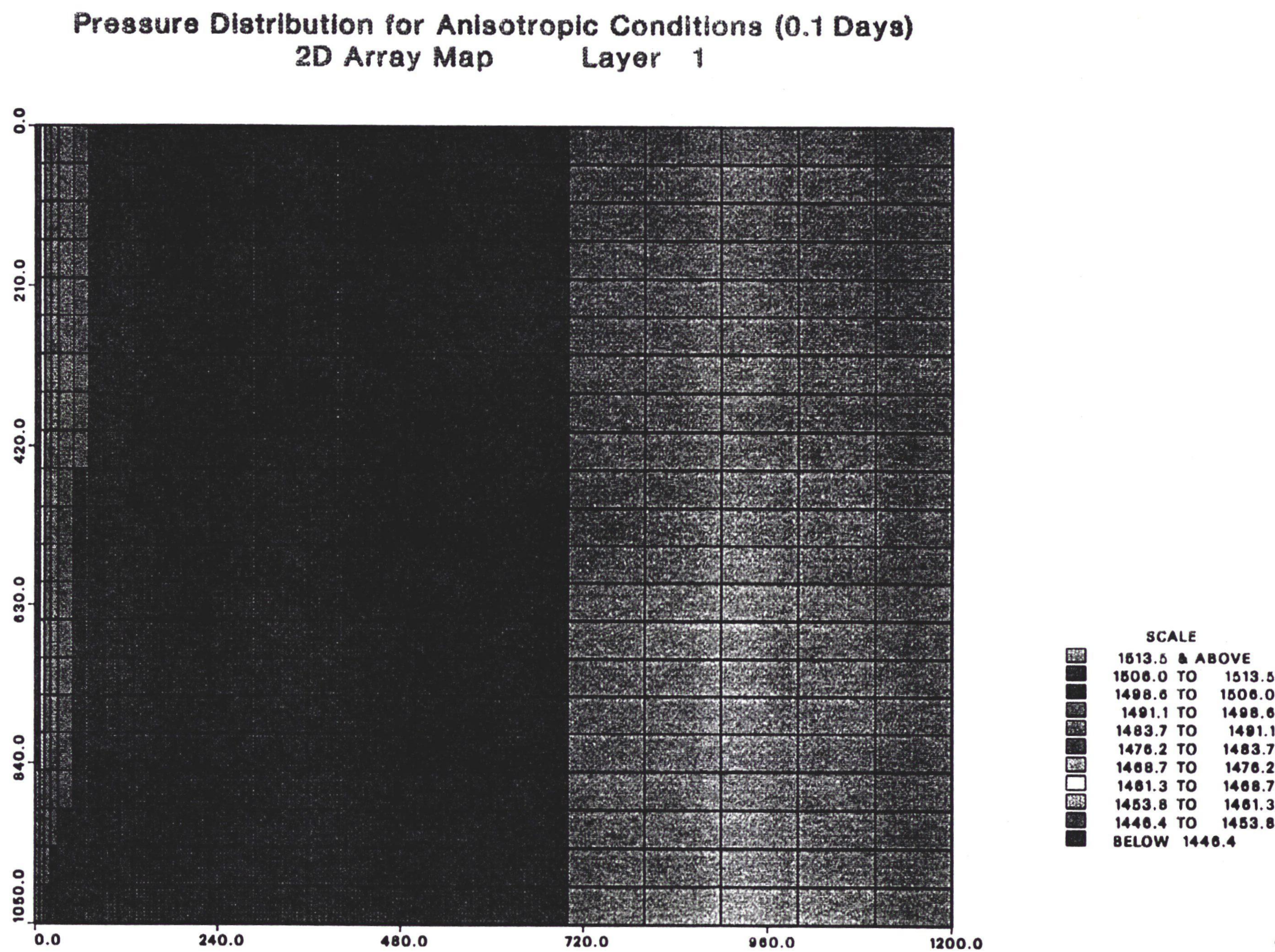


Fig. 7.2b Pressure Distribution with Large Fracture and Permeability Anisotropy



PLOT 1 13.37.05 TUES 22 AUG, 1995 JOB-djb , SIMTECH CONSULTING SERVICES INC DISSPLA 11.0

Fig. 7.3

Pressure Distribution for Anisotropic Conditions (60 Days)
2D Array Map Layer 1

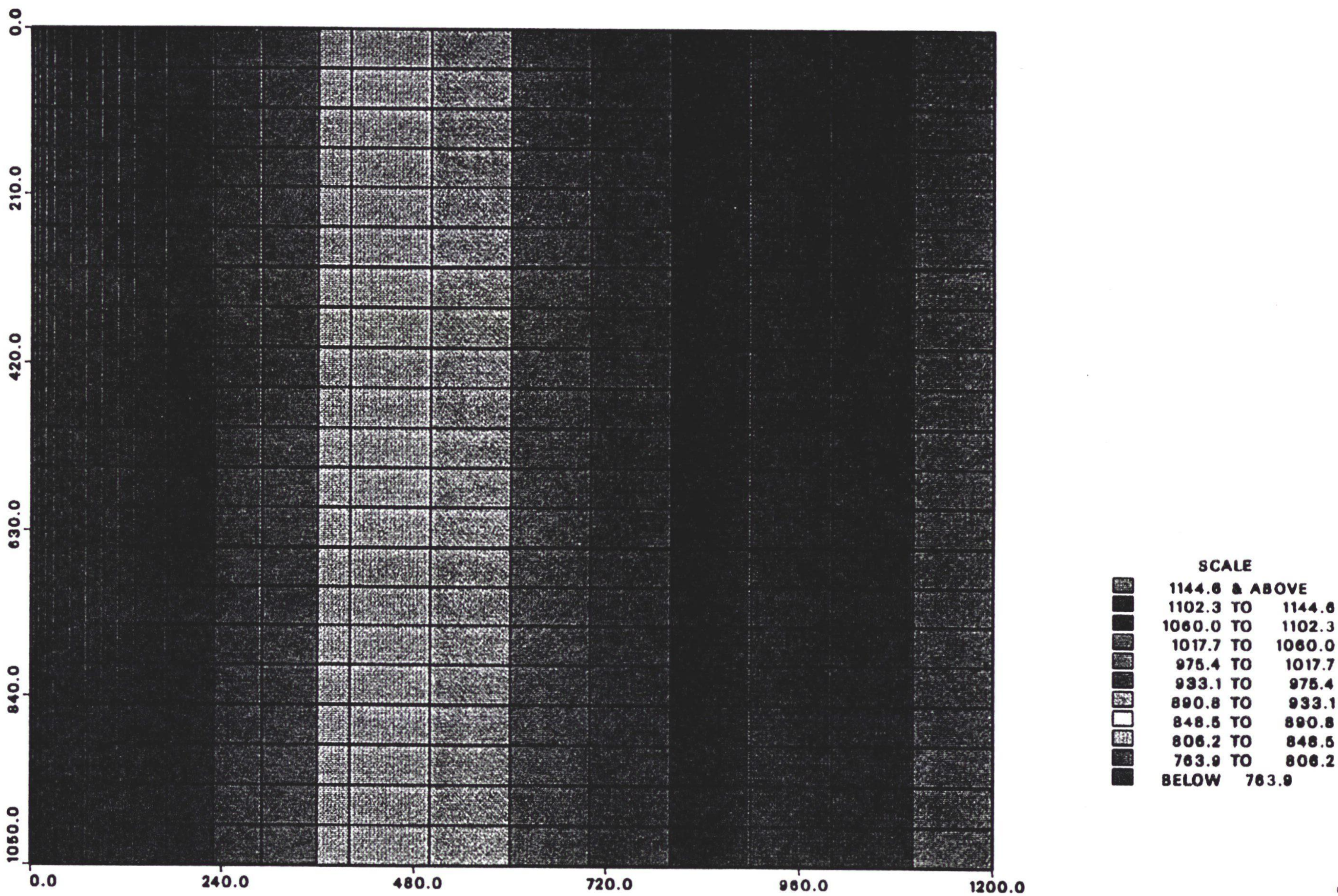
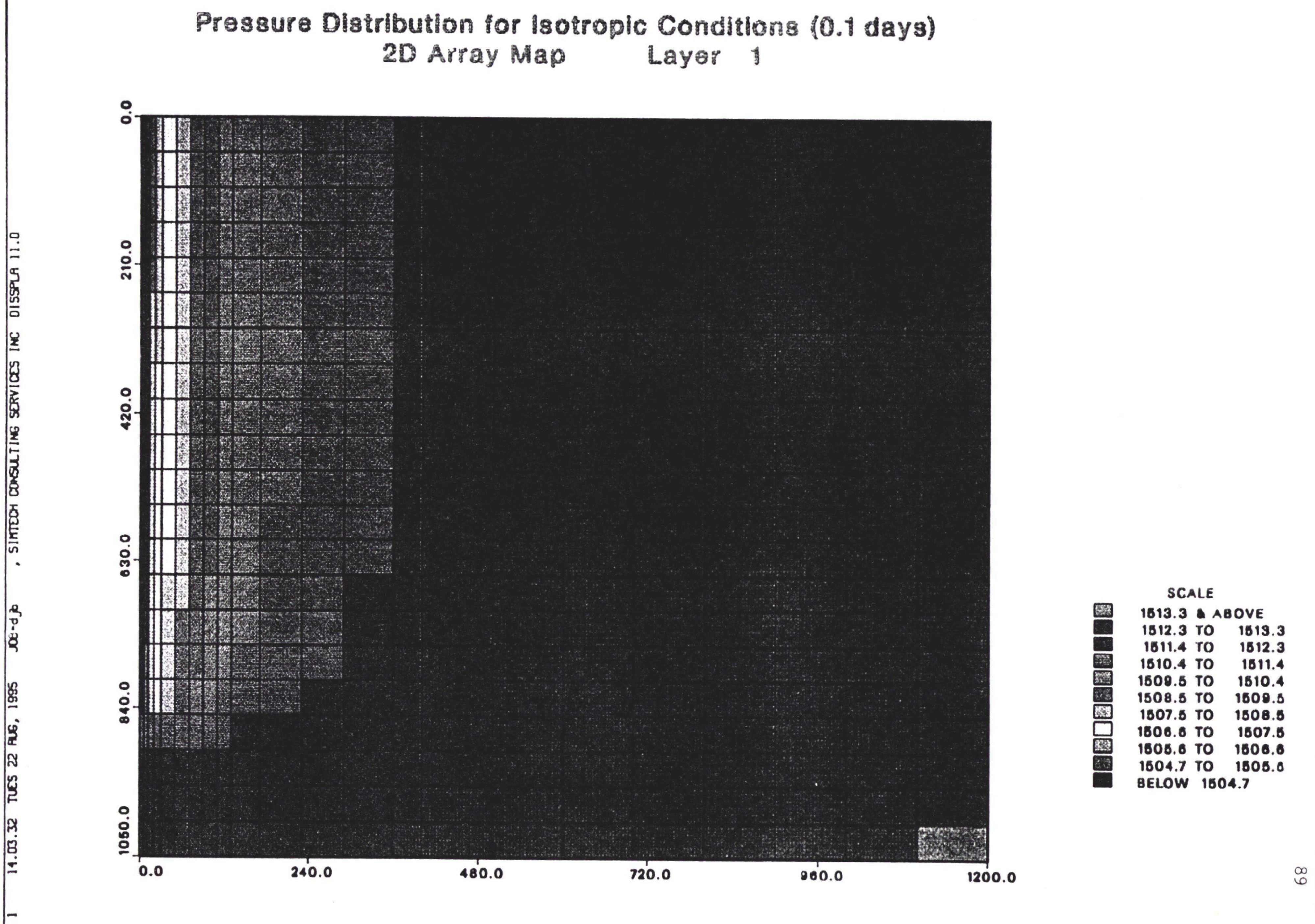


Fig. 7.4

PLOT 1 13.56.01 TUES 22 AUG, 1995 JOB-djb , SIMTECH CONSULTING SERVICES INC DISSPLA 11.0



Pressure Distribution for Isotropic Conditions (0.1 days)
2D Array Map Layer 1
0.0
210.0
420.0
630.0
840.0
1050.0
0.0
240.0
480.0
720.0
960.0
1200.0
SCALE
1513.3 & ABOVE
1512.3 TO 1513.3
1511.4 TO 1512.3
1510.4 TO 1511.4
1509.5 TO 1510.4
1508.5 TO 1509.5
1507.5 TO 1508.5
1506.6 TO 1507.5
1505.6 TO 1506.6
1504.7 TO 1505.6
BELOW 1504.7
PLOT 1 14.03.32 TUES 22 AUG, 1995 JOB-djb , SIMTECH CONSULTING SERVICES INC DISSPLA 11.0

