DEPARTMENT OF MINES AND ENERGY

GEOLOGICAL SURVEY

SOUTH AUSTRALIA

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ESTIMATING RECOVERY FACTORS IN A HETERGOENEOUS GAS RESERVOIR USING A TANK MODEL

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Tank model simulations have shown that regardless of the permeability, if a gas saturated sand is sufficiently thick it is capable of gas recovery. The extent of recovery is dependent on the sand thickness, degree of stimulation via hydraulic fracturing and the minimum economic production rate per well. The minimum permeability thickness (kh) required to attain economic gas recovery was calculated to be 3.0 md-ft.

RFT data has shown significant depletion in otherwise non- productive Cooper Basin wells of low kh. Computer modelling has shown that such depletion is a result of drainage from adjacent wells of higher kh. The degree of depletion is related to the magnitude of the higher kh, the ratio of the khs in adjacent wells and the relative proportion of higher kh to lower kh in between wells.

INTRODUCTION

It is difficult to predict the recovery factor for reservoirs of varying permeability. This is because low permeability zones have a lower recovery than those of higher permeability. The recovery from low permeability zones is dependent not only upon the wellbore intersection but also upon the degree of communication with zones of higher perme- ability. This introduces a level of complexity greater than that normally assumed in calculating recovery factors based on the average reservoir pressure at abandonment. This study determines a method for estimating recovery factors in gas bearing reservoirs of varying permeability.

RECOVERY RELATED TO KH

The Cooper Basin tight gas study by Malavazos, 1991, categorises recoverable gas into various ranges of permeability. That is:

Commercial Gas: found in sands with $k > 1$ md (porosity > 10%). The gas is free flowing, and will achieve high recovery with compression alone;

Tight Gas: found in sands with $0.1 < k < 1.0$ md (7 to 10% porosity) and will only achieve recovery if fracture stimulated or if in contact with higher permeability sands; and,

Very Tight Gas: found in sands with $k < 0.1$ md (porosity less than 7%) and will achieve no recovery regardless of whether it is fracture stimulated or in communication with higher permeability sands.

This study shows that the important parameter to gas recovery is permeability thickness, kh, rather than permeability alone. Tank model runs have shown that regardless of the permeability, if the sand is sufficiently thick it is capable of gas production. For example, even sand layers with permeabilities less than 0.1 md would achieve gas recovery providing the total kh is greater than 2.50 md-ft (Tables 1 to 3), i.e thickness in excess of 25 feet.

Recovery also depends on reservoir abandonment pressure and this is determined by the minimum economic production rate at which a well can be produced (Appendix #2). For each value of kh the ultimate recovery factor was estimated at abandonment rates of 0.5, 0.3, 0.2 and 0.1 MMscfd (Figures 1 to 3).

COMPUTER MODELLING

For various values of kh, ranging from 1 md-ft to 100,000 md- ft, the recovery was modelled using a computer model, DELIV, which has been designed to predict gas well deliverability and field production schedules. The input data consists of parameters used in the calculation of gas-in-place and the results of well tests. The program models the radial flow of gas in a 'Tank' reservoir as constrained by the tubing string, gathering system and compression facilities.

The following paramters were entered into DELIV:

1) initial line pressure of 1100 psig with compressor restaging to 800 and 200 psig,

2) DELIV was run with three values of skin to reflect varing degrees of fracture stimulation effectiveness:
 0.0 skin - no stimulation
 -2.5 skin - average stimulation
 -5.0 skin - extensive stimulation,

3) permeability of 1 md was entered into the model and the h was varied to attain the various values of kh in Tables 1 to 3,

4) OGIP of 10 Bcf per well,

5) average gas composition,

6) average sand porosity of 15%,

7) average water saturation (Sw) of 30%, and

8) initial reservoir pressure of 3000 psi.

Gas recovery is dependent on the abandonment pressure which is sensitive to the line pressure, reservoir permeability and wellbore skin.

MODELLING KH HETEROGENEITY AWAY FROM WELLBORE

Interpretation of Cooper Basin RFT data shows significant depletion in non-productive wells. This was investigated by using the steady - state flow equation to model the pressure profile at the well abandonment rate in a reservoir where the kh decreases at various distances between wells. Three increments were used: 10%, 50% and 90% of the distance between wells.

