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THE COMPARATIVE ECONOMICS OF THERMAL RECOVERY PROJECTS

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ABSTRACT

In 1980, Williams, *et al.*, developed a model for the economic evaluation of steam floods and in-situ combustion recovery projects. This study augments that work.

The purpose of this study is twofold. First, an attempt to predict the oil recoveries for the two thermal recovery methods was made. The Marx and Langenheim model was used to determine the ultimate oil recovery in a steam-injection project, while the Gates and Ramey oil recovered volume burned model was used to determine the oil recovery in an in-situ combustion project. Second, an economic analysis using the Monte-Carlo simulation technique was done for both methods. A discounted net present value was obtained from the oil recovery schedules to facilitate comparison between the two thermal methods. It was found that both methods are economically competitive.

1. INTRODUCTION

One of the critical problems facing the petroleum industry is enhancing the percentage of original oil-in-place that is ultimately recovered. Primary recoveries are usually on the order of one-sixth to one-quarter of the oil-in-place, while some heavy oil reservoirs (such as exist in California) rarely go beyond five to ten percent. A number of secondary and tertiary enhanced oil recovery mechanisms have been tried, with varying degrees of success. One of the most successful techniques, thermal recovery, is now in its third decade of commercial use.

Thermal oil recovery has been defined as a process that intentionally introduces heat into a reservoir in order to enhance the ultimate recovery of the oil, primarily by reducing the viscosity, and thus increasing the mobility, of the oil (Prats, 1982). There are two dominant processes: steam injection and in-situ combustion. Steam injection, or steam flooding, introduces heat into the reservoir via surface-generated steam. In-situ combustion, on the other hand, generates heat in the reservoir by injecting air (or a gas mixture), causing the partial burning of the residual hydrocarbons.

The economic measure of any enhanced recovery method is in its cost-effectiveness. While both steam injection and in-situ combustion will enhance ultimate recovery, the contrasting natures of the two processes entails greatly different costs and cost-patterns. Steam injection is more energy intensive--water must be heated at the surface to generate high-quality steam, necessitating the use of steam generators with their attendant fuel, feed-water treatment, maintenance, and operating costs. There are also heat losses accompanying the entire operation: in the generator, in the surface lines, in the wellbore, and to adjacent rock formations from the heated reservoir. In contrast, in-situ combustion requires the treatment and compression of the injected air. In general, in-situ combustion projects require higher initial capital costs but lower operating costs than steam floods. A recent study by Gates (1979) concluded that the energy requirements per barrel of oil produced from typical California heavy oil operations are two or more times greater for steam injection than for in-situ combustion.

One factor that previous studies have not taken into account is the volatility in the market price of the oil. The recent precipitous drop in oil prices (approximately 50%) is sure to have a great effect on the economics of any enhanced recovery method. It can no longer be assumed that the future price of oil will be relatively stable, much less gradually increasing. This study will take a closer look at the price of oil by incorporating the great uncertainty of this parameter into the economic cash flow calculation.

The comparative economics of steam injection vs. in-situ combustion must be reexamined in the light of recent technical and economic reports. This study attempts to dispel some misconceptions and confusion surrounding the two thermal recovery processes, and presents a general method for comparing the two mechanisms that is easily altered to suit specific field cases.

3. LITERATURE SURVEY

Thermal recovery techniques dominate the available enhanced oil recovery technologies--thermal processes accounted for nearly 80 percent of the total in the United States in 1980 (Matheny, 1980). This was despite the recovery via these techniques of only about 10 percent of the heavy oil (less than 20 degrees API) in California at that time (Colman and Standley, 1979). In addition, recent estimates by the Department of Energy report some 19 billion barrels of oil potentially recoverable nationwide through thermal methods (Johnson, 1982). However, it must be kept in mind that nearly all reserve estimates will vary with the price of oil and the costs of production. In light of the recent fall in oil prices, the amount of oil economically recoverable through thermal processes is sure to be less than previously estimated.

Thermal enhanced oil recovery methods have been shown to be viable, both from a technological and an economical viewpoint. There are two broad classes of commerically useful thermal techniques: first, the injection of a heated fluid into the reservoir--a category which includes hot water flooding as well as both continuous and cyclic steam injection; and second, in-situ combustion, including both dry and wet forward combustion. Prats (1982) has a complete review of these and other thermal recovery methods.

There are many factors that determine the feasibility of a thermal recovery project; some of these are constraints of an economic, technical or regulatory nature. Examples include the starting and operating capital costs, the transportation and refining capacity available, and environmental controls; further examples are given by Williams, *et al.* (1980). An analysis of these is an involved process beyond the scope of this report. However, one factor vital to this decision is the choice of the thermal oil recovery technique. Williams, *et al.*, recommends that the selection be based on an optimal recovery schedule and an estimated cash flow generated by the production schedule. It can be argued that the selection of a method should be based upon optimization of the economics, which may or may not coincide with optimization of the recovery schedule. However, this study will maintain the separation of the economic and production schedules to keep its general usefulness. The choice of whether to optimize the economics, and, if so, which economic parameter to optimize, will be left to others.

A number of methods have been presented in the literature to calculate oil recovery for both hot fluid injection (steam flooding) and in-situ combustion. These are discussed in the following sections.

3.1. STEAM INJECTION

Any thermal recovery method injecting heat into the reservoir from the surface must take into account three general sources of heat loss: loss from the generating unit and surface lines, loss from the wellbore, and loss from the heated portion of the reservoir to adjacent formations. Steam injection is favored in thick formations with low pressure and high oil saturation. Other factors include permeability, which must be high to achieve high injection rates and low heat losses, and depth. The depth can vary, but shallow wells are usually preferred because of lower heat losses, pressures, and drilling costs.

Surface heat losses from the generator and the surface lines are usually negligible, although there may be cases where this is not so. A summary calculation of these losses based on the Nelson (1958) heat loss tables was presented by Ramey (1964). Williams, *et al.* (1980), presented a FORTRAN routine based on these tables as part of their steam injection program. A more substantial source of heat loss is through the wellbore. The studies on wellbore heat

displacement mechanism, much like a piston. This assumption is justified by the work of Schenk (1965) and Miller (1975). The point is that by knowing the rate of growth of the steam zone and the irreducible oil saturation in the zone, it is possible to approximate the oil produced with time.

The major problem with this analytic model is its assumption of a frontal displacement mechanism. In actual application, the buoyancy of steam relative to oil may result in gravity segregation of the fluids (i.e., gravity override). This phenomenon was observed by Baker (1969), and the numerical simulation work of Chu and Trimble (1975) has shown the effect usually to be present. Neuman (1975) treated the steam zone as a stationary plane, justifed by the assumption of a slow steam zone growth rate. His model overlies the reservoir with a steam zone that grows simultaneously outward and downward. Van Lookeren (1977) derived a dimensionless group to be used in calculating the steam-swept thickness. Doscher and Ghassemi (1981), unlike Neuman, treated the steam zone as a descending plane. Vogel (1983) returned to the stationary plane assumption, but also assumed an instantaneous steam overlay with later vertical growth only. Strom and Brigham (1985) discuss the introduction of a surfactant into the injected steam in order to reduce the gravity override effect and channeling (the tendency of the steam to move into the reservoir in a nonuniform front).

The state of the art analytic models have been attempting to obtain a better and more precise understanding of the steam zone shape and behavior over time. These include van Lookeren (1977) and Aydelotte and Pope (1982). A number of numerical simulation models have also appeared in the literature--these were recently reviewed by Farouq Ali and Ferrer (1981).

3.2. IN-SITU COMBUSTION

In-situ combustion usually involves the injection of air or oxygen-nitrogen mixtures into a reservoir to form a combustion front where the residual hydrocarbons are oxidized. The heat provided by this process results in a decrease in the viscosity and a concommitant increase in the relative mobility of the oil. The oil is also displaced by a combination of steam, condensed water, and combustion gases. Dry combustion involves only the injection of the gas, while wet combustion injects water with the air, generally intended to increase the thermal efficiency of the process.

Not all reservoirs are suitable for in-situ combustion. The same basic reservoir properties that are suitable for steam flooding are also preferred for in-situ combustion, although the latter method can be applied to deeper reservoirs. A number of authors have suggested "screening guides" to help choose which reservoirs might respond well to the process. These include Poettmann (1964), Geffen (1973), Chu (1976,1985), Satman, *et al.* (1981), and Lewin, *et al.* (1976). Williams, *et al.* (1980) reviewed some of these and concluded that important parameters include porosity, formation thickness, oil viscosity, initial oil saturation (at start of combustion), oxygen utilization, and total fuel burned.

A frontal displacement model was presented by Nelson and McNiel (1961), who assumed that the fuel concentration and air-oil ratio would remain constant. Gates and Ramey (1980) recommended an oil recovery--volume burned method to compute oil recovery as being more accurate. See also Gates and Sklar (1971). This method presents oil recovery as a function of volume of reservoir burned and initial injected gas saturation. Gates and Ramey also showed that this method yielded greater oil recovered and lower air-oil ratios than the frontal displacement model for the early stages of the combustion process.

4. MODEL DISCUSSION

There have been a number of methods proposed to calculate the oil recovery from a thermal project. We will first discuss a model for a steam flood. The heat losses from surface lines and the wellbore are estimated using the procedures presented by Prats (1982), then the oil recovery is calculated using a modified version of the Marx and Langenheim model introduced by Strom and Brigham (1985). Then we will present the calculation of oil recovery using the Gates and Ramey (1980) oil recovered--volume burned method for in-situ combustion. The last section presents the economic model used to evaluate the performance of these methods. Calculation of the net present value and the internal rate-of-return is demonstrated. The Davidson and Cooper method (1976) of estimating the high, low, and median values of the economic parameters is discussed. The Monte Carlo simulation technique for estimating uncertainty is used in a LOTUS 1-2-3 spreadsheet program to estimate the probable range of future oil prices and other economic parameters.

4.1. STEAM INJECTION MODEL

The most important element of any steam injection model is the treatment of the heat loss to adjacent formations and the heat transfer within the formation. The FORTRAN program used was written by Strom and Brigham (1985), and is based on the Marx and Langenheim (1959) model, with the Ramey (1959) modification for variable injection rates. The Strom and Brigham program includes the use of a surfactant to combat gravity override and channeling, and includes a "sweep efficiency" factor to assist in history-matching. This program, however, does not calculate the heat losses in the wellbore and the surface pipes. These heat losses are estimated using the method presented by Prats (1982).

The Prats method usually estimates the heat losses from the wellbore and surface pipes at steady-state conditions. The steady-state rate of heat loss is directly proportional to the temperature difference between the injected fluid inside the pipe and the ambient temperature at the surface of the earth. The latter is usually estimated by a mean ambient temperature to consider seasonal and daily variances. The rate of heat loss is also inversely proportional to the overall specific thermal resistance of the system, the estimation of which is the most difficult part of the entire calculation. Each system (i.e., wellbore or surface pipes) has a number of different resistances, but, as Prats demonstrates, the resistance of one component usually dominates the system. These resistances are calculated in the following sections.

4.1.1. HEAT LOSSES FROM SURFACE PIPES

The general equation used by Prats to calculate the heat loss per unit length of pipe, $\dot{Q}_{ls}$, is:

$$Q_{ls} = \frac{(T_b - T_A)}{R_h} \tag{4.1}$$

where R_h is usually given as $1/(2\pi rU)$. This is Eq. 10.1 in Prats. Here Q_{ls} is the rate of heat loss per unit length of pipe in Btu/ft-D, T_b is the bulk temperature of the injected fluid in the pipe in degrees Fahrenheit, T_A is the ambient temperature of the atmosphere (or the temperature of the earth surrounding the wellbore in the case of heat losses from the wellbore) in degrees Fahrenheit, and R_h is the overall specific thermal resistance of the system in

EXAMPLE 4.1 - Calculation of Heat Losses from Surface Pipes in a South Belridge Project

Williams, *et al.*, give the inside radius of the surface pipe as 0.1125 feet, and λ_{ins} as 0.03 Btu/ft-hr-°F, but neglect to give the outer radius of the pipe or the radius of the insulation. An estimate of the former will be made using Prats' Table B.15. Three inches of insulation will be assumed.

$$r_i = 1.350 \text{ in.} = 0.1125 \text{ ft.}$$
$$r_o = 1.750 \text{ in.} = 0.1458 \text{ ft.}$$
$$r_{ins} = 4.750 \text{ in.} = 0.3958 \text{ ft.}$$
$$\lambda_{ins} = 0.72 \text{ Btu/ft-D-°F (Prats uses 0.96)}$$

The overall specific thermal resistance is calculated from Eq. 4.4:

$$R_h = \frac{1}{2\pi}\left\{\frac{\ln(4.75/1.75)}{0.72}\right\}$$

$$R_h = \frac{1}{2\pi}(1.3868)$$

$$R_h = 0.2207 \left[\text{Btu/ft-D-°F}\right]^{-1}.$$

Williams, *et al.*, also give the steam temperature as 544°F. It is assumed that the average yearly temperature is 60°F.

$$\dot{Q}_{ls} = \frac{\left[T_b - T_A\right]}{R_h} = \frac{(544 - 60)}{(0.2207)}$$

$$\dot{Q}_{ls} = 2192.9 \text{ Btu/ft-D.}$$

The length of the surface lines as given by Williams, *et al.*, is 1000 feet. Thus, the amount of heat lost over the entire surface line is 2.192×10^6 Btu/D.

An important question is how much of the heat injected is lost through the surface lines. Williams, *et al.*, used a feedwater rate of 350 *B/D* as the lowest injection rate, and gave a generator outlet steam quality of 0.80 for this case. They also gave the temperature of the formation as 93 degrees Fahrenheit. Prats presents an expression to determine the rate of heat injection, Q_i. This is his Eq. 7.11:

$$\dot{Q}_{ls} = w_i \left[C_w \Delta T + f_s L_v\right], \tag{4.5}$$

where $\dot{Q}_i$ is the heat injection rate in Btu/D, w_i is the mass injection rate in lbm/D, ΔT is temperature rise of the steam zone above the initial reservoir temperature in degrees Fahrenheit,

TABLE 4.1

CALCULATION OF HEAT LOSSES FROM SURFACE PIPES

Ri	1.350	0.1125	AMB TEMP	60.00
Ro	1.750	0.1458		
Rins	4.750	0.3958		
LAM INSUL	0.72	BTU/FT-D-DEG F	LAMP P	600
Hf	48000		Hfc	110
Hpo	48000			

CASE	Rh	STEAM TEMP	HT LOSS BTU/FT-D
-WITH INS	0.2207	544	2192.790
-W/O INS	0.0100	544	48305.04

PERCENT LOSS OF HEAT INJECTED

Iw (B/D)	350	500	750	1000	1250	1500
QINJ =	1.2E+08	1.7E+08	2.6E+08	3.5E+08	4.3E+08	5.2E+08
LENGTH	1000	1000	1000	1000	1000	1000
-WITH INS	1.805	1.263	0.842	0.632	0.505	0.421
-W/O INS	39.759	27.832	18.555	13.917	11.133	9.277

Heat losses from the wellbore are also governed by Eq. 4.1; but it is more difficult to calculate R_h, which is now a function of time. Another difference is the ambient temperature, T_A, which is now the temperature of the earth surrounding the wellbore, and is thus a function of depth. Prats presents a modified form of Eq. 4.2 for R_h, which is

$$R_h = \frac{1}{2\pi}\left[\frac{1}{h_f r_i} + \frac{1}{h_{P_i} r_i} + \frac{1}{\lambda_P}\ln\frac{r_o}{r_i} + \frac{1}{h_{P_o} r_o} + \frac{1}{\lambda_{ins}}\ln\frac{r_{ins}}{r_o} + \frac{1}{h_{rc,an} r_{ins}} + \frac{1}{\lambda_P}\ln\frac{r_{co}}{r_{ci}}\right.$$
$$\left. + \frac{1}{\lambda_{cem}}\ln\frac{r_w}{r_{co}} + \frac{1}{\lambda_{Ea}}\ln\frac{r_{Ea}}{r_w} + \frac{f(t_D)}{\lambda_E}\right. \tag{4.6}$$

The first five terms within the brackets were described in the previous section. The radiation and convection coefficient of heat transfer for the annulus is represented by $h_{rc,an}$, and is expressed in Btu/ft-D-°F. The thermal conductivity of the cement, altered earth around the wellbore (from dessication due to the high temperature), and unaltered earth are represented by λ_{cem}, λ_{Ea} and λ_E, respectively. The units are Btu/ft-D-°F. The inner and outer casing radii are given by r_{ci} and r_{co}, r_w is the wellbore radius, and r_{Ea} is the radius of the altered formation near the wellbore, all in feet.

The $f(t_D)$ term is a dimensionless function that has been presented by a number of authors in addition to Ramey (1962) and Willhite (1967). The solution includes the implicit assumption that the earth's thermal conductivity is isotropic in the plane normal to the wellbore, and that heat losses to the earth are primarily due to radial conduction. Prats (1982) describes this function in more detail. For the purpose of this study, it is sufficient to note the following. The dimensionless time, t_D can be found from the equation:

$$t_D = \frac{\alpha_E t}{r_w^2} \tag{4.7}$$

where α_E is the thermal diffusivity of the earth in ft^2/D, t is the time from the start of the steam injection in days, and r_w is the same as before. This is for the case where there is no altered earth zone; if there were such a zone, r_{Ea} would be substituted for r_w in Eq. 4.7. For values of $t_D \geq 100$, Ramey (1962) gives the approximation:

$$f(t_D) \approx 0.5\ \ln(t_D) + 0.403\ . \tag{4.8}$$

For values less than 100, Willhite (1967) gives a table of values for the $f(t_D)$ function for various values of t_D and $R_h'\lambda_E$, where R_h' is:

$$R_h' = R_h - \frac{f(t_D)}{2\pi\lambda_E}. \tag{4.9}$$

This table is reprinted in Prats (1982) as his Table 10.1.

The determination of the heat loss from the wellbore for a specific time can then be calculated using Eqs. 4.6 - 4.9. This involves an iterative process that demands an initial estimate of R_h. Prats (1982) gives an example calculation for tubing with 2.75 inches of insulation that converges within one iteration, although he carries the calculation through twice more to determine the temperature profile. This is beyond the purpose of this study. In general,

where r_{Ea} is the radius of the altered earth zone surrounding the wellbore. Here we assume that there is no altered earth zone, and that λ_P is very large (as we did in Example 4.1). Substituting the proper values into Eq. 4.55, we find:

$$T_{ci} = 100 + \frac{(544 - 100)}{2\pi(0.18)}\left[0 + \frac{\ln\left[\frac{4.3716}{2.748}\right]}{7.2} + 0 + \frac{2.885}{33.6}\right] = 159.0°F.$$

The temperature of the outer surface of the insulation, T_{ins}, is found by Prats' Eq. B.70:

$$T_{ins} = T_B + \frac{(T_B - T_A)}{2\pi R_h}\left[\frac{1}{h_f\, r_i} + \frac{1}{h_{Pi}\, r_i} + \frac{\ln\left[\frac{r_o}{r_i}\right]}{\lambda_P} + \frac{1}{h_{Po}\, r_o} + \frac{\ln\left[\frac{r_{ins}}{r_o}\right]}{\lambda_{ins}}\right] \tag{4.11}$$

We calculate T_{ins} to be:

$$T_{ins} = 544 - \frac{444}{2\pi(0.18)}\left[0 + 0 + 0 + 0 + \frac{\ln\left[\frac{2.4376}{1.4376}\right]}{0.96}\right] = 256.1\ °F.$$

The average temperature, $\overline{T}$, is simply the average of T_{ci} and T_{ins}. Here, $\overline{T}$ is found to be 207.6 degrees Fahrenheit.

The next step is the calculation of $h_{rc,an}$. The following values are found from various tables and graphs in Prats' Appendix B:

$$\rho_a = 0.059\ \text{lbm/ft}^3 \quad \text{(TableB. 1)},$$

$$\mu_a = 0.022\ cp \quad \text{(Fig.B. 41)},$$

$$\lambda_a = 0.45\ \text{Btu/ft–D–°F} \quad \text{(Fig.B. 72)},$$

$$\beta_a = \frac{1}{460+\overline{T}} = 0.0015\ °F^{-1} \quad \text{(Eq.B. 28)}.$$

The Grashof number N_{Gr} is evaluated using Prats' Eq. B.66:

$$N_{Gr} = (7.12 \times 10^7) \cdot \frac{(r_{ci} - r_{ins})^3 \rho_{an}^2 \beta_{an}(T_{ins} - T_{ci})}{\mu_{an}^2}. \tag{4.12}$$

Substituting:

$$N_{Gr} = (7.12\times10^7) \cdot \frac{(0.206 - 0.2031)^3(0.059)^2(0.0015)(256.085 - 159.02)}{(0.22)^2} = 1.80.$$

TABLE 4.3

PERCENT HEAT LOSSES FROM WELLBORE WITH NO INSULATION

Iw (B/D)	350	500	750	1000	1250	1500
QINJ =	1.22E+08	1.74E+08	2.60E+08	3.50E+08	4.34E+08	5.21E+08
LENGTH	1040	1040	1040	1040	1040	1040

TIME (DAYS)	QLOSS BTU/FT-D	HEAT LOST %	%	%	%	%	%
10	1.45E+04	12.382	8.666	5.780	4.298	3.467	2.889
20	1.38E+04	11.828	8.279	5.521	4.106	3.312	2.760
30	1.34E+04	11.497	8.047	5.367	3.991	3.220	2.683
60	1.28E+04	10.972	7.679	5.121	3.809	3.070	2.560
182	1.19E+04	10.220	7.153	4.770	3.548	2.862	2.385
365	1.14E+04	9.797	6.857	4.573	3.401	2.743	2.286
725	1.10E+04	9.412	6.587	4.393	3.267	2.636	2.196
1090	1.07E+04	9.197	6.437	4.293	3.193	2.575	2.146

They calculated the heat losses to be a maximum of 4.02% for their lowest injection rate (2500 lbm/hr) and about 1.17% for their highest injection rate (10,000 lbm/hr). The numbers as calculated in Fig. 4.5 are slightly higher, but this is a result of different parameters (i.e., casing radii, etc.).

Insulation again cuts the heat losses dramatically (Table 4.6), but only by a factor of 4, far less than for the surface lines. Of note is the tendency of insulation to "even out" the heat loss rate over time. Three iterations were also needed to determine R_h (Table 4.7).

These results enable a rough estimation of heat losses from a wellbore as a function of time and injection rate. The heat content injected into the reservoir is then the heat content of the surface less the heat losses. Table 4.2 shows how the heat loss percentage is used to calculate the net bottom hole heat injection rate and downhole heat content. This calculation is detailed in Strom and Brigham (1985).

4.1.3. THE MARX-LANGENHEIM MODEL

The Marx and Langenheim (1959) steam flood model is a frontal displacement model. The solution is derived from a heat balance between the net rate of heat input to the reservoir, the rate of heat transfer to the reservoir, and the rate of heat loss to the adjacent formations. Prats (1982) gives the heat balance as:

$$\dot{Q}_i = (43{,}560 \text{ sq. ft/acre})\, M_R h_t\, \Delta T_i \frac{dA}{dt} + \dot{Q}_l \tag{4.15}$$

where $\dot{Q}_i$ is the constant rate of heat injection, $\dot{Q}_l$ is the rate of heat loss to the overburden and underburden through conduction, M_R is the volumetric heat capacity of the reservoir, h_t is the gross formation thickness, ΔT_i is the rise in formation temperature above the initial reservoir temperature, and dA/dt is the rate of areal growth of the heated zone. The quantity $M_R\, h_t A\, \Delta T_i$ represents the amount of heat required to raise the temperature of a volume of reservoir (given by the area, A, and the thickness, h_t) with a volumetric heat capacity of M_R to ΔT_i above the initial reservoir temperature.

Marx and Langenheim assumed that the heat losses to the adjacent formations were only by vertical conduction. Prats (1982) gives this heat loss as:

$$\dot{Q}_l = \dot{Q}_i \left[1 - e^{t_D} erfc\sqrt{t_D}\right], \tag{4.16}$$

where the dimensionless time, t_D, is:

$$t_D = r\left[\frac{M_S}{M_R}\right]^2 \frac{\alpha_S}{h_t^2} t, \tag{4.17}$$

and $erfc(x)$ is the complementary error function defined as:

$$erfc\left[x\right] = 1 - erf\left[x\right] \tag{4.18}$$

TABLE 4.6

PERCENT HEAT LOSSES FROM WELLBORE WITH INSULATION

Iw (B/D)	350	500	750	1000	1250	1500
QINJ =	1.22E+08	1.74E+08	2.60E+08	3.50E+08	4.34E+08	5.21E+08
LENGTH	1040	1040	1040	1040	1040	1040

TIME (DAYS)	QLOSS BTU/FT-D	HEAT LOST %	%	%	%	%	%
10	2.90E+03	2.472	1.733	1.160	0.862	0.695	0.579
20	2.87E+03	2.451	1.718	1.150	0.854	0.689	0.574
30	2.86E+03	2.437	1.709	1.144	0.850	0.685	0.571
60	2.83E+03	2.414	1.693	1.133	0.842	0.679	0.565
182	2.79E+03	2.378	1.668	1.116	0.829	0.669	0.557
365	2.76E+03	2.356	1.652	1.106	0.821	0.662	0.552
725	2.74E+03	2.335	1.637	1.096	0.814	0.656	0.547
1090	2.72E+03	2.322	1.628	1.090	0.809	0.653	0.544

where $erf(x)$ is the error function. In these equations, α_S is the thermal diffusivity of the overlying and underlying formations, which are assumed to have identical thermal properties. Strom and Brigham (1985) considered the heat loss in the basic Marx and Langenheim form:

$$\dot{Q}_l = 2\int_{\lambda=0}^{\lambda=t}\left[\frac{K_s\Delta T_i}{\sqrt{\pi\alpha_s(t-\lambda)}}\right]\left[\frac{dA}{d\lambda}\right]d\lambda, \tag{4.19}$$

where K_s is the thermal conductivity of the overburden and underburden. For this version, Strom and Brigham used the Lauwerier (1955) assumption that there is no vertical temperature variation within the reservoir, and treated the horizontal temperature variation as a step function.

Their solution of Eq. (4.19) gives the areal extent of the heated zone as a function of the dimensionless time, t_D:

$$A(t) = \left[\frac{\dot{Q}_i M_R h_t \alpha_s}{4K_s^2\Delta T_i}\right]\left[e^{t_D} erfc\sqrt{t_D} + 2\frac{\sqrt{t_D}}{\pi} - 1\right] \tag{4.20}$$

where the dimensionless time is defined as:

$$t_D = \frac{4K_s^2}{M_R^2 h_t^2 \alpha_s} t. \tag{4.21}$$

They then apply the equivalence relationship:

$$\frac{K_s^2}{\alpha_s} = \alpha_s M_s^2 \tag{4.17}$$

to derive the areal extent of the equivalent heated zone equation, which is nearly the same as that presented by Prats (1982):

$$A(t) = \frac{\dot{Q}_i M_R h_t}{4M_s^2\alpha_s\Delta T_i}\left[e^{t_D} erfc\sqrt{t_D} + 2\frac{\sqrt{t_D}}{\pi} - 1\right] \tag{4.23}$$

Here M_s is the volumetric heat capacity of the surrounding strata. Prats (1982) defined a function G such that:

$$G = e^{t_D} erfc\sqrt{t_D} + 2\frac{\sqrt{t_D}}{\pi} - 1. \tag{4.24}$$

The rate of growth of the heated zone can be obtained by differentiation of Eq. (4.23) with respect to time. Strom and Brigham present dA/dt as:

$$\frac{dA}{dt} = \frac{\dot{Q}_i}{\Delta T_i M_R h_t}\left[e^{t_D} + erfc\sqrt{t_D}\right]. \tag{4.25}$$

where ϕ is the porosity, ΔS_o is the change in oil saturation in the heated zone, and E_c is an efficiency factor that is determined by history matching.

Strom and Brigham (1985) used this formulation to construct a FORTRAN program called "Marx4.f". A modified version of this program is used in this study--the code is presented in Appendix B.1. We now consider a model for in-situ combustion oil recovery.

4.2. IN-SITU COMBUSTION MODEL

In-situ combustion differs from steam injection in that the heat is generated in the reservoir by the propagation of a burning front. Compressed air, or some oxidizing gas mixture, is injected into the formation and ignites the residual hydrocarbons. Prats (1982) points out that the fuel is not the crude oil in the reservoir, but actually a residue left from the distillation and thermal cracking of the crude. The combustion front is driven through the reservoir by the injected air, the generated heat lowering the viscosity and increasing the relative mobility of the oil. In addition to the thermal effect, oil recovery is also enhanced by the displacement of oil by steam, hot water, and combustion gases (ie. carbon dioxide) produced at the combustion front. Water can be added to help the latter process--this is termed "wet" combustion. The most common model, and the one used in this study, is that of dry forward combustion, where the combustion front is driven from the injector to the producer(s), and no water is injected with the air.

One factor of major interest is the amount of air required to burn a unit bulk volume of reservoir rock. This is usually determined by tests in the laboratory on a core or section from the reservoir. The advance of a combustion front in the reservoir is simulated by propagating a front in a combustion tube. The details of this process are covered by Prats (1982). Prats also gives some broad correlations for the fuel burned in a reservoir for those cases where experimental values are not available.