Fig. 7.5

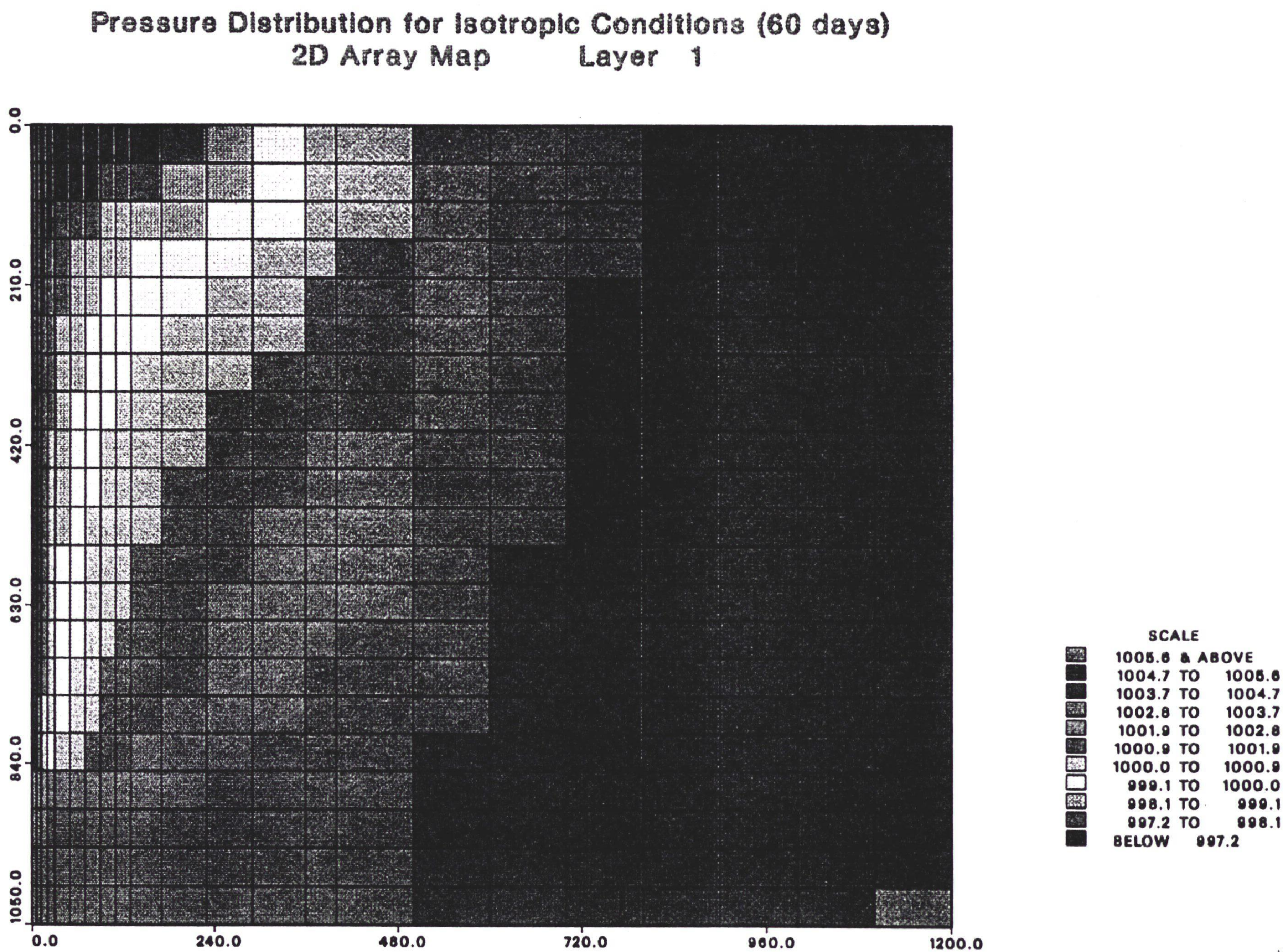


Fig. 7.6

PLOT 1 14.16.10 TUES 22 AUG, 1995 JOB-djb , SIMTECH CONSULTING SERVICES INC DISSPLA 11.0

Chapter 8

8. Conclusions and Recommendations

8.1 Conclusions

The following conclusions can be drawn from this study:

1) Analytical solutions, for predicting productivity indices of fractured horizontal wells can overlook the subtleties that are more readily exposed from simulation modeling. The simulation model will accommodate and more accurately determine the consequences of changes in reservoir parameters and well/fracture configurations.

2) The accuracy of analytical solutions becomes dependent upon where one is within the range of the particular parameter(s) being considered. This is especially true if assumed boundary conditions are not met and do not expose the non-linear relationship between the fracture half length and productivity calculation.

3) An empirical equation was developed for predicting the productivity of a horizontal well with multiple fractures, based on a library of simulation results.

4) This work has provided a practical formula for engineering calculations that, when applied to any particular reservoir type and size, will accurately predict productivity indices for the desired isotropic permeability and well/fracture configuration.

5) The developed empirical solution can be used for general economic screening and optimization of fractured horizontal wells.

6) The numerical model used to generate the data base for the formula can be used to investigate effects of anisotropy, finite fracture conductivity, turbulence, stress dependent reservoir properties and many other variables.

8.2 Recommendations for Future Work

Given any particular set of reservoir parameters this technique of determining productivity for any desired well/fracture configuration can be applied with a host of other parameter sensitivities. These might include finite fracture conductivities, gas turbulence, skin damage, varying the fracture orientation (i.e. non-orthogonal), multi-phase flow or stress dependent reservoir properties.

The regression analysis, perhaps with higher (or lower) order polynomials could be applied to other parameters, in addition to permeability and fracture half length, to enhance the versatility of this technique. Similar numerical techniques, as have been applied in this study, could also be used to assess the longer term productivity of multi-fractured wells. This would be important for evaluating the economic viability of accelerated production and long term enhanced recovery features.