The steady-state, flow equation is:

$$P_1^2 - P_2^2 = 1.424\mu z_{avg} T_f q_g LN(r_1/r_2)/(kh)$$

$$+ 3.161E\text{-}12\beta\Gamma q_g z_{avg} T_f (1/r_2 - 1/r_1)/h^2$$

where:

P_1 = reservoir pressure at any distance r_1 from the wellbore, psi

P_2 = reservoir pressure at any distance r_2 from the wellbore, psi

μ) = gas viscosity, centipoise

z_{avg}= average gas deviation factor

T_f = average reservoir temperature, ^oR

q_g = gas rate at well, Mscfd

r_1,r_2 = distance from wellbore, ft

k = reservoir permeability, darcies

h = pay thickness, ft

β = turbulence factor, ft^{-1}

Γ = gas specific gravity.

The second part of the equation accounts for the turbulent gas flow effects at the wellbore. In the modelling carried out turbulence was assumed to be negligible.

Figure 4 shows the pressure profile at an abandonment rate of 0.2 MMscfd in homogenous reservoirs of various kh. This illustrates that the higher the kh the lower the average reservoir pressure at abandonment. The affect on the pressure profile of kh changing away from the wellbore was investigated. Examples of this affect are presented for cases where the kh is reduced from 100 md-ft down to 2 and 20 md-ft, respectively, at a distance of 1000, 2000, 3000 and 5000 feet from the wellbore (figures 5 & 6). These profiles indicate that the pressure in the lower permeability section will be drawn down substantially more as a result of an adjacent well producing from a zone of higher permeability. The broader the extent of the higher permeability zone the greater the pressure drawdown in the lower kh zone.

The affect on the gas recovery in the lower kh region was modelled by reducing the permeability thickness (kh) at 90%, 50% and 10% of the distance between wells. This is illustrated in figure 7, where the higher kh region is represented by KH1, and is intercepted by well #1 and the lower kh region is represented by KH2, intercepted by well #2. For each of these cases, at the abandonment of well #1, the pressure at well #2 was estimated from the pressure profile between both wells as calculated from the steady-state flow equation. Assuming the pressure at well #2 represents the average reservoir pressure, the recovery factors for various ratios of kh1/kh2 were calculated. These have been reported as a percentage of the recovery factor at well #2 calculated for the case in which the reservoir consists of kh1 permeability thickness only (Tables 4 to 6).

It should be noted that these results are independent of the scale of the system. i.e. the same recovery factors are calculated for a system for which the wells are 100 feet apart or, for a system for which the wells are 10000 feet apart. This is evident from the steady-state equation where the pressure difference between any two points in the reservoir is a function of the ratio of their distance from the wellbore.

This method for modelling the change in recovery factor in the radial direction is only approximate because of the difficulty in predicting reservoir heterogeneity away from the wellbore. However it is expected that recoverable gas calculated using this method will be more accurate than the current practice of estimating an average field wide recovery factor.

EXAMPLE OF RECOVERY FACTOR ESTIMATION

Using Tables 1 to 6 it is possible to estimate gas recovery in a heterogeneous reservoir as follows:

1) Calculate the kh from DST data or in its absence log porosity data for each well in the field;
2) Read the recovery factor for each well from tables 1 to 3; and
3) Calculate the recovery in the lower kh zones (kh2) from the recovery factors in the higher kh zones (kh1) using Tables 4 to 6.

The method for estimating the gas recovery in a heterogeneous reservoir can be illustrated by the following example. Consider the case where the kh changes at 50% of the distance between wells. In this example, wells #1 and #2 have the following properties from which their corresponding recoveries are calculated.

<u>Well #1:</u> (Higher kh zone)
kh1: 250 md-ft
Skin: 0
Abandonment Rate: 0.2 MMscfd
Recovery at well #1: 87% (Table 1)

<u>Well #2:</u> (Lower kh zone)
kh2: 50 md-ft
Skin: 0
Abandonment Rate: 0.2 MMscfd
Recovery at well #2: 79% (Table 1)

However, the recovery factor at well #1 will influence the recovery at well #2. From Table 5 (kh1=250 md-ft and kh1/kh2= 5/1), the recovery at well #2 would be 96% of the recovery at well #1, therefore:

Recovery in lower kh zone at well #2 (0.96*87%) = 83.5%

REFERENCES

Michael Malavazos, April 1991, "Tight Gas Definition and Reservoir Selection Criteria", South Australian Department of Mines and Energy, Rept Bk No. 91/50.