A second important factor is the amount of crude available for displacement and ultimate recovery in the "burned" zone. It is usually assumed that the oil displaced equals the oil in place at the start of the air injection less the oil consumed as fuel--that is, there is no unburned residue left in the "burned" zone. Prats (1982) notes that this is not always so, but that the residue is negligible where combustion takes place at high temperaures.

A number of models have already been briefly discussed. In this study, the formulation used was first proposed by Gates and Ramey (1980), who determined that the cumulative oil production was a function of the reservoir volume burned. It was proposed that the air required to burn the fuel in a given volume of reservoir rock must be constant if the fuel concentration was constant, thus making the volume burned proportional to the cumulative air injected. Gates and Ramey then used this to generate a correlation between the oil recovery and the burned reservoir volume. They presented a graph of this relationship for the South Belridge Field test based on the test data of Gates and Ramey (1958). This correlation was used to design the commercial in-situ combustion operation in the Moco Zone (see Gates and Sklar, 1971). Field results were actually better as shown by Gates and Sklar (see Fig. 4.1). The straight line respresents the frontal displacement situation where the air/oil ratio is constant. The design curve is based on the Gates and Ramey correlation (1980), and considers the effects of gravity drainage, and water and gas drive, for the South Belridge in-situ combustion experiment (Gates *et al.*, 1975, 1977). The Moco Zone commercial operation had greater formation thickness and significant dip, and thus actual results were better than designed, as shown in Fig. 4.1. The Moco Zone operation is still being produced.

Williams, *et al.* (1980), suggest that the above information shows that the oil is recovered from the unburned zone just ahead of the combustion front, and that the air/oil ratio may be much less than indicated by frontal displacement calculations during early time. They conclude that the air compression costs could then be lowered because the air requirements would be less, and that the air injection could be terminated earlier, before the combustion front has covered the entire reservoir. This would have a favorable effect on the overall economics of an in-situ combustion.

Gates and Ramey (1980) base their "oil recovered--volume burned" model on the relationship between the displaced oil and the bulk burned volume of the reservoir. The model was based on field and laboratory tube run results. Their method is the one used in this study.

In addition to the standard reservoir properties (such as porosity and area), the amount of fuel burned in the reservoir is required. This is usually determined by a combustion tube experiment. Several parameters are calculated from such an experiment. The rate of volume burned, V_B is:

$$V_B = A_{CT} v_b \tag{4.33}$$

where A_{CT} is the cross-section area of the combustion tube and v_b is the measured velocity of the propagated combustion front. The effluent gas composition can be used to determine the atomic H/C (hydrogen-to-carbon) ratio as:

$$\frac{H}{C} = \frac{4\left[\left(\frac{21.0}{79.0}\right)C_{N_2} - C_{CO_2} - 0.5\, C_{CO} - C_{O_2}\right]}{C_{CO_2} + C_{CO}} \tag{4.34}$$

where C_{N_2}, C_{CO_2}, C_{CO}, and C_{O_2} are the volume percent concentrations of nitrogen, carbon dioxide, carbon monoxide and oxygen in the effluent gases from the combustion tube. The H/C ratio can then be used to determine the amount of fuel burned per unit of air, A, as

$$A = \frac{(C_{CO_2} + C_{CO})\left(12.0 + \frac{H}{C}\right)}{100.0 \cdot 379.00}. \tag{4.35}$$

The fuel burning rate, m_b is:

$$m_b = u_a A \tag{4.36}$$

where m_b is the fuel rate in pounds per unit time, and u_a is the air rate in the same direction as the advancing combustion front. The tube fuel concentration is:

$$m_E = \frac{m_b}{V_B} \tag{4.37}$$

The original oil-in-place, N_o, is determined in the usual fashion:

$$N_o = 7750 \cdot \phi_{res} \cdot \frac{S_{o_i}}{B_{o_i}} \tag{4.45}$$

where S_{o_i} and B_{o_i} are the initial oil saturation (at the start of the thermal recovery project) and formation volume factor, respectively. The oil displaced from the heated volume is assumed to be the original oil-in-place less the oil burned as fuel. In equation form:

$$N_D = N_o - m_R. \tag{4.46}$$

The air/oil ratio is calculated as the air required over the oil displaced:

$$AOR = \frac{A_{sr} \times 10^{-3}}{N_D} \tag{4.47}$$

where AOR is the air/oil ratio. Similarly, the water/oil, or water/fuel, ratio (in lb/lb) is determined by

$$WOR = \frac{\frac{H}{C}}{12 + \frac{H}{C}} + \frac{18}{2}. \tag{4.48}$$

Before the amount of oil displaced can be determined, however, the initial gas saturation must be considered. Experiments with a combustion tube with different initial gas saturations should be done to derive a graph plotting oil recovery as a function of the volume burned and the gas saturation. This was done by Gates and Ramey (1980) for the South Belridge thermal recovery experiment (Fig 4.2). The curves of the different initial gas saturations were based on the slope of the field data and interpolation of the combustion tube test data. This graph is for the South Belridge field, and new data relevant to any given field should be plotted for that field if available. Gates and Ramey (1978) also presented a graph of excess air as a function of the oil recovery (Fig 4.3). Excess air is defined as the unused air over the air used to burn the fuel.

Combining the given graphical data and previously stated equations enables the determination of cumulative oil recovered, cumulative air required, the cumulative air/oil ratio, the excess air factor, and the ratio of the total amount of air injected to oil produced. These are determined by the following equations:

$$N_{R_{cum}} = \frac{N_R \cdot N_D \cdot h \cdot A_T}{100} \tag{4.49}$$

where N_R is the percentage oil recovery determined from Fig. 4.2, and $N_{R_{cum}}$ is the cumulative oil recovered (in barrels). The cumulative air requirement, $A_{R_{cum}}$, is calculated from:

$$A_{R_{cum}} = \frac{V_{Rb} \cdot A_{sr} \cdot h \cdot A_T}{100} \tag{4.50}$$

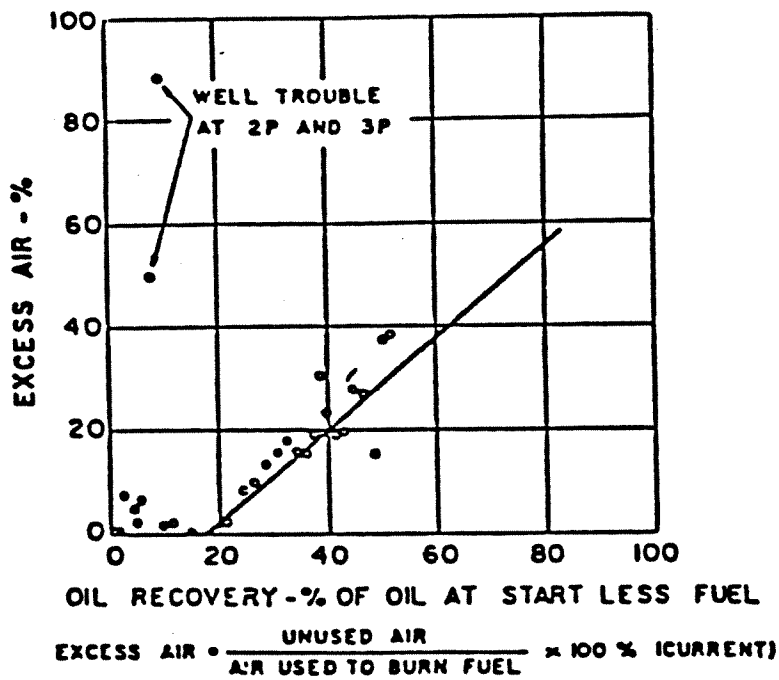

Fig. 4.3 Excess Air vs. Oil Recovery for South Belridge Thermal Recovery Experiment (From Gates and Ramey, 1978).

The LOTUS 1-2-3 program was used for several reasons. First, it generates a spreadsheet of an easily understood nature that can be modified as the user desires. Second, the Monte Carlo simulation technique is readily added to the spreadsheet. The discretized probability tables are also easily modified. Third, the program is in widespread use and is readily available. These factors combine to give a Monte Carlo spreadsheet model that can be quickly altered to suit individual needs. This economic model is not limited to thermal recovery operations--it is suitable for any type of project.

4.3.1. THE TIME VALUE OF MONEY

Money received in the future is not worth as much as money received today. The present value, P, of a cash inflow, F_t, at some time t, is:

$$P = d_t F_t \tag{4.55}$$

where d_t is the discount factor for year t. For a series of future cash flows, the individual present values of each cash flow can be summed to give the present value:

$$PV = \sum_t d_t F_t. \tag{4.56}$$

The discount factor is related to a discount rate, r, as given by:

$$d_t = \frac{1}{(1+r)^t}. \tag{4.57}$$

This assumes, of course, that r is constant for all future periods. The period, t, is usually given in years (i.e., 1,2,3,...), but can be used at half-years. In this case, called mid-year discounting, t takes the values of 0.5, 1.5, 2.5, etc. Those who use mid-year discounting feel that it gives a more accurate value of the present value of money. Also note that the r's for future periods do not have to be constant. That is, the discount factor is:

$$d_t = \frac{1}{(1 + r_1)(1 + r_2) \cdots (1 + r_t)} \tag{4.58}$$

where the r_t are the spot rates for future years. This is of interest for financial instruments. It is sufficient to assume constant r for petroleum investments.

The net present value is defined as the present value of the series of future cash flows (as described above) less the initial capital investment. This capital investment is usually undiscounted as it is assumed to be an outlay now (i.e., the discount factor is 1.00). Future outlays, such as for well-pulling or maintenance, are then included in the future cash flows and discounted at the appropriate rate. The net present value can then be easily calculated using any discount rate desired. In practice, most companies set a rate for a class of investments, and judge the desireability of a project by the net present value discounted at that rate. The major problem with the net present value criterion is determining what is an acceptable rate. A common proposal is the rate at which capital can be obtained, but this neglects the risk involved in the project. A risk-weighted discount factor is sometimes used--the riskier the project, the

TABLE 4.8

SPREADSHEET MODEL, PART A

THERMAL TECHNIQUE: IN-SITU COMBUSTION
FIELD: SOUTH BELRIDGE
PATTERN: 5-AC, 5-SPOT

DATE: MAY 30
INJ RATE: 5
NO. PATT: 33

NET PRESENT VALUE CALCULATION USING MONTE CARLO SIMULATION

YEAR	YEAR	1 OIL PROD. (MB)	2 OIL PRICE ($/B)	3 GROSS INCOME (M$)	4 LEASE ROYALTY @10%	5 FUEL COSTS (M$)
0						
1	1986	5102.99	14.25	72718	7272	8868
2	1987	5877.73	14.00	82288	8229	8713
3	1988	4699.86	14.00	65798	6580	8713
4	1989	3584.53	14.50	51976	5198	9024
5	1990	2319.83	16.00	37117	3712	9957
6	1991	242.29	16.80	4070	407	1743
7	1992	0.00	17.64	0	0	0
8	1993	0.00	18.52	0	0	0
9	1994	0.00	19.45	0	0	0
10	1995	0.00	20.42	0	0	0
11	1996	0.00	21.44	0	0	0
12	1997	0.00	22.51	0	0	0
13	1998	0.00	23.64	0	0	0
14	1999	0.00	24.82	0	0	0
15	2000	0.00	26.06	0	0	0
16	2001	0.00	27.37	0	0	0
17	2002	0.00	28.73	0	0	0
18	2003	0.00	30.17	0	0	0
19	2004	0.00	31.68	0	0	0
20	2005	0.00	33.26	0	0	0
21	REMAIN	0.00	34.93	0	0	0
	TOTAL	21827		313967	31397	0

TABLE 4.10

SPREADSHEET MODEL, PART C

THERMAL TECHNIQUE: IN-SITU COMBUSTION
FIELD: SOUTH BELRIDGE
PATTERN: 5-AC, 5-SPOT

DATE: MAY 30
INJ RATE: 5
NO. PATT: 33

P3

13 FED INC TAX @48% (M$)	14 INV. TAX CREDIT @10%	15 NET PROFIT (M$)	16 D.N.P. @5% (M$)	17 D.N.P. @10% (M$)	18 D.N.P. @15% (M$)	19 D.N.P. @20% (M$)
-7032	2198	-27397	-27397	-27397	-27397	-27397
17165	0	19969	19488	19040	18621	18229
20908	0	24024	22880	21840	20890	20020
13784	0	16306	15156	14134	13222	12405
7664	0	9676	8776	7996	7316	6719
-3454	0	-2368	-2096	-1866	-1670	-1501
-1370	0	-111	-96	-84	-73	-64
-659	0	659	556	472	404	348
-659	0	659	542	450	377	318
-659	0	659	529	429	352	290
-659	0	659	517	409	328	265
-659	0	659	504	390	306	242
-659	0	659	492	372	285	221
-659	0	659	480	355	266	202
-659	0	659	469	338	248	184
-659	0	659	457	323	231	168
-659	0	659	446	308	216	153
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	0
41072	2198	46692	41703	37511	33922	30802

The investments are split into tangible and intangible columns so that the tangible investments may be depreciated. These costs were calculated in a fashion similar to the operating costs. The first category of investments is the drilling and well completion costs, which are calculated as an average rate (in dollars per foot drilled per well) times the number of wells times the average depth of the wells. The actual costs on a per well basis may be summed and substituted if they are known. The production equipment costs and the injection equipment costs are also based on an average rate (dollars per unit per well). The final category of initial investments is the installation costs for the compressor or generator. These are calculated by multiplying an average rate (dollars per unit) by the number of units installed. It was assumed that tangibles were 60% of the total investment, while intangibles were 40%. Again, if these costs are known, they should be used instead.

Depreciation of the tangible investments is based on the straight-line method. That is, the yearly depreciation is the total intangible investment less any salvage value, all divided by the estimated life of the equipment. Here it was assumed that the salvage value was zero, and that all the equipment had a life of 16 years. Other common depreciation methods include sum-of-the-years-digits, unit of production, and accelerated cost recovery. Depletion (Column 11) is included only for completeness. In some instances it is possible to "depreciate" the purchase price of a prospect in a fashion similar to depreciation of the tangible investments. Note that the depreciation life of sixteen years is often greater than the productive life of the project. We have assumed that the operator is an on-going concern and has other cash flows from other projects that these depreciation allowances can be charged against. Various operators will have different policies regarding depreciation, of course, and we have done this only so that the entire tangible expenses may be included.

The taxable income is the net operating income less the intangibles less the depreciation allowance less any depletion allowance. The tangible investments are not included as they are charged against future cash flows at a set rate (ie. depreciated). The tax rate is here assumed to be 48%, but this can be changed. The investment tax credit of 10% is based on the tangible investments, and is treated as a positive cash flow. The net profit (also known as net worth, net revenue, etc.) is the net operating income less the intangible and tangible investments less the Federal income tax plus the investment tax credit. This column can then be discounted at any desired discount rate to attain a net present value. Here the net present value (the sums at the bottom of Columns 16 through 19) have been calculated at discount rates of 5%, 10%, 15%, and 20%.

Note that only the first twenty years are presented as individual rows. After the twenty-first year all production revenue and costs are lumped together. This is justified by the tendency of the discount factor to diminish any later cash flows. Any production after the first twenty years is relatively insignificant.

4.3.3. STATISTICAL AND PROBABILITY ANALYSIS

In this section we will present the statistical measures used in this study. We will also briefly describe the normal distribution curve, and the cumulative probability distribution curve derived from it. This assumes a working knowledge of basic statistics. The concepts of probability, random variables, sampling theory, etc., are beyond the scope of this work. There are a number of texts on this subject--one such is Madsen and Moeschberger (1983).

There are a number of measures of central tendency used. One of the most familiar is the mean. We can represent a number chosen from a series of numbers, $x_1,...,x_n$, by a discrete random variable X. The probability that the X chosen at random will be equal to any specific x of

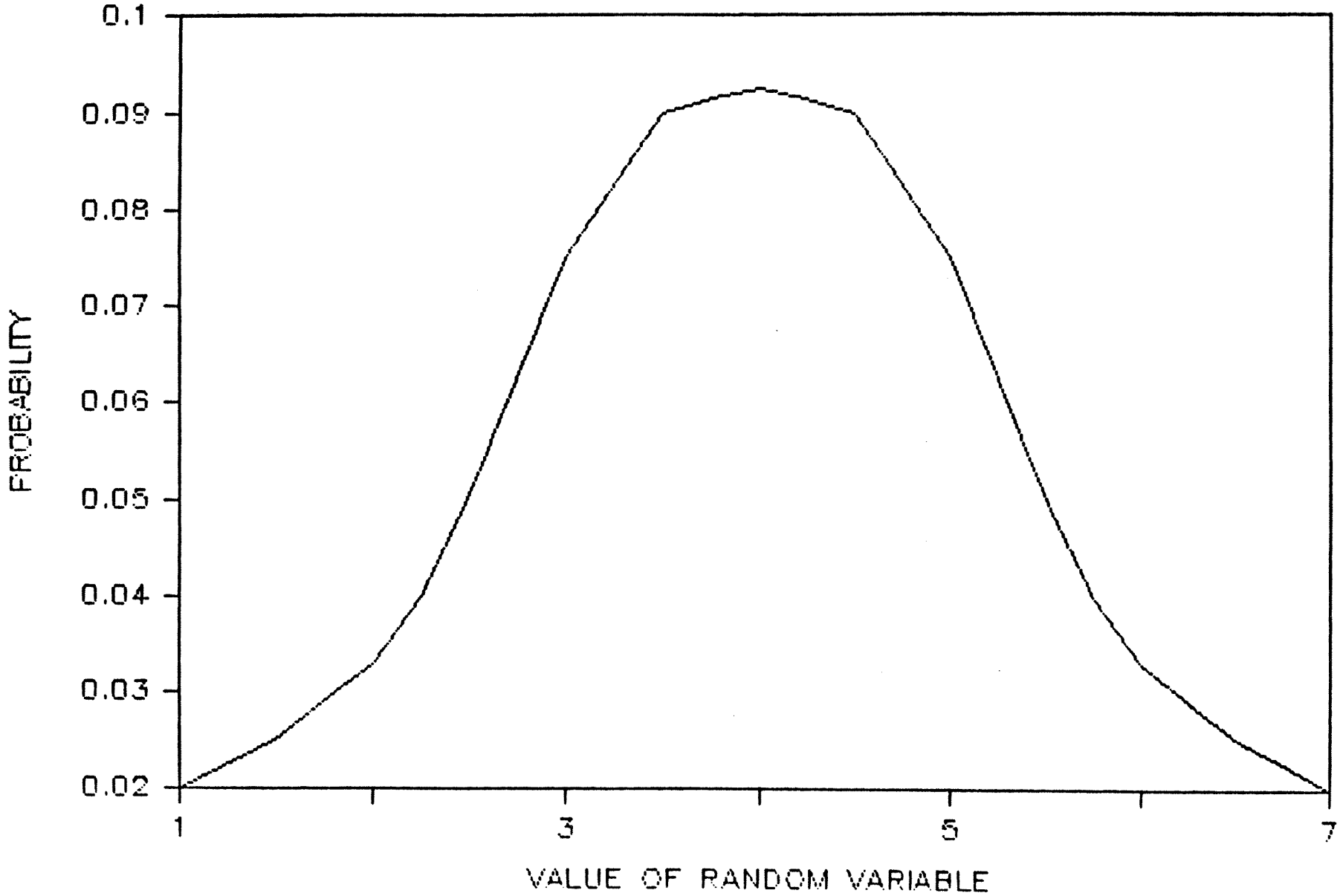

Fig. 4.4 General Probability Density Function

The cumulative probability distribution function is the graph used by the LOTUS software in the Monte Carlo simulation. This involves discretizing the graph so as to derive a cumulative probability table. The details of this process are given in the following section.

4.3.4. MONTE CARLO SIMULATION USING LOTUS

It has already been noted that the Monte Carlo simulation technique uses the probability distribution of the input parameters to generate the probability distribution of the desired output. A full Monte Carlo simulation uses as accurate a distribution of each variable as possible. The problem lies in finding this distribution for each parameter. Williams, *et al* (1980) uses Murphy's (1977) modification of the parameter method presented by Davidson and Cooper (1976). This method involves estimating the mean and variance of an uncertain variable from three representative numbers: a low, most likely, and high value for the variable. Williams notes that the low and high values should be picked so that there is only a 10% chance to be beyond the high value or beyond the low value. That is, there is an 80% probability that the value of the parameter will lie within this range. This is termed the "80% confidence interval range". As will be seen, this information can easily be used in a Monte Carlo simulation. Those interested in using the more rigorous statistical formulae are referred to Williams and the works cited above.

There are two special functions on LOTUS that make Monte Carlo simulation possible (Bonini, 1985). The first is the *@RAND* function, which generates uniform random numbers in decimal form between 0 and 1.0. There is a 10% chance that the value generated will be between 0.30 and 0.40, or between 0.70 and 0.80. The second function, *@VLOOKUP*, uses this random number to find a value for a random variable. The *@VLOOKUP* requires that the probability distribution for the random variable be in table form. The general form is *@VLOOKUP(X,Y..Z,N)*, where X is the cell location of the random number, *Y..Z* are the cell boundaries of the probability table, and *N* is the number of the column in the table where the random variable values are located.

The most difficult part of the simulation is determining what the probability distribution table will be. If the cumulative probability function is known (Section 4.3.3), then a table can be contructed by discretizing the function. The process of using a discrete approximation to the continuous distribution is also known as the "bracket median" method. A detailed description of this method is given by Holloway (1979).

First, the probability axis must be divided into intervals of equal probability. The number of intervals should be large giving a finer approximation of the continuous function. Second, the middle point, or median, of each interval is chosen on the probability axis. This point is read over to the curve and down to the random variable axis. The value of the random variable is the median value for the associated probability interval. Repeating this process gives a set of values for the random variable, all with equal probability. A probability distribution table can now be constructed on LOTUS. The first column contains the endpoints of the probability intervals, while the second (and successive) columns contain the associated variable values.

Figures 4.6 and 4.7 show a cumulative probability function that has been discretized. The probability axis has been broken into 10 intervals of 10%, and the associated value has been found. Table 4.11 shows how these values are used to contruct a probability distribution table on LOTUS. The *Y...Z* values for the location of the table (as used in the *@VLOOKUP* function) are the upper left-hand corner and the lower right-hand corner, repectively. In this table these would be cell locations C6 and E15. This table also has only one column. Additional columns could be added to give the values for other random variables. Of course, these would have to be discretized in a compatible way.

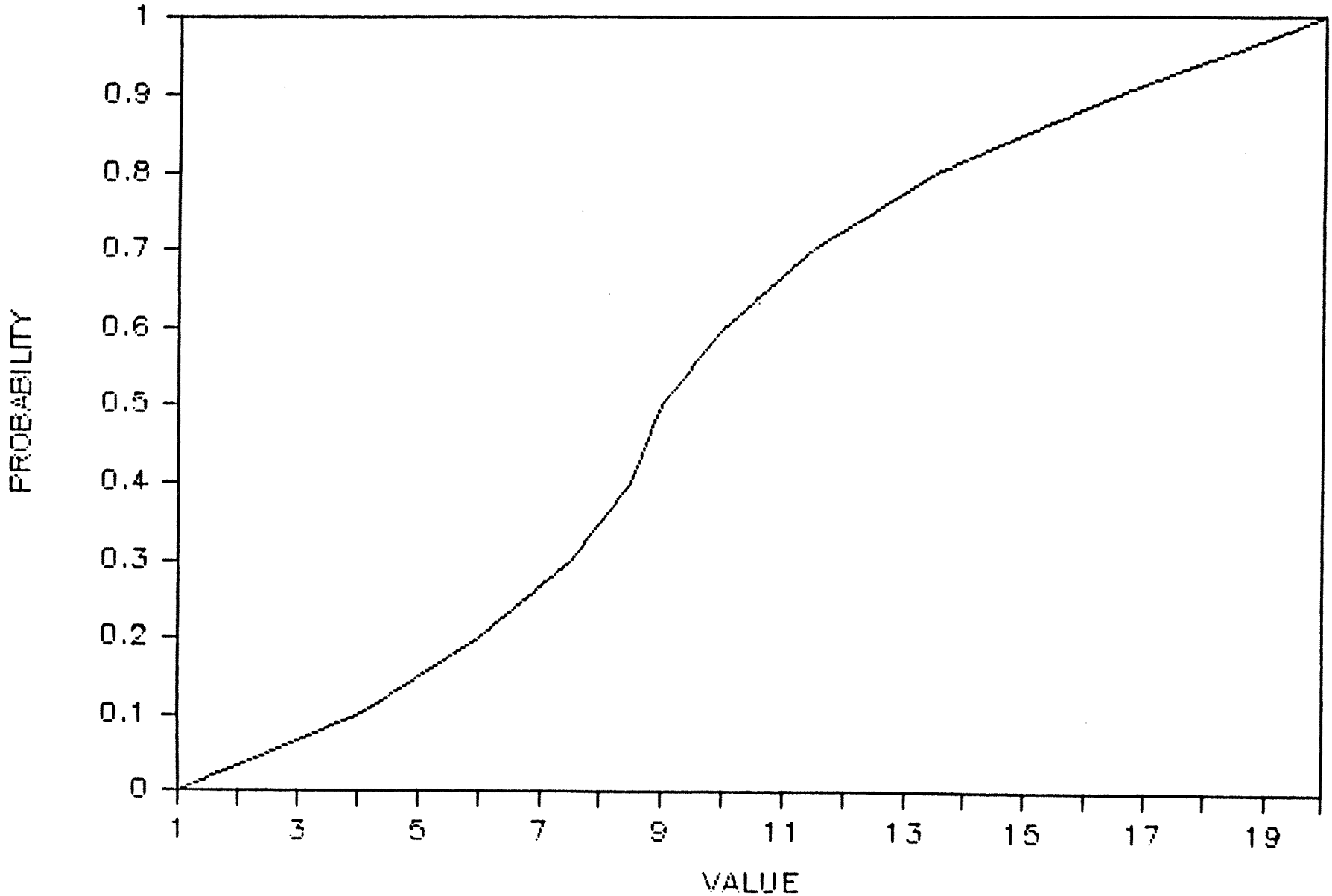

Fig. 4.6 Undiscretized Cumulative Probability Function

Unfortunately, it is not possible to obtain the continuous cumulative probability function for many of the economic parameters. Davidson and Cooper (1976), as noted above, use a high, most likely, and low estimation of these parameters. These values can be used to drive a very low resolution probability table. The most likely value is given an 80% chance to occur, with the remaining 20% split evenly between the high and low values. Probability distribution tables demonstrating this are shown in Table 4.12. Other probability distributions are possible, including linear interpolation between these values to obtain smaller intervals.

The Monte Carlo simulation on LOTUS involves generating several of these tables, and using several random numbers to choose values for the desired input parameters. The random variables are the general overhead and maintenance costs, the compressor overhead and maintenance, and the escalating factor for these costs. Three random numbers are generated independently to determine the value for each of these inputs. These values are then used to calculate the operating costs as detailed in the previous section. A complete listing of the cell values for the entire spreadsheet is in Appendix B.3.

The calculation of the net present value can thus be repeated many times, with each recalculation generating a new set of random numbers to determine the new parameter values. A large number of net present value results can be calculated in this fashion; we used 50 calculations as a bare minimum. More repetitions give greater accuracy of the resulting range of values. These values can be graphed as a cumulative probability function. The */ DATA SORT* command can be used to sort the results in ascending order. Since each value has an equal chance of occurring (i.e., $1/N$, where N is the number of trials), the cumulative probability of any given value is simply the sum of all the probabilities of those values less than the value (the */ DATA FILL* command is useful here). The graph is generated as an *XY* type with the *X* data set being the variable range and the *Y* data set being the cumulative probability (using LOTUS, the *Y* data set is entered as the *A* data range). Examples of these graphs can be seen in Appendix C.

4.3.5. THE DETERMINATION OF FUTURE OIL PRICES

One of the most uncertain economic factors is the future selling price of oil. This is not a problem if a set contract price has been negotiated, but the majority of cases demands some estimation of future prices. Table 4.13 presents the probability distribution table designed for LOTUS that was used for this variable in this study. The first five years for any particular oil price schedule are listed, along with an escalating factor for years 6 and later. Graphically, some of the schedules are graphed in Figs. 4.8 and 4.9. Each scenario has a 5% chance of occurrence. We assumed that the starting price for all cases would be 14.50 dollars per barrel. The majority of cases had the oil price for the next five years staying near to this value and increasing slowly. However, there are a number of cases that have the oil price increasing more rapidly or, conversely, decreasing substantially before turning up. This general scenario is to simulate the greater probability that future oil prices will not be far different from the previous year. The spread in the schedules denotes the uncertainty of this assumption.

The prediction of future oil prices is usually based on estimating the demand in relation to the supply. We feel that oil demand worldwide will be fueled by the prevailing low oil prices. Lower gasoline prices will prompt consumers to use their automobile more. A number of industries will switch back to using low-cost oil as a power source instead of coal, which was relatively cheaper at high oil prices. This increase in demand will be mitigated by consumer awareness of the effectiveness of conservation. For example, the "gas-guzzling" automobile of the past is not expected to return. In addition, a number of economies worldwide are growing, especially in Third World regions. This in turn will increase the demand for energy.