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APPENDIX A: Data File (3 Frac Case) of Reservoir Model

```
  FILE: Multiple Fracture (3d) case
        Low compressibility, Pseudo-steady state boundary conditions
NOECHO
INIT     0    1    0    1    1
COM X----*----*----*----*----*
COM ^    ^    ^    ^    ^    ^
COM |    |    |    |    |    '--PROD. PLOT/FILE; 0=NO; 1=PLOT ONLY
COM |    |    |    |    |                       2=PLOT AND GRAPHICS(ECON) FILE
COM |    |    |    |    |                       3=PLOT AND LOTUS FILE
COM |    |    |    |    |                       4=PLOT AND GEP PRODUCTION FILE
COM |    |    |    |    |                       5=AS IN 4 + GEP BUILDUP FILE
COM |    |    |    |    ,--0=SINGLE PASS ONLY; 1=WITH AND WITHOUT FRACTURE
COM |    |    |    ,-->=0WELL NUMBER FOR WHICH SUMMARY IS PRINTED; -1=NO SUM
COM |    |    ,--0=METRIC; 1=OILFIELD UNITS
COM |    ,--0=OIL RESERVOIR; 1=GAS RESERVOIR
COM ,--'INIT' KEYWORD OR 'REST' KEYWORD
COM
COM
COM                        **********************************
COM                        * SIMTECH CONSULTING SERVICES LTD *
COM                        *       FRACWELL TEMPLATE         *
COM                        *          VERSION 4.0            *
COM                        *            91-03-03             *
COM                        **********************************
COM
COM
COM    *** 4.3.1 INITIALIZATION CONTROL DATA 1 - PROBLEM SIZE ***
COM
COM ,--NUMBER OF GRID BLOCKS IN X OR R DIRECTION
COM |    ,--NUMBER OF GRID BLOCKS IN Y OR THETA DIRECTION
COM |    |    ,--NUMBER GRID BLOCKS IN Z DIRECTION
COM |    |    |    ,--NUMBER ENTRIES IN PVT TABLE
COM V    V    V    V
COM *----*----*----*
   23   21    9   11
COM *----*----*----*
COM
COM    *** 4.3.1 INITIALIZATION CONTROL DATA 1 - GEOMETRY SPECIFICATIONS ***
COM
COM ,--0=CARTESIAN COORDINATES; 1=RADIAL COORDINATES
COM |    ,--0=ORTHOGONAL GRID; 1=NONORTHOGONAL GRID
COM |    |    ,--0=GRIDS SAME SIZE(UNIFORM); 1=IRREGULAR; 2=GEOMETRIC
COM |    |    |    ,--0=HOMOGENEOUS RESERVOIR; 1=HETEROGENEOUS; 2=LAYERED
COM |    |    |    |    ,--0=ELEMENT OF SYMMETRY; 1=MODEL IS FULL FIELD
COM |    |    |    |    |    ,--GRID TYPE IN Z DIRECTION; 0=POINT; 1=BLOCK
COM V    V    V    V    V    V
COM *----*----*----*----*----*
    0    0    1    0    0    1
COM *----*----*----*----*----*
COM
COM    *** 4.3.1 INITIALIZATION CONTROL DATA 1 - OPTION SPECIFICATIONS ***
COM
COM ,--KEY FOR STRESS DEPENDENT RESERVOIR PROPERTIES; 0=NO; 1=YES
COM |    ,--KEY FOR TURBULENCE; 0=NO; 1=YES
COM |    |    ,--KEY FOR WELLHEAD PRESSURE CALCULATION; 0=NO; 1=YES
COM |    |    |    ,--KEY FOR RELATIVE PERM AS A FUNCTION OF TIME; 0=NO; 1=YES
COM |    |    |    |    ,--NUMBER OF POROUS MEDIA; 0,1=SINGLE POR; 2=DOUBLE POR
COM V    V    V    V    V
COM *----*----*----*----*
    0    0    0    0    0
COM *----*----*----*----*
COM
COM    *** 4.3.1 INITIALIZATION CONTROL DATA 1 - OUTPUT CONTROLS ***
COM
COM ,--0=PRINT AREAL PLANES; 1=CROSS-SECTIONAL PLANES OF 3-D ARRAYS
COM |    ,--1=PRINT GRID ARRAYS; 0=NONE
COM |    |    ,--2=PRINT ALL ROCK PROP ARRAYS; 1=PRINT PV + TRAN ARRAYS; 0=NONE
COM |    |    |    ,--1=PRINT INITIAL RESERVOIR CONDITION ARRAYS; 0=NONE
COM V    V    V    V
COM *----*----*----*
    0    1    0    0
COM *----*----*----*
COM
COM
COM            *** 4.3.2 INITIALIZATION GRID DATA ***
```

```
COM
COM  TABLE FOR WELL SPACING DATA ASSUMING SQUARE AND 1/4 ELEMENT
COM
COM         ACRES       FEET       METRES    WELLS/SECTION
COM         640         2640       804.7          1
COM         320         1867       569.1          2
COM         160         1320       402.3          4
COM         80          933        284.4          8
COM         40          660        201.2         16
COM         20          467        142.3         32
COM
COM            *** CARTESIAN GRIDS ***
COM
COM            *** OPTION 0 - UNIFORM GRID ***
COM            (use for Cartesian Grid only)
COM
COM ,--TOTAL GRID LENGTH X DIRECTION
COM |         ,--TOTAL GRID LENGTH Y DIRECTION
COM |         |         ,--TOTAL GRID LENGTH Z DIRECTION
COM V         V         V
COM m/ft      m/ft      m/ft
COM -----|---------|---------|
COM
COM -----|---------|---------|
COM
COM            *** OPTION 1 - IRREGULAR GRID ( SPECIAL CASES ONLY) ***
COM            (use for Cartesian Grid only)
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS X DIRECTION
COM |   (number of values equals number of grid intervals in x direction)
COM V
COM <------------------------- m/ft -------------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM   TOTAL = 1000 FT
    2.        3.        5.        5.        10.       10.       10.       10.
   10.        20        30.       30.       35.       20.       100.      100.
  100.       100.       100.      100.      100.      100.
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS Y DIRECTION
COM |   (number of values equals number of grid intervals in y direction)
COM V
COM <------------------------- m/ft -------------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM  TOTAL = 1000 FT
     50.      50.       50.       50.       50.       50.       50.       50.
     50.      50.       50.       50.       50.       50.       50.       50.
     50.      50.       50.       50.
COM   FORM HEIGHT = 100 FT
   27.       14.        6.        2.25      1.5       2.25      6.        14.
   27.
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM            *** OPTION 2 - GEOMETRIC GRID ***
COM            (use for Cartesian Grid only)
COM
COM ,--TOTAL GRID LENGTH IN THE X DIRECTION
COM |         ,--SIZE OF INTERVAL NEAREST ORIGIN
COM V         V
COM m/ft      m/ft
COM -----|---------|
COM
COM -----|---------|
COM
COM ,--TOTAL GRID LENGTH IN THE Y DIRECTION
COM |         ,--SIZE OF INTERVAL NEAREST ORIGIN
COM V         V
COM m/ft      m/ft
COM -----|---------|
COM
COM -----|---------|
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS Z DIRECTION
COM V     (for one block use gross thickness of reservoir)
COM <------------------------- m/ft -------------------------------------->
```

```
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM             *** RADIAL GRIDS ***
COM
COM             *** OPTION 0 - UNIFORM GRID ***
COM             (use for Radial Grid only)
COM
COM ,--TOTAL GRID LENGTH R DIRECTION
COM |         ,--TOTAL GRID ANGLE THETA DIRECTION
COM |         |         ,--TOTAL GRID LENGTH Z DIRECTION
COM |         |         |         ,--INNER WELL RADIUS
COM V         V         V         V
COM m/ft   degrees     m/ft      m/ft
COM -----|---------|---------|---------|
COM
COM -----|---------|---------|---------|
COM
COM             *** OPTION 1 - IRREGULAR GRID ( SPECIAL CASES ONLY) ***
COM             (use for Radial Grid only)
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS R DIRECTION
COM |    (number of values equals number of grid intervals in r direction)
COM V
COM <---------------------------- m/ft ------------------------------------>
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM ,---ARRAY OF VALUES SPECIFYING ANGLES BETWEEN GRID POINTS THETA DIRECTION
COM |    (number of values equals number of grid intervals in theta direction)
COM V
COM <-------------------------- degrees ----------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM ,--INNER WELL RADIUS
COM V
COM m/ft
COM -----|
COM
COM -----|
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS Z DIRECTION
COM |    (number of values equals number of grid intervals in z direction)
COM V
COM <---------------------------- m/ft ------------------------------------>
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM             *** OPTION 2 - GEOMETRIC GRID ***
COM             (use for Radial Grid only)
COM
COM ,--TOTAL GRID LENGTH IN THE R DIRECTION
COM |         ,--SIZE OF INTERVAL NEAREST ORIGIN
COM |         |         ,--INNER WELL RADIUS
COM V         V         V
COM m/ft     m/ft      m/ft
COM -----|---------|---------|
COM
COM -----|---------|---------|
COM
COM ,---ARRAY OF VALUES SPECIFYING ANGLES BETWEEN GRID POINTS THETA DIRECTION
COM |    (number of values equals number of grid intervals in theta direction)
COM V
COM <-------------------------- degrees ----------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|---------|
COM
COM ,---ARRAY OF VALUES SPECIFYING DISTANCES BETWEEN GRID POINTS Z DIRECTION
COM |    (number of values equals number of grid intervals in z direction)
```

```
COM V
COM <---------------------------- m/ft ------------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM            *** POINT DEPTHS - GROUP 2 ***
COM
COM            *** OPTION 0 - ORTHOGONAL GRID ***
COM
COM ,--DEPTH TO CENTRE PAY OR TOP OF (1,1,1) BLOCK FOR MORE THAN 1 LAYER
COM |           ,--SINE OF X DIRECTION DIP
COM |           |         ,--SINE OF Y DIRECTION DIP
COM V           |         |
COM m/ft        V         V
COM -----|---------|---------|
5000.0    0.        0.
COM -----|---------|---------|
COM
COM            *** OPTION 1- NONORTHOGONAL GRID (DETAILED STUDIES ONLY) ***
COM
COM ,---ARRAY OF VALUES SPECIFYING DEPTHS OF EACH GRID BLOCK
COM |    ( entries needed for all grid blocks ,
COM |      read in rows of number of intervals in x direction + 1 ,
COM V      for purposes of block numbering x increments fastest then y then z)
COM <---------------------------- m/ft ------------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM
COM            *** 4.3.3 INITIALIZATION ROCK DATA ***
COM
COM            *** ROCK COMPRESSIBILITY - GROUP 1 ***
COM
COM ,--REFERENCE PRESSURE FOR ROCK COMPRESSIBILITY
COM |         ,--RESERVOIR ROCK COMPRESSIBILITY
COM |         |
COM V         V      NOTE:    If properties are stress-dependent and the res.
COM kPa      1/kPa            rock compressibility is non zero then the porosity
COM psia     1/psi            reduction factors read in SECTION 4.3.5 will be
COM -----|---------|          ignored and a table will be constructed internally.
 14.7      0.0000048
COM -----|---------|
COM
COM
COM            *** RESERVOIR PROPERTIES - GROUP 2 ***
COM
COM            *** OPTION 0 - HOMOGENEOUS RESERVOIR ***
COM
COM ,--ABSOLUTE POROSITY FRACTION
COM |         ,--ABSOLUTE PERMEABILITY X-DIRECTION
COM |         |         ,--ABSOLUTE PERMEABILITY Y-DIRECTION
COM |         |         |         ,--ABSOLUTE PERMEABILITY Z-DIRECTION
COM |         |         |         |         ,--RELATIVE PERMEABILITY OF
COM |         |         |         |         |  HYDROCARBON @ Sw
COM |         |         |         |         |         ,--INSITU WATER
COM |         |         |         |         |         |  SATURATION Sw
COM |         |         |         |         |         |
COM |         V         V         V         V         V
COM V        md        md        md      fraction  fraction
COM -----|---------|---------|---------|---------|---------|
 0.1       50.0      50.0      25.0      1.0       0.1
COM -----|---------|---------|---------|---------|---------|
COM
COM
COM            *** OPTION 1 - HETEROGENEOUS ***
COM
COM    ARRAYS FOR POROSITY(fraction) ,kx,ky,kz(md) (8F10.0) ARE EACH PRECEEDED
COM    BY THE FOLLOWING KEY WORDS:
COM          CON - CONSTANT VALUE FOR PERMEABILITY ie value on next card
COM           X  - PROPERTY VARIES IN X-DIRECTION  ie i-values on card(s)
COM           Y  - PROPERTY VARIES IN Y-DIRECTION  ie j-values on card(s)
COM           Z  - PROPERTY VARIES IN Z-DIRECTION  ie k-values on card(s)
COM          XYZ - PROPERTY VARIES BLOCK BY BLOCK  read i no. on set of card(s)
```

```
COM          R   - PROPERTY VARIES IN R-DIRECTION  ie i-values on card(s)
COM          THET- PROPERTY VARIES IN THETA-DIRECTION  ie j-values on card(s)
COM          RTZ - PROPERTY VARIES BLOCK BY BLOCK  read i no. on set of card(s)
COM key
COM -----|---------|---------|---------|---------|---------|---------|---------|
COM   POROSITY ARRAY (repeated for kx,ky,kz arrays)
COM -----|---------|---------|---------|---------|---------|---------|---------|
COM
COM ,--RELATIVE PERMEABILITY TO HYDROCARBON AT INSITU WATER SATURATION
COM |         ,--INSITU WATER SATURATION Sw
COM V         V
COM   fractions
COM -----|---------|
COM
COM -----|---------|
COM
COM
COM              *** OPTION 2 - LAYERED RESERVOIR ***
COM
COM ,--LAYER ABSOLUTE POROSITY FRACTION
COM |         ,--LAYER AVERAGE HORIZONTAL PERMEABILITY
COM |         |         ,--LAYER AVERAGE PERMEABILITY Z-DIRECTION
COM |         |         |
COM |         V         V
COM V         md        md
COM -----|---------|---------|
COM   (provide one card for
COM    each layer)
COM -----|---------|---------|
COM
COM ,--RELATIVE PERMEABILITY TO HYDROCARBON AT INSITU WATER SATURATION
COM |         ,--INSITU WATER SATURATION Sw
COM V         V
COM   fractions
COM -----|---------|
COM
COM -----|---------|
COM
COM              *** 4.3.4 DUAL POROSITY DATA ***
COM                    (only if NMEDIA = 2)
COM
COM ,--LAMBDA(INTER-POROSITY FLOW COEFFICIENT)
COM |         ,--OMEGA(FRACTURE TO TOTAL POROSITY RATIO)
COM |         |         ,--KAPPA(FRACTURE TO TOTAL PERMEABILITY RATIO)
COM V         V         V
COM -----|---------|---------|
COM
COM -----|---------|---------|
COM
COM
COM              *** RESERVOIR MODIFIERS - GROUP 3 ***
COM
COM                   DATA 1 -  REGIONS TO BE MODIFIED
COM
COM ,-------LOWER X-DIRECTION INDEX I1
COM |    ,--UPPER X-DIRECTION INDEX I2
COM |    |    ,-------LOWER Y-DIRECTION INDEX J1
COM |    |    |    ,--UPPER Y-DIRECTION INDEX J2
COM |    |    |    |    ,-------LOWER Z-DIRECTION INDEX K1
COM |    |    |    |    |    ,--UPPER Z-DIRECTION INDEX K2
COM V    V    V    V    V    V
COM *----*----*----*----*----*
     1    1   11   11    1    1
COM -----|---------|---------|---------|---------|
     0.0       1.0       0.0       1.0       1.0
     2   15   11   11    1    1
  49.40      1.0       0.0       1.0       1.0
    16   16   11   11    1    1
  13.58      1.0       0.0       1.0       1.0
    17   23   11   11    1    1
    1.0      1.0       0.0       1.0       1.0
     1    1   11   11    2    2
     0.0       1.0     97.80       1.0       1.0
     2   15   11   11    2    2
  49.40      1.0     97.80       1.0       1.0
```

```
 16   16    11    11     2     2
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     2     2
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     3     3
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     3     3
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     3     3
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     3     3
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     4     4
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     4     4
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     4     4
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     4     4
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     5     5
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     5     5
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     5     5
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     5     5
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     6     6
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     6     6
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     6     6
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     6     6
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     7     7
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     7     7
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     7     7
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     7     7
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     8     8
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     8     8
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     8     8
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     8     8
 1.0        1.0          1.0           1.0         1.0
  1    1    11    11     9     9
  0.0       1.0        97.80           1.0         1.0
  2   15    11    11     9     9
49.40       1.0        97.80           1.0         1.0
 16   16    11    11     9     9
13.58       1.0          1.0           1.0         1.0
 17   23    11    11     9     9
 1.0        1.0          1.0           1.0         1.0

COM *----*----*----*----*----*
COM
COM          DATA 2 - TRANSMISSIBILTY MULTIPLIERS
COM
COM ,--MULTIPLIER ON X-DIRECTION "INTERBLOCK" TRANSMISSIBILITY
COM |          ,--MULTIPLIER ON Y-DIRECTION "INTERBLOCK" TRANSMISSIBILITY
COM |          |          ,--MULTIPLIER ON Z-DIRECTION "INTERBLOCK" TRANS
COM |          |          |          ,--MULTIPLIER ON PORE VOLUME
COM |          |          |          |          ,--MULTIPLIER ON MATRIX/NATURAL
COM |          |          |          |          |  FRACTURE TRANSMISSIBILITY
COM V          V          V          V          V
COM -----|----------|----------|----------|----------|
COM -----|----------|----------|----------|----------|
COM
```

```
COM NOTE:  Data groups 1 and 2 are read in pairs,
COM        follow the modification set with a BLANK CARD
COM
COM
COM             *** 4.3.4 FLUID DATA INITIALIZATION ***
COM
COM
COM             *** REFERENCE DENSITY - GROUP 1 ***
COM
COM ,--REFERENCE PRESSURE FOR DENSITY (FOR OIL USE BUBBLE POINT PRESSURE)
COM |         ,--HYDROCARBON DENSITY AT REFERENCE PRESSURE
COM |         |         ,--RESERVOIR TEMPERATURE (default = 120 deg f)
COM |         |         |         ,--STOCK TANK PRESSURE (default = 14.65 psia)
COM |         |         |         |         ,--STOCK TANK TEMP (def = 60 deg f)
COM V         V         V         V         V
COM kPa    kg/m3      deg c      kPa       deg c
COM psia   lb/ft3     deg f      psia      deg f
COM -----|---------|---------|---------|---------|
   1348.0 38.825343     175.0     14.70      60.0
COM -----|---------|---------|---------|---------|
COM
COM             *** PVT TABLE - GROUP 2 ***
COM
COM  NOTE: the number of entries in this set is given on 4.3.1 DATA 1 Prob Size
COM
COM ,--PRESSURE (INCREASING ORDER)
COM |        ,--FORMATION VOLUME FACTOR: Bt for Oil, Bg for Gas
COM V        |         ,--HYDROCARBON VISCOSITY
COM kPa      V         V
COM psia  res/std     cp
COM -----|---------|---------|
COM   SMALL CONST. COMPRESSIBILITY
     14.65     1.0000   1.
    200.00     0.9995   1.
    400.00     0.9990   1.
    600.00     0.9985   1.
    800.00     0.9980   1.
   1000.00     0.9975   1.
   1200.00     0.9970   1.
   1400.00     0.9965   1.
   1600.00     0.9960   1.
   1800.00     0.9955   1.
   2000.00     0.9950   1.