L.P. Dake, Elsevier, 1978, Fundamentals of Reservoir Engineering.

Chi U. Ikoku, Wiley, 1984, Natural Gas Reservoir Engineering.

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Minimum Economic Gas Rate

The cutoff gas flow rate is regarded as the minimum production rate required to meet the well's operating costs, including its share of the satellite and compression costs. Drilling, completion, connection and flow line capital costs are assumed sunk and it is assumed that the well is only required to meet operating costs. Examples of such calculations are shown in Tables #1 and #2.

During the latter part of the well's life, tubing or flowlines may need to be replaced or additional compression installed to maintain the well online. The extra production due to these late workovers may not be sufficient to pay back the additional expenditure. Therefore, wells may have to be abandoned at higher rates if too much additional CAPEX is required in the latter part of their life to keep them online.

The minimum economic rate for a well has been estimated to be 0.20 MMscfd and 0.10 MMscfd for dry and wet gas fields, respectively. These assume that no additional CAPEX is required in the latter life of the wells to maintain them online. However, chances that such expenditure will occur is believed to be high and that it is more likely that wells will be abandoned at higher rates such as 0.5 MMscfd due to tubing/flowline corrosion, liquid holdup or lack of compression.

Therefore the following abandonment rates and their associated probability of occurrence for the dry and wet gas fields are assumed:

Abandonment Rate (MMscfd) Dry field	Wet field	Probability of occurrence
0.50	0.50	
0.30	0.30	50%
0.20	0.10	10%

Gas Recovery at various Cutoff Rates

no well stimulation (o skin)