TABLE 4.13

PREDICTED FUTURE OIL PRICES

SCHEDULE ONE: MONTE CARLO FOR OIL PRICES

CUM PROB OF OIL PRICE SCENARIO	OIL PRICE PREDICTIONS FOR FIRST FIVE YEARS YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	ESCALAT. FACTOR
0.00	20.00	25.00	30.00	35.00	40.00	0.20
0.05	19.00	23.00	27.00	31.00	35.00	0.15
0.10	17.00	20.00	23.00	26.00	29.00	0.10
0.15	19.00	20.00	20.00	20.50	21.00	0.05
0.20	16.00	18.00	20.00	22.00	24.00	0.05
0.25	15.50	16.50	17.50	18.50	19.50	0.05
0.30	15.25	16.00	16.50	17.00	17.50	0.05
0.35	15.00	15.50	16.00	16.50	17.00	0.05
0.40	14.75	15.00	15.50	16.00	16.50	0.05
0.45	14.50	14.50	14.50	15.00	16.00	0.05
0.50	14.25	14.00	14.00	14.50	16.00	0.05
0.55	14.25	14.00	15.00	16.00	20.00	0.05
0.60	14.00	14.50	15.00	16.00	17.00	0.05
0.65	14.00	13.50	13.50	14.50	15.50	0.05
0.70	13.50	12.75	12.25	12.50	13.00	0.05
0.75	13.25	12.25	12.25	12.50	13.00	0.05
0.80	13.00	12.00	11.75	12.75	14.00	0.05
0.85	12.00	11.00	10.50	13.00	16.00	0.05
0.90	11.00	10.00	10.00	12.00	15.00	0.05
0.95	18.00	20.00	22.00	25.00	30.00	0.05
1.00						

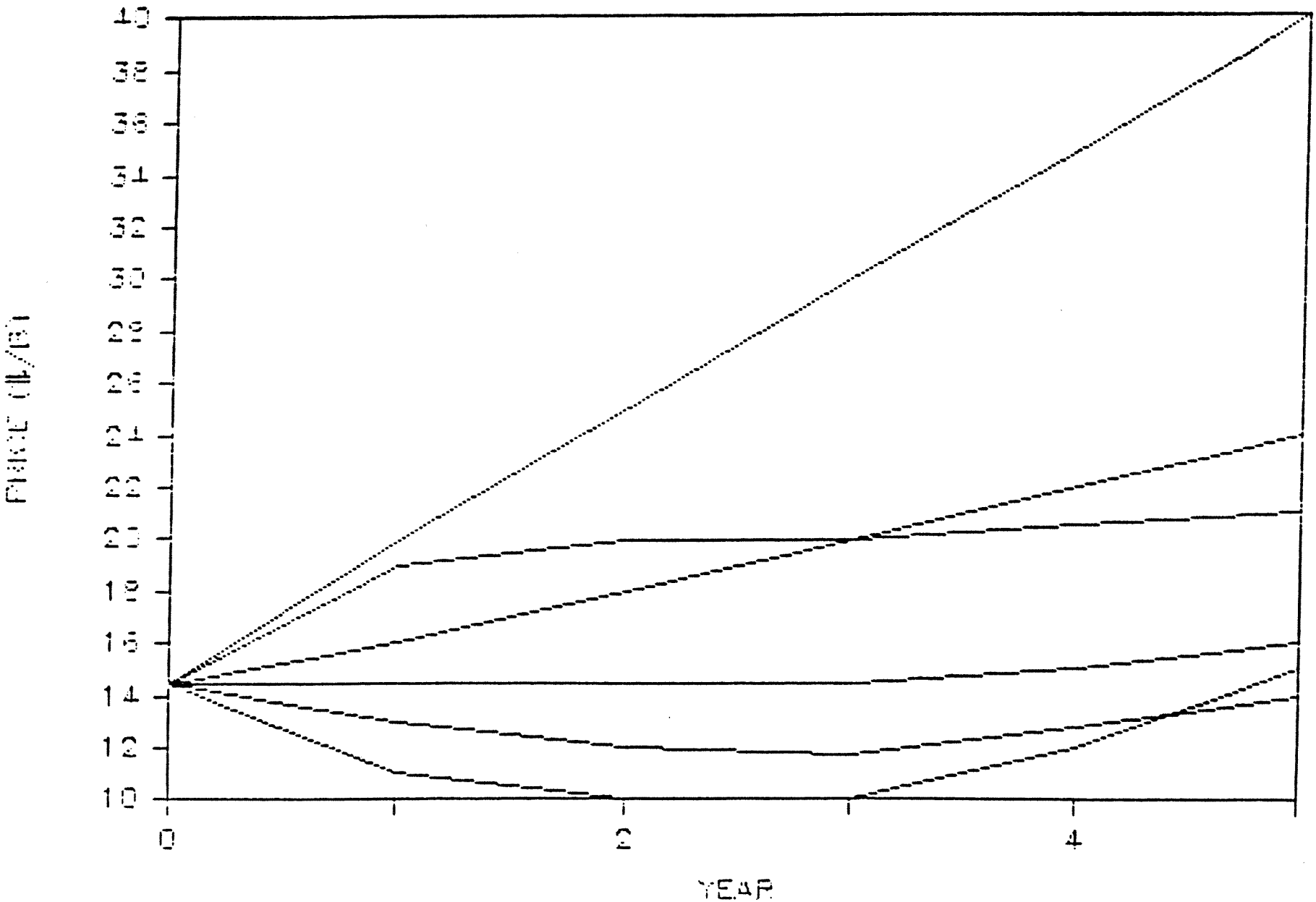

Fig. 4.9 Unusual 5-Yr. Oil Price Predictions

5. INPUT PARAMETERS

There are three classes of input parameters used in this study. First are the reservoir parameters which are assumed to be known with some certainty. These include porosity, permeability, thermal properties, tubing size, etc. The first section covers these in detail. Second are the economic parameters, some of which are known with some certainty while others are not so well known. These include oil price, drilling and well completion costs, capital investments, operating costs, etc. The second section discusses these. The third class contains the operating parameters such as pattern size and injection rates. These, unlike the first two types, are directly controllable by the operator. The third section discusses these.

5.1. RESERVOIR PARAMETERS

Both the in-situ combustion and the steam injection programs use the same basic reservoir parameters. These are listed in Table 5.1. A number of assumptions were made regarding these properties in this study. First, the temperature of the reservoir is assumed to be constant in a vertical direction, and constant throughout the reservoir initially. Second, it was assumed that the thermal properties of the reservoir and the adjacent formations (i.e., M_R,α_E, etc.) were constant throughout the pattern. Third, the reservoir properties of porosity, thickness, etc., were also assumed constant throughout the reservoir. Fourth, the wellbore, tubing and casing dimensions were assumed constant for all wells in a pattern. The values of these parameters were provided by a number of sources: Prats (1982), Willhite (1967), and Williams, *et al.* (1980) were the principal sources. These values are "ballpark" figures--they are fairly close to reality, but should be replaced for each project if new figures are available.

Note that the "Marx.f " program has a sweep efficiency factor that can be varied to match the output to field production data. For new projects without a steam flood production history, this parameter can be estimated from projects similar to the one under consideration. Strom and Brigham (1982), for example, found the parameter to be approximately 33% to 38% in the Kern River field. This will vary with the reservoir, and may also vary with pattern spacing.

5.2. ECONOMIC PARAMETERS

Economic parameters include the cost variables which cannot be changed by the operator. Examples are oil price, compressor installation costs, drilling costs, and the like. These costs are determined by factors beyond the control of the operator. The uncertainty inherent in these variables is considered by the Monte Carlo simulation technique. A complete listing of these variables is given in Tables 5.2 and 5.3. These numbers are "ballpark" figures for thermal recovery operations in California; case specific values should be substituted where known.

5.3. OPERATING PARAMETERS

This study uses two operating parameters to vary the oil production: pattern size and injection rate. A total project area of 160 to 165 acres was assumed. This area was then divided into a number of patterns of equal size, the number of patterns depending on the pattern size. For example, there are 66 2.5-acre, 33 5-acre, 16 10-acre, or 8 20-acre patterns in the above project area. The injection rate was then varied within each pattern group to obtain the oil recovery. The in-situ combustion air injection rates were 2, 3.5, 5, 7.5 and 10 MMSCF/D for the 5-acre pattern size, and 5, 7.5, 10, 12.5, 15, 17.5 and 20 MMSCF/D for the 20-acre

TABLE 5.2

OPERATING COSTS FOR MONTE-CARLO SIMULATION

OPERATING COSTS

I. GENERAL OVERHEAD AND MAINTENANCE

A. STEAM INJECTION

	$/WELL/YEAR		
	LOW	MIDDLE	HIGH
PRODUCER	24500	29500	34500
INJECTOR	24500	29500	34500

B. IN-SITU COMBUSTION

	$/WELL/YEAR		
	LOW	MIDDLE	HIGH
PRODUCER	24500	29500	34500
INJECTOR	39850	44850	49850

II. STEAM GENERATOR OVERHEAD AND MAINTENANCE

$/UNIT/YEAR		
LOW	MIDDLE	HIGH
242000	277000	311000

III. AIR COMPRESSOR OVERHEAD AND MAINTENANCE

$/UNIT/YEAR		
LOW	MIDDLE	HIGH
265000	303000	341000

IV. FUEL COSTS -BASED ON OIL PRICES

A. STEAM GENERATOR 1 B FUEL = 15 B STEAM

FEEDWATER TREATMENT

$/B		
LOW	MIDDLE	HIGH
0.21	0.25	0.29

B. AIR COMPRESSOR 1000 HP PER UNIT

8100 BTU/HP-HR = 194.4 MCF/D = 31 B/D

V. ESCALATING FACTOR

%		
LOW	MIDDLE	HIGH
4.00	5.00	6.00

pattern size. The steam injection rates were constant for all pattern sizes: 350, 500, 750, 1000, 1250, and 1500 B/D. Oil production schedules were obtained for each combination of injection rate and pattern size. This schedule was then multiplied by the number of appropriate patterns (as above) to determine a project-wide production schedule. This total schedule was then used to determine the cash flow. The number of wells and generators or compressors is a function of the method and the spacing size. The steam injection pattern assumes a 5-spot pattern, as does the 5-acre in-situ combustion pattern. The 20-acre in-situ combustion pattern assumes a 9-spot pattern. These numbers are listed in Tables 5.4 and 5.5.

A related parameter is the downhole heat content of the injected steam, which depends on the injection rate, temperature and pressure. These values are incorporated in the "Marx.f " program, and must be changed for other injection conditions. The calculations are described in Section 4.1.

TABLE 5.5

IN-SITU COMBUSTION PATTERN SPECIFICATIONS

PATTERN SPECIFICATION
IN-SITU COMBUSTION

	PATTERN SPACING	
	5-ACRE	20-ACRE
NO. OF PATTERNS	33	8
NO. OF PRODUCTION WELLS	44	37
NO. OF INJECTION WELLS	33	8
TOTAL NO. OF WELLS	77	45
NO. OF COMPRESSORS BY INJECTION RATE (MMSCF/D)		
2.0	22	-
3.5	38	-
5.0	55	14
7.5	83	20
10.0	110	27
12.5	-	34
15.0	-	40
17.5	-	47
20.0	-	54

TABLE 6.1

STEAM INJECTION OIL PRODUCTION SCHEDULE, 2.5 ACRE SPACING

OIL PRODUCTION SCHEDULE
STEAM INJECTION - 2.5 ACRE SPACING
ANNUAL PRODUCTION, MB

	INJECTION RATE, B/D					
YEAR	350	500	750	1000	1250	1500
1	94.92	137.43	204.88	274.57	335.85	343.76
2	77.55	112.29	134.51	64.81	2.39	
3	69.06	89.65				
4	63.30					
5	34.55					
TOTAL	339.38	339.37	339.38	339.38	338.23	343.76
RESIDUAL (YEARS)	0.59	0.90	0.80	0.29	0.01	0.86

TABLE 6.3

STEAM INJECTION OIL PRODUCTION SCHEDULE. 10 ACRE SPACING

OIL PRODUCTION SCHEDULE
STEAM INJECTION - 10 ACRE SPACING
ANNUAL PRODUCTION, MB

	INJECTION RATE, B/D					
YEAR	350	500	750	1000	1250	1500
1	94.92	137.43	204.88	274.57	335.85	399.96
2	77.55	112.29	167.39	224.34	274.40	326.78
3	69.06	100.00	149.07	199.78	244.37	291.02
4	63.30	91.67	136.65	183.13	224.00	266.76
5	58.97	85.39	127.29	170.59	208.67	73.01
6	55.52	80.40	119.85	160.62	70.25	
7	52.67	76.27	113.70	144.50		
8	50.26	72.78	108.49			
9	48.18	69.76	103.99			
10	46.35	67.11	100.05			
11	44.73	64.77	26.18			
12	43.28	62.66				
13	41.96	60.76				
14	40.77	59.04				
15	39.68	57.45				
16	38.67	56.00				
17	37.74	54.65				
18	36.88	49.08				
19	36.07					
20	35.32					
REMAIN	345.64					
TOTAL	1357.51	1357.51	1357.52	1357.53	1357.53	1357.53
RESIDUAL (YEARS)	11.87	0.92	0.27	0.95	0.36	0.85

TABLE 6.5

IN-SITU COMBUSTION OIL PRODUCTION SCHEDULE, 5 ACRE SPACING

OIL PRODUCTION SCHEDULE
IN-SITU COMBUSTION - 5 ACRE SPACING
ANNUAL PRODUCTION, MB

	INJECTION RATE, MMSCF/D				
YEAR	2.0	3.5	5.0	7.5	10.0
1	34.42	94.50	154.64	249.08	332.75
2	80.39	136.19	178.11	226.09	251.05
3	78.40	117.924	142.42	151.49	77.64
4	73.55	101.43	108.62	34.77	
5	65.99	82.65	70.30		
6	61.29	69.66	7.34		
7	56.02	47.37			
8	49.90	11.69			
9	44.72				
10	40.12				
11	36.41				
12	24.18				
13	17.05				
TOTAL	662.43	661.43	661.43	661.43	661.43
RESIDUAL (YEARS)	0.00	0.20	0.17	0.50	0.50

TABLE 6.7

STEAM INJECTION NET PRESENT VALUE DISCOUNTED AT 15%

DISCOUNTED NET PRESENT VALUE @ 15%
(MM$)

INJECTION RATE (B/D)	2.5-ACRE SPACING		5-ACRE SPACING	
	MEAN	STD DEV	MEAN	STD DEV
350.0	106.397	39.949	105.589	60.812
500.0	108.321	32.934	117.871	34.604
750.0	104.554	28.081	117.390	30.199
1000.0	97.355	25.413	115.609	29.225
1250.0	90.882	22.075	114.062	31.801
1500.0	85.406	19.415	109.151	28.110

INJECTION RATE (B/D)	10-ACRE SPACING		20-ACRE SPACING	
	MEAN	STD DEV	MEAN	STD DEV
350.0	100.131	72.638	103.035	121.379
500.0	111.161	46.103	116.182	92.646
750.0	112.397	43.872	130.440	148.506
1000.0	116.646	34.530	133.224	89.788
1250.0	115.040	34.284	131.349	68.643
1500.0	114.041	34.476	122.384	55.059

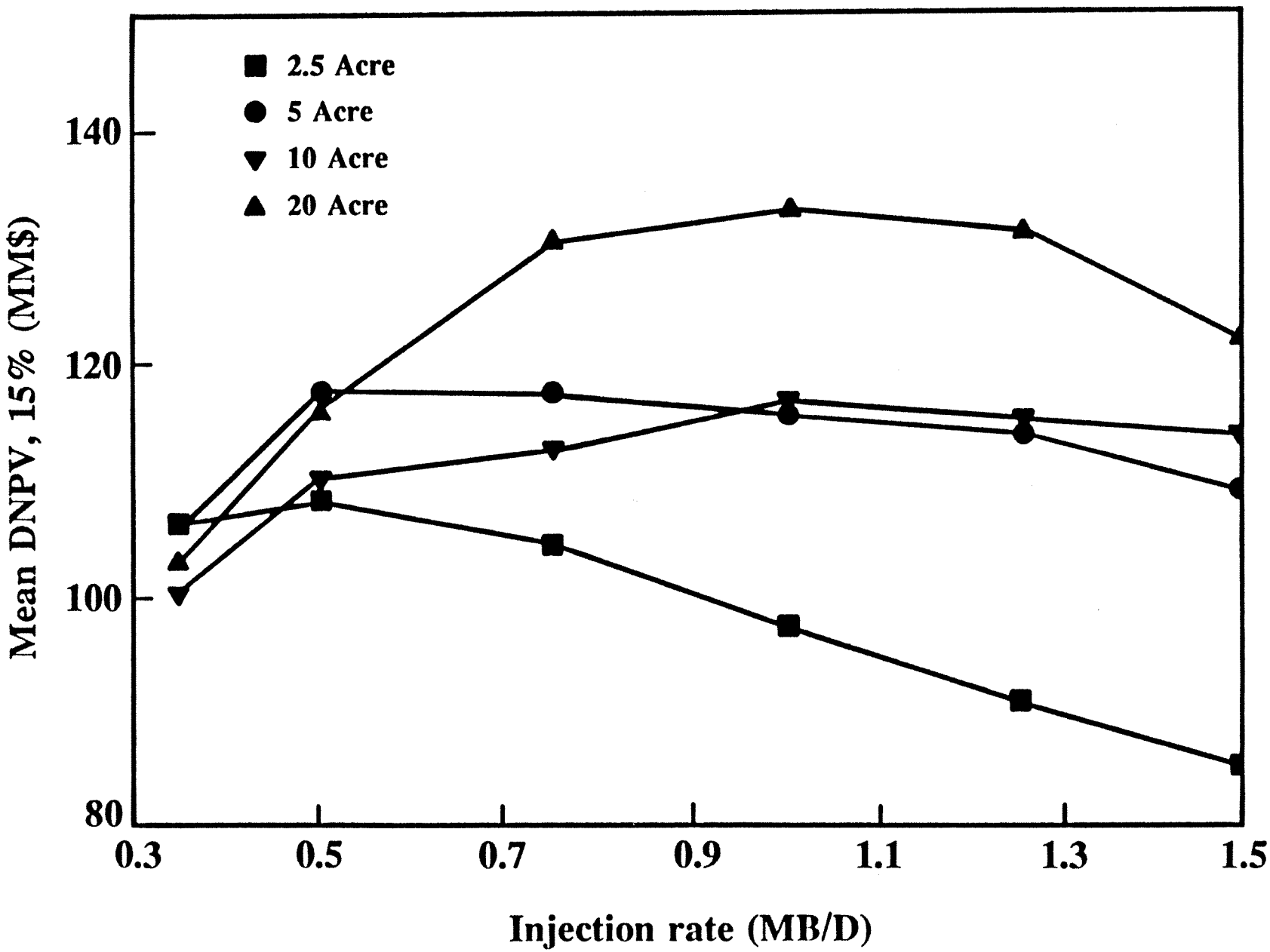

Fig. 6.1. Steam Injection DNPV at 15%

The highest average net present value for steam injection is obtained with a combination of 20-acre spacing and a 1000 B/D injection rate. The mean is 133 million dollars, and has a standard deviation (based on 50 runs) of 90.

The patterns were well-behaved except for large pattern sizes and low injection rates. The cumulative probability functions in Appendix C show that the results varied over a very large range. For instance, the 20-acre spacing pattern shows a high concentration of values around 90 million dollars, but has possible values of 700 or more (injection rate of 750 B/D). For this case, this gives a standard deviation of 149 for a mean of only 130. This also occurs for other cases.

The highest net present value for in-situ combustion is obtained with a combination of 20-acre spacing and an injection rate of 7.5 MMscf/D. The mean is 80 million dollars, and has a standard deviation of 55. The fuel used is gas. A perusal of the table shows that using gas-fueled compressors generates the highest net present value. The highest values within a given pattern size are generally seen at low injection rates. The cumulative probability functions show that there were cases of high injection rates that showed a few net losses (i.e., negative net present values). As with the steam injection results, the values are well-behaved except for large pattern sizes and low injection rates where the standard deviations are nearly equal to the mean.

Comparing the results shows that steam injection gives a generally higher average net present value than in-situ combustion for the conditions used in this study. The efficiency factor for the steam injection model was set at 1.0 for these calculations. This is already not realistic. A lower efficiency, such as the 33 to 38% obtained by Strom and Brigham (1985), would lower the total oil recovery and the net present value for steam injection. For nearly all cases, the in-situ combustion results show a higher relative variance than the steam injection results. There are two reasons for this. First, the number of compressors for any given pattern size is far greater than the number of steam generators required. For example, the 20-acre pattern at maximum injection rates requires 54 compressors but only 5 generators. This directly affects the calculation of initial investments: the in-situ combustion projects have a higher capital investment. Second, and less importantly, the operating costs used for an injection well in an in-situ combustion project are about one-and-one-half times the costs for a steam flood. These factors combine to give a larger relative spread of the resulting values.

The results of this study are intended to demonstrate the features of the calculation method to assess risk. Many of the cases considered are clearly not practical or real. Results also appear to contradict current results from in-situ combustion and steam injection. A recent observation is that California steam injection oil production is considered high cost oil production and is being shut in or considered for shut in by several operators. On the other hand, in-situ combustion oil production is not being shut in. It appears that more realistic and current operating cost data should be sought for future evaluations.

Another important factor neglected in this study is injectivity. Increasing rate and pattern area requires an increase in injection pressure for both processes. Injection rates should be limited to cases actually possible. High pressure can have a dramatic effect on steam injection that is not observed in in-situ combustion. High pressure requires high temperature for two-phase steam and thermal efficiency drops rapidly. This causes a rapid drop in present worth as injection rate increases for steam injection. Future work with this evaluation program should add consideration of injectivity to obtain more realistic results.

The shape of the cumulative probability function for all cases is unusual. A large proportion of the values are clustered at the low end of the possible spectrum, with very little,

TABLE 6.9

STEAM INJECTION CUTOFF FACTOR AT 5% SIGNIFICANCE LEVEL

INJECTION RATE (B/D)	2.5-AC SPACING			5-AC SPACING		
	MEAN	STD DEV	L	MEAN	STD DEV	L
350.0	106.397	39.949	9.265	105.589	60.812	14.104
500.0	108.321	32.934	7.638	117.871	34.604	8.026
750.0	104.554	28.081	6.513	117.390	30.199	7.004
1000.0	97.355	25.413	5.894	115.609	29.225	6.778
1250.0	90.882	22.075	5.120	114.062	31.801	7.376
1500.0	85.406	19.415	4.503	109.151	28.110	6.520

INJECTION RATE (MMCF/D)	10-AC SPACING			20-AC SPACING		
	MEAN	STD DEV	L	MEAN	STD DEV	L
350.0	100.131	72.638	16.847	103.035	121.379	28.152
500.0	111.161	46.103	10.693	116.182	92.646	21.487
750.0	112.397	43.872	10.175	130.440	148.506	34.443
1000.0	116.646	34.530	8.009	133.224	89.788	20.825
1250.0	115.040	34.284	7.952	131.349	68.643	15.920
1500.0	114.041	34.476	7.996	122.384	55.059	12.770

the reservoir was measured as a result of changes in certain input parameters. For both steam injection and in-situ combustion, the operating parameter was held constant for all tests at the value that optimized the economics of the project. Ideally, once the optimal operating parameters are found, all input parameters should be held constant while the operating parameters are varied from their optimal values. The sensitivity will then be reflected in the change in the oil recovered over a given time period. However, it proved impossible to find the optimal injection parameter (Section 6.3), so this test could not be done.

Attempting to measure the sensitivity of the Marx and Langenheim model (FORTRAN program "Marx.f") poses a question: which output value to use? This is a result of the variance in the cumulative oil production fluctuating with time. In general, it appears that the smallest change in the oil production, as a percentage of the "optimal" value for the same time, occurs in the first month, and steadily increases afterwards. Bearing this in mind, the standard value of cumulative oil production was chosen to be the "optimal" value (the value determined at the optimal net present value and at standard, original, values of the input parameters) at one month (30.4 days).

The results are shown in Table 6.11. The net pay thickness and the porosity of the reservoir show a direct one-to-one correlation to the cumulative oil production. The initial oil saturation shows the highest sensitivity: a 10% change in the value of the saturation results in an 11.7% change in the cumulative oil production after one month. Other sensitive parameters include the total pay thickness of the reservoir, the formation volume factor, and the volumetric heat capacity of the reservoir. The temperature of the undisturbed formation and the residual oil saturation show less sensitivity. The most insensitive parameters, however, are the volumetric heat capacity and the thermal diffusivity of the adjacent formations; the latter showing a change of only 0.04% in oil production per 1% change in the parameter. A general trend is evident: the most important parameters are those reflecting the properties of the reservoir. The properties of the adjacent formations are important, but can be estimated with little worry for their accuracy beyond a ten to twenty percent variance.

The determination of the sensitivity of the oil recovered to variances in the input parameters for the Gates and Ramey oil recovered-volume burned model (FORTRAN program "Vol.f ") was simpler. There was no change with time in the variance of the oil production, so any value could be picked as the basis. In practice, this study used the first calculated value--the oil recovered after burning 5% of the reservoir volume.

The results (Table 6.12) are similar to those obtained for the Marx and Langenheim model. The porosity, areal extent, height of the reservoir, initial oil saturation, and oil formation volume factor all show great sensitivity. The initial gas saturation shows very little sensitivity. This parameter comes into play primarily as a determinant for the Gates and Ramey oil recovery-volume burned graph (Fig. 4.2). This parameter differs from the others in that the variance in the oil recovered does change with time (and amount of volume burned), but a visual study of the graph shows that this variance is greatest at early times. Therefore, the variances shown are the largest that will be seen (for this case), and ultimately the same amount of oil will be recovered. The result is an input parameter that acts like an operating parameter--its effect is on the timing of the oil recovery, not on the total oil recovery.

A parameter similar to this is the oxygen utilization coefficient. This parameter has no effect on the oil production as a function of the volume burned, but it does affect the timing of the recovery, and also the amount of air required. This will affect the economics of the project.

The sensitivity of the oil production to the combustion tube parameters is also shown. These are, on the whole, much smaller than the sensitivities to the reservoir parameters. Note

TABLE 6.12

IN-SITU COMBUSTION MODEL SENSITIVITY

OIL RECOVERED-VOLUME BURNED MODEL SENSITIVITY
FOR IN-SITU COMBUSTION

% CHANGE IN OIL PRODUCTION DUE TO CHANGE IN PARAMETER

CHANGE IN PARAMETER (%)	PARAMETER - COMBUSTION TUBE DATA - POROS	AF	VF	PARAMETER ---- RESERVOIR DATA ----- AREA	HEIGHT	POROS
+10	-1.174	-2.062	1.875	10.000	10.000	13.125
+ 5	-0.571	-1.031	0.982	5.000	5.000	6.562
+ 1	-0.112	-0.206	0.204	1.000	1.000	1.313
- 1	0.110	0.206	-0.208	-1.000	-1.000	-1.313
- 5	0.541	1.031	-1.085	-5.000	-5.000	-6.562
-10	1.054	2.062	-2.292	-10.000	-10.000	-13.125

CHANGE IN PARAMETER (%)	PARAMETER RESERVOIR DATA So	Sg	Bo
+10	12.062	0.593	-10.966
+ 5	6.031	0.296	-5.744
+ 1	1.206	0.059	-1.194
- 1	-1.206	-0.059	1.218
- 5	-6.031	-0.296	6.349
-10	-12.062	-0.593	13.403

NO EFFECT
API
UTO2
RAD CT

DEFINITION OF VARIABLES:

POROS - POROSITY OF THE COMBUSTION TUBE OR RESERVOIR
AF - AIR FLUX IN THE COMBUSTION TUBE
VF - VELOCITY OF THE BURNING FRONT IN THE TUBE
AREA - AREA OF THE RESERVOIR
HEIGHT - HEIGHT OF THE RESERVOIR
So - INITIAL OIL SATURATION
Sg - INITIAL GAS SATURATION
Bo - FORMATION VOLUME FACTOR FOR OIL
API - OIL GRAVITY IN DEGREES API
UTO2 - OXYGEN UTILIZATION COEFFICIENT
RAD CT - RADIUS OF THE COMBUSTION TUBE

7. CONCLUSIONS AND RECOMMENDATIONS

The foremost result to be concluded from this study is that in-situ combustion is economically competitive with steam injection as an alternative thermal recovery method. If evaluation of the reservoir indicates that both methods are technically feasible, then projected cash flows should be obtained under a number of operating parameters for both thermal methods. Given the proper input parameters, it should be possible to determine which method will yield the highest return.

The results obtained in this study demonstrate that a Monte Carlo simulation technique is an effective way to consider the uncertainty of the economic parameters when calculating cash flows. This method can be used for spreadsheet analysis of other investments besides thermal recovery projects. In addition, a Monte Carlo simulation can be added to production programs to simulate the uncertainty of reservoir parameters where the probability distributions of these parameters can be estimated.

The variability of the resulting net present values in this study is primarily a result of the low number of trials and uncertain future oil prices. The first can remedied by using larger number of trials; the second can only be cured with time. The volatility of the market price of oil at present causes any prediction to be uncertain. This in turn makes it nearly impossible to determine the optimal injection rate for any given patten spacing, but it is possible to determine that low injection rates, coupled with large spacing patterns, are generally more profitable because they delay the recovery of the oil for a significant period of time, thus taking advantage of the later higher oil prices. This assumes that oil prices will indeed be higher in later years (approximately a 7-year horizon for all scenarios). The implication is that a thermal recovery project started today would be most profitable if the oil production is delayed until after the oil price increases (or at least stabilizes). In fact, it might be advisable to delay starting the project altogether.

It is also seen that there is economy of scale--larger pattern sizes mean higher average net present values. This is the result of the delay in oil production as noted in conjunction with lower capital investments and operating costs due to the fewer number of wells and operating units.

All conclusions reached are of course specific to the conditions used in this study. Although an attempt was made to find realistic conditions, certain cost and experience data were estimated. Also, it is known that consideration of injectivity would have had a significant influence.

There are many areas in which this material can be expanded. We recommend the following areas of investigation:

1. This method should be applied to a number of other projects, such as the Bodcau in-situ combustion project. This will necessitate substituting the project-specific parameters into the models as appropriate. In cases where a project has been running for some time, a history-match should be attempted.
2. Hopefully, a better prediction of oil prices may be made in order to eliminate part of the variance in the net present value results. This should enable a determination of optimum injection rates for a given pattern size. Also injectivity should be considered so that the effect of injection pressure on steam injection will be realistic.

NOMENCLATURE

A = Fuel-air requirement, lb/scf
A_{CT} = Cross-section area of combustion tube, ft^2
A_{EX} = Excess air, %
A_{inj} = Total air injected, ft^3
$A_{R_{cum}}$ = Cumulative air requirement, ft^3
A_r = Air required to burn a given reservoir volume, ft^3
A_{sr} = Air required to burn a given reservoir volume, MMscf/ac-ft
A_T = Total areal extent of reservoir, acres
$\frac{A}{F}$ = Air/fuel ratio, ft^3/lb
AOR = Air/oil ratio, MMscf/B
AOR_c = Current air/oil ratio, ft^3/B
AOR_{cum} = Cumulative air/oil ratio, MMscf/B
AP = Total air injected to oil produced ratio
α_E = Thermal diffusivity of the earth, ft^2/D
α_s = Thermal diffusivity of adjacent formations, ft^2/D
B_{o_i} = Initial oil formation volume factor, vol/vol
B_a = Isobaric thermal coefficient of volume expansion, $°F^{-1}$
C_F = Fuel cost for air compressor, \$/yr.
C_{CO} = Concentration of CO, vol. %
C_{CO_2} = Concentration of CO_2, vol. %
C_{N_2} = Concentration of N_2, vol. %
C_{O_2} = Concentration of O_2, vol. %
C_W = Average specific heat, Btu/lbm-°F
d_t = Discount factor for year t, fraction
$E(x)$ = Expected value of x
E_c = Capture efficiency, fraction
E_h = Fraction of injected heat remaining in reservoir
ε_{ci} = Emissivity of inner casing surface
ε_{ins} = Emissivity of insulation
F_t = Future value, \$
$\frac{H}{C}$ = Atomic hydrogen-to-carbon ratio
h = Height, ft
h_f = Film coefficient of heat transfer, Btu/ft^2-D-°F
h_{fc} = Forced convection coefficient of heat transfer, Btu/ft^2-D-°F
h_n = Net pay thickness, ft
h_{p_i} = Coefficient of heat transfer across scale deposits, Btu/ft^2-D-°F

$\dot{Q}_{ls}$ = Rate of heat loss per unit length of pipe, Btu/ft-D
R = Reciprocal of slope, dimensionless
R_h = Overall specific thermal resistance, (Btu/ft-D-°F)$^{-1}$
r = Radius, ft
r_{ci} = Inner casing radius, ft
r_{co} = Outer casing radius, ft
r_{CT} = Radius of combustion tube, ft
r_i = Inner radius of pipe/tubing, ft
r_{ins} = Radius of insulation, ft
r_o = Outer radius of pipe/tubing, ft
r_t = Discount rate at time t, fraction
r_w = Wellbore radius, ft
ρ_a = Density of fluid in annulus, lbm/ft^3
S_{g_i} = Initial gas saturation, fraction
S_{o_i} = Initial oil saturation, fraction
S_{o_r} = Residual oil saturation, fraction
S_{w_i} = Initial water saturation, fraction
σ_x = Standard deviation of x
$\bar{T}$ = Average temperature, °F
T_A = Ambient temperature, °F
T_b = Bulk fluid temperature, °F
T_{c_i} = Casing inner surface temperature, °F
T_{ins} = Insulation outer surface temperature, °F
T_R = Temperature of reservoir, °F
t = Time, D
t_B = Time to burn a reservoir volume, D
t_D = Dimensionless time
t_j = Time at step j, D
U = Overall coefficient of heat transfer, Btu/D-°F ft^2
U_{o_2} = Oxygen utilization coefficient, fraction
u_a = Air rate, ft^3/D
$V(x)$ = Variance of x
V_B = Combustion tube volume burned in a given time, ft^3/D
V_{Rb} = Standard reservoir volume burned, ft^3
V_{stm} = Volume of steam zone, ac-ft
v_b = Velocity of combustion front, ft/D
v_w = Wind velocity, mi/hr
WOR = Water-to-oil, or water-to-fuel, ratio
w_i = Mass injection rate, lbm/D
x, X = Random variables
z_L = Standardized normal probability

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APPENDIX A: SAMPLE INPUT FILES

TABLE A.1
INPUT FILE FOR MARX.F, 35Ø B/D

```
1
1.ØØ
1.Ø3
Ø.67
.1Ø
93
93
.34
93.ØØ
.72Ø
7Ø
365.Ø
1Ø64Ø    1
1Ø64Ø    1
  .
  .
  .
  .
1Ø64Ø    1
1Ø64Ø    1
1.ØØ
365.Ø
36
41
```

TABLE A.2
INPUT FILE FOR MARX.F, 5ØØ B/D

```
1
1.ØØ
1.Ø3
Ø.67
.1Ø
93
93
.34
93.ØØ
.72Ø
6Ø
365.Ø
152ØØ    2
152ØØ    2
  .
  .
  .
  .
152ØØ    2
152ØØ    2
1.ØØ
365.Ø
36
41
```

TABLE A.3
INPUT FILE FOR MARX.F, 75Ø B/D

```
1
1.ØØ
1.Ø3
Ø.67
.1Ø
93
93
.34
93.ØØ
.72Ø
3Ø
365.Ø
228ØØ    3
228ØØ    3
  .
  .
  .
  .
228ØØ    3
228ØØ    3
1.ØØ
365.Ø
36
41
```

TABLE A.7
INPUT FILE FOR VOL.F, 20 ACRE, 20 MMSCF/D

```
8712000.00        93.00    0.67     0.07     0.26     0.340    13.00    1.030
1.0       0.0
0.3500    1.25     120.0    3.5
3.0       12.0     0.5      84.5
21.0      79.0
20.00     20.0
```

TABLE A.8
INPUT FILE FOR VOL.F, 5 ACRE, 10 MMSCF/D

```
2178000.00        93.00    0.67     0.07     0.26     0.340    13.00    1.030
1.0       0.0
0.3500    1.25     120.0    3.5
3.0       12.0     0.5      84.5
21.0      79.0
10.00     5.0
```

APPENDIX B.1: "MARX.F" STEAM INJECTION PROGRAM LISTING

```
      program marxlangenheim

c     This program will predict the oil production based on Marx and
c     Langenheim's steam flood model with Ramey's correction for
c     variable heat injection rates

c     Dimension the necessary arrays and open storage files.



      implicit real*8(a-h,o-z)
      real*8 lv(72), ms, mr
      dimension qr(72), wi(72), cw(72),ts(72), fs(72), lv(72), hpr(72)
      dimension td(72), time(72), delqr(72), delwi(72), tint(72),wib(72)
      dimension win(10,72),ll(72),q(72),pop(10,72),nip(10),totoil(72)
      dimension steam(10,72),prodoil(10,72),stinj(10,72)
      dimension totsteam(72)

      open(unit=3,file='result')
      rewind(unit=3)
      open(unit=4,file='grap')
      rewind(unit=4)
      OPEN(UNIT=8, FILE='marx.in', STATUS='old', ACCESS='sequential')
      REWIND(UNIT=8)

c     This begins the interactive portion of the program, in which the user
c     requested all necessary reservoir poperties, thermal and non-thermal.
c     This data may easily be inputted with a file as well.


c     The variable kseg and its accompanying do loop allows for running all
c     six well groupings at the same time. kseg is simply the number of well
c     groupings utilized per run.

      read(8,*) kseg

      do 17 ll5=1,kseg
              do 18 m=1,72
                      qr(m) = 0.0
                      wi(m) = 0.0
                      cw(m) = 0.0
                      ts(m) = 0.0
                      fs(m) = 0.0
                      lv(m) = 0.0
                      hpr(m) =0.0
                      td(m) = 0.0
                      time(m) = 0.0
                      delqr(m) = 0.0
                      delwi(m) = 0.0
                      tint(m) = 0.0
                      wib(m) = 0.0
                      ll(m) = 0.0
                      q(m) = 0.0
18            continue
              opold = 0.0
              qold = 0.0
              vsold = 0.0

              read(8,*) ec
              read(8,*) bo
              read(8,*) soi
              read(8,*) sor
```

```
     *f8.2,/,
     *'Temperature of Undisturbed Reservoir (deg F)',16x,f9.2,/,
     *'Thermal Diffusivity of Adj. Formations (sq.ft./day)',9x,f9.2,/,
     *'Porosity',52x,f9.2,/,
     *'Initial Oil Saturation',38x,f9.2,/,'Residual Oil Saturation',37x,
     *f9.2,/,
     *'Net Pay Thickness (ft)',38x,f9.2,/,'Total Pay Thickness (ft)',36x,
     *f9.2,/,
     *'Oil Formation Volume Factor',33x,f9.2,/,
     *'Capture Efficiency',42x,f9.2,//)

c       Input parameters that vary from month to month may also be printed
c       out. Here, however, that step has been bypassed becuase of the
c       lengthiness of that data. Removal of the "GOTO 60" statement will
c       implement this printed output.

        GOTO 60

        do 60 i=1,ni
                write(6,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
                write(3,51) i,tint(i),wib(i),fs(i),lv(i),cw(i),ts(i),hpr(i)
51              format(25x,'INTERVAL #',i2,/,'time (days)',20x,f12.2,/,
     *'injection rate (bbls/day)',6x,f12.2,/,
     *'quality of steam',15x,f12.2,/,
     *'latent heat of vaporization',4x,f12.2,/,
     *'heat capacity of steam (btu.lb-degF)',f7.2,/,
     *'temperature of steam (deg F)',3x,f12.2,/,
     *'fraction of injected heat produced',f9.2,//)
60      continue

c       Here the downhole heat injected is calculated for each month.

                do 100 i = 1,ni
                        qr(i)= wi(i)*q(i)
100             continue

c       The multiplicative step for determining dimensionless time is
c       calculated in this step.

                c = 4.0 * ((ms/mr)**2) * (alpha/(ht**2))
                d = 1.0/c
                tcum = 0.0

c       The following loop calculates and stores time and dimensionless
c       time for each monthly interval.

                do 200 i=1, ni
                        tcum = tcum+tint(i)
                        td(i) = c*tcum
                        time(i) = tcum
200             continue

c       Next, the change in the rate of heat input over each month is
c       calculated and stored. The same is done with the rate of barrels of
c       water equivalent injected.

                delqr(1) = qr(1)
                delwi(1) = wi(1)
                if (ni.eq.1) go to 300
                do 300 i=1,ni-1
                        delqr(i+1) = qr(i+1)-qr(i)
                        delwi(i+1) = wi(i+1)-wi(i)
300             continue
```

```
c       for that month is set to zero.

                op = 7758.Ø* porpay*(hn/ht)*(soi-sor)*ec*vs/bo
                if (op.lt.opold) op = opold
                pop(115,mm) = op
                steam(115,mm) = vw
                difop = op-opold
                write(6,75Ø) tt,vw,op,vs,difop
                write(3,75Ø) tt,vw,op,vs,difop
75Ø             format(f7.1,9x,f1Ø.1,11x,f9.1,14x,f9.3,11x,f9.1)

c       The old values of oil produced, steam zone volume, and heat in the
c       reservoir are now set to the latest calculated values, and the time
c       step is increased to the next month. The program then loops back to
c       perform the entire calculation again. When the total number of
c       intervals exceeds that which had previously been inputted as the
c       maximum, the program proceeds to the next well grouping.

                opold = op
                vsold = vs
                qold = qcum
                tt = tt + tstep
                mm = mm+1
                if(tt.le.time(ni)) go to 39Ø
17      continue

c       The following set of calculations adds the separate well groupings
c       results and prepares an input file for automatic graphing by
c       computer.

        do 8ØØ k=1,kseg
                mn = 72-nip(k)
                do 81Ø j=1,mn
                        prodoil(k,j) = Ø.Ø
                        stinj(k,j) = Ø.Ø
81Ø             continue
                do 82Ø j=1,nip(k)
                        mmn = mn+j
                        prodoil(k,mmn) = pop(k,j)
                        stinj(k,mmn) = steam(k,j)
82Ø             continue
8ØØ     continue

        do 9ØØ  n=1,72
                do 91Ø k=1,kseg
                        totoil(n)=totoil(n)+prodoil(k,n)
                        totsteam(n) = totsteam(n)+ stinj(k,n)
91Ø             continue
9ØØ     continue

        jkl = 29
        write(4,92Ø) jkl
92Ø     format(i5)
        write (6,1ØØØ)
1ØØØ    format ('Totsteam and Totoil:')
        do 94Ø j=44,72
                write(4,93Ø) totsteam(j), totoil(j)
93Ø             format(2f13.4)
94Ø     continue

        stop
        end

c       This is the defined function the Marx and Langenheim solution.


        function g(a)
        implicit real*8(a-h,o-z)
        b=sqrt(a)
        pi=3.1415927
        g=2.Ø*((a/pi)**Ø.5)-1.Ø+(dexp(a)*derfc(b))
        return
        end
```

```
      OPEN(UNIT=10, FILE='v.in', STATUS='old', ACCESS='sequential')
      REWIND(UNIT=10)
      OPEN(UNIT=9, FILE='z.in', STATUS='old', ACCESS='sequential')
      REWIND(UNIT=9)

c     Initialize all necessary variables:

      read (10,*) area, h, soi, sgi, swi, por, api, boi
      read (10,*) uto2, pripro
      read (10,*) porc, rad, af, velf
      read (10,*) cco, cco2,co2,cn2
      read (10,*) ao2, an2
      read (10,*) airinj,totar

      read (9,*) ((z(i,j),i=1,21),j=1,6)

c     Print Input Variable Values

      write(6,2)
2     format ('     INPUT DATA FOR RESERVOIR')
      write(6,4) area, h
4     format ('Area (sq ft)',15x,f10.2,/,
     C'Thickness (ft)',13x,f10.2)
      write(6,5) soi, sgi, swi
5     format ('Initial Saturations',/,'   Oil',21x,f10.2,/,
     C'   Gas',21x,f10.2,/,'   Water',19x,f10.2)
      write(6,6) por, api, boi
6     format ('Porosity',19x,f10.2,/,
     C'API Gravity', 16x, f10.2,/,
     C'Formation Volume Factor',3x,f11.2)
      write(6,13) airinj , totar
13    format ('Air Injection Rate',9x,f10.2,/,
     C'Total Area of Project',9x,f7.2,//)
      write(6,7)
7     format ('     INPUT DATA FOR TUBE RUN')
      write(6,8) porc, rad, af, velf
8     format ('Porosity ',18x,f10.2,/,'Radius (in.)',15x,f10.2,/,
     C'Air Flux',19x,f10.2,/,'Velocity of Burning Front',2x,f10.2,/)
      write(6,9)
9     format ('Gas Composition')
      write(6,10) cco,cco2,co2,cn2
10    format (17x,'CO, (wt %) ',f10.4,/,17x,'CO2,(wt %)',
     Cf11.4,/,17x,'O2, (wt %) ',f10.4,/,17x,'N2, (wt %)', f11.4,/)
      write(6,11)
11    format ('Air-Used Compostion')
      write(6,12) ao2, an2
12    format (17x,'O2, (wt %) ',f10.4,/,17x,'N2, (wt %) ',f10.4,//)

c     TUBING RUN:

      write(6,20)
20    format(5x,'TUBING RUN')

c     Calculate volume burned in combustion tube (cu.ft./m)

      areac = 3.1417*(rad/12)**2
      volb = areac*velf/12.0

c     Calculate amount of air need to burn a pound of fuel

      hc = 4.0 * (21.0/79.0*cn2-cco2-0.5*cco-co2)/(cco2+cco)
      a = (cco+cco2)*(12.0 + HC)/100.0/379.0
```

```
c       End interpolation of graph

c       Calculate barrels produced per acre-foot
c       Calculate air required for burned volume (mcf/acre-foot)
c       Calculate cumulative air/oil ratio (mcf/bbl)

c       Determine the production schedule and cum. oil production:

        print 71
71      format (31x,'TABLE 2',/)
        print 72
72      format ('Volume Burned  Oil Rec"d  Reciprocal   Current AOR',
     C          '   Excess Air  Injected AOR  Time')
        print 73
73      format (7x,'%',11x,'%',7x,'of slope',6x,'mscf/bbl',5x,
     C          'fraction',5x,'mscf/bbl',4x, 'days')

        do 80 i=2,21
                vb = 5.0 * (i-1)
                x=0.0
                do 81 ii = 2,6
                        if (sgi-x.le.0) go to 82
81              x=x+10.0
82              fracx = (x-sgi) *0.1
                orec = (1-fracx)*z(i,ii-1) + fracx*z(i,ii)

c       Find the reciprocal for slope of curve from % of oil at start
c        less fuel graph...

                xr = abs(( z(i-1,ii)-z(i,ii))/5.0)
                r = 1.0/xr
                airreq = totar*h*asr
                aorcur = r*asr/odis*1000.0
                exair = 0.9*orec-15.85
                ap = aorcur* (1.0+exair/100.0)
                time = vb/100.0 * airreq/airinj

                print 74, vb, orec, r, aorcur, exair, ap, time
74              format (1x,f10.3,1x,f10.2,1x,f10.2,4x,f10.2,3x,f10.2,2x,
     C                  f10.2,1x,f10.2)
80      continue

c       Calculations for Table 3

        write(6,1)
1       format(' ',///)

        print 91
91      format (31x,'TABLE 3',/)
        print 92
92      format ('Volume Burned  Oil Recovered  Oil Recovered
     C,'Air Required    Cumulative AOR')
        print 93
93      format (8x,'%',15x,'%',11x,'bbl',12x,'mmscf',10x,'mscf/bbl')

        do 90 i=2,21
                vb = 5.0 * (i-1)
                x = 0.0
                do 96 ii=2,6
                        if (sgi-x.le.0) go to 95
96              x=x+10
95              fracx = (x-sgi)*0.1
                orec = (1-fracx)*z(i,ii-1)+fracx*z(i,ii)
c
```

APPENDIX B.3: LOTUS SPREADSHEET MODEL LISTING

THERMAL TECHNIQUE: IN-SITU COMBUSTION DATE: MAY 30
FIELD: SOUTH BELRIDGE INJ RATE: 5
PATTERN: 5-AC, 5-SPOT NO. PATT: 33

NET PRESENT VALUE CALCULATION USING MONTE-CARLO SIMULATION

YEAR	YEAR	1 OIL PROD. (MB)	2 OIL PRICE ($/B)	3 GROSS INCOME (M$)	4 LEASE ROYALTY @10%	5 FUEL COSTS (M$)
0						
1	1986	5102.99	14.25	72718	7272	8868
2	1987	5877.73	14.00	82288	8229	8713
3	1988	4699.86	14.00	65798	6580	8713
4	1989	3584.53	14.50	51976	5198	9024
5	1990	2319.83	16.00	37117	3712	9957
6	1991	242.29	16.80	4070	407	1743
7	1992	0.00	17.64	0	0	0
8	1993	0.00	18.52	0	0	0
9	1994	0.00	19.45	0	0	0
10	1995	0.00	20.42	0	0	0
11	1996	0.00	21.44	0	0	0
12	1997	0.00	22.51	0	0	0
13	1998	0.00	23.64	0	0	0
14	1999	0.00	24.82	0	0	0
15	2000	0.00	26.06	0	0	0
16	2001	0.00	27.37	0	0	0
17	2002	0.00	28.73	0	0	0
18	2003	0.00	30.17	0	0	0
19	2004	0.00	31.68	0	0	0
20	2005	0.00	33.26	0	0	0
21	REMAIN	0.00	34.93	0	0	0
	TOTAL	21827		313967	31397	0

```
H15: (F0) (($E15*31*365*$C$76))/1000
B16: +B15+1
C16: +C15+1
D16: (F2) 142.42*33
E16: (F2) @VLOOKUP(G$40,$A$46..$H$66,4)
F16: (F0) +D16*E16
G16: (F0) +F16*(0.1)
H16: (F0) (($E16*31*365*$C$76))/1000
B17: +B16+1
C17: +C16+1
D17: (F2) 108.622*33
E17: (F2) @VLOOKUP(G$40,$A$46..$H$66,5)
F17: (F0) +D17*E17
G17: (F0) +F17*(0.1)
H17: (F0) (($E17*31*365*$C$76))/1000
B18: +B17+1
C18: +C17+1
D18: (F2) 70.298*33
E18: (F2) @VLOOKUP(G$40,$A$46..$H$66,6)
F18: (F0) +D18*E18
G18: (F0) +F18*(0.1)
H18: (F0) (($E18*31*365*$C$76))/1000
B19: +B18+1
C19: +C18+1
D19: (F2) 7.342*33
E19: (F2) +E18*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F19: (F0) +D19*E19
G19: (F0) +F19*(0.1)
H19: (F0) (($E19*31*365*$C$76))/1000/6
B20: +B19+1
C20: +C19+1
D20: (F2) 0
E20: (F2) +E19*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F20: (F0) +D20*E20
G20: (F0) +F20*(0.1)
H20: (F0) 0
B21: +B20+1
C21: +C20+1
D21: (F2) 0
E21: (F2) +E20*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F21: (F0) +D21*E21
G21: (F0) +F21*(0.1)
H21: (F0) 0
B22: +B21+1
C22: +C21+1
D22: (F2) 0
E22: (F2) +E21*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F22: (F0) +D22*E22
G22: (F0) +F22*(0.1)
H22: (F0) 0
B23: +B22+1
C23: +C22+1
D23: (F2) 0
E23: (F2) +E22*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F23: (F0) +D23*E23
G23: (F0) +F23*(0.1)
```

```
H31: (F0) 0
B32: +B31+1
C32: +C31+1
D32: (F2) 0
E32: (F2) +E31*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F32: (F0) +D32*E32
G32: (F0) +F32*(0.1)
H32: (F0) 0
B33: +B32+1
C33: +C32+1
D33: (F2) 0
E33: (F2) +E32*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F33: (F0) +D33*E33
G33: (F0) +F33*(0.1)
H33: (F0) 0
B34: +B33+1
C34: "REMAIN
D34: (F2) 0
E34: (F2) +E33*(1+@VLOOKUP(G$40,$A$46..$H$66,7))
F34: (F0) +D34*E34
G34: (F0) +F34*(0.1)
H34: (F0) 0
H35: (F0) '
C36: "TOTAL
D36: (F0) @SUM(D14..D34)
F36: (F0) @SUM(F14..F34)
G36: (F0) @SUM(G14..G34)
H36: (F0) (($E36*31*365*$C$76))/1000
```

```
J2: 'THERMAL TECHNIQUE:
L2: 'IN-SITU COMBUSTION
O2: 'DATE:
P2: 'MAY 30
J3: 'FIELD:
K3: 'SOUTH BELRIDGE
O3: 'INJ RATE:
P3: 5
J4: 'PATTERN:
K4: ' 5-AC, 5-SPOT
O4: 'NO. PATT:
P4: 33
J8: '     6
K8: '     7
L8: '     8
M8: '     9
N8: '     10
O8: '     11
P8: '     12
J9: 'OPERATING
K9: ' NET OPER
L9: '     INVESTMENTS
N9: ' DEPREC
O9: 'DEPLETION
P9: '  TAXABLE
J10: '  COSTS
K10: '  INCOME
L10: '   TANG.
M10: ' INTANG.
P10: '  INCOME
J11: '    (M$)
K11: '    (M$)
L11: '    (M$)
M11: '    (M$)
N11: '    (M$)
O11: '    (M$)
P11: '    (M$)
J12: ' -------
K12: ' -------
L12: ' -------
M12: ' -------
N12: ' -------
O12: ' -------
P12: ' -------
L13: (F0) +P48
M13: (F0) +Q48
P13: (F0) +K13-M13-N13-O13
J14: (F0) +H14+G76/1000
K14: (F0) +F14-G14-J14
L14: (F0) 0
M14: (F0) 0
N14: (F0) +$O$97
O14: (F0) 0
P14: (F0) +K14-M14-N14-O14
J15: (F0) +H15+(G$76*(1+$G$78))/1000
K15: (F0) +F15-G15-J15
```

```
L23:  (F0)  0
M23:  (F0)  0
N23:  (F0)  +$0$97
O23:  (F0)  0
P23:  (F0)  +K23-M23-N23-O23
J24:  (F0)  0
K24:  (F0)  +F24-G24-J24
L24:  (F0)  0
M24:  (F0)  0
N24:  (F0)  +$0$97
O24:  (F0)  0
P24:  (F0)  +K24-M24-N24-O24
J25:  (F0)  0
K25:  (F0)  +F25-G25-J25
L25:  (F0)  0
M25:  (F0)  0
N25:  (F0)  +$0$97
O25:  (F0)  0
P25:  (F0)  +K25-M25-N25-O25
J26:  (F0)  0
K26:  (F0)  +F26-G26-J26
L26:  (F0)  0
M26:  (F0)  0
N26:  (F0)  +$0$97
O26:  (F0)  0
P26:  (F0)  +K26-M26-N26-O26
J27:  (F0)  0
K27:  (F0)  +F27-G27-J27
L27:  (F0)  0
M27:  (F0)  0
N27:  (F0)  +$0$97
O27:  (F0)  0
P27:  (F0)  +K27-M27-N27-O27
J28:  (F0)  0
K28:  (F0)  +F28-G28-J28
L28:  (F0)  0
M28:  (F0)  0
N28:  (F0)  +$0$97
O28:  (F0)  0
P28:  (F0)  +K28-M28-N28-O28
J29:  (F0)  0
K29:  (F0)  +F29-G29-J29
L29:  (F0)  0
M29:  (F0)  0
N29:  (F0)  +$0$97
O29:  (F0)  0
P29:  (F0)  +K29-M29-N29-O29
J30:  (F0)  0
K30:  (F0)  +F30-G30-J30
L30:  (F0)  0
M30:  (F0)  0
N30:  (F0)  0
O30:  (F0)  0
P30:  (F0)  +K30-M30-N30-O30
J31:  (F0)  0
K31:  (F0)  +F31-G31-J31
```

THERMAL TECHNIQUE: IN-SITU COMBUSTION
FIELD: SOUTH BELRIDGE
PATTERN: 5-AC, 5-SPOT

DATE: MAY 30
INJ RATE: 5
NO. PATT: 33

P3

13 FED INC TAX @48% (M$)	14 INV. TAX CREDIT @10%	15 NET PROFIT (M$)	16 D.N.P. @5% (M$)	17 D.N.P. @10% (M$)	18 D.N.P. @15% (M$)	19 D.N.P. @20% (M$)
-7032	2198	-27397	-27397	-27397	-27397	-27397
17165	0	19969	19488	19040	18621	18229
20908	0	24024	22880	21840	20890	20020
13784	0	16306	15156	14134	13222	12405
7664	0	9676	8776	7996	7316	6719
-3454	0	-2368	-2096	-1866	-1670	-1501
-1370	0	-111	-96	-84	-73	-64
-659	0	659	556	472	404	348
-659	0	659	542	450	377	318
-659	0	659	529	429	352	290
-659	0	659	517	409	328	265
-659	0	659	504	390	306	242
-659	0	659	492	372	285	221
-659	0	659	480	355	266	202
-659	0	659	469	338	248	184
-659	0	659	457	323	231	168
-659	0	659	446	308	216	153
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	0
41072	2198	46692	41703	37511	33922	30802

```
S14:  (F0)  0.1*L14
T14:  (F0)  +K14-L14-M14-R14+S14
U14:  (F0)  +$T14/(1+0.05)^($B14/2)
V14:  (F0)  +$T14/(1+0.1)^($B14/2)
W14:  (F0)  +$T14/(1+0.15)^($B14/2)
X14:  (F0)  +$T14/(1+0.2)^($B14/2)
R15:  (F0)  0.48*P15
S15:  (F0)  0.1*L15
T15:  (F0)  +K15-L15-M15-R15+S15
U15:  (F0)  +$T15/(1+0.05)^($B15/2)
V15:  (F0)  +$T15/(1+0.1)^($B15/2)
W15:  (F0)  +$T15/(1+0.15)^($B15/2)
X15:  (F0)  +$T15/(1+0.2)^($B15/2)
R16:  (F0)  0.48*P16
S16:  (F0)  0.1*L16
T16:  (F0)  +K16-L16-M16-R16+S16
U16:  (F0)  +$T16/(1+0.05)^($B16/2)
V16:  (F0)  +$T16/(1+0.1)^($B16/2)
W16:  (F0)  +$T16/(1+0.15)^($B16/2)
X16:  (F0)  +$T16/(1+0.2)^($B16/2)
R17:  (F0)  0.48*P17
S17:  (F0)  0.1*L17
T17:  (F0)  +K17-L17-M17-R17+S17
U17:  (F0)  +$T17/(1+0.05)^($B17/2)
V17:  (F0)  +$T17/(1+0.1)^($B17/2)
W17:  (F0)  +$T17/(1+0.15)^($B17/2)
X17:  (F0)  +$T17/(1+0.2)^($B17/2)
R18:  (F0)  0.48*P18
S18:  (F0)  0.1*L18
T18:  (F0)  +K18-L18-M18-R18+S18
U18:  (F0)  +$T18/(1+0.05)^($B18/2)
V18:  (F0)  +$T18/(1+0.1)^($B18/2)
W18:  (F0)  +$T18/(1+0.15)^($B18/2)
X18:  (F0)  +$T18/(1+0.2)^($B18/2)
R19:  (F0)  0.48*P19
S19:  (F0)  0.1*L19
T19:  (F0)  +K19-L19-M19-R19+S19
U19:  (F0)  +$T19/(1+0.05)^($B19/2)
V19:  (F0)  +$T19/(1+0.1)^($B19/2)
W19:  (F0)  +$T19/(1+0.15)^($B19/2)
X19:  (F0)  +$T19/(1+0.2)^($B19/2)
R20:  (F0)  0.48*P20
S20:  (F0)  0.1*L20
T20:  (F0)  +K20-L20-M20-R20+S20
U20:  (F0)  +$T20/(1+0.05)^($B20/2)
V20:  (F0)  +$T20/(1+0.1)^($B20/2)
W20:  (F0)  +$T20/(1+0.15)^($B20/2)
X20:  (F0)  +$T20/(1+0.2)^($B20/2)
R21:  (F0)  0.48*P21
S21:  (F0)  0.1*L21
T21:  (F0)  +K21-L21-M21-R21+S21
U21:  (F0)  +$T21/(1+0.05)^($B21/2)
V21:  (F0)  +$T21/(1+0.1)^($B21/2)
W21:  (F0)  +$T21/(1+0.15)^($B21/2)
X21:  (F0)  +$T21/(1+0.2)^($B21/2)
R22:  (F0)  0.48*P22
```

```
S30:  (F0)  0.1*L30
T30:  (F0)  +K30-L30-M30-R30+S30
U30:  (F0)  +$T30/(1+0.05)^($B30/2)
V30:  (F0)  +$T30/(1+0.1)^($B30/2)
W30:  (F0)  +$T30/(1+0.15)^($B30/2)
X30:  (F0)  +$T30/(1+0.2)^($B30/2)
R31:  (F0)  0.48*P31
S31:  (F0)  0.1*L31
T31:  (F0)  +K31-L31-M31-R31+S31
U31:  (F0)  +$T31/(1+0.05)^($B31/2)
V31:  (F0)  +$T31/(1+0.1)^($B31/2)
W31:  (F0)  +$T31/(1+0.15)^($B31/2)
X31:  (F0)  +$T31/(1+0.2)^($B31/2)
R32:  (F0)  0.48*P32
S32:  (F0)  0.1*L32
T32:  (F0)  +K32-L32-M32-R32+S32
U32:  (F0)  +$T32/(1+0.05)^($B32/2)
V32:  (F0)  +$T32/(1+0.1)^($B32/2)
W32:  (F0)  +$T32/(1+0.15)^($B32/2)
X32:  (F0)  +$T32/(1+0.2)^($B32/2)
R33:  (F0)  0.48*P33
S33:  (F0)  0.1*L33
T33:  (F0)  +K33-L33-M33-R33+S33
U33:  (F0)  +$T33/(1+0.05)^($B33/2)
V33:  (F0)  +$T33/(1+0.1)^($B33/2)
W33:  (F0)  +$T33/(1+0.15)^($B33/2)
X33:  (F0)  +$T33/(1+0.2)^($B33/2)
R34:  (F0)  0.48*P34
S34:  (F0)  0.1*L34
T34:  (F0)  +K34-L34-M34-R34+S34
U34:  (F0)  +$T34/(1+0.05)^($B34/2)
V34:  (F0)  +$T34/(1+0.1)^($B34/2)
W34:  (F0)  +$T34/(1+0.15)^($B34/2)
X34:  (F0)  +$T34/(1+0.2)^($B34/2)
R36:  (F0)  @SUM(R13..R34)
S36:  (F0)  @SUM(S13..S34)
T36:  (F0)  @SUM(T13..T34)
U36:  (F0)  @SUM(U13..U34)
V36:  (F0)  @SUM(V13..V34)
W36:  (F0)  @SUM(W13..W34)
X36:  (F0)  @SUM(X13..X34)
```

SCHEDULE THREE: INITIAL INVESTMENTS

			TOTALS (M$) TANG	INTANG
NO. OF WELLS =	77	DRILL. AND COMPL.	3582.35	2388.23
NO. OF PRODUCERS =	44	PROD. EQUIP.	2230.80	1487.20
NO. OF INJECTORS =	33	INJECT. EQUIP	1480.05	986.70
NO. OF COMPRESS. =	38.0	COMP. INSTALL.	10530.00	7020.00
AVERAGE DEPTH =	1000			
		TOTALS	17823.20	11882.13

CUM PROB OF DRILLING & COMPL. COSTS	COSTS ($/FT)
0.00	69.79
0.10	77.54
0.90	85.29
1.00	

CUM PROB OF PRODUCTION EQUIPMENT COSTS	COSTS (M$/WELL)
0.00	78.500
0.10	81.500
0.90	84.500
1.00	

CUM PROB OF INJECTION EQUIPMENT COSTS	COSTS (M$/WELL)
0.00	71.750
0.10	74.750
0.90	77.750
1.00	

CUM PROB OF COMPRESSOR INSTALL. COSTS	COSTS (M$/UNIT)
0.00	900.000
0.10	1200.000
0.90	1500.000
1.00	

RANDOM NUMBERS

DRILL & COMPL.	PRODUCT. EQUIP.	INJECT. EQUIP.	COMPRESSOR INSTALL.
0.4205	0.9857	0.4078	0.0032

COSTS ARE 1/2 FOR SECOND AND SUCCESSIVE COMP. UNITS

NOTE THAT PART OF THE O & M COSTS MAY BE TANGIBLE, AND THUS MAY BE SUBJECT TO DEPRECIATION. HOWEVER, THEY ARE NOT INCLUDED HERE AS THEY HAVE ALREADY BEEN INCLUDED UNDER OPERATING COSTS.
TANGIBLES ARE 60% OF THE TOTAL INVESTMENT;
INTANGIBLES ARE 40%.

```
P66: (F4) @RAND
Q66: (F4) '
J67: (F2) 0.1
K67: (F3) 1200
J68: (F2) 0.9
K68: (F3) 1500
J69: (F2) 1
K69: (F3) '
M69: '
J70: 'COSTS ARE 1/2 FOR SECOND AND SUCCESSIVE COMP. UNITS
J72: 'NOTE THAT PART OF THE O & M COSTS MAY BE TANGIBLE, AND
      THUS MAY BE
J73: 'SUBJECT TO DEPRECIATION. HOWEVER, THEY ARE NOT INCLUDED
      HERE AS THEY
J74: 'HAVE ALREADY BEEN INCLUDED UNDER OPERATING COSTS.
J75: 'TANGIBLES ARE 60% OF THE TOTAL INVESTMENT;
J76: 'INTANGIBLES ARE 40%.
```

```
J40: 'SCHEDULE THREE:
L40: 'INITIAL INVESTMENTS
P40: (F2) '      TOTALS (M$)
P41: (F2) '    TANG
Q41: (F2) '    INTANG
N42: (F2) '
O42: (F2) '
P42: (F2) '--------
Q42: (F2) '--------
J43: 'NO. OF WELLS =
L43: (F0) +D74
N43: (F2) 'DRILL. AND COMPL.
P43: (F2) ($L$47*$L$43*@VLOOKUP($M$66,$J$55..$K$58,1))*0.6/1000
Q43: (F2) ($L$47*$L$43*@VLOOKUP($M$66,$J$55..$K$58,1))*0.4/1000
J44: 'NO. OF PRODUCERS =
L44: (F0) +D75
N44: (F2) 'PROD. EQUIP.
P44: (F2) ($L$44*@VLOOKUP($N$66,$M$55..$N$58,1))*0.6
Q44: (F2) ($L$44*@VLOOKUP($N$66,$M$55..$N$58,1))*0.4
J45: 'NO. OF INJECTORS =
L45: (F0) +D76
N45: (F2) 'INJECT. EQUIP
P45: (F2) ($L$45*@VLOOKUP($O$66,$P$55..$Q$58,1))*0.6
Q45: (F2) ($L$45*@VLOOKUP($O$66,$P$55..$Q$58,1))*0.4
J46: 'NO. OF COMPRESS. =
L46: (F1) +D77
N46: (F2) 'COMP. INSTALL.
P46: (F2) (((($L$46-1)*@VLOOKUP($P$66,$J$66..$K$69,1)/2)+
(@VLOOKUP($P$66,$J$66..$K$69,1)))*0.6
Q46: (F2) (((($L$46-1)*@VLOOKUP($P$66,$J$66..$K$69,1)/2)+
(@VLOOKUP($P$66,$J$66..$K$69,1)))*0.4
J47: 'AVERAGE DEPTH     =
L47: (F0) 1000
N47: (F2) '
P47: (F2) '--------
Q47: (F2) '--------
O48: (F2) 'TOTALS
P48: (F2) @SUM(P43..P46)
Q48: (F2) @SUM(Q43..Q46)
J50: 'CUM PROB OF
M50: 'CUM PROB OF
P50: 'CUM PROB OF
J51: 'DRILLING &
L51: '
M51: 'PRODUCTION
P51: 'INJECTION
J52: '  COMPL.
K52: '  COSTS
M52: 'EQUIPMENT
N52: '    COSTS
P52: 'EQUIPMENT
Q52: '    COSTS
J53: '  COSTS
K53: '  ($/FT)
M53: '  COSTS
N53: '(M$/WELL)
P53: '  COSTS
Q53: '(M$/WELL)
```

15330.0	5365500.0	1660404.9	1137.490	25641.3
15695.0	5493250.0	1685776.9	1154.872	25372.2
16060.0	5621000.0	1710887.9	1172.075	25111.1
16425.0	5748750.0	1735746.1	1189.104	24858.2
16790.0	5876500.0	1760358.9	1205.966	24612.8
17155.0	6004250.0	1784733.5	1222.664	24374.6
17520.0	6132000.0	1808876.7	1239.204	24143.3
17885.0	6259750.0	1832795.2	1255.589	23918.5
18250.0	6387500.0	1856495.1	1271.825	23699.9
18615.0	6515250.0	1879982.3	1287.916	23487.2
18980.0	6643000.0	1903262.5	1303.864	23280.2
19345.0	6770750.0	1926341.2	1319.675	23078.7
19710.0	6898500.0	1949223.5	1335.351	22882.3
20075.0	7026250.0	1971914.3	1350.895	22690.9
20440.0	7154000.0	1994418.6	1366.312	22504.2
20805.0	7281750.0	2016740.7	1381.605	22322.1
21170.0	7409500.0	2038885.1	1396.775	22144.4
21535.0	7537250.0	2060856.0	1411.827	21970.9
21900.0	7665000.0	2082657.5	1426.762	21801.5
22265.0	7792750.0	2104293.4	1441.584	21635.9
22630.0	7920500.0	2125767.5	1456.295	21474.1
22995.0	8048250.0	2147083.3	1470.898	21315.8
23360.0	8176000.0	2168244.3	1485.395	21161.2
23725.0	8303750.0	2189253.9	1499.788	21009.6
24090.0	8431500.0	2210115.4	1514.079	20861.4
24455.0	8559250.0	2230831.7	1528.271	20716.3
24820.0	8687000.0	2251405.9	1542.366	20574.2
25185.0	8814750.0	2271841.0	1556.366	20435.2
25550.0	8942500.0	2292139.6	1570.271	20298.7

15330.0	7665000.0	2404298.3	1647.108	37129.1
15695.0	7847500.0	2441037.4	1672.277	36739.1
16060.0	8030000.0	2477398.8	1697.187	36361.3
16425.0	8212500.0	2513393.8	1721.846	35995.1
16790.0	8395000.0	2549033.6	1746.261	35639.8
17155.0	8577500.0	2584328.5	1770.441	35294.9
17520.0	8760000.0	2619288.4	1794.391	34959.9
17885.0	8942500.0	2653922.8	1818.118	34634.4
18250.0	9125000.0	2688240.7	1841.628	34317.9
18615.0	9307500.0	2722250.6	1864.927	34009.9
18980.0	9490000.0	2755960.9	1888.021	33710.2
19345.0	9672500.0	2789379.2	1910.914	33418.4
19710.0	9855000.0	2822513.2	1933.613	33134.1
20075.0	10037500.0	2855370.0	1956.123	32856.8
20440.0	10220000.0	2887956.6	1978.447	32586.9
20805.0	10402500.0	2920279.5	2000.590	32322.9
21170.0	10585000.0	2952345.0	2022.557	32065.8
21535.0	10767500.0	2984159.3	2044.352	31814.1
21900.0	10950000.0	3015728.3	2065.979	31568.9

TABLE C.4
OUTPUT FILE FOR MARX.F, 1000 B/D

RESERVOIR AND STEAM PROPERTIES

Volumetric Heat Cap. of Reservoir (Btu/cu.ft.-degF)	36.00
Volumetric Heat Cap. of Adj. Formations (Btu/cu.ft.-degF)	41.00
Temperature of Undisturbed Reservoir (deg F)	93.00
Thermal Diffusivity of Adj. Formations (sq.ft./day)	0.72
Porosity	0.34
Initial Oil Saturation	0.67
Residual Oil Saturation	0.10
Net Pay Thickness (ft)	93.00
Total Pay Thickness (ft)	93.00
Oil Formation Volume Factor	1.03
Capture Efficiency	1.00

Time (days)	Cum Steam Injected (bbls water equiv)	Cum Oil Produced (bbls)	Size of Steam Zone (acre-ft)	Incremental Oi (bbls)
365.0	365000.0	274570.8	188.100	274570.8
730.0	730000.0	498907.2	341.785	224336.4
1095.0	1095000.0	698691.9	478.651	199784.7
1460.0	1460000.0	881820.2	604.107	183128.3
1825.0	1825000.0	1052414.9	720.976	170594.6
2190.0	2190000.0	1213029.9	831.008	160615.0
2555.0	2555000.0	1365404.6	935.395	152374.7
2920.0	2920000.0	1510798.1	1034.999	145393.5
3285.0	3285000.0	1650162.7	1130.474	139364.6
3650.0	3650000.0	1784242.2	1222.327	134079.5
4015.0	4015000.0	1913632.8	1310.969	129390.5
4380.0	4380000.0	2038821.7	1396.732	125189.0
4745.0	4745000.0	2160214.5	1479.894	121392.8
5110.0	5110000.0	2278153.0	1560.690	117938.5
5475.0	5475000.0	2392929.0	1639.319	114776.1
5840.0	5840000.0	2504794.4	1715.954	111865.4
6205.0	6205000.0	2613968.2	1790.746	109173.8
6570.0	6570000.0	2720642.5	1863.825	106674.3
6935.0	6935000.0	2824987.2	1935.308	104344.7
7300.0	7300000.0	2927153.2	2005.299	102166.0

TABLE C.6
OUTPUT FILE FOR MARX.F, 1500 B/D

RESERVOIR AND STEAM PROPERTIES

Volumetric Heat Cap. of Reservoir (Btu/cu.ft.-degF)	36.00
Volumetric Heat Cap. of Adj. Formations (Btu/cu.ft.-degF)	41.00
Temperature of Undisturbed Reservoir (deg F)	93.00
Thermal Diffusivity of Adj. Formations (sq.ft./day)	0.72
Porosity	0.34
Initial Oil Saturation	0.67
Residual Oil Saturation	0.10
Net Pay Thickness (ft)	93.00
Total Pay Thickness (ft)	93.00
Oil Formation Volume Factor	1.03
Capture Efficiency	1.00

Time (days)	Cum Steam Injected (bbls water equiv)	Cum Oil Produced (bbls)	Size of Steam Zone (acre-ft)	Incremental Oil (bbls)
365.0	547500.0	399960.0	274.000	399960.0
730.0	1095000.0	726744.9	497.870	326784.9
1095.0	1642500.0	1017766.0	697.239	291021.1
1460.0	2190000.0	1284524.1	879.986	266758.1
1825.0	2737500.0	1533024.8	1050.226	248500.7
2190.0	3285000.0	1766988.5	1210.507	233963.7
2555.0	3832500.0	1988948.6	1362.565	221960.1
2920.0	4380000.0	2200739.5	1507.656	211790.9
3285.0	4927500.0	2403748.2	1646.731	203008.7
3650.0	5475000.0	2599058.3	1780.532	195310.1
4015.0	6022500.0	2787538.1	1909.653	188479.8
4380.0	6570000.0	2969897.5	2034.582	182359.4
4745.0	7117500.0	3146727.2	2155.722	176829.6
5110.0	7665000.0	3318525.0	2273.415	171797.9
5475.0	8212500.0	3485716.3	2387.953	167191.3
5840.0	8760000.0	3648667.6	2499.585	162951.3
6205.0	9307500.0	3807698.1	2608.532	159030.5
6570.0	9855000.0	3963087.8	2714.985	155389.7
6935.0	10402500.0	4115084.0	2819.112	151996.1
7300.0	10950000.0	4263906.4	2921.066	148822.5

TABLE 2

Volume Burned %	Oil Rec'd %	Reciprocal of slope	Current AOR mscf/bbl	Excess Air fraction	Injected AOR mscf/bbl	Time days
5.000	1.06	5.00	71.47	-14.89	60.82	94.54
10.000	8.67	0.66	9.40	-8.05	8.65	189.08
15.000	16.67	0.63	8.93	-0.85	8.86	283.62
20.000	24.46	0.64	9.16	6.17	9.73	378.16
25.000	31.96	0.67	9.53	12.92	10.76	472.70
30.000	39.16	0.69	9.93	19.39	11.85	567.24
35.000	45.76	0.76	10.83	25.33	13.57	661.77
40.000	52.06	0.79	11.34	31.00	14.86	756.31
45.000	58.06	0.83	11.91	36.40	16.25	850.85
50.000	63.75	0.88	12.54	41.53	17.74	945.39
55.000	69.05	0.94	13.48	46.29	19.73	1039.93
60.000	73.84	1.04	14.89	50.61	22.42	1134.47
65.000	78.34	1.11	15.88	54.65	24.56	1229.01
70.000	82.63	1.16	16.62	58.52	26.35	1323.55
75.000	86.62	1.25	17.87	62.11	28.96	1418.09
80.000	90.32	1.35	19.32	65.44	31.95	1512.63
85.000	93.81	1.43	20.42	68.58	34.42	1607.17
90.000	96.31	2.00	28.59	70.83	48.83	1701.71
95.000	98.40	2.38	34.03	72.71	58.78	1796.25
100.000	100.00	3.13	44.67	74.15	77.79	1890.78

TABLE 3

Volume Burned %	Oil Recovered %	Oil Recovered bbl	Air Required mmscf	Cumulative AOR mscf/bbl
5.00	1.06	28124.03	1890.78	67.23
10.00	8.67	229384.20	3781.57	16.49
15.00	16.67	440930.91	5672.35	12.86
20.00	24.46	647260.25	7563.14	11.68
25.00	31.96	845634.00	9453.92	11.18
30.00	39.16	1036070.56	11344.71	10.95
35.00	45.76	1210688.13	13235.49	10.93
40.00	52.06	1377387.25	15126.28	10.98
45.00	58.06	1536093.63	17017.06	11.08
50.00	63.75	1686714.50	18907.85	11.21
55.00	69.05	1826789.88	20798.63	11.39
60.00	73.84	1953636.38	22689.41	11.61
65.00	78.34	2072546.00	24580.20	11.86
70.00	82.63	2186164.00	26470.98	12.11
75.00	86.62	2291844.50	28361.77	12.38
80.00	90.32	2389569.75	30252.55	12.66
85.00	93.81	2481966.00	32143.34	12.95
90.00	96.31	2548016.50	34034.12	13.36
95.00	98.40	2603521.00	35924.91	13.80
100.00	100.00	2645723.25	37815.69	14.29

TABLE 2

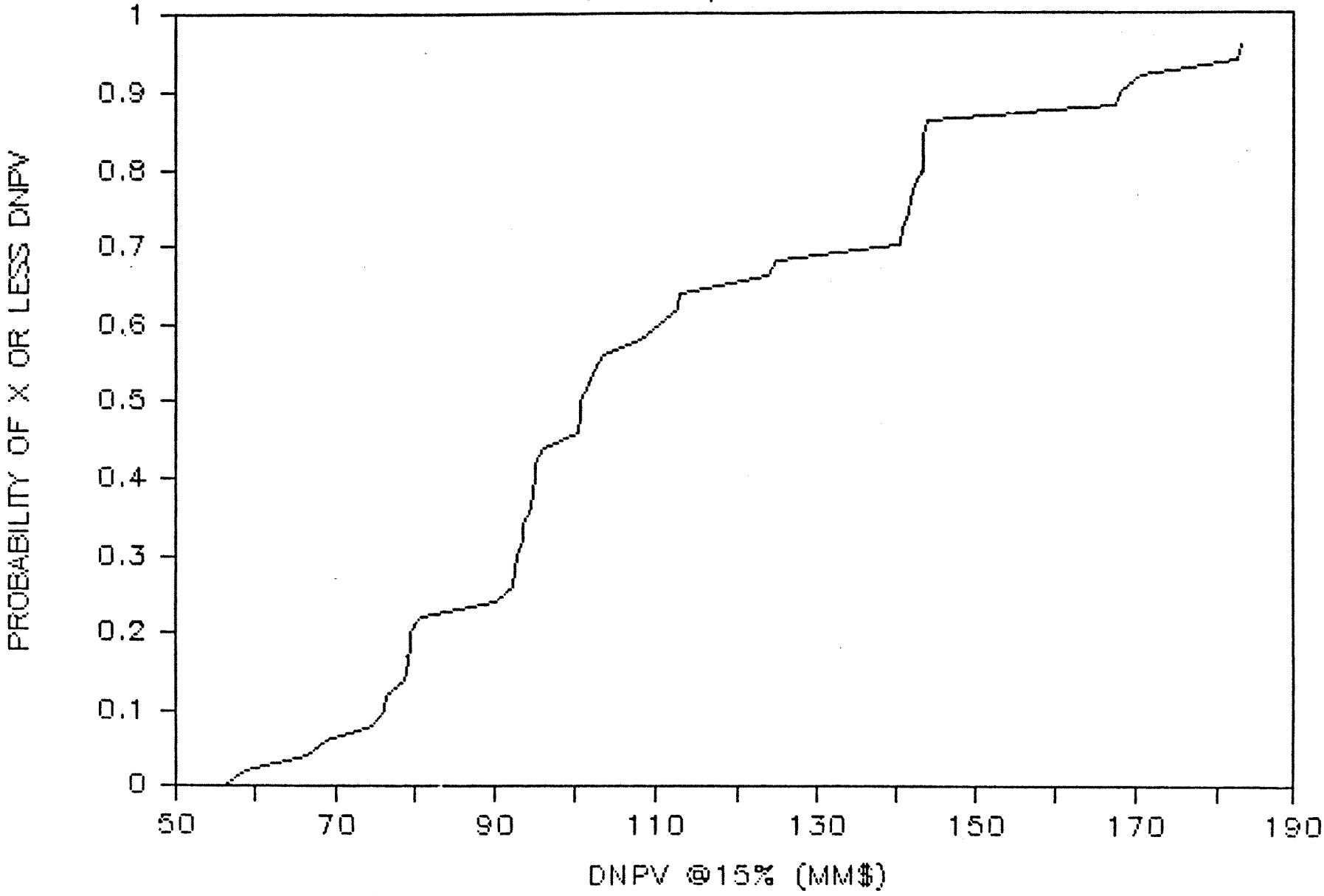
Volume Burned %	Oil Rec'd %	Reciprocal of slope	Current AOR mscf/bbl	Excess Air fraction	Injected AOR mscf/bbl	Time days
5.000	1.06	5.00	71.47	-14.89	60.82	47.27
10.000	8.67	0.66	9.40	-8.05	8.65	94.54
15.000	16.67	0.63	8.93	-0.85	8.86	141.81
20.000	24.46	0.64	9.16	6.17	9.73	189.08
25.000	31.96	0.67	9.53	12.92	10.76	236.35
30.000	39.16	0.69	9.93	19.39	11.85	283.62
35.000	45.76	0.76	10.83	25.33	13.57	330.89
40.000	52.06	0.79	11.34	31.00	14.86	378.16
45.000	58.06	0.83	11.91	36.40	16.25	425.43
50.000	63.75	0.88	12.54	41.53	17.74	472.70
55.000	69.05	0.94	13.48	46.29	19.73	519.97
60.000	73.84	1.04	14.89	50.61	22.42	567.24
65.000	78.34	1.11	15.88	54.65	24.56	614.51
70.000	82.63	1.16	16.62	58.52	26.35	661.77
75.000	86.62	1.25	17.87	62.11	28.96	709.04
80.000	90.32	1.35	19.32	65.44	31.95	756.31
85.000	93.81	1.43	20.42	68.58	34.42	803.58
90.000	96.31	2.00	28.59	70.83	48.83	850.85
95.000	98.40	2.38	34.03	72.71	58.78	898.12
100.000	100.00	3.13	44.67	74.15	77.79	945.39

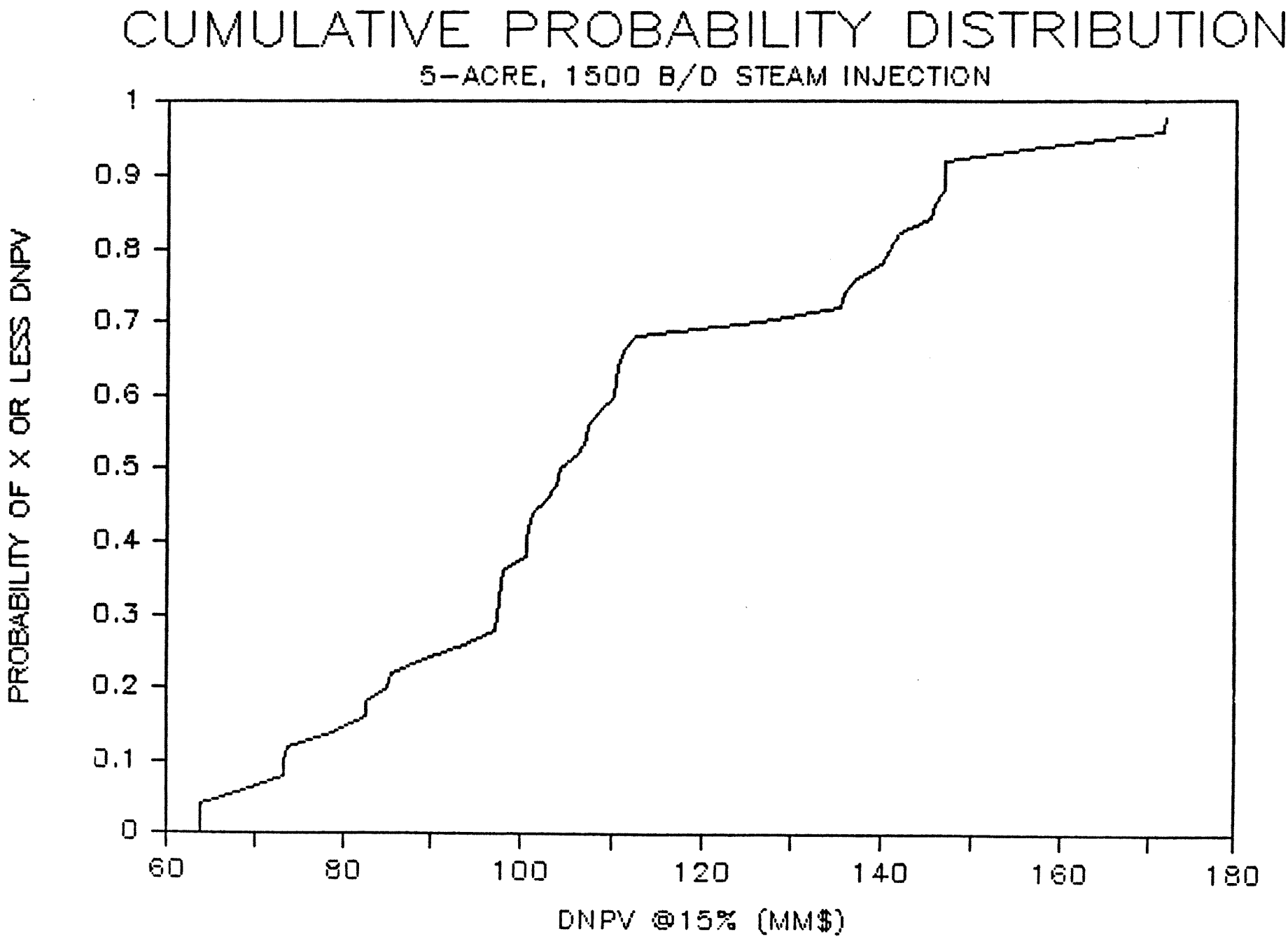
TABLE 3

Volume Burned %	Oil Recovered %	Oil Recovered bbl	Air Required mmscf	Cumulative AOR mscf/bbl
5.00	1.06	7031.01	472.70	67.23
10.00	8.67	57346.05	945.39	16.49
15.00	16.67	110232.73	1418.09	12.86
20.00	24.46	161815.06	1890.78	11.68
25.00	31.96	211408.50	2363.48	11.18
30.00	39.16	259017.64	2836.18	10.95
35.00	45.76	302672.03	3308.87	10.93
40.00	52.06	344346.81	3781.57	10.98
45.00	58.06	384023.41	4254.27	11.08
50.00	63.75	421678.63	4726.96	11.21
55.00	69.05	456697.47	5199.66	11.39
60.00	73.84	488409.09	5672.35	11.61
65.00	78.34	518136.50	6145.05	11.86
70.00	82.63	546541.00	6617.75	12.11
75.00	86.62	572961.13	7090.44	12.38
80.00	90.32	597392.44	7563.14	12.66
85.00	93.81	620491.50	8035.83	12.95
90.00	96.31	637004.13	8508.53	13.36
95.00	98.40	650880.25	8981.23	13.80
100.00	100.00	661430.81	9453.92	14.29

CUMULATIVE PROBABILITY DISTRIBUTION

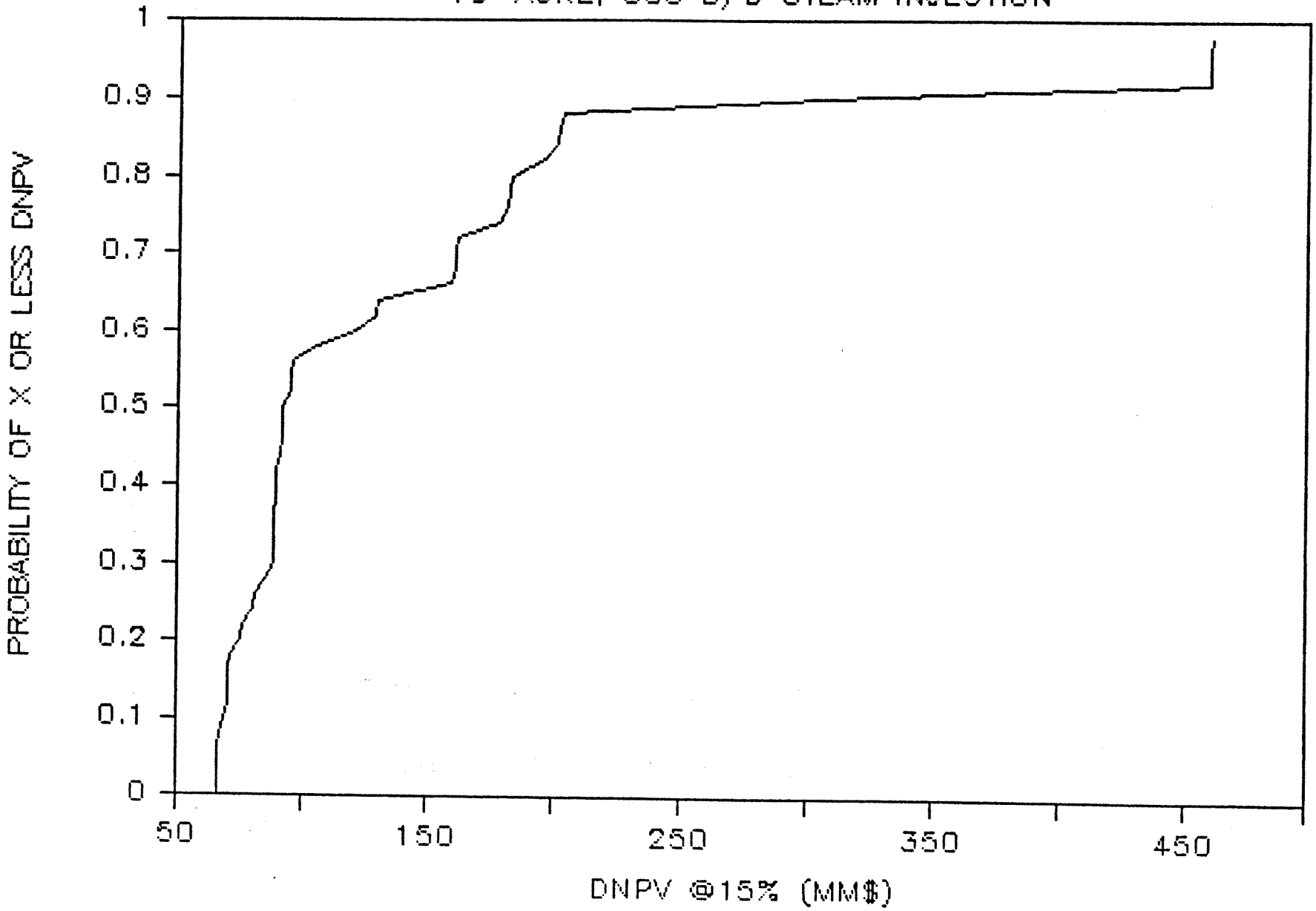
2.5 ACRE, 500 B/D STEAM INJECTION




CUMULATIVE PROBABILITY DISTRIBUTION
5-ACRE, 1500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
60
80
100
120
140
160
180
DNPV @15% (MM$)

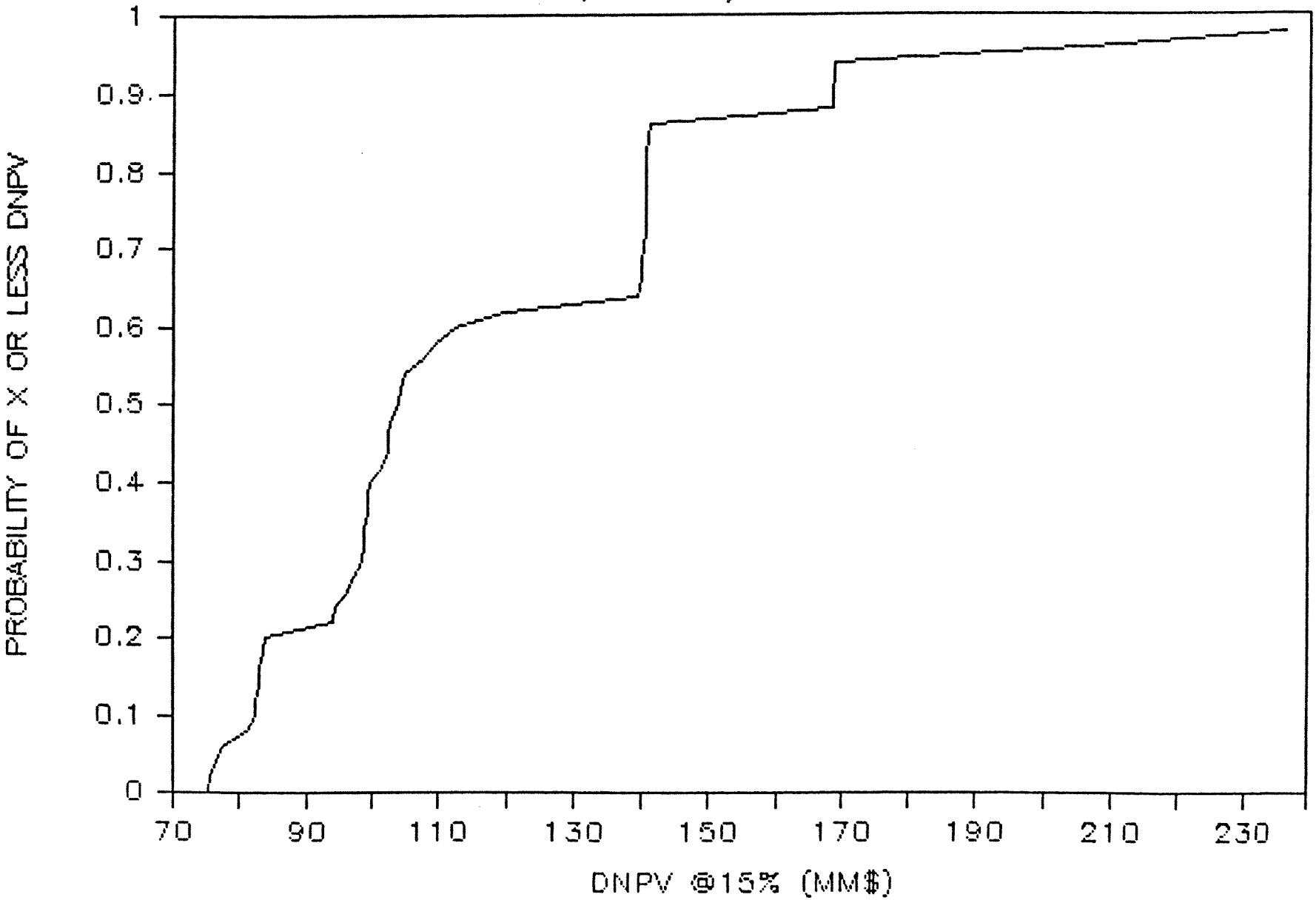
CUMULATIVE PROBABILITY DISTRIBUTION

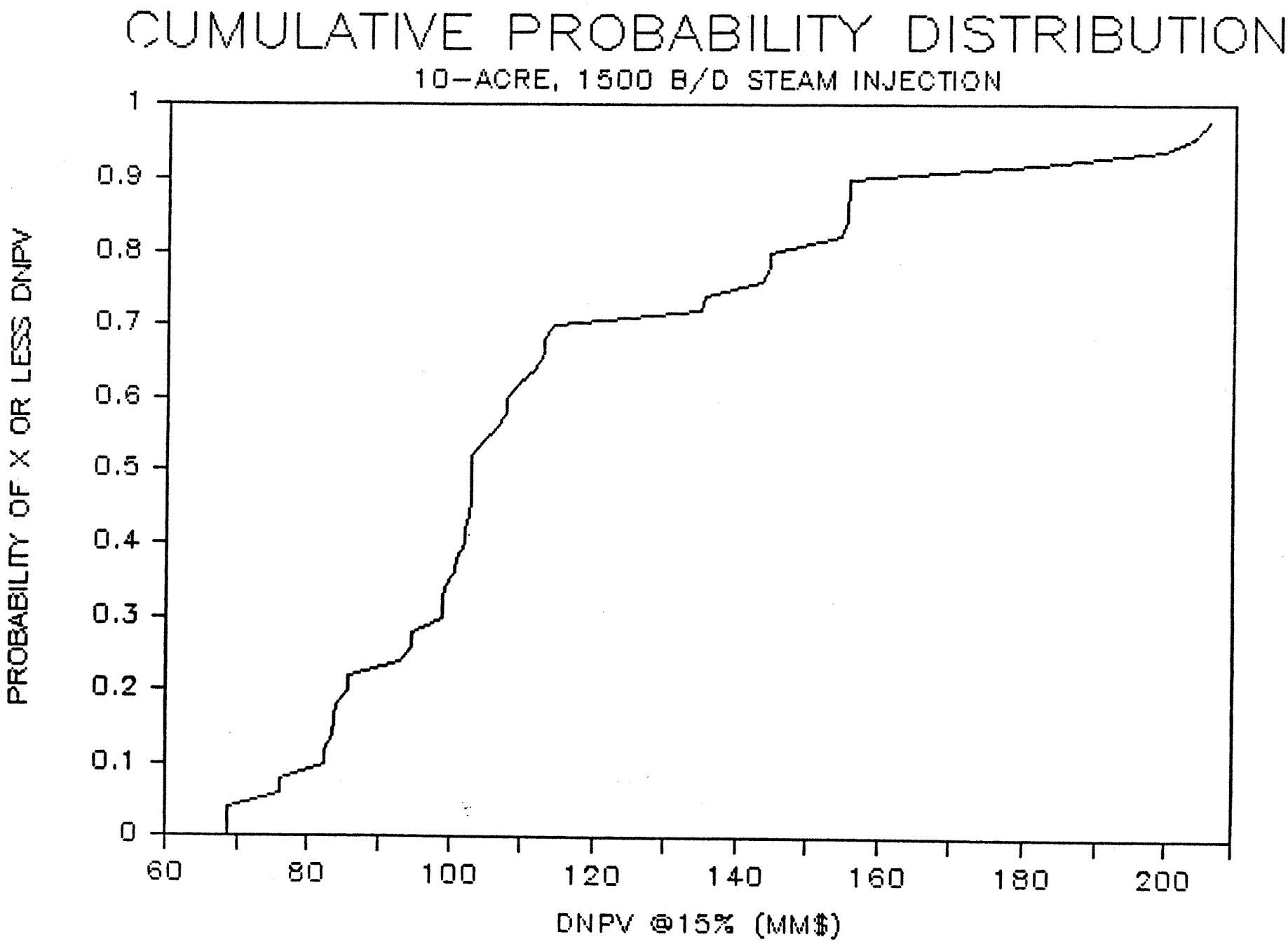
10-ACRE, 500 B/D STEAM INJECTION

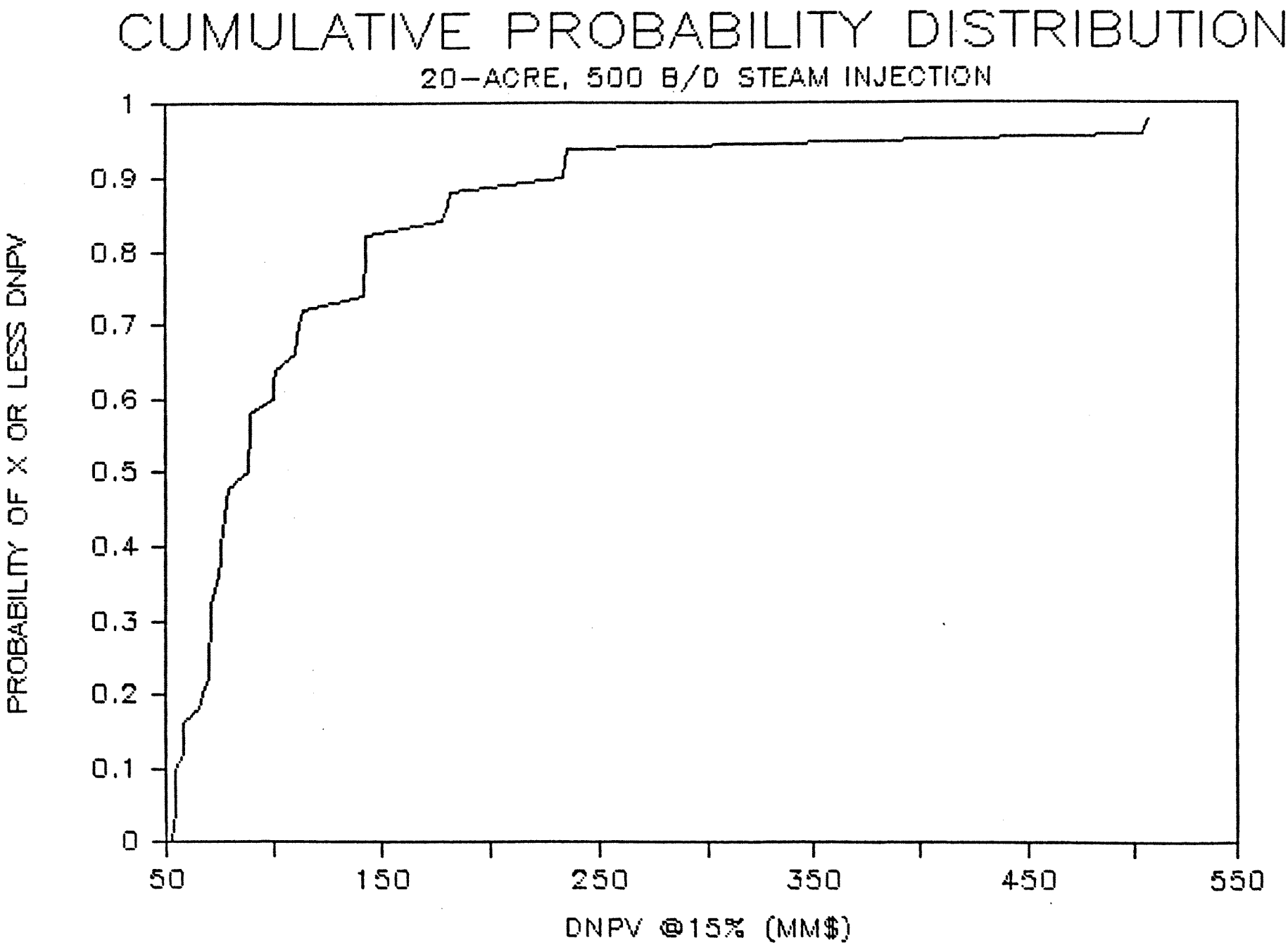


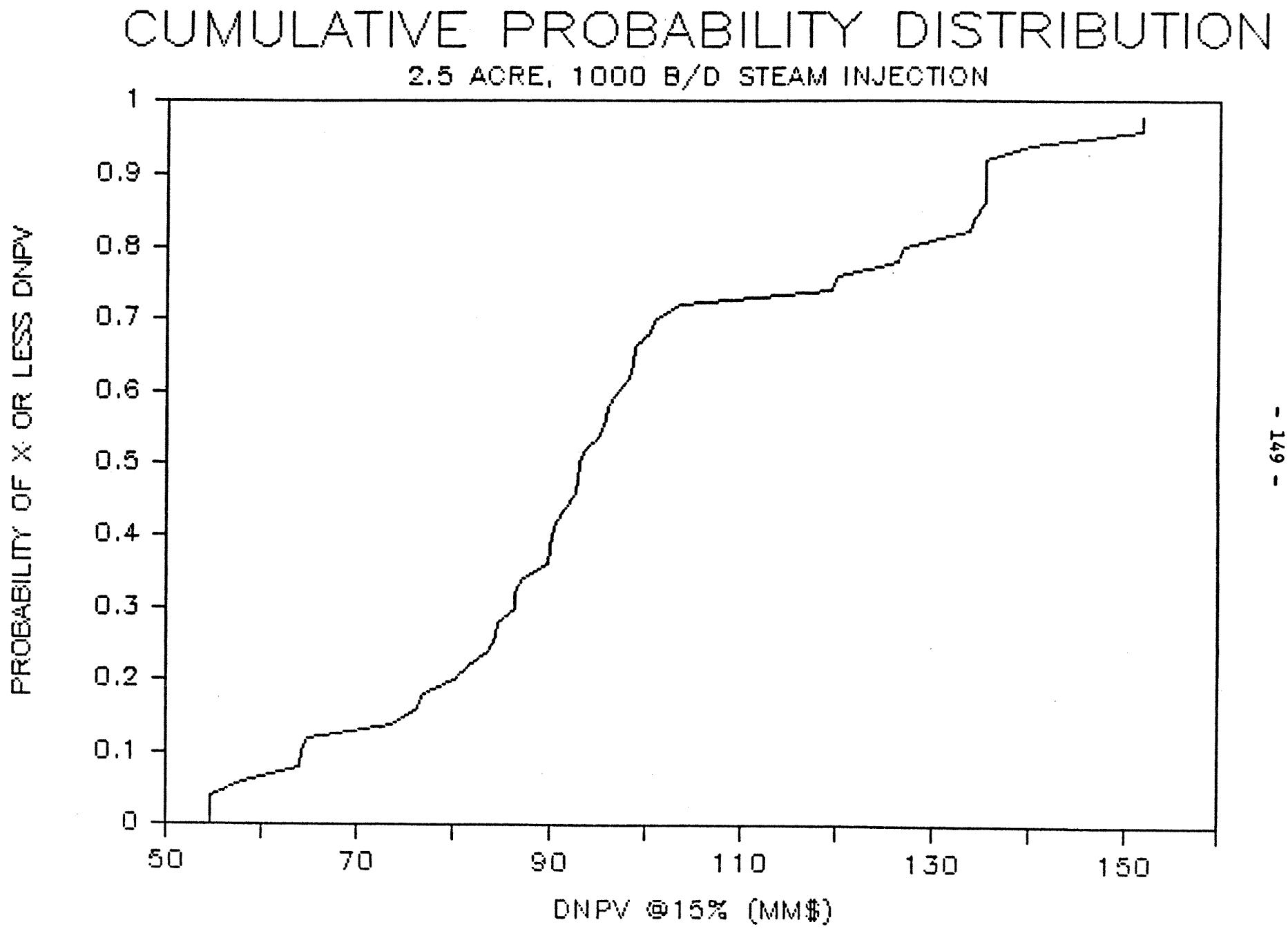
CUMULATIVE PROBABILITY DISTRIBUTION

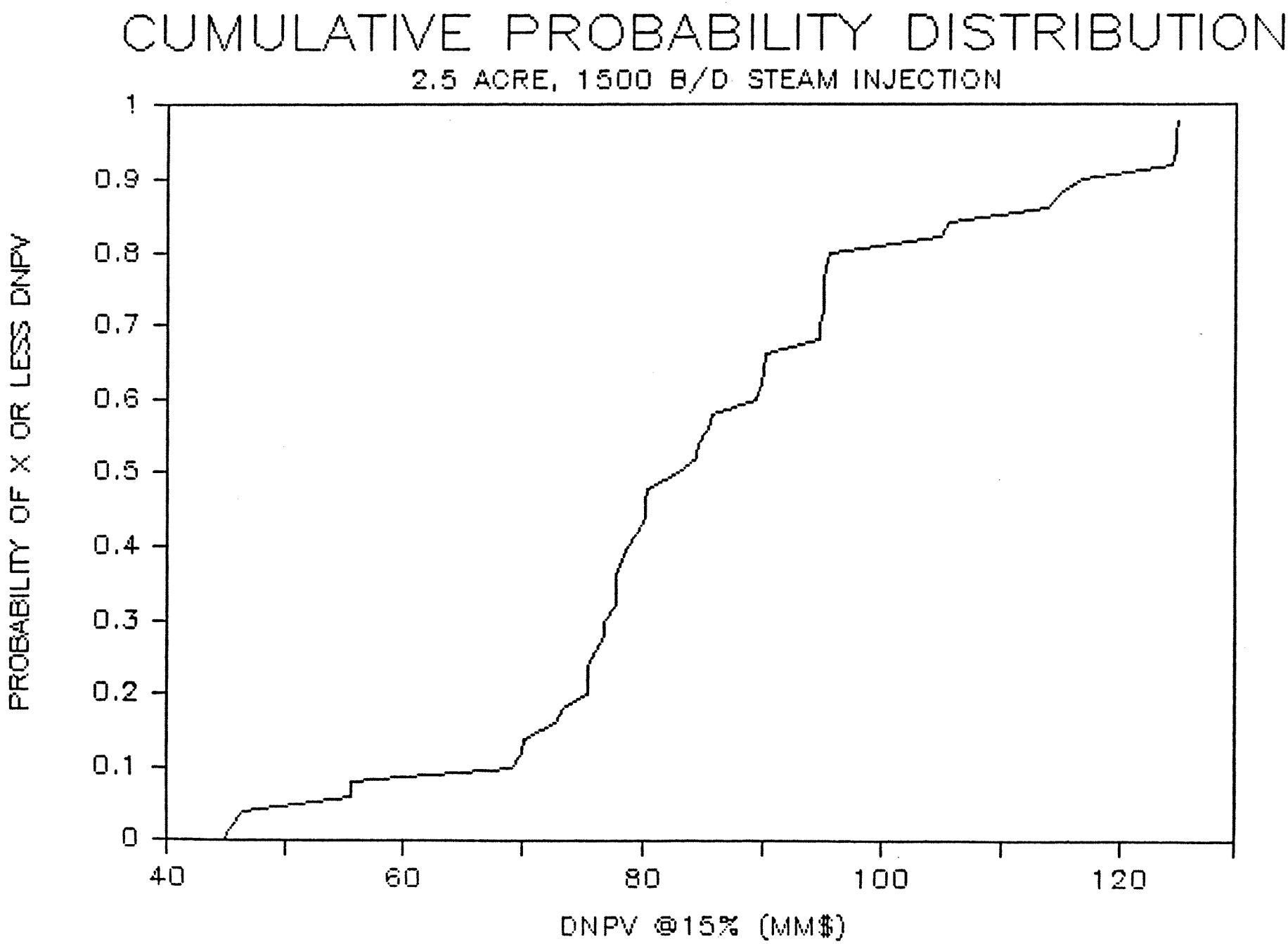
10-ACRE, 1000 B/D STEAM INJECTION

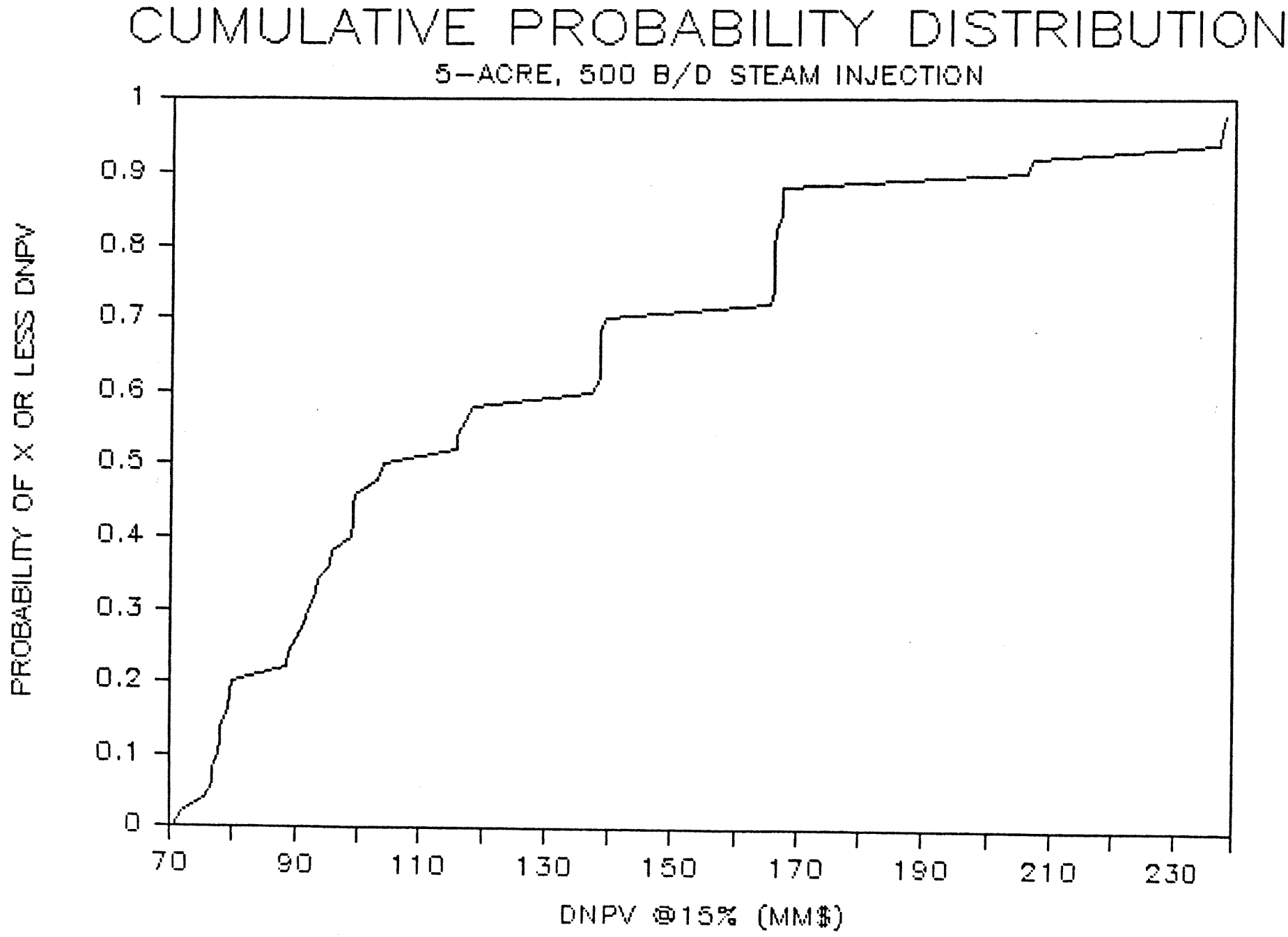


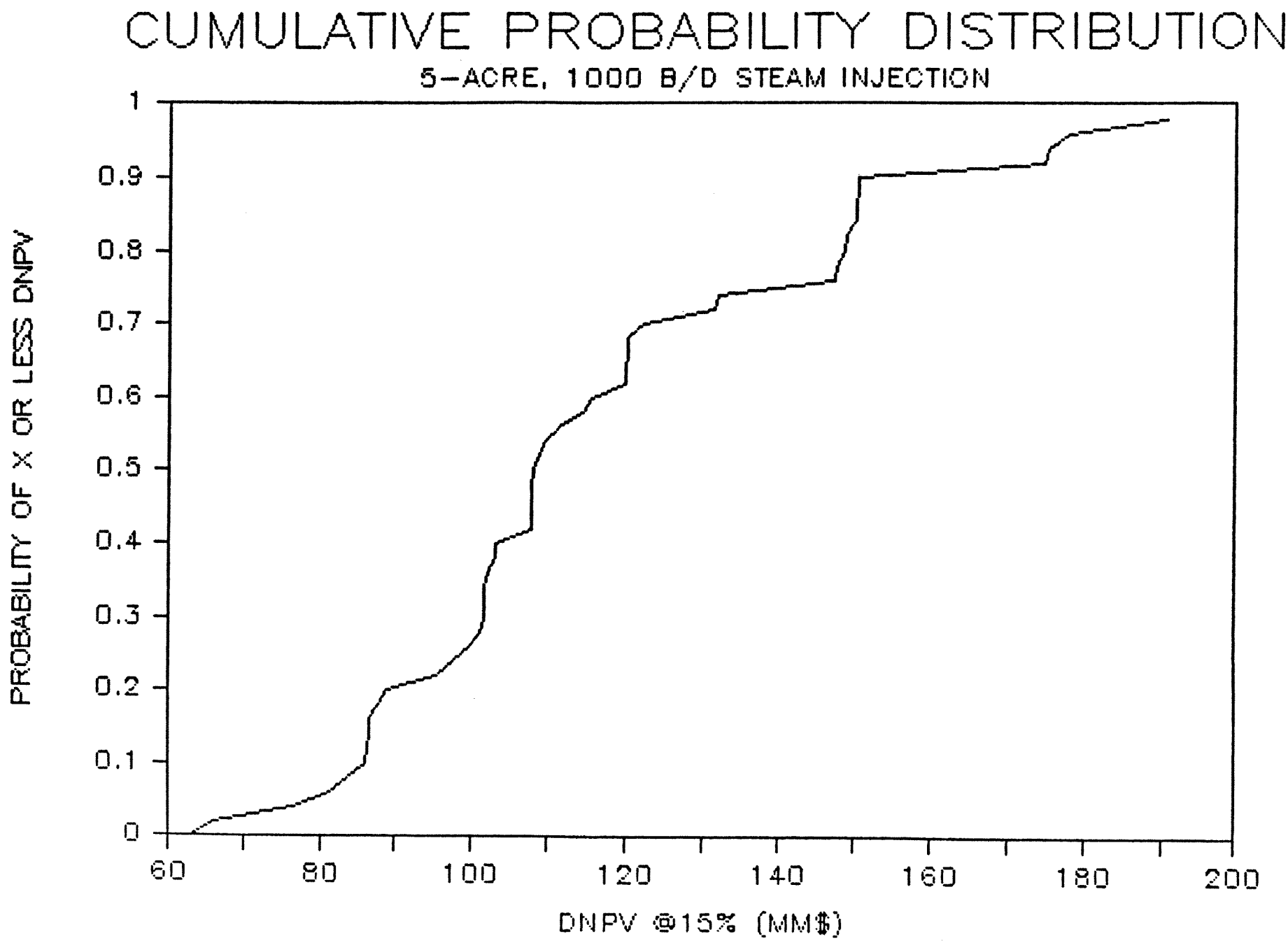

CUMULATIVE PROBABILITY DISTRIBUTION
10-ACRE, 1500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
60
80
100
120
140
160
180
200
DNPV @15% (MM$)

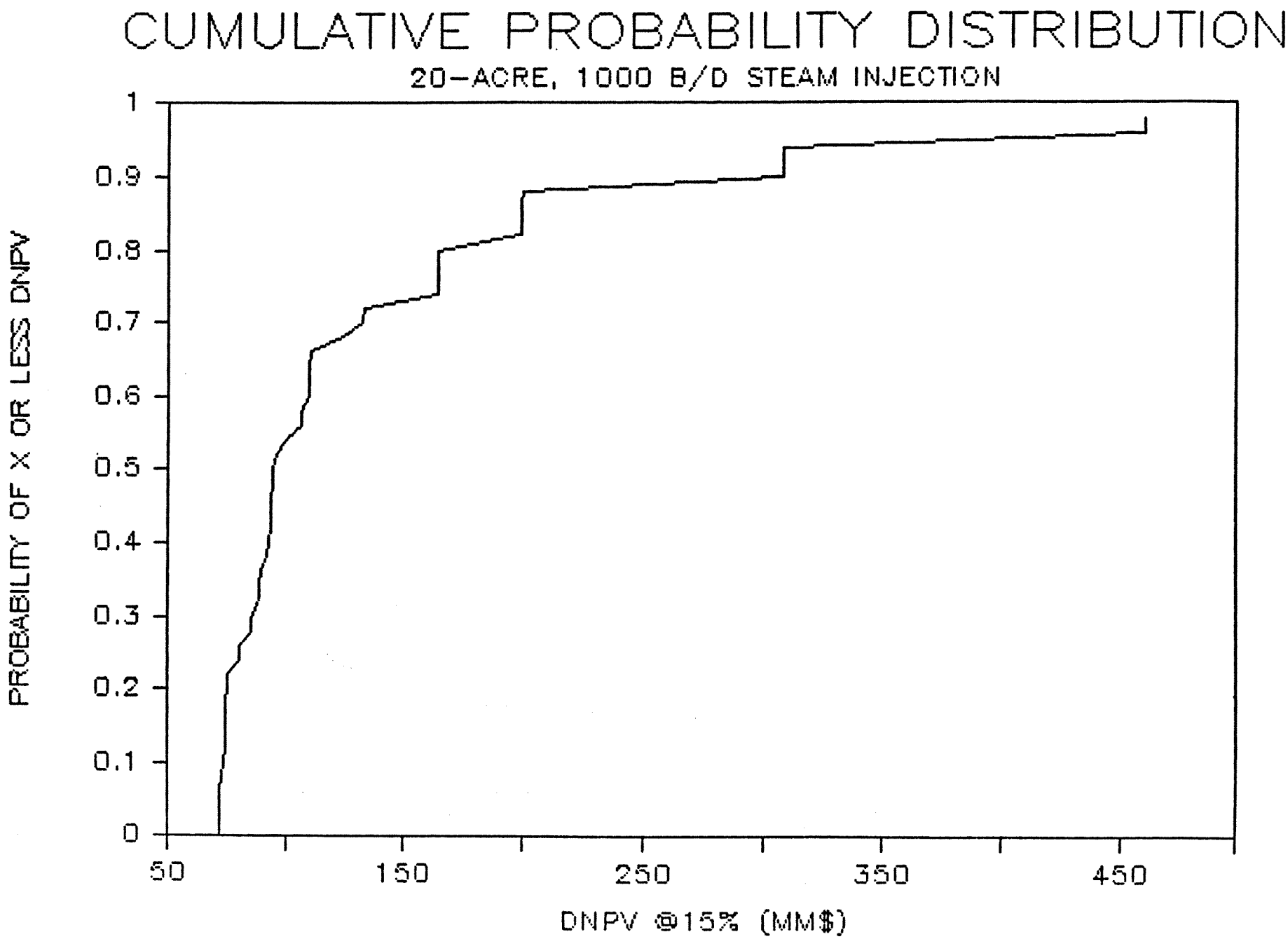

CUMULATIVE PROBABILITY DISTRIBUTION
20-ACRE, 500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
50
150
250
350
450
550
DNPV @15% (MM$)

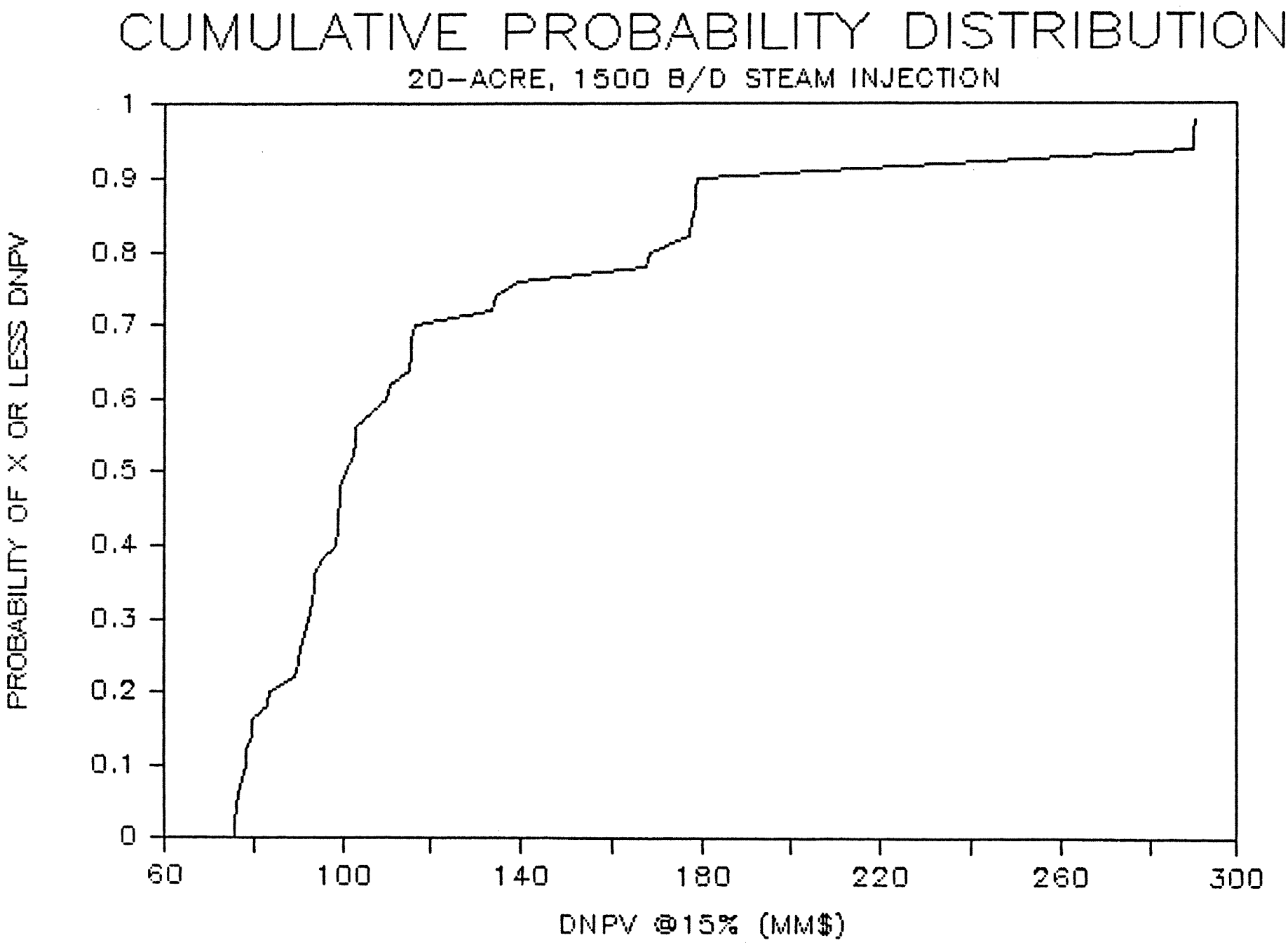

CUMULATIVE PROBABILITY DISTRIBUTION
2.5 ACRE, 1000 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
50
70
90
110
130
150
DNPV @15% (MM$)

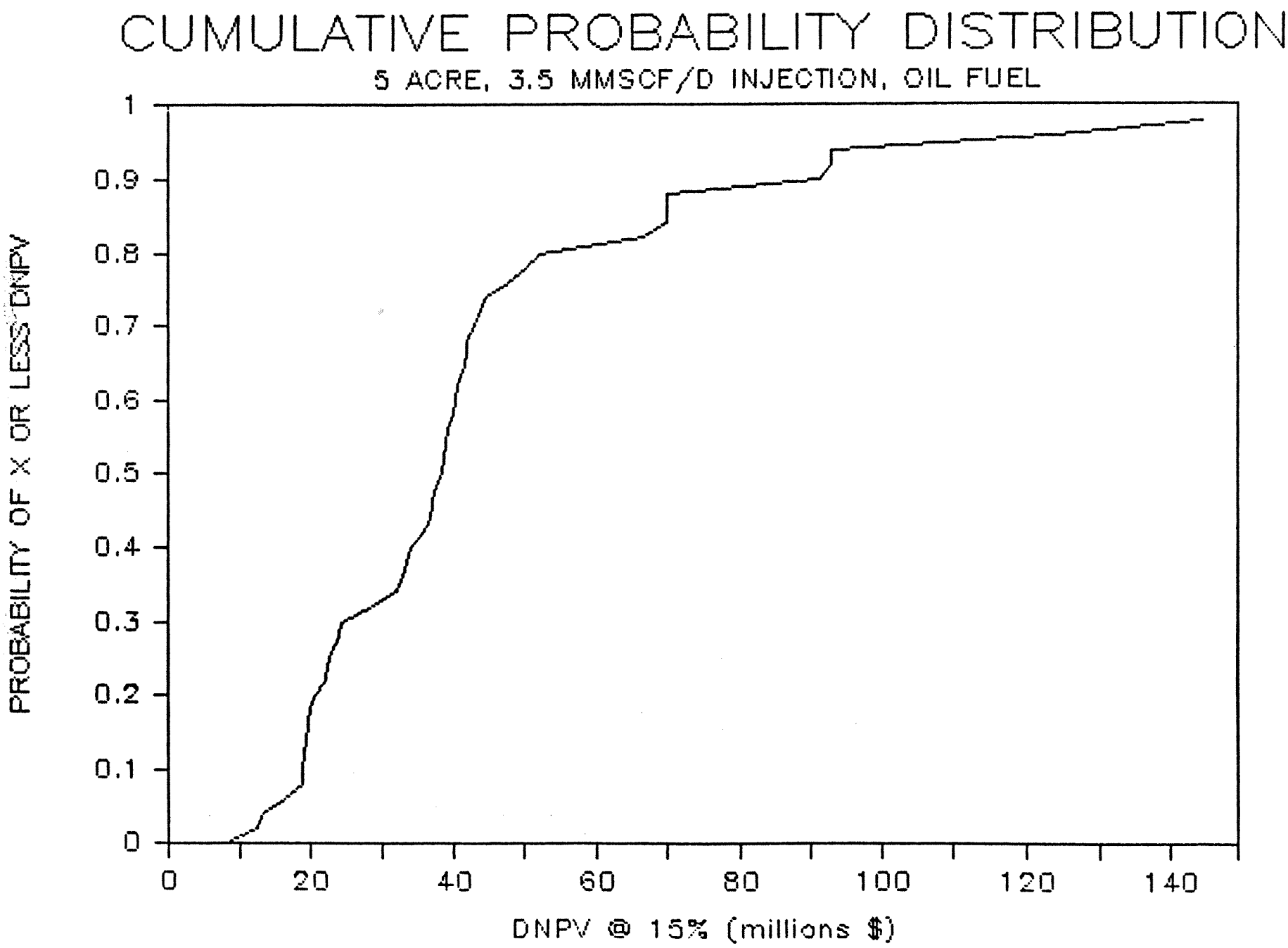

CUMULATIVE PROBABILITY DISTRIBUTION
2.5 ACRE, 1500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
40
60
80
100
120
DNPV @15% (MM$)

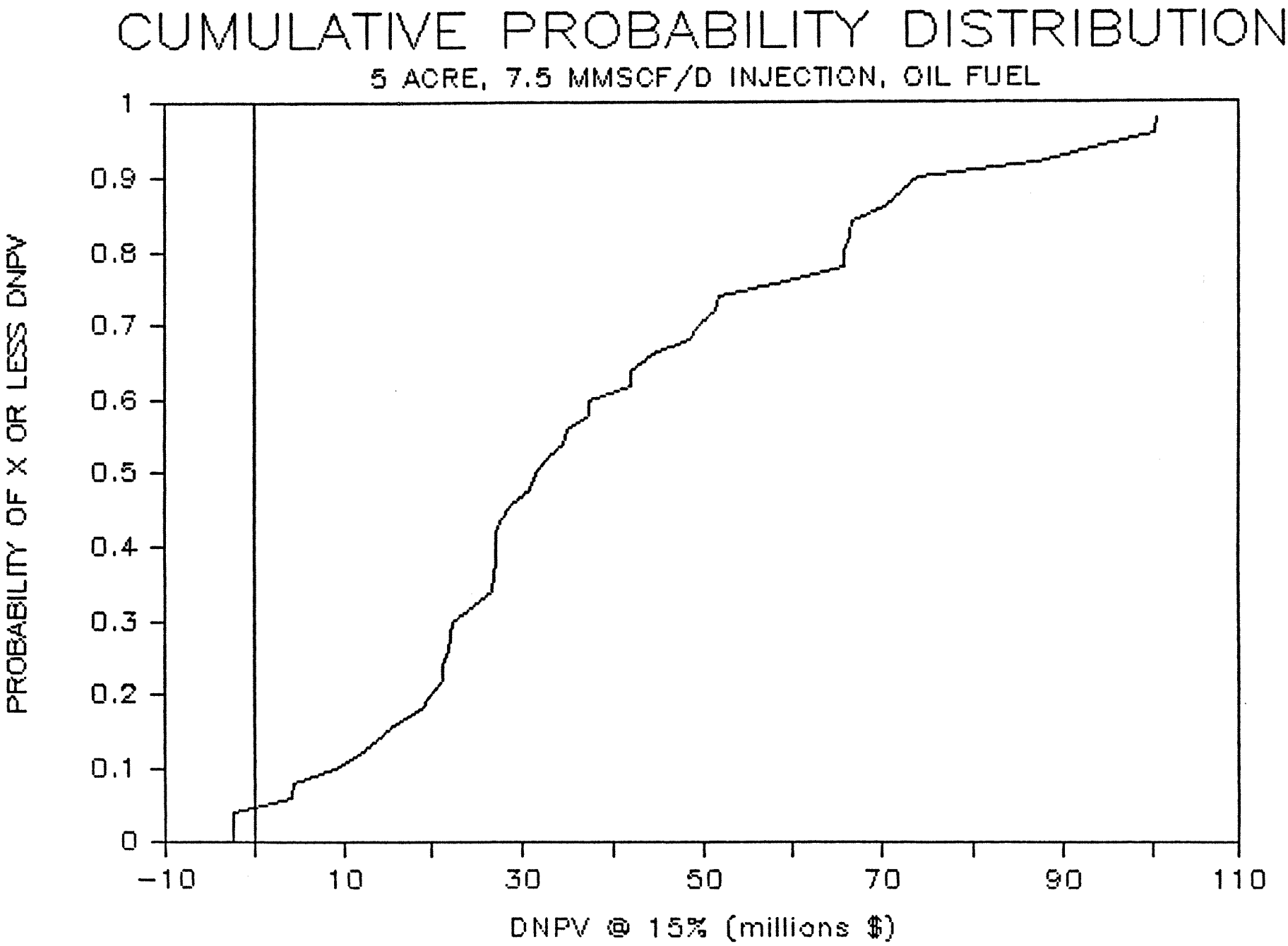

CUMULATIVE PROBABILITY DISTRIBUTION
5-ACRE, 500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
70
90
110
130
150
170
190
210
230
DNPV @15% (MM$)

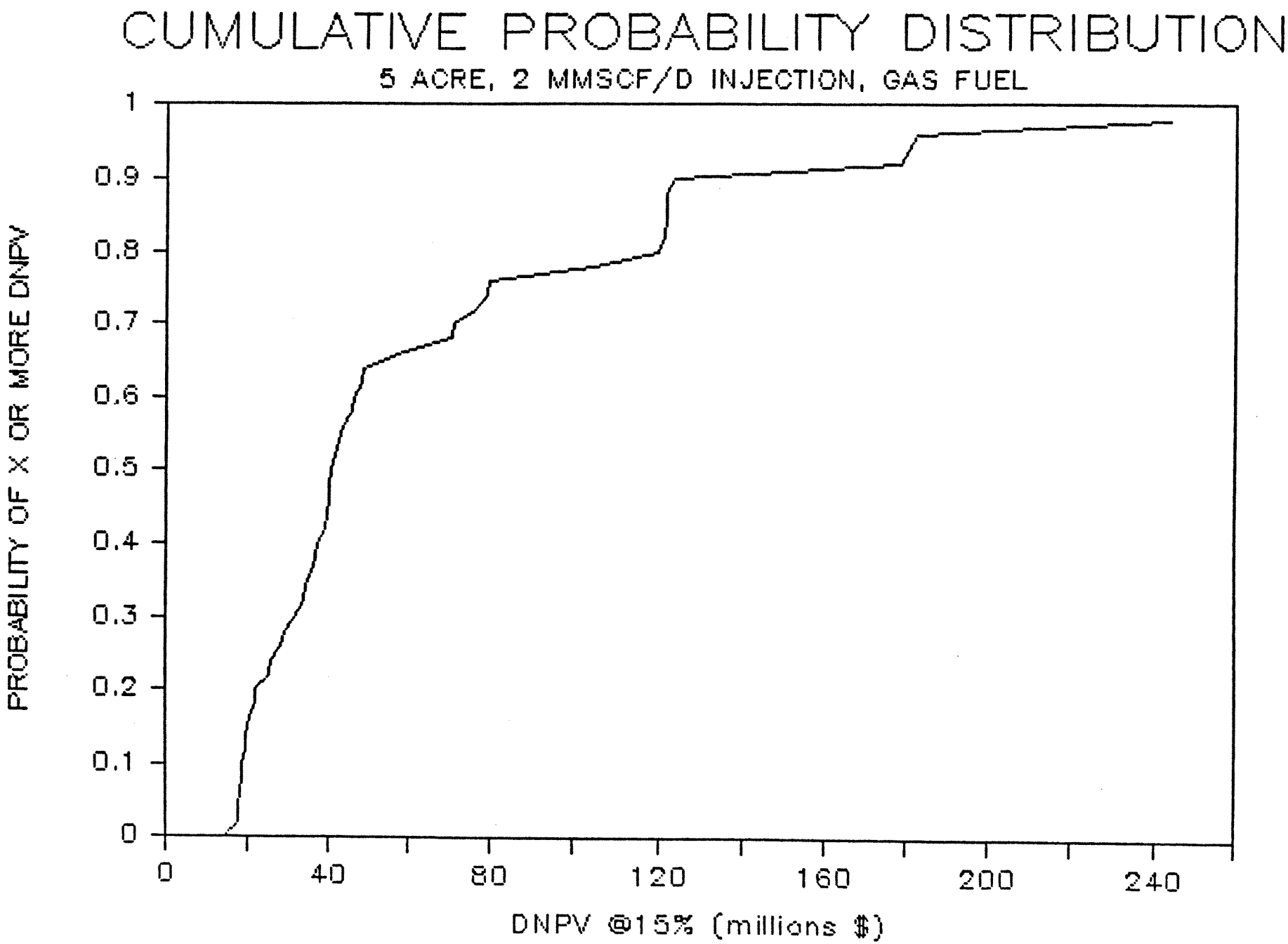

CUMULATIVE PROBABILITY DISTRIBUTION
5-ACRE, 1000 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
60
80
100
120
140
160
180
200
DNPV @15% (MM$)

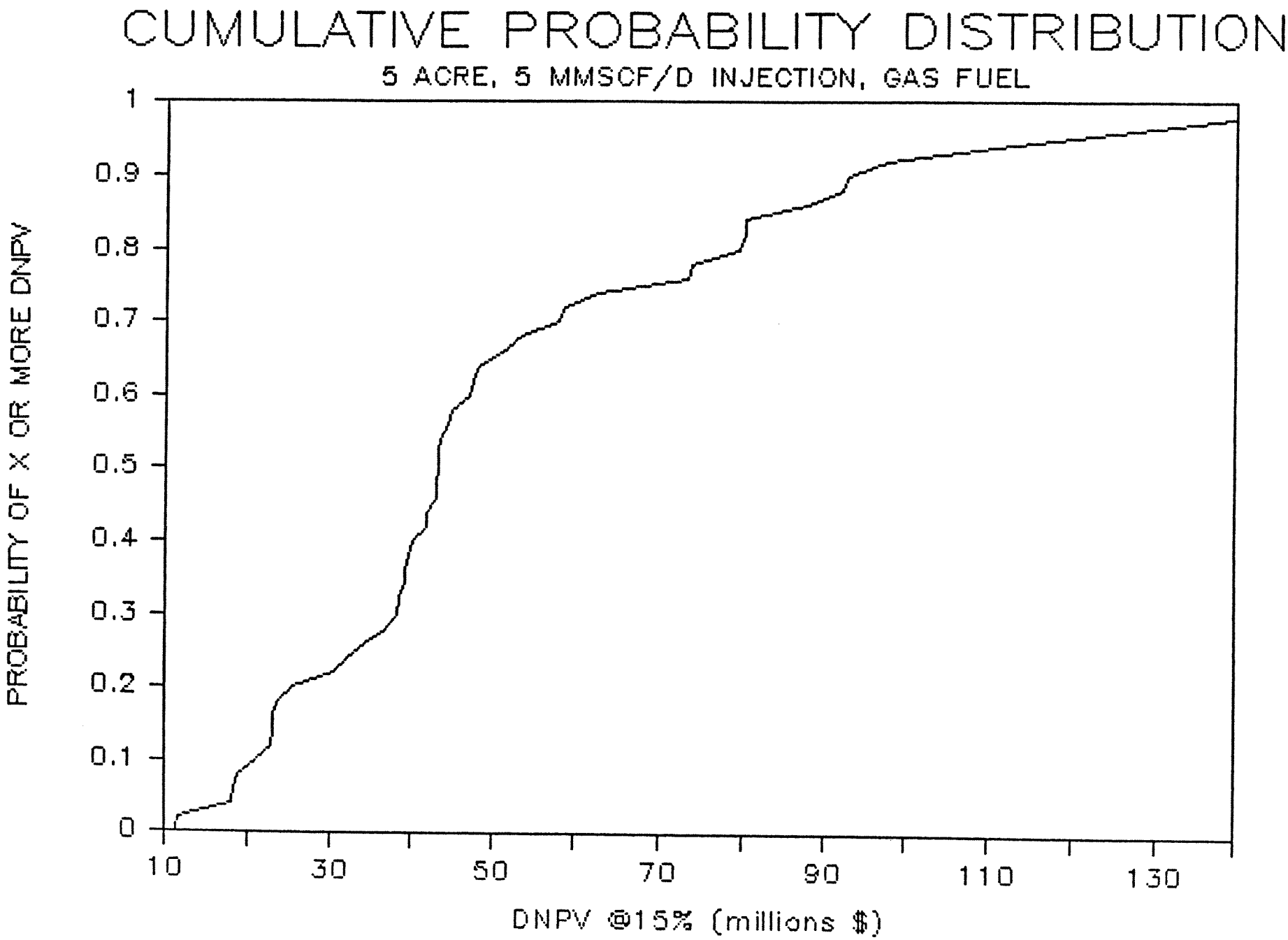

CUMULATIVE PROBABILITY DISTRIBUTION
20-ACRE, 1000 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
50
150
250
350
450
DNPV @15% (MM$)


CUMULATIVE PROBABILITY DISTRIBUTION
20-ACRE, 1500 B/D STEAM INJECTION
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
60
100
140
180
220
260
300
DNPV @15% (MM$)


CUMULATIVE PROBABILITY DISTRIBUTION
5 ACRE, 3.5 MMSCF/D INJECTION, OIL FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
20
40
60
80
100
120
140
DNPV @ 15% (millions $)

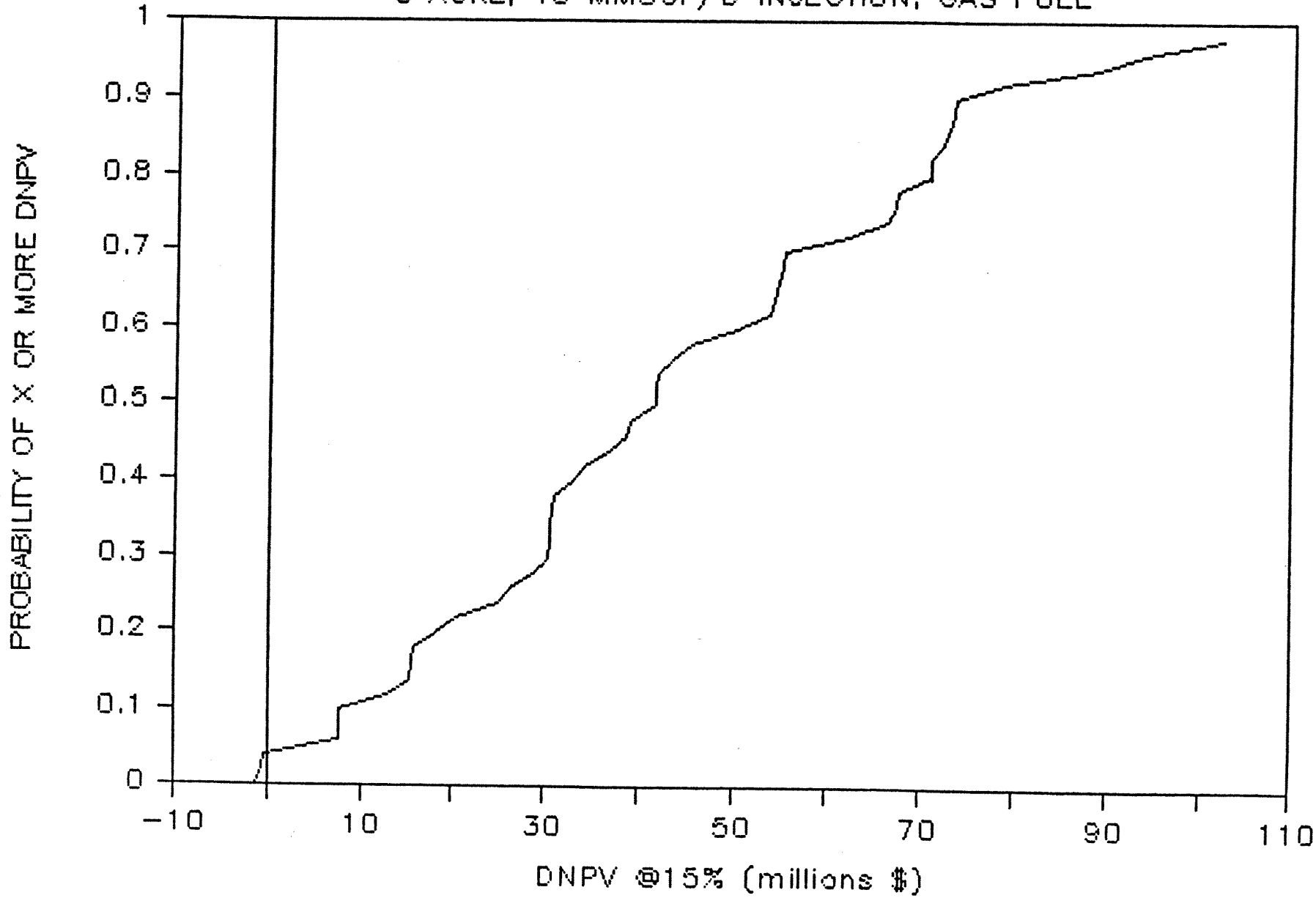

CUMULATIVE PROBABILITY DISTRIBUTION
5 ACRE, 7.5 MMSCF/D INJECTION, OIL FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
-10
10
30
50
70
90
110
DNPV @ 15% (millions $)

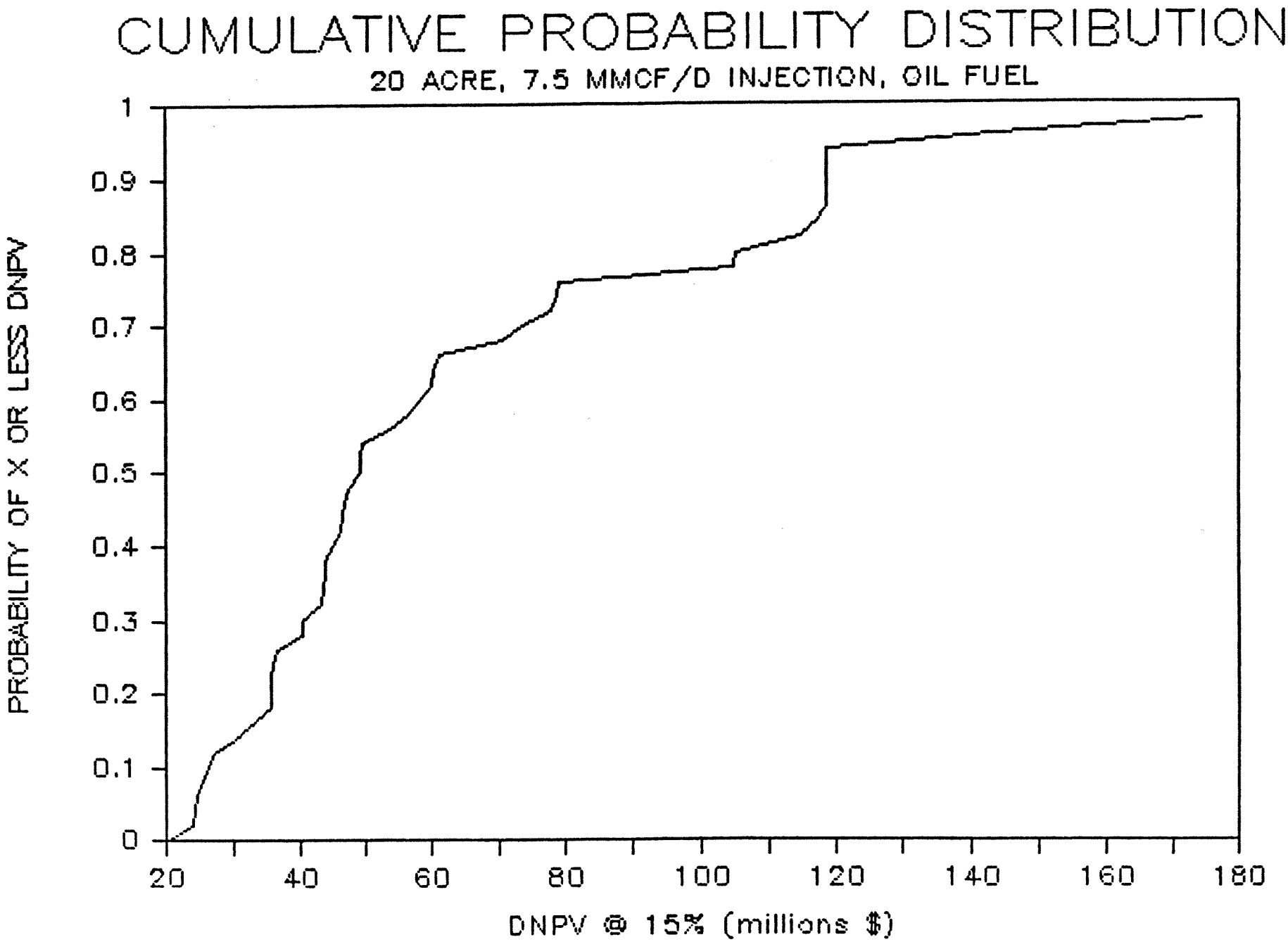

CUMULATIVE PROBABILITY DISTRIBUTION
5 ACRE, 2 MMSCF/D INJECTION, GAS FUEL
PROBABILITY OF X OR MORE DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
40
80
120
160
200
240
DNPV @15% (millions $)

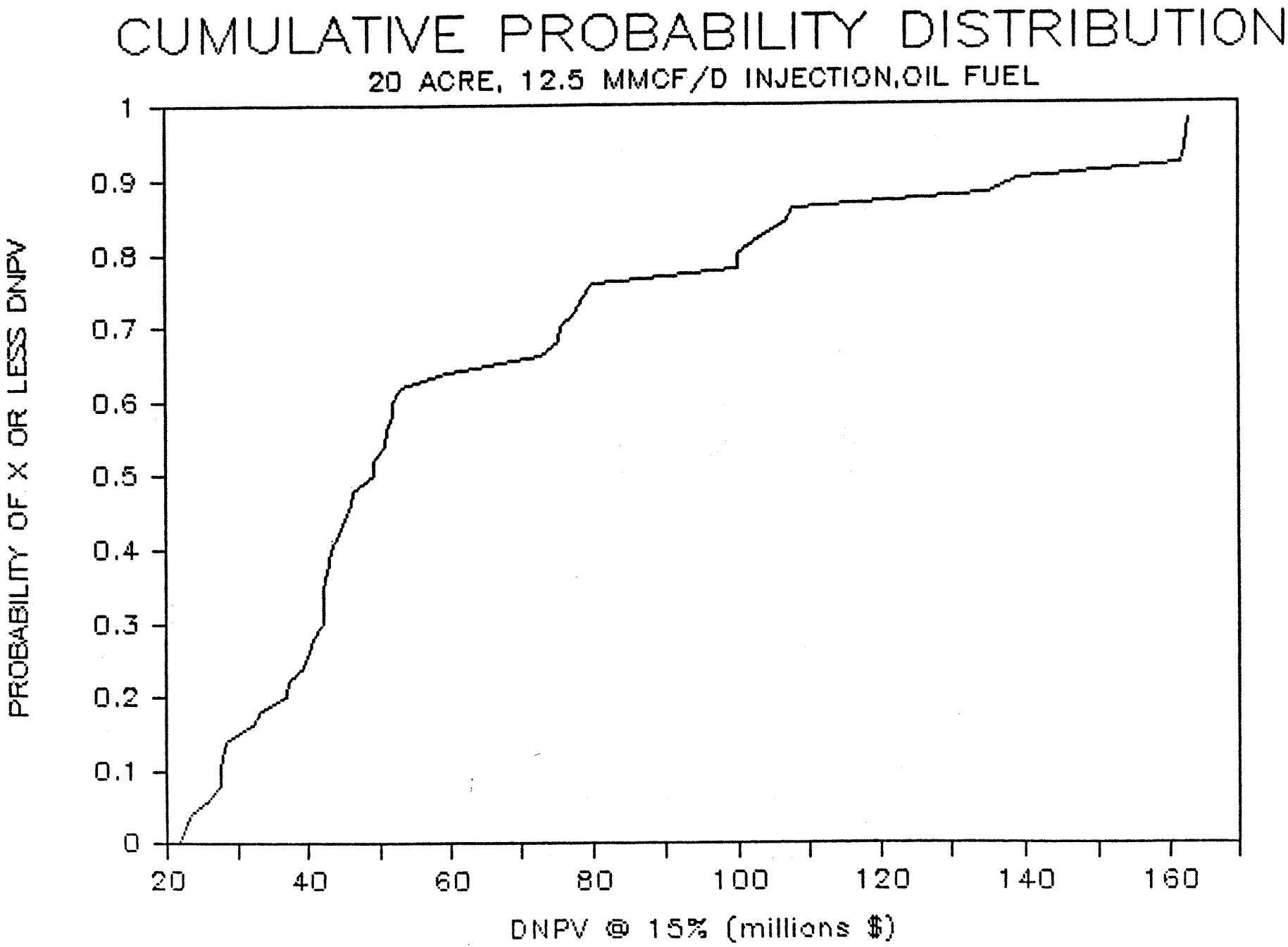

CUMULATIVE PROBABILITY DISTRIBUTION
5 ACRE, 5 MMSCF/D INJECTION, GAS FUEL
PROBABILITY OF X OR MORE DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
10
30
50
70
90
110
130
DNPV @15% (millions $)

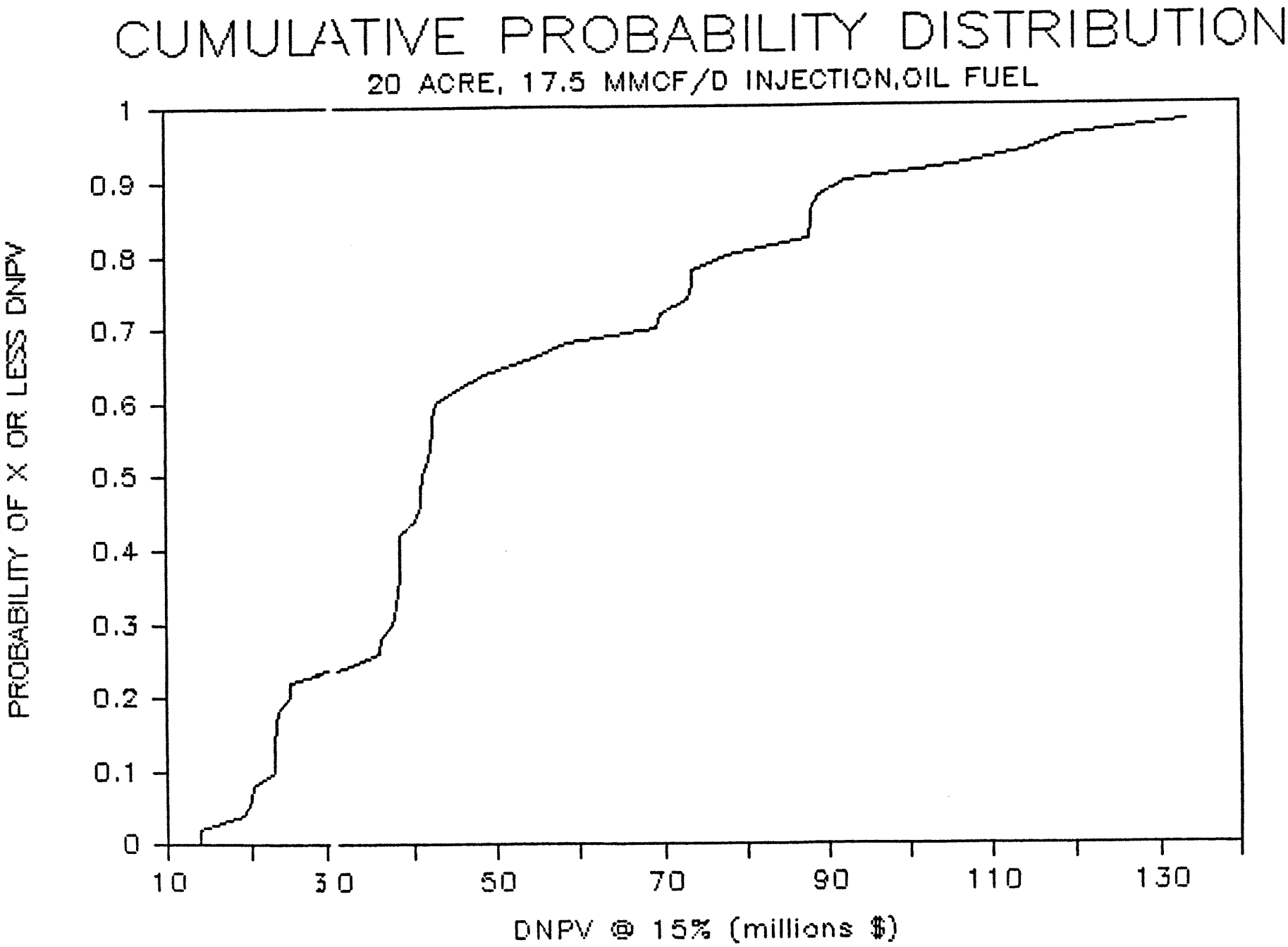
CUMULATIVE PROBABILITY DISTRIBUTION

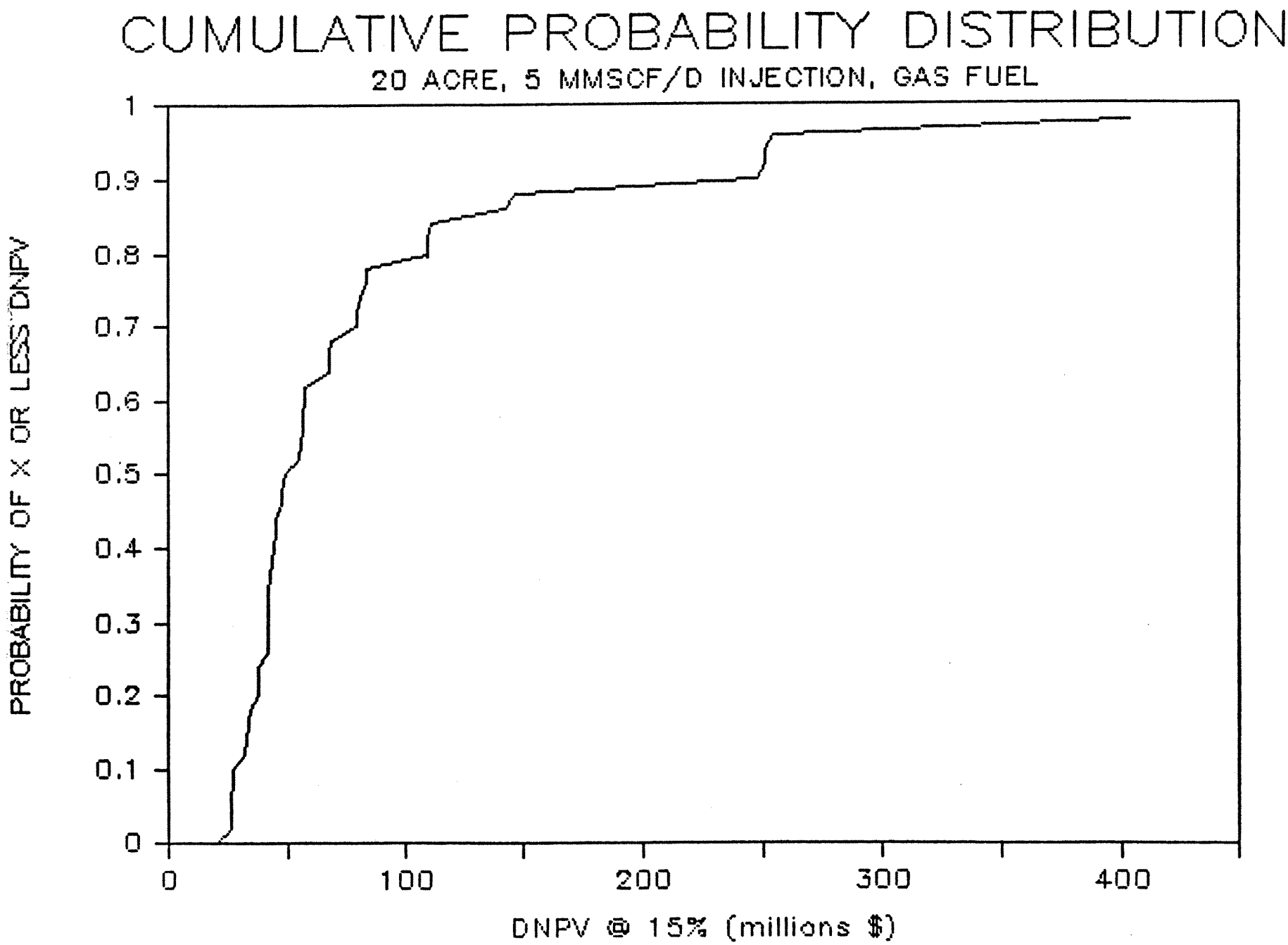
5 ACRE, 10 MMSCF/D INJECTION, GAS FUEL

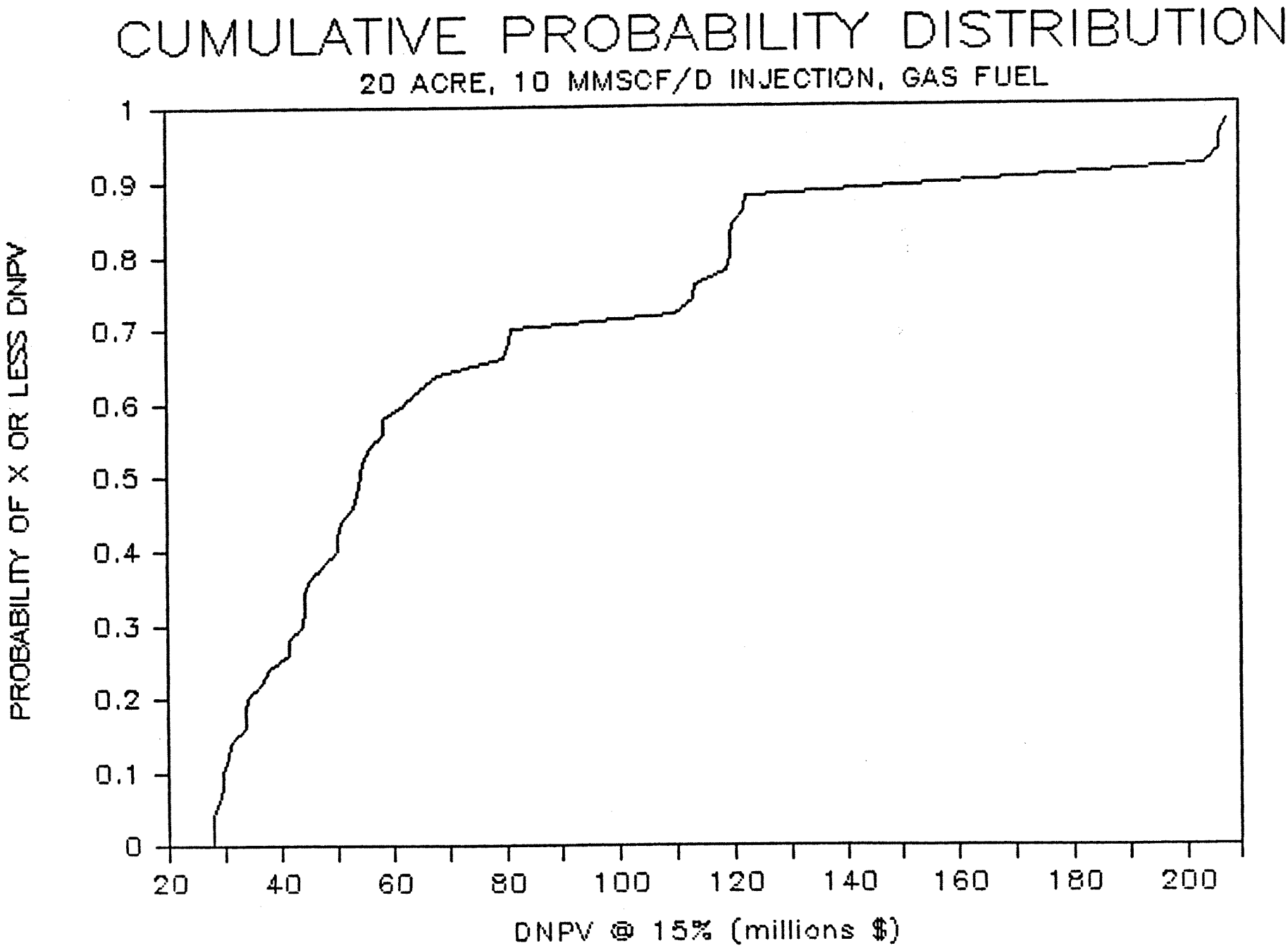


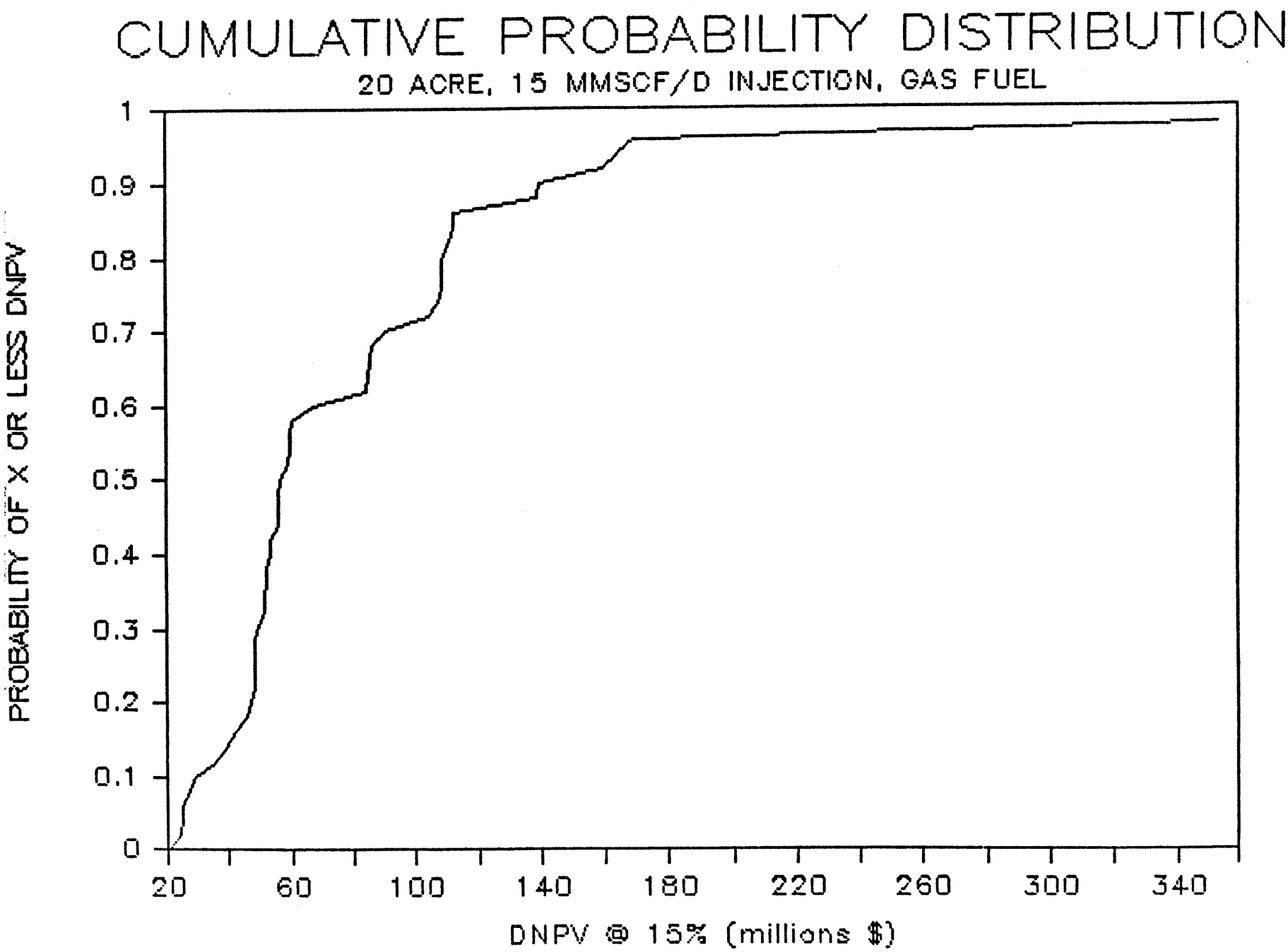

CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 7.5 MMCF/D INJECTION, OIL FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
20
40
60
80
100
120
140
160
180
DNPV @ 15% (millions $)


CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 12.5 MMCF/D INJECTION,OIL FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
20
40
60
80
100
120
140
160
DNPV @ 15% (millions $)


CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 17.5 MMCF/D INJECTION,OIL FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
10
30
50
70
90
110
130
DNPV @ 15% (millions $)

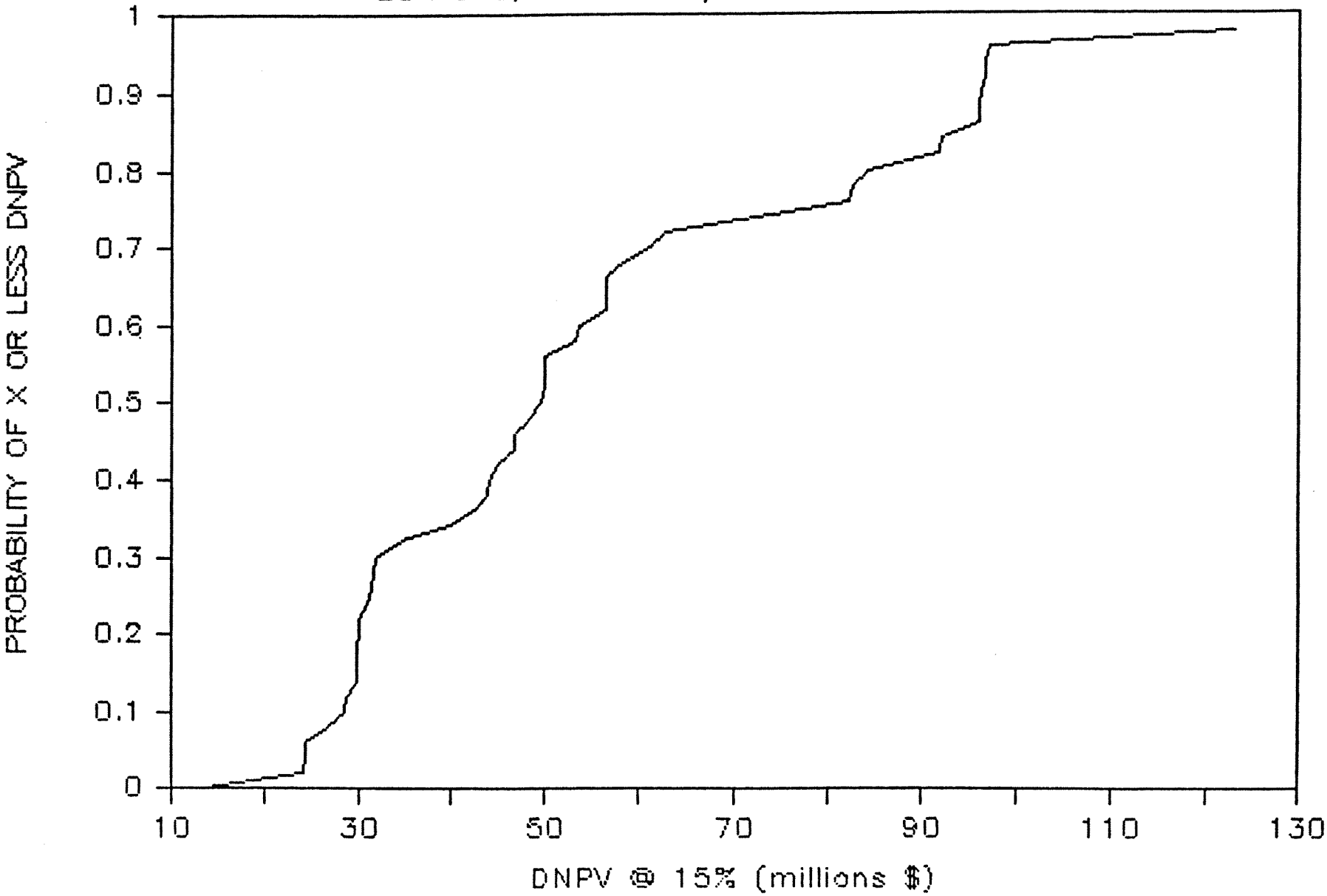

CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 5 MMSCF/D INJECTION, GAS FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0
100
200
300
400
DNPV @ 15% (millions $)


CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 10 MMSCF/D INJECTION, GAS FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
20
40
60
80
100
120
140
160
180
200
DNPV @ 15% (millions $)


CUMULATIVE PROBABILITY DISTRIBUTION
20 ACRE, 15 MMSCF/D INJECTION, GAS FUEL
PROBABILITY OF X OR LESS DNPV
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
20
60
100
140
180
220
260
300
340
DNPV @ 15% (millions $)

CUMULATIVE PROBABILITY DISTRIBUTION

20 ACRE, 20 MMSCF/D INJECTION, GAS FUEL



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