COM -----|---------|---------|
COM
COM
COM             *** 4.3.5 OPTIONAL INITIALIZATION DATA ***
COM
COM             *** STRESS DEPENDENT PROPERTIES - GROUP 1 ***
COM   (read only if STRESS DEPENDENT OPTION is selected (4.3.1 DATA 1 Opt Spec))
COM
COM                          DATA 1 - CONTROLS
COM
COM ,--NUMBER OF ENTRIES IN STRESS TABLE (1<#<dimensional limit)
COM |    ,--0=PROPERTIES READ IN ARE AT ZERO STRESS ;1= INSITU STRESS
COM |    |
COM V    V
COM *----*
COM
COM *----*
COM
COM                DATA 2 - ROCK MECHANICS DATA
COM
COM ,--VERTICAL STRESS
COM |        ,--HORIZONTIAL STRESS
COM |        |         ,--YOUNG'S MODULUS
COM |        |         |         ,--POISSON'S RATIO
COM V        V         V         |         ,--BIOT'S CONSTANT
COM kPa     kPa       kPa        |         |
COM psia    psia      psia       V         V
COM -----|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|
COM
COM NOTE:  vertical stress > horizontal stress
```

```
COM
COM                   DATA 3 - STRESS DEPENDENT PROPERTIES
COM
COM NOTE:  CR must be set to 0 in (4.2.3 GROUP 1) to use this table
COM
COM ,--EFFECTIVE STRESS (increasing order)
COM |         ,--PERMEABILITY REDUCTION RELATIVE TO UNSTRESSED STATE
COM V         |         ,--POROSITY REDUCTION RELATIVE TO UNSTRESSED
COM kPa       V         V  (ignored if CR > 0 on Card 4.3.3)
COM psia    frac      frac
COM -----|--------|--------|
COM
COM -----|--------|--------|
COM
COM                *** NON-DARCY PROPERTIES - GROUP 2 ***
COM    (read only if TURBULENCE OPTION is selected (4.3.1 DATA 1 Option Spec) )
COM
COM ,--NON-DARCY FACTOR FOR RESERVOIR FLOW
COM |         ,--'A' COEFFICIENT IN NON-DARCY
COM |         |   EQUATION (OPTIONAL)
COM |         |         ,-- 'B' COEFFICIENT IN
COM |         |         |    NON-DARCY EQUATION (OPTIONAL)
COM |         |         |         ,--'C' COEFFICIENT IN
COM |         |         |         |    NON-DARCY EQUATION (OPTIONAL)
COM |         |         |         |         ,--'D' COEFFICIENT IN
COM |         |         |         |         |    NON-DARCY EQUATION (OPTIONAL)
COM V         V         |         |         |
COM 1/m       1/m       V         V         V
COM 1/ft      1/ft    fraction  fraction  fraction
COM -----|---------|---------|---------|---------|
COM
COM -----|---------|---------|---------|---------|
COM
COM             *** WELLBORE HYDRAULICS DATA - GROUP 3 ***
COM (read only if WELLBORE HYDRAULICS OPTION is selected (4.3.1 Option Spec) )
COM
COM             *** DATA 1 WELLBORE HYDRAULICS CONTROLS ***
COM
COM ,--NUMBER OF WELLBORE SEGMENTS
COM |
COM |
COM V
COM *
COM
COM *
COM
COM             *** DATA 2 COMPLETION DATA ***
COM        (number of entries equals number of well segments)
COM
COM ,--KB DEPTH OF SEGMENT
COM |          ,--OUTER DIAMETER OF THE SEGMENT
COM |          |         ,--INNER DIAMETER OF THE SEGMENT
COM |          |         |   (default to area of openhole with tubing diameter)
COM |          |         |         ,--SEGMENT ROUGHNESS (default = 0.00006 in)
COM V          V         V         V
COM m/ft     cm/in     cm/in     cm/in
COM -----|---------|---------|---------|
COM
COM -----|---------|---------|---------|
COM
COM             *** DATA 3 KB DATA ***
COM
COM ,--KB ELEVATION
COM |
COM |
COM V
COM m/ft
COM -----|
COM
COM -----|
COM
COM             *** TIME DEPENDENT RELATIVE PERM PROPERTIES - GROUP 4 ***
COM    (read only if RELATIVE PERMEABILITY VS. TIME OPTION is selected
COM                    (CARD 4.3.1 GROUP 3) )
COM
```

```
COM ,--NUMBER OF ENTRIES IN  RELATIVE PERM VS TIME TABLE
COM V
COM *
COM
COM *
COM
COM ,--TIME (increasing order)
COM |         ,--RELATIVE PERMEABILITY TO HYDROCARBON
COM V         V
COM days   fraction
COM -----|---------|
COM
COM -----|---------|
COM
COM              *** 4.2.6 INITIAL CONDITION DATA ***
COM
COM              *** REFERENCE PRESSURE - GROUP 1 ***
COM (read as many of these cards as is necessary to cover entire reservoir)
COM
COM ,--REFERENCE DEPTH
COM |         ,--INITIAL PRESSURE AT REFERENCE DEPTH
COM |         |          ,--TOP LAYER OF REGION TO BE INITIALIZED
COM V         V          |    ,--BOTTOM LAYER OF REGION TO BE INITIALIZED
COM m/ft   kPa/psi       V    V  (if layers left blank defaults to entire res)
COM -----|---------|----*----*
 5000.0    1500.0
COM -----|---------|----*----*
COM
COM              *** 4.2.7 INITIALIZATION END ***
COM         (END CARD required)
END
NOECHO
COM
COM
COM ******************************************************************
COM ******************** RECURRENT DATA SECTION***************************
COM              (repeat for each desired time step grouping)
COM
COM              *** 4.4.1 RECURRENT CONTROL DATA ***
COM
COM              *** CONTROL DATA - GROUP 1 ***
COM
COM ,--KEYWORD "REC" SIGNALS START OF THIS SET OF RECURRENT DATA
COM |    ,--WELL DATA READ; 0=NO; 1=YES
COM |    |    ,--0 OR 1=GAUSSIAN ELIMINATION
COM |    |    |    ,--MINIMUM ITERATIONS PER TIME STEP (default=2)
COM |    |    |    |    ,--MAXIMUM ITERATIONS PER TIME STEP (default=20)
COM V    V    V    V    V
COM *----*----*----*----*
REC      1    0    2   40
COM *----*----*----*----*
COM
COM              *** FRACTURE INITIATION - GROUP 2 (optional) ***
COM
COM ,--ENTER KEYWORD "FRAC" IN COLS 1-4 when fracture treatment is desired;
COM |                                    otherwise similation preceeds
COM |                                    with unfractured case until a FRAC card
COM |                                    is detected ,
COM |                                    only one frac card is allowed in any
COM |                                    dataset but it can be at any time
COM V                                    not valid for radial coordinate runs
COM
COM              *** 4.4.2  RECURRENT WELL DATA ***
COM                (used only if well data read)
COM
COM              *** NUMBER OF WELLS - GROUP 1 ***
COM
COM ,--TOTAL NUMBER OF WELLS
COM |    ,--NUMBER OF BLOCKS HAVING A CONSTANT PRESSURE
COM V    V
COM *----*
    1    0
COM *----*
COM
COM              *** WELL LOCATIONS AND PARAMETERS - GROUP 2 ***
```

```
COM
COM ,--FIRST INDEX FOR BLOCK CONTAINING WELL
COM |   IDIR=0,1 I INDEX; IDIR=2 K INDEX; IDIR=3 I INDEX
COM |    ,-- SECOND INDEX OF BLOCK CONTAINING WELL
COM |    |    IDIR=0,1 J INDEX; IDIR=2 J INDEX; IDIR=3 K INDEX
COM |    |    ,--STARTING THIRD INDEX OF UPPERMOST PERFORATIONS
COM |    |    |    IDIR=0,1 K INDEX; IDIR=2 I INDEX; IDIR=3 J INDEX
COM |    |    |    ,-- LAST THIRD INDEX OF LOWERMOST PERFORATIONS
COM |    |    |    |    IDIR=0,1 K INDEX; IDIR=2 I INDEX; IDIR=3 J INDEX
COM |    |    |    |    ,-- DIRECTION OF WELL 0,1=K(VERTICAL); 2=I(HOR); 3=J(HOR)
COM |    |    |    |    |    ,--0=CALCULATE WELL INDEX INTERNALLY; 1=WI READ IN
COM |    |    |    |    |    |    2=SKIN FACTOR READ IN
COM |    |    |    |    |    |    ,--0=PRODUCER; 1=INJECTOR
COM |    |    |    |    |    |    |    ,--0=RATE AT STC WITH POSSIBLE BHP LIMIT
COM |    |    |    |    |    |    |    |    1=RATE AT RC  WITH POSSIBLE BHP LIMIT
COM |    |    |    |    |    |    |    |    2=RATE AT STC WITH POSSIBLE THP LIMIT
COM |    |    |    |    |    |    |    |    3=RATE AT RC  WITH POSSIBLE THP LIMIT
COM V    V    V    V    V    V    V    V
COM *----*----*----*----*----*----*----*
    1    5    1   17    3    2    0    0
COM *----*----*----*----*----*----*----*
COM
COM             *** RATE DATA - GROUP 3 ***
COM
COM ,--LIMITING RATE WHICH WELL CAN PRODUCE OR INJECT
COM |        ,--LIMITING BOTTOMHOLE OR TUBINGHEAD PRESSURE
COM |        |         ,--WELLBORE RADIUS (default = 0.25 ft,
COM |        |         |                 ignored if radial coordinates and I=1)
COM |        |         |         ,-- WELL SYMMETRY FACTOR
COM |        |         |         |    (default = 0.25 if model is symmetry
COM |        |         |         |     element and cartesian or TOTANG/360
COM |        |         |         |     if symmetry element and radial
COM m3/d     V         |         |     default = 1.00 if model is full field
COM bbl/d   kPa        V         V     see 4.3.1 DATA 1 Geom specs)
COM Mscf/d  psia      m/ft     fraction
COM -----|---------|---------|---------|
200.      500.     0.25      0.5        0.0      100000.
COM -----|---------|---------|---------|
COM
COM             *** WELL INDEX DATA - GROUP 4 ***
COM              (used only if well index or skin factor is specified )
COM
COM              IF WELL INDEX IS SPECIFIED ,
COM
COM ,WELL INDEX ARRAY FOR EACH LAYER; START AT TOP LAYER
COM V
COM <---------------------- m3*cp/kPa-d ------------------------------------>
COM <---------------------- bbl*cp/psi-d ----------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM              IF SKIN FACTOR IS SPECIFIED ,
COM
COM ,SKIN FACTOR ARRAY FOR EACH LAYER; START AT TOP LAYER
COM V
COM -----|---------|---------|---------|---------|---------|---------|--------|
0.0        0.0       0.0       0.0       0.0       0.0       0.0       0.0
0.0        0.0       0.0       0.0       0.0       0.0       0.0       0.0
0.0
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM             *** 4.4.2A CONSTANT PRESSURE DATA ***
COM      (used only if positive number of constant pressure blocks ,
COM       enter as many cards as there are constant pressure blocks)
COM
COM             *** TIME CARD - GROUP 1 ***
COM ,--I INDEX OF CONSTANT PRESSURE BLOCK
COM |    ,--J INDEX OF CONSTANT PRESSURE BLOCK
COM |    |    ,--K INDEX OF CONSTANT PRESSURE BLOCK
COM |    |    |    ,--GRID BLOCK PRESSURE
COM |    |    |    V
COM V    V    V  kPa/psi
COM *----*----*---------|
COM   SPEC P AT TOP AND CONNECT BY TZx100
```

```
COM *----*----*---------|
COM
COM              *** 4.4.3 RECURRENT TIME DATA ***
COM
COM              *** TIME CARD - GROUP 1 ***
COM
COM ,--END OF TIME INTERVAL WHERE CURRENT DATA APPLIES
COM |        ,--TIME STEP SIZE (<0 INVOKES AUTOMATIC TIME STEP,VALUE IS INITIAL
COM |        |                     TIME STEP SIZE)
COM |        |      (NOTE : next entries apply only for automatic time stepping)
COM |        |          ,--MIN TIME STEP SIZE
COM |        |          |         ,--MAX TIME STEP SIZE
COM |        |          |         |          ,--LIMITING PRESSURE FOR TIME STEP
COM |        |          |         |          |          ,--WEIGHT FACTOR FOR
COM |        |          |         |          |          |  OSCILLATION CONTROL
COM |        |          |         |          |          |  (default = 0.2)
COM |        |          |         |          |          |        ,--CORD FOR DER
COM |        |          |         |          |          |        |  CALCULATION
COM V        V          V         V          V          |        V (default=50psi)
COM days    days       days      days      kPa/psi      V      kPa/psi
COM -----|---------|---------|---------|---------|---------|---------|
 0.1       -0.1       0.1       100.       100.
COM -----|---------|---------|---------|---------|---------|---------|
COM
COM              *** OUTPUT CONTROLS - GROUP 2 ***
COM
COM ,--1=PRINT SUMMARY EVERY TIME STEP; 0=NO SUMMARY
COM |    ,--PRINT ITERATION SUMMARY EVERY TIME STEP; 0=NO; 1=YES
COM |    |    ,--FREQUENCY OF TIME STEP OUTPUT (default = 1)
COM |    |    |    ,--1=WRITE RESTART RECORD AT END OF PERIOD; 0=NO
COM |    |    |    |    ,--1=PRINT TURBULENCE ARRAYS WITH OTHER ARRAYS; 0=NO
COM V    V    V    V    V
COM *----*----*----*----*
    1    1  100    0    0
COM *----*----*----*----*
COM
COM
COM                   ***  END OF RECURRENT DATA  ***
COM                               OR
COM         ***  GO BACK TO BEGINNING OF RECURRENT DATA SECTION ***
COM         ***      FOR ADDITIONAL RECURRENT TIME GROUPINGS     ***
COM
COM
COM              *** 4.4.1 RECURRENT CONTROL DATA ***
COM
COM              *** CONTROL DATA - GROUP 1 ***
COM
COM ,--KEYWORD "REC" SIGNALS START OF THIS SET OF RECURRENT DATA
COM |    ,--WELL DATA READ; 0=NO; 1=YES
COM |    |    ,--0 OR 1=GAUSSIAN ELIMINATION
COM |    |    |    ,--MINIMUM ITERATIONS PER TIME STEP (default=2)
COM |    |    |    |    ,--MAXIMUM ITERATIONS PER TIME STEP (default=20)
COM V    V    V    V    V
COM *----*----*----*----*
REC      0    0
COM *----*----*----*----*
COM
COM              *** FRACTURE INITIATION - GROUP 2 (optional) ***
COM
COM ,--ENTER KEYWORD "FRAC" IN COLS 1-4 when fracture treatment is desired;
COM |                                    otherwise similation preceeds
COM |                                    with unfractured case until a FRAC card
COM |                                    is detected ,
COM |                                    only one frac card is allowed in any
COM |                                    dataset but it can be at any time
COM V                                    not valid for radial coordinate runs
FRAC
COM
COM              *** 4.4.2  RECURRENT WELL DATA ***
COM                (used only if well data read)
COM
COM              *** NUMBER OF WELLS - GROUP 1 ***
COM
COM ,--TOTAL NUMBER OF WELLS
COM |    ,--NUMBER OF BLOCKS HAVING A CONSTANT PRESSURE
```

```
COM V    V
COM *----*
COM
COM *----*
COM
COM            *** 4.4.2A CONSTANT PRESSURE DATA ***
COM     (used only if positive number of constant pressure blocks ,
COM      enter as many cards as there are constant pressure blocks)
COM
COM            *** TIME CARD - GROUP 1 ***
COM ,--I INDEX OF CONSTANT PRESSURE BLOCK
COM |    ,--J INDEX OF CONSTANT PRESSURE BLOCK
COM |    |    ,--K INDEX OF CONSTANT PRESSURE BLOCK
COM |    |    |    ,--GRID BLOCK PRESSURE
COM |    |    |    V
COM V    V    V  kPa/psi
COM *----*----*---------|
COM
COM *----*----*---------|
COM
COM            *** WELL LOCATIONS AND PARAMETERS - GROUP 2 ***
COM
COM ,--FIRST INDEX FOR BLOCK CONTAINING WELL
COM |  IDIR=0,1 I INDEX; IDIR=2 K INDEX; IDIR=3 I INDEX
COM |    ,-- SECOND INDEX OF BLOCK CONTAINING WELL
COM |    |    IDIR=0,1 J INDEX; IDIR=2 J INDEX; IDIR=3 K INDEX
COM |    |    ,--STARTING THIRD INDEX OF UPPERMOST PERFORATIONS
COM |    |    |  IDIR=0,1 K INDEX; IDIR=2 I INDEX; IDIR=3 J INDEX
COM |    |    |    ,-- LAST THIRD INDEX OF LOWERMOST PERFORATIONS
COM |    |    |    |    IDIR=0,1 K INDEX; IDIR=2 I INDEX; IDIR=3 J INDEX
COM |    |    |    |    ,-- DIRECTION OF WELL 0,1=K(VERTICAL); 2=I(HOR); 3=J(HOR)
COM |    |    |    |    |    ,--0=CALCULATE WELL INDEX INTERNALLY; 1=WI READ IN
COM |    |    |    |    |    |  2=SKIN FACTOR READ IN
COM |    |    |    |    |    |    ,--0=PRODUCER; 1=INJECTOR
COM |    |    |    |    |    |    |    ,--0=RATE AT STC WITH POSSIBLE BHP LIMIT
COM |    |    |    |    |    |    |    |  1=RATE AT RC  WITH POSSIBLE BHP LIMIT
COM |    |    |    |    |    |    |    |  2=RATE AT STC WITH POSSIBLE THP LIMIT
COM |    |    |    |    |    |    |    |  3=RATE AT RC  WITH POSSIBLE THP LIMIT
COM V    V    V    V    V    V    V    V
COM *----*----*----*----*----*----*----*
COM
COM *----*----*----*----*----*----*----*
COM
COM            *** RATE DATA - GROUP 3 ***
COM
COM ,--LIMITING RATE WHICH WELL CAN PRODUCE OR INJECT
COM |        ,--LIMITING BOTTOMHOLE OR TUBINGHEAD PRESSURE
COM |        |         ,--WELLBORE RADIUS (default = 0.25 ft,
COM |        |         |                  ignored if radial coordinates and I=1)
COM |        |         |         ,--WELL SYMMETRY FACTOR
COM |        |         |         |   (default = 0.25 if model is symmetry
COM |        |         |         |    element and cartesian or TOTANG/360
COM |        |         |         |    if symmetry element and radial
COM m3/d     V         |         |    default = 1.00 if model is full field
COM bbl/d   kPa        V         V    see 4.3.1 DATA 1 Geom specs)
COM Mscf/d  psia      m/ft     fraction
COM -----|---------|---------|---------|
COM
COM -----|---------|---------|---------|
COM
COM            *** WELL INDEX DATA - GROUP 4 ***
COM             (used only if well index or skin factor is specified )
COM
COM             IF WELL INDEX IS SPECIFIED ,
COM
COM ,WELL INDEX ARRAY FOR EACH LAYER; START AT TOP LAYER
COM V
COM <----------------------- m3*cp/kPa-d ----------------------------------->
COM <----------------------- bbl*cp/psi-d ---------------------------------->
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM -----|---------|---------|---------|---------|---------|---------|--------|
COM
COM             IF SKIN FACTOR IS SPECIFIED ,
COM
```

```
COM ,SKIN FACTOR ARRAY FOR EACH LAYER; START AT TOP LAYER
COM V
COM -----|---------|---------|---------|---------|---------|---------|---------|--------|
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|--------|
COM
COM              *** 4.4.3 RECURRENT TIME DATA ***
COM
COM              *** TIME CARD - GROUP 1 ***
COM
COM ,--END OF TIME INTERVAL WHERE CURRENT DATA APPLIES
COM |        ,--TIME STEP SIZE (<0 INVOKES AUTOMATIC TIME STEP,VALUE IS INITIAL
COM |        |                   TIME STEP SIZE)
COM |        |     (NOTE : next entries apply only for automatic time stepping)
COM |        |        ,--MIN TIME STEP SIZE
COM |        |        |         ,--MAX TIME STEP SIZE
COM |        |        |         |         ,--LIMITING PRESSURE FOR TIME STEP
COM |        |        |         |         |         ,--WEIGHT FACTOR FOR
COM |        |        |         |         |         |  OSCILLATION CONTROL
COM |        |        |         |         |         |  (default = 0.2)
COM |        |        |         |         |         |        ,--CORD FOR DER
COM |        |        |         |         |         |        |  CALCULATION
COM V        V        V         V         V         |        V (default=50psi)
COM days     days     days      days      kPa/psi   V       kPa/psi
COM -----|---------|---------|---------|---------|---------|---------|---------|
365.      -0.1      0.1       100.      100.
COM -----|---------|---------|---------|---------|---------|---------|---------|
COM
COM              *** OUTPUT CONTROLS - GROUP 2 ***
COM
COM ,--1=PRINT SUMMARY EVERY TIME STEP; 0=NO SUMMARY
COM |    ,--PRINT ITERATION SUMMARY EVERY TIME STEP; 0=NO; 1=YES
COM |    |    ,--FREQUENCY OF TIME STEP OUTPUT (default = 1)
COM |    |    |    ,--1=WRITE RESTART RECORD AT END OF PERIOD; 0=NO
COM |    |    |    |    ,--1=PRINT TURBULENCE ARRAYS WITH OTHER ARRAYS; 0=NO
COM V    V    V    V    V
COM *----*----*----*----*
    1    1  100    0    0
COM *----*----*----*----*
COM
COM
COM                   ***  END OF RECURRENT DATA  ***
COM                               OR
COM         ***  GO BACK TO BEGINNING OF RECURRENT DATA SECTION ***
COM         ***      FOR ADDITIONAL RECURRENT TIME GROUPINGS    ***
COM
END
EOF
```