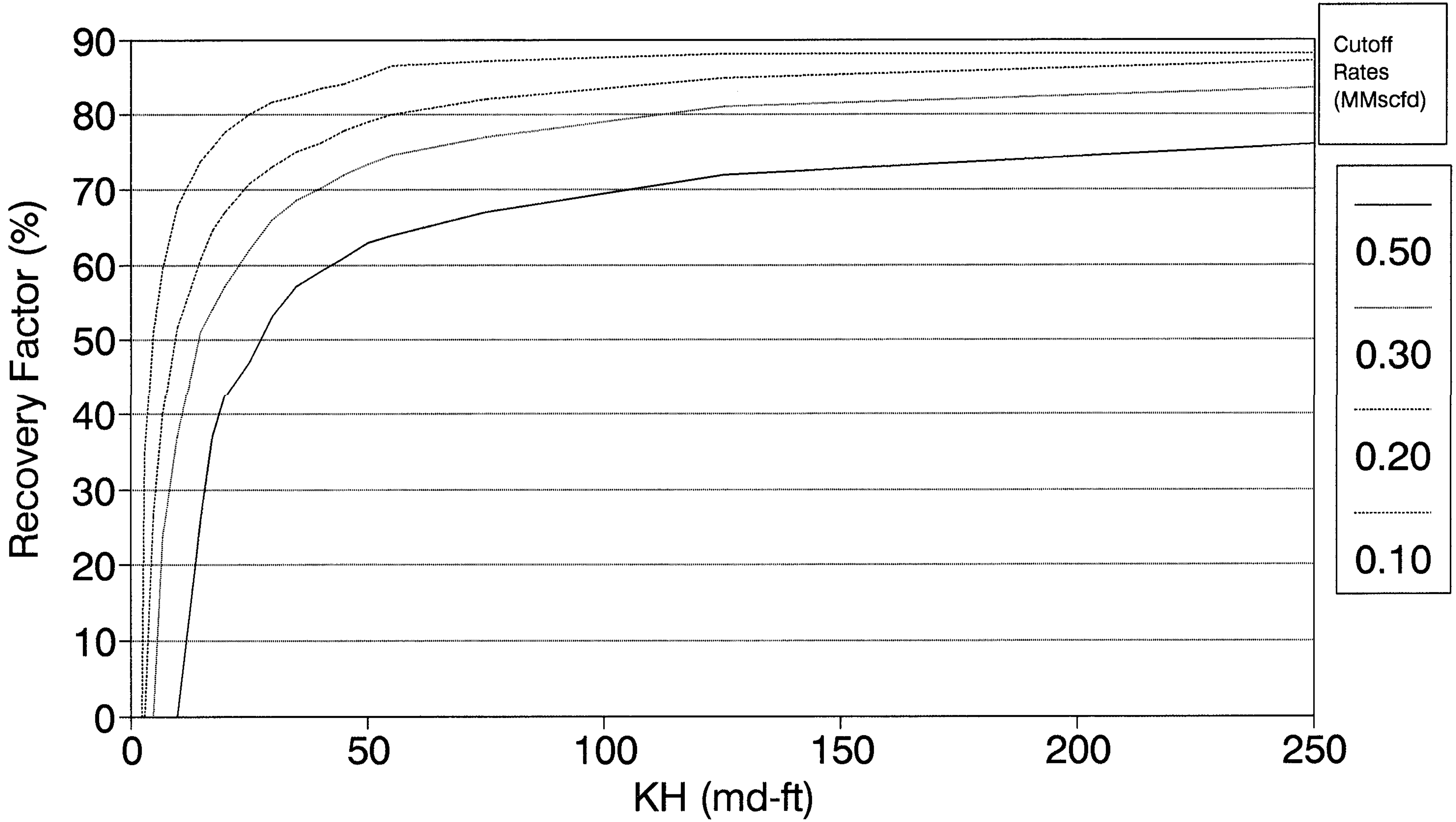

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Figure...1

Gas Recovery at various Cutoff Rates

well stimulation (-2.5 skin)

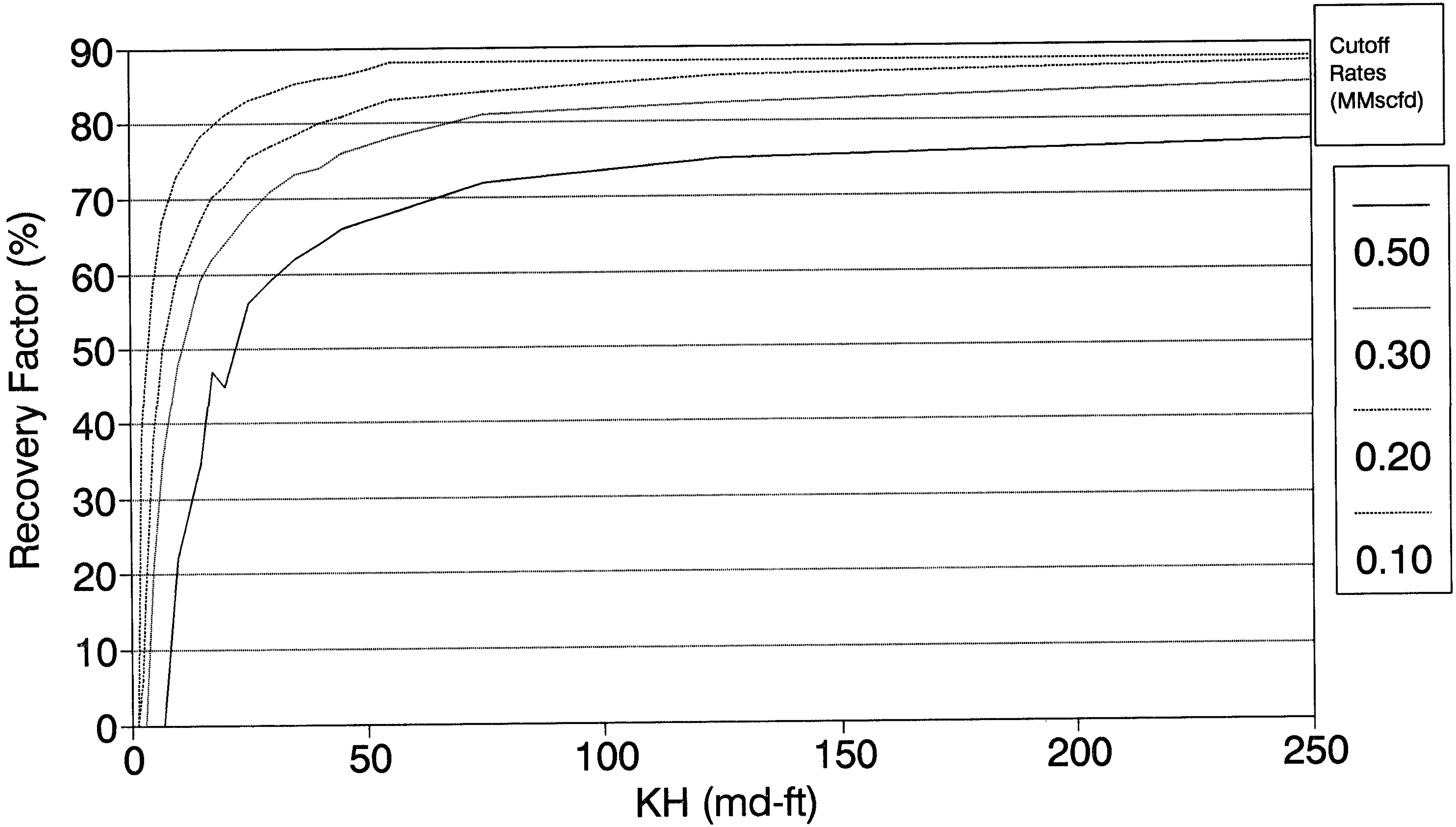

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Figure...2

Gas Recovery at various Cutoff Rates

well stimulation (-5.0 skin)