APPENDIX B: Interface File of Fracture

```
NOECHO
COM
COM                         ***********************************
COM                         * SIMTECH CONSULTING SERVICES LTD *
COM                         *     FRAC INTERFACE TEMPLATE     *
COM                         *           VERSION 5.1           *
COM                         *            92-01-14             *
COM                         ***********************************
COM
COM
COM
COM                      *** INTERFACE CONTROL DATA 1 ***
COM
COM ,--0=METRIC UNITS; 1=ENGLISH UNITS
COM |    ,--INTERFACE PRINTOUT CONTROL; 0=NONE; 1=1 LINE; 2=EVERYTHING
COM |    |    ,--INPUT FRAC DESCRIPTION KEY; 0=READ FROM LINK FILE; >0=SIMPLE
COM |    |    |    ,--KEY TO PRINT DATA FROM LINK FILE; 0=NO; 1=YES
COM |    |    |    |    ,--FRAC FLUID PHASE; 0=WATER; 1=OIL
COM |    |    |    |    |  (used in 3 phase models only; not in FRACWELL)
COM |    |    |    |    |    ,--TREATMENT TYPE; 0=PROP; 1=ACID
COM |    |    |    |    |    |    ,--PERM REDUCTION FACTOR VS TIME; 0=OFF; 1=ON
COM |    |    |    |    |    |    |    ,--HYSTERESIS IN PERM + WIDTH;0=OFF;1=ON
COM |    |    |    |    |    |    |    |    ,--NUMBER OF FRACTURED FORECASTS
COM V    V    V    V    V    V    V    V    V
COM *----*----*----*----*----*----*----*----*
    1    0    1    1    0    0    0    0    1
COM *----*----*----*----*----*----*----*----*
COM
COM                    *** FRACTURE POST-CLOSURE DATA ***
COM
COM                      GROUP A - FRACTURE DECRIPTION
COM
COM                    *** A1 - DETAILED FRACTURE DATA ***
COM                   ( only if fracture description is detailed)
COM
COM ,--ENTER KEYWORD "READ" IN COLS 1-4 and linkage filename from COLS 5 on
COM |
COM V
COM -----------------------------------
COM READ file_name
COM -----------------------------------
COM
COM                   *** A2 - PROPPED OR ACIDIZED FRACTURE DATA ***
COM
COM                   ( only if input fracture description is simple ,
COM           enter as many times as simple frac description key indicates
COM              from furthest stage out to closest stage to wellbore ,
COM     each stage is considered to be a unique proppant type for a propped frac)
COM
COM   (Enter as many sets of A2 data as there are fracture forecasts ,
COM    each set of data will encompass an entire run from time zero)
COM
COM ,--MAXIMUM PROP/ACID DISTANCE FROM WELLBORE FOR THIS STAGE
COM |         ,--TOTAL PROPPANT PLACED FOR THIS STAGE (BOTH WINGS);
COM |         |  OR PROPPED WIDTH (IF VALUE ENTERED < 10.0)
COM |         |  FOR ACID FRACS, ENTER TOTAL ACIDIZED (DISSOLVED) VOLUME
COM |         |         ,--PROPPED/ACIDIZED FRACTURE HEIGHT
COM |         |         |         ,--FRACTURE OVERLAP AT BOTTOM
COM |         V         |         |         ,--PROPPANT GRAIN DENSITY
COM |       kg/lb       |         |         |  (default = 165.3 lb/ft3)
COM |         or        |         |         |         ,--SETTLED POROSITY
COM V       cm/in       V         V         V         |  (default = 0.40)
COM m         or        m         m       kg/m3       |         ,--PROP NUMBER
COM ft      m3/ft3      ft        ft      lb/ft3      V         V  (default=1)
COM -----|---------|---------|---------|---------|---------|----*
COM    50.0    24000.     100.       0.
COM   100.0    48000.     100.       0.
COM   162.5    78000.     100.       0.
   250.0   120000.    100.       0.
COM   350.0   168000.     100.       0.
COM   550.0   264000.     100.       0.
COM   750.0   360000.     100.       0.
COM -----|---------|---------|---------|---------|---------|----*
COM
COM                      *** A3 - RESERVOIR DATA ***
COM
```

```
COM
COM ,--FRACTURE OPENING AND CLOSURE PRESSURE
COM |         ,--DEPTH OF INVASION FOR FRAC FLUID FILTRATE
COM |         |         ,--MOBILITY OF THE FILTRATE
COM |         |         |         ,--IN-SITU WATER SATURATION
COM |         |         |         |         ,--RESIDUAL HYDROCARBON SATURATION
COM |         |         |         |         |
COM V         V         V         V         V
COM kPa/psi   m/ft      1/cp      fraction  fraction
COM -----|---------|---------|---------|---------|
   5180.0      0.00       0.4       0.1       0.3
COM -----|---------|---------|---------|---------|
COM
COM
COM        *** GROUP B - POST-CLOSURE FRAC DATA - PROPPED FRACS ***
COM
COM        (Read as many sets of GROUP B as there are proppant types )
COM
COM                  *** B1 - PROPPANT STRESS DATA ***
COM
COM                           *** CARD 1 ***
COM
COM       In this data, only the first 5 items are required if the prop size
COM       and type are in the StimLab data bank. Any of the 6 optional data
COM       items can be entered to modify the internal correlation coefficients.
COM       If the prop is not in the data bank, and the user enters ALL of the
COM       optional data, prop permeability will be still calculated by the
COM       StimLab correlation. In any other case, user must specify his own
COM       table under Card 2 below.
COM
COM ,--NCPR,NUMBER OF ENTRIES IN PERM. VS. STRESS TABLE FOR THIS PROP
COM |    (default=13 for table generated by Stim-Lab correlation)
COM |    ,--NTPR,NUMBER OF ENTRIES IN PERM RED. FACTOR VS. TIME FOR THIS PROP
COM |    |  ,--PROP SIZE (0816,1220,1020,1630,2040,4060,4070,100 or other)
COM |    |  |     ,--PROP TYPE (JORD,BRAD,COLO,RCSC,RCSP,HS  ,CBOL,LWT ,INTR,
COM |    |  |     |   CBHC,ULTR,BAUX,ARIZ,ENGL,ENDC,SAND,ISP,ISPL or other)
COM |    |  |     |      ,--DAMAGE FACTOR FOR FLUIDS (default = 1.)
COM |    |  |     |      |          ---------- Optional data --------------
COM |    |  |     |      |          ,--PROP MEAN DIAMETER (mm)
COM |    |  |     |      |          |         ,--PROP POROSITY (fraction)
COM |    |  |     |      |          |         |    ,--PROP SPEC.GRAVITY
COM |    |  |     |      |          |         |    |    ,--STD.DEV. OF PROP DIAM.
COM |    |  |     |      |          |         |    |    |   FROM SIEVE ANALYSIS
COM |    |  |     |      |          |         |    |    |    ,--COEFF a
COM |    |  |     |      |          |         |    |    |    |       ,--b
COM V    V  V     V      V          V         V    V    V    V       V
COM *----*|---||---|---------|---------|----|----|----|----|---------|
    4    0 INF  COND
COM *----*|---||---|---------|---------|----|----|----|----|---------|
COM
COM            *** CARD 2 - PERMEABILITY VS. STRESS TABLE ***
COM        (as many lines as no. of perm vs. stress entries NCPR dictates)
COM
COM            READ THIS TABLE ONLY IF DATA GIVEN IN CARD 1 IS NOT SUFFICIENT
COM                 TO USE STIMLAB CORRELATIONS
COM
COM ,--STRESS ON PROPPANT
COM |         ,--PROPPANT PERMEABILITY
COM |         |         ,--CROSSECTIONAL AREA REDUCTION FACTOR
COM |         |         |         ,--FRACTURE NON-DARCY FACTOR (OPTIONAL)
COM |         |         |         |         ,--'A' COEFFICIENT IN NON-DARCY
COM |         |         |         |         |    EQUATION (OPTIONAL)
COM |         |         |         |         |         ,-- 'B' COEFFICIENT IN
COM |         |         |         |         |         |    NON-DARCY EQUATION
COM |         |         |         V         V         |    (OPTIONAL)
COM V         V         V         1/m       1/m       V
COM kPa/psi   md        fraction  1/ft      1/ft      fraction
COM -----|---------|---------|---------|---------|---------|
 0.           10000000.  1.
 1000.        10000000.  1.
 2000.        10000000.  1.
 3000.        10000000.  1.
COM -----|---------|---------|---------|---------|---------|
COM
COM              *** B2 - PERM REDUCTION FACTOR VS TIME TABLE ***
```

```
COM          (as many lines as no. of perm vs. time entries dictates)
COM          (data not used unless permeability vs time switch on)
COM
COM ,--TIME SINCE FRACTURE WAS INITIATED
COM |          ,--PROPPANT PERMEABILITY REDUCTION FACTOR
COM V          |
COM days       V
COM -----|---------|
COM
COM -----|---------|
COM
COM   *** B3 - PLASTIC PERMEABILITY AND WIDTH REDUCTION MULTIPLIER ***
COM       (one value for this proppant if hysteresis is turned on)
COM
COM ,--PERMEABILITY AND WIDTH REDUCTION HYSTERESIS MULT (0 = full recovery)
COM |                                                    1 = no recovery)
COM V                                            0 < x < 1 = intermediate)
COM frac
COM -----|
COM
COM -----|
COM
COM          *** GROUP BC - POST-CLOSURE FRAC DATA - ACID FRACS ***
COM
COM                    *** BC1 - EMBEDMENT STRENGTH AND TABLE SIZE ***
COM
COM ,--EMBEDMENT STRENGTH OF THE ROCK
COM |          ,--NCPR, NO OF ENTRIES IN CONDUCTIVITY VS STRESS TABLE
COM |          |      0 = default: method of Nierode-Kruk
COM |          |     >0 = read table of reduction factor vs stress
COM |          |          ,--REDFNK, OVERALL REDUCTION FACTOR ON CONDUCTIVITY
COM V          |          |  (used only if NCPR = 0, default REDFNK = 1)
COM kPa/psia   V          V
COM -----|----*----*---------|
COM
COM -----|----*----*---------|
COM
COM                    *** BC2 - CONDUCTIVITY REDUCTION WITH STRESS ***
COM                         Read only if no of entries NCPR > 0
COM
COM ,--STRESS ON ACIDIZED FRACTURE
COM |          ,--REDUCTION FACTOR (MULTIPLIER ON CONDUCTIVITY AT 0 STRESS)
COM V          V
COM kPa/psi   (-)
COM -----|---------|
COM
COM -----|---------|
COM
COM                 *** GROUP C - DAMAGE AND CLEANUP DATA ***
COM
COM
COM ,--MULTIPLIER ON ABSOLUTE PERMEABILITY IN INVADED ZONE
COM |          ,--RATE OF CLEANUP FROM THE FRACTURE FACE
COM |          |          ,--RESIDUAL FILTRATE AS FRACTION OF ORIGINAL FILTRATE
COM |          |          |          ,--REL.PERM TO RES. FLUID AFTER CLEANUP
COM |          |          |          |  (if > 0, different method of cleanup
COM |          |          |          |   calc used-more suitable for gas wells)
COM V          V          V          V
COM frac   frac/d     fraction   frac
COM -----|---------|---------|---------|
 1.0       0.33      0.0
COM -----|---------|---------|---------|
END
```

APPENDIX C: Regression Input and Output for Polynomial Correction Term ("D")

```
--------------------------------------------------------------------------
COM |     ,--MIN POLYN. ORDER TO REGRESS ON
COM |    |    ,--MAX POLYN. ORDER
COM |    |    |    ,--IPRINT=PRINT CONTROL (0=MIN, 1=STATISTICS,2=DEBUG
COM |    |    |    |    ,--IPLOT=PLOT CONTROL (NOT OPERATIONAL)
COM |    |    |    |    |
COM |    |    |    |    |
COM V    V    V    V    V
COM *----*----*----*----*
  4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.0        10.0       50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   const for single frac.
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.0145     1.0154    1.02456    1.02551
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
   4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
   1.0        10.0       50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   first coeff for single frac.
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 -0.3402  -0.28221   -0.0604   -0.12067
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
   4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 1.0        10.0       50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   second coeff for single frac case
```

Truncated data points for better definition of the curve

```
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.6547   1.45279   0.80242   0.28579
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
   4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   third coeff for single frac. case
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 -1.3382  -1.194519  -0.77210  -0.43581
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM *----*----*----*----*
   4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   const for three fracs
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.0765    1.0750   1.08468   1.09129
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
   4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   first coeff for three fracs
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 -0.6257  -0.49958  -0.45557   -0.36809
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
```

```
  4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   second coeff for three frac case
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  2.4844   2.17410   1.92872   1.64925
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
   1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   third coeff for three frac. case
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 -1.9529  -1.76574  -1.57103  -1.38374
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   const for five fracs
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.14985  1.15907   1.16109   1.16505
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100.0
```

```
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   first coeff for five fracs
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 -1.9972  -1.81501  -1.78540   -1.63221
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 1.0        10.0      50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   second coeff for five frac case
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  5.42678  4.98758   4.78581   4.39686
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 1.0        10.0      50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   third coeff for five frac. case
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
 -3.60325  -3.3554  -3.18020  -2.94729
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
   1.0        10.0      50.0      100.0
COM -----|---------|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   const for seven frac. case
COM
COM -----|---------|---------|---------|---------|---------|---------|---------|-
  1.18036  1.18954   1.194576  1.198511
COM -----|---------|---------|---------|---------|---------|---------|---------|-
```

```
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
  1.0       10.0      50.0     100..0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   first coeff for seven frac case
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 -2.78339 -2.75009   -2.63573 -2.54422
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   second coeff for seven frac case
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 7.10939   6.96861   6.64846   6.39760
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM
COM *----*----*----*----*
    4    3    3    1    0
COM *----*----*----*----*
COM
COM   OBSERVED X- DATA
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 1.0       10.0      50.0     100.0
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM   OBSERVED Y- DATA   third coeff for seven frac. case
COM
COM -----|---------|---------|---------|---------|---------|---------|-
 -4.53225 -4.43217  -4.23024  -4.07408
COM -----|---------|---------|---------|---------|---------|---------|-
COM
COM
COM   REPEAT THE DATA SETS, STOP BY PUTTING M=0
COM
COM *----*----*----*----*
    0
```

```
      COM *----*----*----*----*
      COM
      END

 OLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

      X(I)          Y(I)

    1.00000       1.01450
   10.00000       1.01540
   50.00000       1.02456
  100.00000       1.02551

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =     1.0144514073

     B( 1)  =     0.0000429504
     B( 2)  =     0.0000056925
     B( 3)  =    -0.0000000502

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 0.1014E+01  0.1015E+01  0.1025E+01  0.1026E+01
 0.1014E+01  0.1015E+01  0.1025E+01  0.1026E+01

POLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

      X(I)          Y(I)

    1.00000      -0.34020
   10.00000      -0.28221
   50.00000      -0.06040
  100.00000      -0.12067

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =    -0.3465403581

     B( 1)  =     0.0063243354
     B( 2)  =     0.0000165952
     B( 3)  =    -0.0000005725

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.3402E+00 -0.2822E+00 -0.6040E-01 -0.1207E+00
```