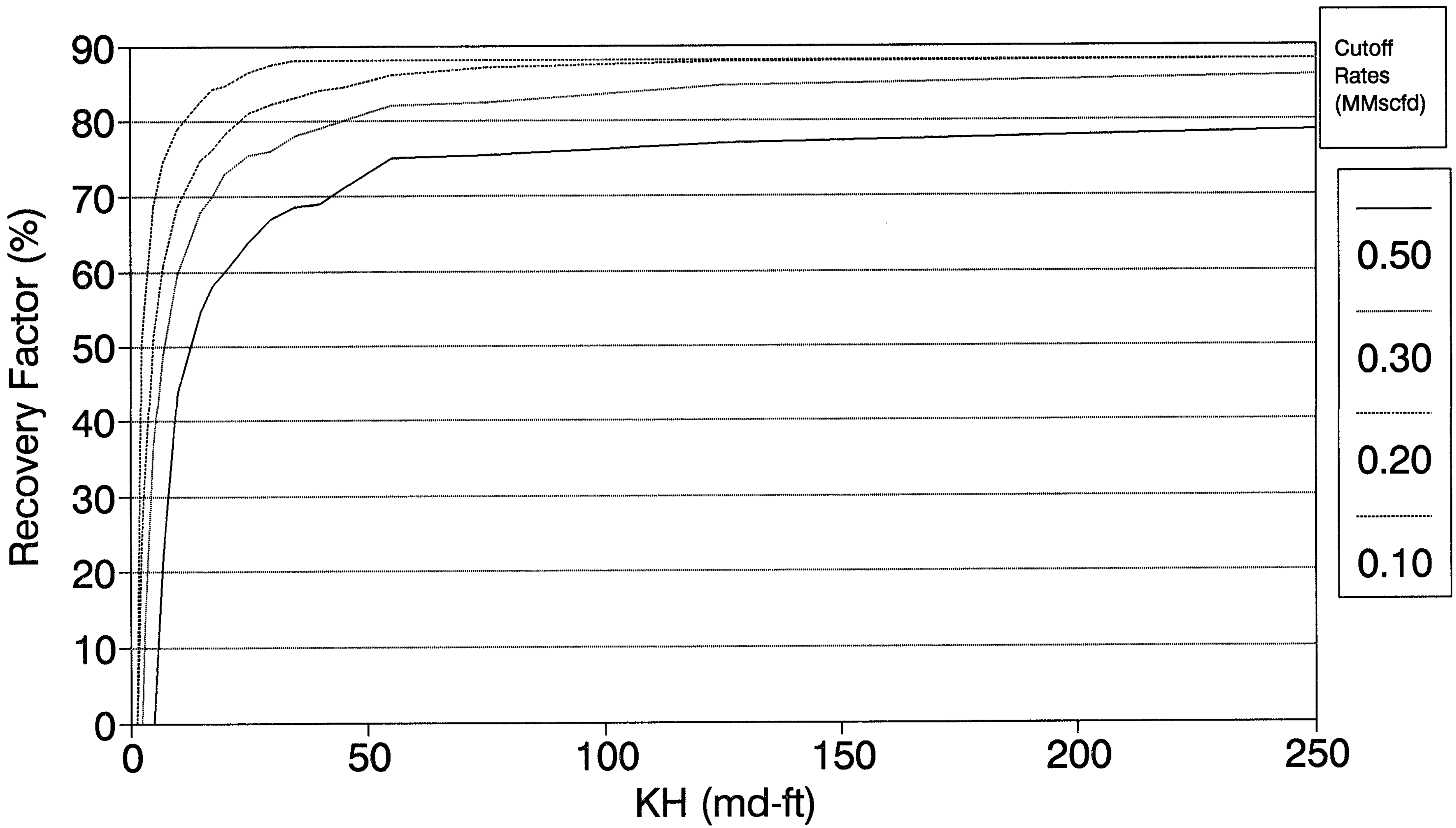

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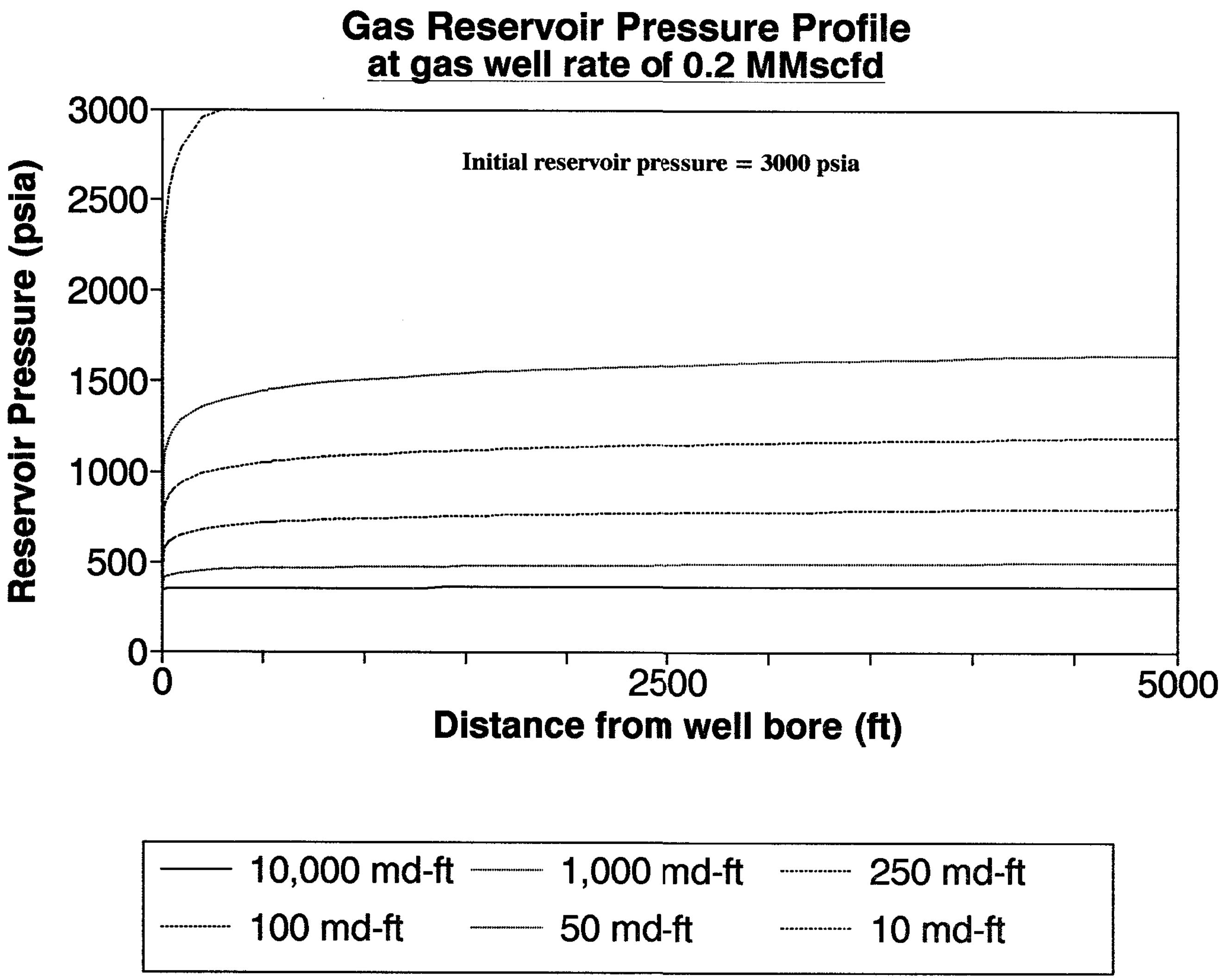
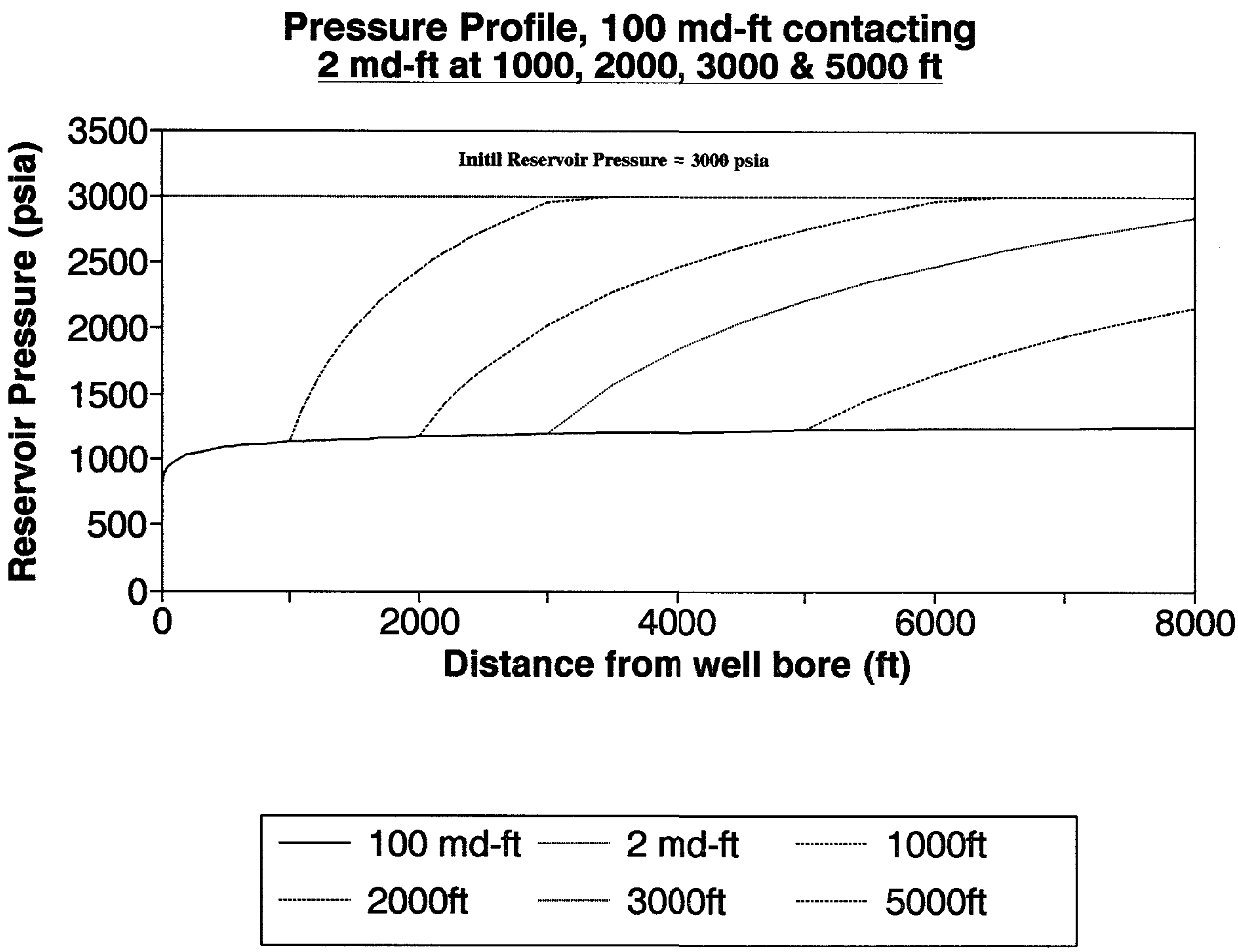
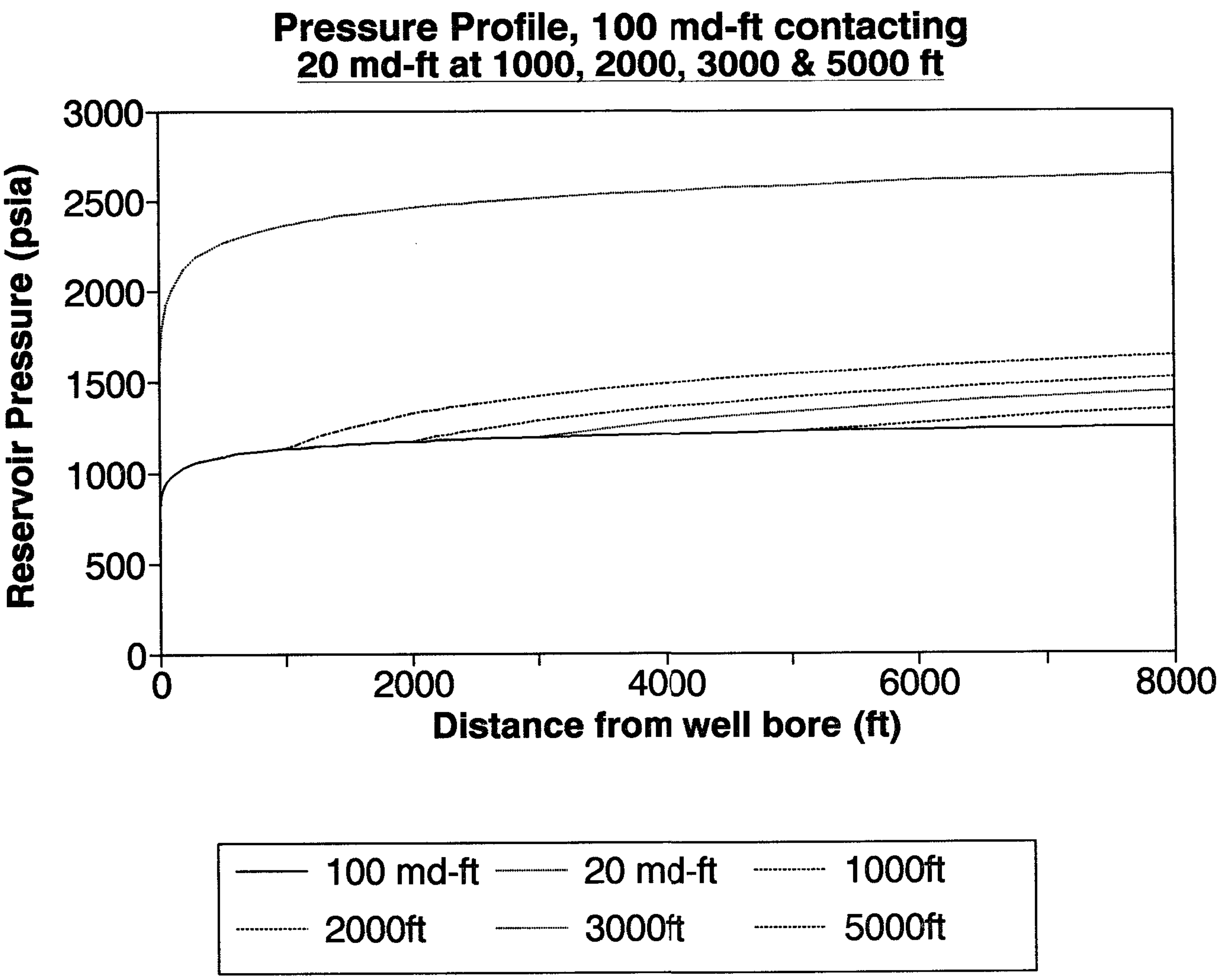
Figure...3


Gas Reservoir Pressure Profile
at gas well rate of 0.2 MMscfd
Initial reservoir pressure = 3000 psia
Reservoir Pressure (psia)
3000
2500
2000
1500
1000
500
0
2500
5000
Distance from well bore (ft)
10,000 md-ft
1,000 md-ft
250 md-ft
100 md-ft
50 md-ft
10 md-ft



Pressure Profile, 100 md-ft contacting
2 md-ft at 1000, 2000, 3000 & 5000 ft
Initil Reservoir Pressure = 3000 psia
Reservoir Pressure (psia)
3500
3000
2500
2000
1500
1000
500
0
2000
4000
6000
8000
Distance from well bore (ft)
100 md-ft
2 md-ft
1000ft
2000ft
3000ft
5000ft


Pressure Profile, 100 md-ft contacting
20 md-ft at 1000, 2000, 3000 & 5000 ft
Reservoir Pressure (psia)
3000
2500
2000
1500
1000
500
0
0
2000
4000
6000
8000
Distance from well bore (ft)
100 md-ft
20 md-ft
1000ft
2000ft
3000ft
5000ft

Diagramatic Representations of kh variation
away from the wellbore

KH1 = higher kh region