2

```
-0.3402E+00 -0.2822E+00 -0.6040E-01 -0.1207E+00

POLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

      X(I)          Y(I)

    1.00000       1.65470
   10.00000       1.45279
   50.00000       0.80242
  100.00000       0.28579

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =     1.6786985908

     B( 1) =   -0.0241610835
     B( 2) =    0.0001631005
     B( 3) =   -0.0000006078

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 0.1655E+01  0.1453E+01  0.8024E+00  0.2858E+00
 0.1655E+01  0.1453E+01  0.8024E+00  0.2858E+00

POLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

      X(I)          Y(I)

    1.00000      -1.33820
   10.00000      -1.19452
   50.00000      -0.77210
  100.00000      -0.43581

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =    -1.3556092466

     B( 1) =    0.0175605521
     B( 2) =   -0.0001519891
     B( 3) =    0.0000006836

 OMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.1338E+01 -0.1195E+01 -0.7721E+00 -0.4358E+00
-0.1338E+01 -0.1195E+01 -0.7721E+00 -0.4358E+00
```

3

4

```
POLYNOMIAL REGRESSION, WITH M =              4 DATA POINTS

       X(I)          Y(I)

    1.00000       1.07650
   10.00000       1.07500
   50.00000       1:08468
  100.00000       1.09129

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =    3       MAX =    3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =     1.0767983515

     B( 1) =    -0.0003124857
     B( 2) =     0.0000142307
     B( 3) =    -0.0000000966

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 0.1076E+01  0.1075E+01  0.1085E+01  0.1091E+01
 0.1077E+01  0.1075E+01  0.1085E+01  0.1091E+01
```

5

```
POLYNOMIAL REGRESSION, WITH M =              4 DATA POINTS

       X(I)          Y(I)

    1.00000      -0.62570
   10.00000      -0.49958
   50.00000      -0.45557
  100.00000      -0.36809

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =    3       MAX =    3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =    -0.6437160671

     B( 1) =     0.0184436887
     B( 2) =    -0.0004303564
     B( 3) =     0.0000027348

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 ).6257E+00 -0.4996E+00 -0.4556E+00 -0.3681E+00
-0.6257E+00 -0.4996E+00 -0.4556E+00 -0.3681E+00
```

6

```
POLYNOMIAL REGRESSION, WITH M =              4 DATA POINTS
```

X(I)	Y(I)
1.00000	2.48440
10.00000	2.17410
50.00000	1.92872
100.00000	1.64925

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

7

S = 0.00000000
A = 2.5275529160

B(1) = -0.0440782457
B(2) = 0.0009311113
B(3) = -0.0000057816

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

0.2484E+01	0.2174E+01	0.1929E+01	0.1649E+01
0.2484E+01	0.2174E+01	0.1929E+01	0.1649E+01

POLYNOMIAL REGRESSION, WITH M = 4 DATA POINTS

X(I)	Y(I)
1.00000	-1.95290
10.00000	-1.76574
50.00000	-1.57103
100.00000	-1.38374

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

S = 0.00000000
A = -1.9785248713

8

B(1) = 0.0261393777
B(2) = -0.0005176639
B(3) = 0.0000031575

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.1953E+01	-0.1766E+01	-0.1571E+01	-0.1384E+01
-0.1953E+01	-0.1766E+01	-0.1571E+01	-0.1384E+01

POLYNOMIAL REGRESSION, WITH M = 4 DATA POINTS

X(I) Y(I)

```
  1.00000       1.14985
 10.00000       1.15907
 50.00000       1.16109
100.00000       1.16505

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =    3        MAX =    3

POLYNOMIAL REGRESSION OF ORDER N  =     3

     DET = 0.15439477E+20

     S =    0.00000000
     A =     1.1485247949

     B( 1) =     0.0013573211
     B( 2) =    -0.0000323200
     B( 3) =     0.0000002040

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 0.1150E+01  0.1159E+01  0.1161E+01  0.1165E+01
 0.1150E+01  0.1159E+01  0.1161E+01  0.1165E+01

POLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

       X(I)          Y(I)

  1.00000       -1.99720
 10.00000       -1.81501
 50.00000       -1.78540
100.00000       -1.63221

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =    3        MAX =    3

POLYNOMIAL REGRESSION OF ORDER N  =     3

     DET = 0.15439477E+20

     S =    0.00000000
     A =    -2.0235641571

     B( 1) =     0.0270190515
     B( 2) =    -0.0006591756
     B( 3) =     0.0000042812

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.1997E+01 -0.1815E+01 -0.1785E+01 -0.1632E+01
-0.1997E+01 -0.1815E+01 -0.1785E+01 -0.1632E+01

POLYNOMIAL REGRESSION, WITH M =            4 DATA POINTS

       X(I)          Y(I)

  1.00000        5.42678
 10.00000        4.98758
```

9

10

```
  50.00000      4.78581
 100.00000      4.39686

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =     5.4891731823

     B( 1) =   -0.0638457693
     B( 2) =    0.0014619138
     B( 3) =   -0.0000093269

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

 0.5427E+01  0.4988E+01  0.4786E+01  0.4397E+01
 0.5427E+01  0.4988E+01  0.4786E+01  0.4397E+01

POLYNOMIAL REGRESSION, WITH M =           4 DATA POINTS

      X(I)          Y(I)

   1.00000      -3.60325
  10.00000      -3.35540
  50.00000      -3.18020
 100.00000      -2.94729

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

     MIN =   3       MAX =   3

POLYNOMIAL REGRESSION OF ORDER N  =    3

     DET = 0.15439477E+20

     S =    0.00000000
     A =    -3.6379178266

     B( 1) =    0.0354287730
     B( 2) =   -0.0007657517
     B( 3) =    0.0000048053

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.3603E+01 -0.3355E+01 -0.3180E+01 -0.2947E+01
-0.3603E+01 -0.3355E+01 -0.3180E+01 -0.2947E+01

POLYNOMIAL REGRESSION, WITH M =           4 DATA POINTS

      X(I)          Y(I)

   1.00000       1.18036
  10.00000       1.18954
  50.00000       1.19458
 100.00000       1.19851
```

11

12

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

S = 0.00000000
A = 1.1790680231

13

B(1) = 0.0013209648
B(2) = -0.0000291669
B(3) = 0.0000001790

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

0.1180E+01	0.1190E+01	0.1195E+01	0.1199E+01
0.1180E+01	0.1190E+01	0.1195E+01	0.1199E+01

POLYNOMIAL REGRESSION, WITH M = 4 DATA POINTS

X(I)	Y(I)
1.00000	-2.78339
10.00000	-2.75009
50.00000	-2.63573
100.00000	-2.54422

HE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

S = 0.00000000
A = -2.7872905829

14

B(1) = 0.0039212202
B(2) = -0.0000206952
B(3) = 0.0000000579

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.2783E+01	-0.2750E+01	-0.2636E+01	-0.2544E+01
-0.2783E+01	-0.2750E+01	-0.2636E+01	-0.2544E+01

POLYNOMIAL REGRESSION, WITH M = 4 DATA POINTS

X(I)	Y(I)
1.00000	7.10939
10.00000	6.96861
50.00000	6.64846
100.00000	6.39760

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

S = 0.00000000
A = 7.1272108077

15

B(1) = -0.0180510606
B(2) = 0.0002314923
B(3) = -0.0000012394

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

0.7109E+01	0.6969E+01	0.6648E+01	0.6398E+01
0.7109E+01	0.6969E+01	0.6648E+01	0.6398E+01

POLYNOMIAL REGRESSION, WITH M = 4 DATA POINTS

X(I)	Y(I)
1.00000	-4.53225
10.00000	-4.43217
50.00000	-4.23024
100.00000	-4.07408

THE LOWEST AND HIGHEST ORDER POLYNOMIALS TO BE TRIED ARE

MIN = 3 MAX = 3

POLYNOMIAL REGRESSION OF ORDER N = 3

DET = 0.15439477E+20

S = 0.00000000
A = -4.5451269297

16

B(1) = 0.0130629786
B(2) = -0.0001870845
B(3) = 0.0000010356

COMPARISON OF COMPUTED AND INPUT VALUES OF Y

-0.4532E+01	-0.4432E+01	-0.4230E+01	-0.4074E+01
-0.4532E+01	-0.4432E+01	-0.4230E+01	-0.4074E+01

Appendix D: Economic Summaries for Example Problem

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:36:1
File: HORZ1

[------------------ CASE DESCRIPTION --------------------]

Horizontal well with one fracture

Royalty Regime:	ALBERTA	Gas Holiday:	NO
Reserve type:	PDP	Oil Holiday:	NO
Royalty Type:Crwn		Eval/Prod Start:	95- 1/95- 1
Reversion Pt:		Proj/Econ Life:	5.0/ 1.0 yrs

[------------- NET PRESENT VALUES (M$) --------------]

DISC RATE (%)	0.0	10.0	12.0	15.0	18.0	20.0
B.T. OPER INC	4373	4170	4132	4078	4026	3992
B.T. CAP INV.	2250	2145	2126	2098	2071	2054
B.T. CASH FLOW	2123	2025	2006	1980	1955	1938
A.T. OPER INC	2642	2519	2497	2464	2433	2412
A.T. CAP INV.	2250	2145	2126	2098	2071	2054
A.T. CASH FLOW	392	374	371	366	361	358

[-------- ECONOMIC INDICATORS --------]

		B.TAX	A.TAX
ROR	- PCNT	800.0	800.0
PAYOUT PERIOD	- EVAL	0.5	0.9
UNDISC PIR	- $/$	0.94	0.17
15.0 PCT PIR	- $/$	0.94	0.17
12.0 PCT PIR	- $/$	0.94	0.17
NPV @ 15.0	- $/Bbl	7.75	1.43
NPV @ 12.0	- $/Bbl	7.85	1.45

[---------- PRODUCTS RECOVERY -----------]

		GROSS	WI	ROY	NET
OIL	MSTB	256	256	70	186
GAS-RAW	MSCF	0	0		
GAS-SALES	MSCF	0	0	0	0
ETHANE	STB	0	0	0	0
PROPANE	STB	0	0	0	0
BUTANE	STB	0	0	0	0
PENTS+	STB	0	0	0	0
SULPHUR	LT	0	0	0	0
OTHER	STB	0	0	0	0

[-------- COMPANY W.I. -------]

	Init%	Finl%
REVENUE	100.0	100.0
FIELD CAP	100.0	100.0
PLANT CAP		
GATH CAP		
ORR-GAS		
ORR-OIL		
ROYALTY	27.3	0.0

[-- WI CASH FLOW SUMMARY --]

YEAR	OIL PRODUCTION RATE Bbl/D	OIL PRODUCTION VOL. MSTB	OIL PRODUCTION PRICE $/Bbl	TOTAL REV. M$	BURDENS M$	OPERATING EXPENSE M$	OPERATING EXPENSE $/Bbl	OPER INC. M$	NETBACK B.TAX $/Bbl	CAPTL INV. M$	B.TAX CASH M$	TOTAL TAX M$	AFTER TAX CASH M$	AFTER TAX 15.0% M$	AFTER TAX CUM M$
ZERO										0	0	0	0	0	0
1995	700	256	24.00	6132	1675	84	0.33	4373	17.12	2250	2123	1731	392	366	366
1996	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	366
1997	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	366
1998	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	366
1999	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	366
SUBT		256		6132	1675	84		4373		2250	2123	1731	392	366	
REM.		0		0	0	0		0		0	0	0	0	-0	
TOTL		256		6132	1675	84		4373		2250	2123	1731	392	366	
15.0% DISC				5718	1562	78		4078		2098	1980	1614	366		
% OF REV.				100	27	1		71		37	35	28	6		

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:36:1
File: HORZ1

Comment: Horizontal well with one fracture
Case Notes

Evaluation Begins in 1995 1
Production Begins in 1995 1
Discount date is 1995 1

Parameter File:

Parameter file name: param (NOT all parameters read each run)
SUNCOR PROJECT EVALUATION PARAMETERS
BASE CASE
July 1995

Discount Method: ANNUAL MID PERIOD

Default Escalation Rates

Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate
1991	0.00	0.00	0.00	1996	0.00	3.00	3.00	2001	0.00	3.00	3.00
1992	0.00	0.00	0.00	1997	0.00	3.00	3.00	2002	0.00	3.00	3.00
1993	0.00	0.00	0.00	1998	0.00	3.00	3.00	2003	0.00	3.00	3.00
1994	0.00	0.00	0.00	1999	0.00	3.00	3.00	2004	0.00	3.00	3.00
1995	0.00	3.00	3.00	2000	0.00	3.00	3.00	2005	0.00	3.00	3.00

Case Parameters:

Category: PDP

Production:

Price Files Used:

Royalties:

Oil for royalties is 100 % new in first year.

Alberta light oil par price files used: PAR95B1
Alberta old oil select price file used: ABOLD95S
Alberta new light oil select price file used: ABLG95S

Capital:

Capital Comments:

Constant dollar year for capital comments is 1995.

1995 Development	investment of	1600 M$:	D&C intangible	Delay 1995 years
1995 Tangibles	investment of	400 M$:	D&C tangible	Delay 1995 years
1995 Development	investment of	250 M$:	single frac	Delay 1995 years

Tax Data:

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:51:3
File: HORZ3

[------------------ CASE DESCRIPTION --------------------]

Horizontal well with three fractures

Royalty Regime: ALBERTA   Gas Holiday: NO
Reserve type: PDP   Oil Holiday: NO
Royalty Type:Crwn   Eval/Prod Start: 95- 1/95- 1
Reversion Pt: Proj/Econ Life: 5.0/ 1.0 yrs

[------------- NET PRESENT VALUES (M$) ---------------]

DISC RATE (%)	0.0	10.0	12.0	15.0	18.0	20.0
B.T. OPER INC	10642	10146	10055	9923	9796	9714
B.T. CAP INV.	2750	2622	2599	2564	2532	2510
B.T. CASH FLOW	7892	7524	7457	7359	7265	7204
A.T. OPER INC	6109	5825	5772	5697	5624	5577
A.T. CAP INV.	2750	2622	2599	2564	2532	2510
A.T. CASH FLOW	3359	3203	3174	3132	3092	3066

[-------- ECONOMIC INDICATORS --------]

		B.TAX	A.TAX
ROR	- PCNT	800.0	800.0
PAYOUT PERIOD	- EVAL	0.3	0.5
UNDISC PIR	- $/$	2.87	1.22
15.0 PCT PIR	- $/$	2.87	1.22
12.0 PCT PIR	- $/$	2.87	1.22
NPV @ 15.0	- $/Bbl	11.91	5.07
NPV @ 12.0	- $/Bbl	12.07	5.14

[---------- PRODUCTS RECOVERY -----------]

		GROSS	WI	ROY	NET
OIL	MSTB	618	618	171	447
GAS-RAW	MSCF	0	0		
GAS-SALES	MSCF	0	0	0	0
ETHANE	STB	0	0	0	0
PROPANE	STB	0	0	0	0
BUTANE	STB	0	0	0	0
PENTS+	STB	0	0	0	0
SULPHUR	LT	0	0	0	0
OTHER	STB	0	0	0	0

[-------- COMPANY W.I. -------]

	Init%	Finl%
REVENUE	100.0	100.0
FIELD CAP	100.0	100.0
PLANT CAP		
GATH CAP		
ORR-GAS		
ORR-OIL		
ROYALTY	27.7	0.0

[-- WI CASH FLOW SUMMARY ---]

YEAR	[----OIL PRODUCTION--]			TOTAL	BURDENS	--OPERATING---		OPER	NETBACK	CAPTL	B.TAX	TOTAL	[----AFTER TAX-----]		
	RATE	VOL.	PRICE	REV.		EXPENSE		INC.	B.TAX	INV.	CASH	TAX	CASH	15.0%	CUM
	Bbl/D	MSTB	$/Bbl	M$	M$	M$	$/Bbl	M$	$/Bbl	M$	M$	M$	M$	M$	M$
ZERO										0	0	0	0	0	0
1995	1693	618	24.00	14831	4105	84	0.14	10642	17.22	2750	7892	4533	3359	3132	3132
1996	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	3132
1997	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	3132
1998	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	3132
1999	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	3132
SUBT		618		14831	4105	84		10642		2750	7892	4533	3359	3132	
REM.		0		0	0	0		0		0	0	0	0	0	
TOTL		618		14831	4105	84		10642		2750	7892	4533	3359	3132	
15.0% DISC				13830	3828	78		9923		2564	7359	4227	3132		
% OF REV.				100	28	1		72		19	53	31	23		

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:51:4
File: HORZ3

Comment: Horizontal well with three fractures
Case Notes

Evaluation Begins in 1995 1
Production Begins in 1995 1
Discount date is 1995 1

Parameter File:

Parameter file name: param (NOT all parameters read each run)
SUNCOR PROJECT EVALUATION PARAMETERS
BASE CASE
July 1995

Discount Method: ANNUAL MID PERIOD

Default Escalation Rates

Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate
1991	0.00	0.00	0.00	1996	0.00	3.00	3.00	2001	0.00	3.00	3.00
1992	0.00	0.00	0.00	1997	0.00	3.00	3.00	2002	0.00	3.00	3.00
1993	0.00	0.00	0.00	1998	0.00	3.00	3.00	2003	0.00	3.00	3.00
1994	0.00	0.00	0.00	1999	0.00	3.00	3.00	2004	0.00	3.00	3.00
1995	0.00	3.00	3.00	2000	0.00	3.00	3.00	2005	0.00	3.00	3.00

Case Parameters:

Category: PDP

Production:

Price Files Used:

Royalties:

Oil for royalties is 100 % new in first year.

Alberta light oil par price files used: PAR95B1
Alberta old oil select price file used: ABOLD95S
Alberta new light oil select price file used: ABLG95S

Capital:

Capital Comments:

Constant dollar year for capital comments is 1995.

1995 Development	investment of	1600 M$:	D&C intangible	Delay 1995 years
1995 Tangibles	investment of	400 M$:	D&C tangible	Delay 1995 years
1995 Development	investment of	750 M$:	three frac	Delay 1995 years

Tax Data:

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:38:4
File: HORZS

CASE DESCRIPTION

Horizontal well with five fractures

Royalty Regime: ALBERTA — Gas Holiday: NO
Reserve type: PDP — Oil Holiday: NO
Royalty Type:Crwn — Eval/Prod Start: 95- 1/95- 1
Reversion Pt: — Proj/Econ Life: 5.0/ 1.0 yrs

NET PRESENT VALUES (M$)

DISC RATE (%)	0.0	10.0	12.0	15.0	18.0	20.0
B.T. OPER INC	18507	17646	17487	17258	17037	16894
B.T. CAP INV.	3250	3099	3071	3031	2992	2967
B.T. CASH FLOW	15257	14547	14416	14227	14045	13928
A.T. OPER INC	10441	9955	9866	9737	9612	9532
A.T. CAP INV.	3250	3099	3071	3031	2992	2967
A.T. CASH FLOW	7191	6857	6795	6706	6620	6565

ECONOMIC INDICATORS

		B.TAX	A.TAX
ROR	- PCNT	800.0	800.0
PAYOUT PERIOD	- EVAL	0.2	0.3
UNDISC PIR	- $/$	4.69	2.21
15.0 PCT PIR	- $/$	4.69	2.21
12.0 PCT PIR	- $/$	4.69	2.21
NPV @ 15.0	- $/Bbl	13.26	6.25
NPV @ 12.0	- $/Bbl	13.44	6.33

PRODUCTS RECOVERY

		GROSS	WI	ROY	NET
OIL	MSTB	1073	1073	298	775
GAS-RAW	MSCF	0	0		
GAS-SALES	MSCF	0	0	0	0
ETHANE	STB	0	0	0	0
PROPANE	STB	0	0	0	0
BUTANE	STB	0	0	0	0
PENTS+	STB	0	0	0	0
SULPHUR	LT	0	0	0	0
OTHER	STB	0	0	0	0

COMPANY W.I.

	Init%	Finl%
REVENUE	100.0	100.0
FIELD CAP	100.0	100.0
PLANT CAP		
GATH CAP		
ORR-GAS		
ORR-OIL		
ROYALTY	27.8	0.0

WI CASH FLOW SUMMARY

YEAR	OIL PRODUCTION RATE Bbl/D	VOL. MSTB	PRICE $/Bbl	TOTAL REV. M$	BURDENS M$	OPERATING EXPENSE M$	$/Bbl	OPER INC. M$	NETBACK B.TAX $/Bbl	CAPTL INV. M$	B.TAX CASH M$	TOTAL TAX M$	AFTER TAX CASH M$	15.0% M$	CUM M$
ZERO										0	0	0	0	0	0
1995	2939	1073	24.00	25746	7155	84	0.08	18507	17.25	3250	15257	8066	7191	6706	6706
1996	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	6706
1997	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	6706
1998	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	6706
1999	0	0	0.00	0	0	0	0.00	0	0.00	0	0	0	0	0	6706
SUBT		1073		25746	7155	84		18507		3250	15257	8066	7191	6706	
REM.		0		0	0	0		0		0	0	0	0	0	
TOTL		1073		25746	7155	84		18507		3250	15257	8066	7191	6706	
15.0% DISC				24008	6672	78		17258		3031	14227	7521	6706		
% OF REV.				100	28	0		72		13	59	31	28		

PETROLEUM ECONOMICS EVALUATION PROGRAM

Version: Rel 7.7.1c
Time: 95/08/27 01:38:4
File: HORZS

Comment: Horizontal well with five fractures
Case Notes

Evaluation Begins in 1995 1
Production Begins in 1995 1
Discount date is 1995 1

Parameter File:

Parameter file name: param (NOT all parameters read each run)
SUNCOR PROJECT EVALUATION PARAMETERS
BASE CASE
July 1995

Discount Method: ANNUAL MID PERIOD

Default Escalation Rates

Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate	Year	Rev. Rate	Opc. Rate	Cap. Rate
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1992	0.00	0.00	0.00	1997	0.00	3.00	3.00	2002	0.00	3.00	3.00
1993	0.00	0.00	0.00	1998	0.00	3.00	3.00	2003	0.00	3.00	3.00
1994	0.00	0.00	0.00	1999	0.00	3.00	3.00	2004	0.00	3.00	3.00
1995	0.00	3.00	3.00	2000	0.00	3.00	3.00	2005	0.00	3.00	3.00

Case Parameters:

Category: PDP

Production:

Price Files Used:

Royalties:

Oil for royalties is 100 % new in first year.

Alberta light oil par price files used: PAR95B1
Alberta old oil select price file used: ABOLD95S
Alberta new light oil select price file used: ABLG95S

Capital:

Capital Comments:

Constant dollar year for capital comments is 1995.

1995 Development	investment of	1600 M$: D&C intangible	Delay 1995 years
1995 Tangibles	investment of	400 M$: D&C tangible	Delay 1995 years
1995 Development	investment of	1250 M$: five fracs	Delay 1995 years

Tax Data: