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THE UNIVERSITY OF ALBERTA

THE PRICE AND INCOME SENSITIVITY OF CANADA'S POTENTIAL FRONTIER CRUDE OIL RESOURCES

BY

© DENNIS J. MCCONAGHY

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled The Price and Income Sensitivity of Canada's Potential Frontier Crude Oil Resources submitted by DENNIS J. MCCONAGHY in partial fulfilment of the requirements for the degree of Master of Science.

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ABSTRACT

The process of acquiring additional reserves of crude oil from Canada's frontier sedimentary basins (Mackenzie-Beaufort, Sverdrup, and Labrador) involves two phases of activity, exploration and development. The ability of a company to generate sufficient cash flow to commence and continue the drilling of wells is the critical factor in exploration; whereas, in the development phase, it is the obtaining of a sufficient price to cover the costs of production from a particular pool. Using statistical simulation techniques, both the income and price sensitivity of Canadian frontier crude oil potential were examined.

Fiscal and royalty policies affected the income sensitivity strongly. With increasingly punitive tax regulations and present royalties rates, the cash flow requirements to definitively explore a given basin indicated a two-fold increase in the producer's share of the posted price of crude oil.

If producibilities and pay thicknesses, encountered in the frontier basin (Mackenzie-Beaufort, Artic Islands and Labrador regions) are similar to those found in Alberta, substantial increases in crude oil price would be required to justify the production of any possible discoveries. The price-sensitivity function generated suggests that the costs of production for frontier oil are an order of magnitude greater than those of the majority of Alberta pools.

ACKNOWLEDGEMENTS

To Dr. J.T. Ryan for his wisdom and sensitivity.

To Mrs. K. Therrien for her typing and smiles.

To Beverly and North Garneau for a sense of perspective.

The trouble with you
Is the trouble with me,
You got two good eyes
But you still don't see.

— G.D.

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CHAPTER ONE

INTRODUCTION

About 1850, oil was first discovered in Canada at Oil Springs, Ontario[1]. Prior to that discovery, Peter Pond and Alexander Mckenzie observed the McMurray Oil Sands on the banks of the Athabasca River in 1778[1]. During the early years of oil production (1850-1900), a single oil discovery would saturate the available market, causing a rapid decline in price. Due to primitive production techniques, newly discovered reservoirs would be quickly depleted and a period of oil shortage would result with crude prices increasing significantly. Crude oil price would fluctuate violently depending on current discoveries and production levels. The available market for crude oil in this early period did not expand significantly beyond lubrication and lighting purposes until the invention of the automobile.

Natural gas was accidently discovered by the Canadian Pacific Railways at Langevin, Alberta, in 1893, while boring for water. In Western Canada, the first commercial natural gas was found at Medicine Hat in 1901[1]. Later in 1913, a commercial oil field at Turner Valley, Alberta was found. A curious discovery of oil was also made at Norman Wells, Northwest Territories in 1920[1]. During the early development of the Western Canadian fields, the oil market was a buyer's market. The market price of a barrel of crude oil was controlled by the American industry and market, bearing little relation to the worldwide cost of production.[6] Oil was a commodity in world over-supply.

After the virtual exhaustion of the Turner Valley production capacity in the late 1920's, no significant oil production took place in Canada for approximately 25 years. During this interval, domestic demand was satisfied by imports.

At Leduc, Alberta, in 1947, oil was discovered in Devonian reefs, a geological zone previously thought to be barren. The size of this single discovery was not phenomenal by world standards, but it did prove that the Western Canadian basin was a significant oil province. By 1966, a recoverable reserve of 9 million to 10 billion barrels of oil had been confirmed[3].

Canada had, by the late 1950's, the capacity to meet its domestic demand. However, all of Canada was not supplied with domestic crude. Only British Columbia, Prairie and Ontario markets were supplied with Alberta crude through the Trans Mountain and Interprovincial pipeline systems. American markets were also significant. Nevertheless, Western Canadian producers faced an oversupply situation and the need of increased markets. Small-and intermediate-sized oil producing companies lobbied for the construction of a pipeline from Alberta into the Montreal market. Because of the opposition from the large, integrated, international oil companies, the Montreal market was closed to Western Canadian crude and continued to be supplied by imports from Venezuela and the Middle East. Canadian producers were forced to seek new markets on the North American continent exclusive of Montreal. This arrangement was called the National Oil Policy, formulated in the early 1960's by the Diefenbaker government. The price of crude still was set by the international market.[14]

By the 1970's, both international political events and a clearer consciousness of the finite character of oil reserves changed industry and government objectives and policy. The Middle Eastern political situation in 1973 precipitated a five-fold increase in the average world market price, from $3.00/bbl. to $15.00/bbl. The Organization of Petroleum Exporting

Countries (OPEC) imposed an embargo to selected coutries for an extended period. Concurrently, existing production from Western Canada was recognized as being insufficient to meet projected domestic demand. (See Figure 1-1) A shortfall was predicted to occur in the early 1980s[5,6]. The situation had suddenly inverted intself from oversupply to expected shortages.

One alternative to avoid the shortfall and assure the security of supply was to bring on stream oil and gas from frontier areas (See Figure 1-2 for designation and location of frontier areas). Portions of the oil industry had, since the mid-1960s been participating actively in frontier exploration. The urgency and significance of these efforts were now magnified.

The purpose of this work is to analyze the effect price would have on realizing frontier crude oil production. For the purposes of this work, the term "price" requires some precise definition. Generally, two types of crude oil price are referred to:

1) market or posted price, and,

2) wellhead price.

The market price is the price received for crude oil delivered to a refinery gate. Wellhead price is simply the market price minus the cost of transporting the crude from the producing well to the refinery gate. A certain portion of the wellhead price is a government share. The term "price" will hereafter refer specifically to wellhead price.

For example, assume the price of crude oil delivered to the Ontario market is $7.15/bbl. The wellhead price in Alberta is given by:

Ontario market price - transportation charge = wellhead price.

Assuming a sixty-five cents per barrel transportation tariff, this gives a wellhead price of $6.50/bbl. in Alberta. The Alberta government royalty

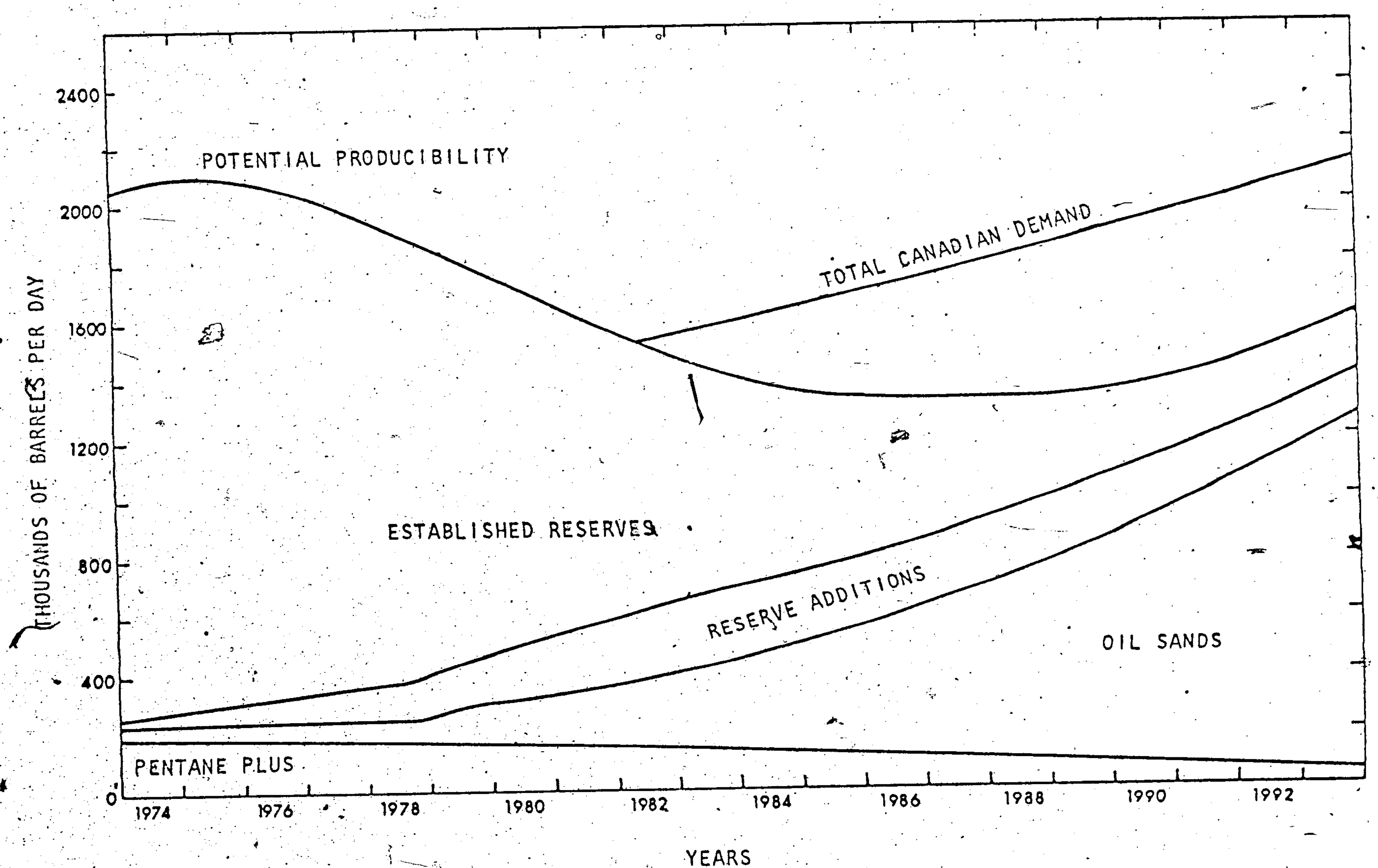

FIGURE I-1 N.E.B. FORECAST OF CANADIAN CRUDE OIL AND EQUIVALENT SUPPLY AND DEMAND

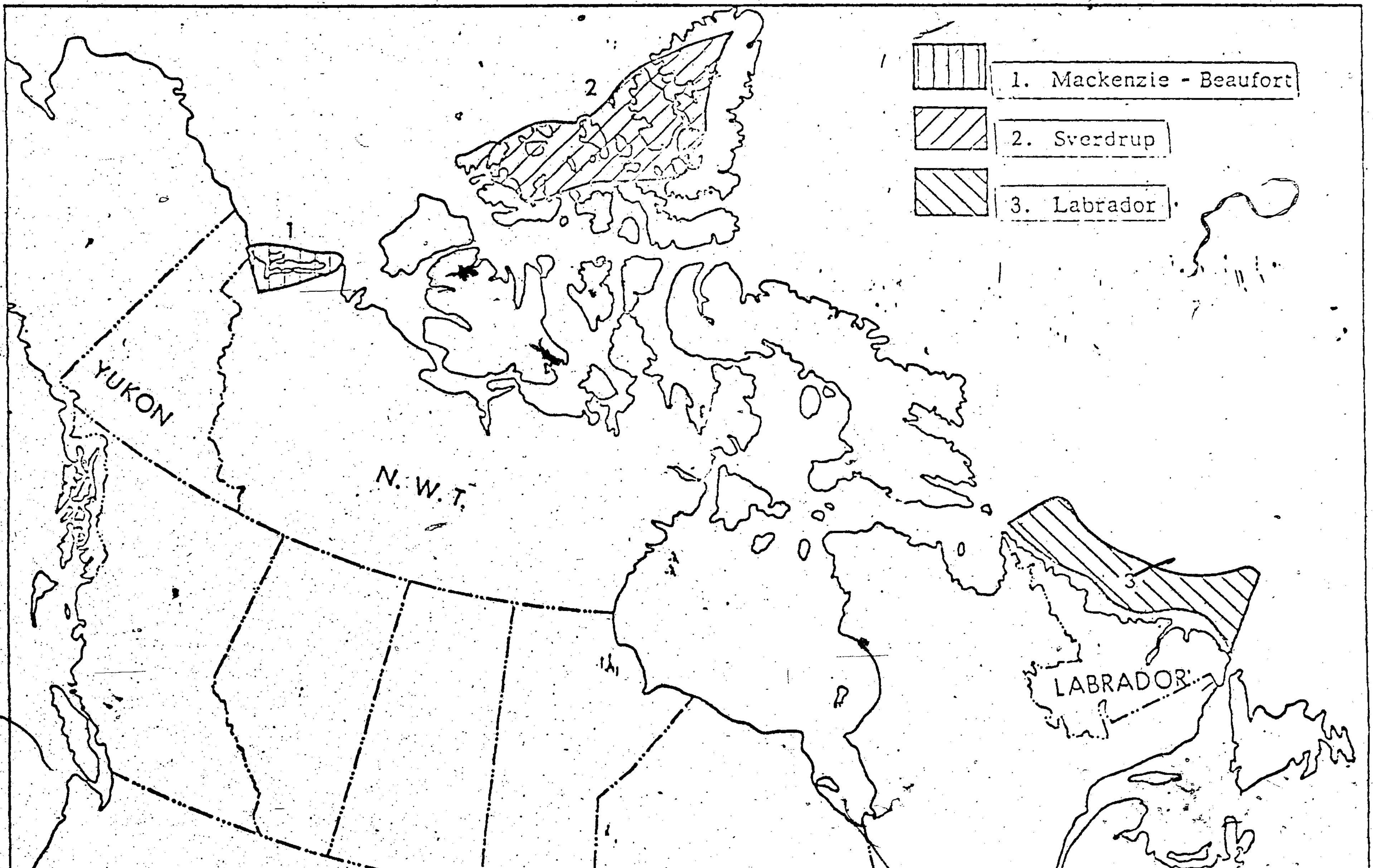

FIGURE 1-2 MAP OF CANADA'S THREE MOST LIKELY PETROLIFEROUS FRONTIER BASINS

is forty-two and a half per cent of the wellhead price. The producer's before-Tax share is \$6.50 [1-.425] = \$3.73/bbl. If income tax is \$1.50/bbl. and operating expenses another \$1.00/bbl, the effective return to the producer is \$1.23/bbl.

Before crude oil becomes available for refinery processing, it must be found in its underground reservoirs and made to flow from the reservoir to the transportation system. These two fundamental processes of crude-oil supply, exploration and development, will be analysed separately. Each phase reacts differently to price, either by an income sensitivity or a direct price sensitivity.

For the purposes of this work, income or price sensitivity will refer to the relationship of increased oil supply (via recoverable reserve additions or new discoveries) attributable to an increase in income or price,

$$\text{Supply}_1 = \psi\ (\text{Price}) \qquad - \quad 1\text{-}1$$

$$\text{Supply}_2 = \eta\ (\text{Income}) \qquad - \quad 1\text{-}2.$$

Instead of describing income or price elasticities, i.e.

$$E_{INCOME} = (\Delta S/S)/(\Delta I/I) \qquad - \quad 1\text{-}3$$

$$E_{PRICE} = (\Delta S/S)/(\Delta P/P) \qquad 1\text{-}4$$

where E = elasticity

S = supply (bbl)

I = income (\$)

P = price (\$/bbl)

which are simply statistics of Equations 1-1 and 1-2[7], the relationship itself was derived.

The distinction between the income and price sensitivity can be made clear by a simple analogy. What is the reaction of a consumer in his purchases of bread if his total income is reduced by $10.00? Similarly, how is his consumption affected if the price of a loaf of bread is increased by $10.00? His reaction to the first question would constitute his demand-income sensitivity; his response to the second question defining his demand-price sensitivity.

In the following chapters the price and income sensitivity of the exploration and development phases will be examined.

CHAPTER TWO

THE GEOLOGICAL COMPONENT OF FRONTIER EXPLORATION

II.1 Introduction

In order to describe the effect of price on the exploration phase of oil supply, one must answer two questions:

1) What is the extent of exploration effort (number of wildcat wells to be drilled, seismic and surface activity, etc.) necessary to resolve the uncertainty of oils being present in required amounts?

2) Are sufficient funds available to carry out the required level of exploration?

These questions are the physical (or geological) and economic components of the discovery process. They will be considered separately. This chapter presents a procedure whereby the first question can be answered.

Exploration is fundamentally a sequential sampling procedure. On the basis of the best available geologic judgments, potential oil-bearing rock strata are identified. If the oil potential is considered economically significant, the prospects are drilled. When there is a significant discovery, the drilling will have confirmed the existence of oil. If oil is not found, the continued failures produce downward revisions of original expectations of oil reserves. Presumably, failures are tolerated until expectations reach an economically unacceptable limit. Any model related to oil exploration must express the sequential success-failure nature of the search.

The geological question is how many wells must be drilled until expectations of oil potential are below the economic limit? To answer this question, a model simulating the exploration process was developed.

The general procedure was to conceive of a potential petroliferous basin as consisting of a certain number of prospects. The sizes of these prospects were distributed in some highly skewed fashion. On the basis of these prospects an estimate of the oil potential for the basin, U_∞, was made before any drilling activity took place. A single well was then drilled into the largest prospect and was assumed to be a failure. A new estimate for U_∞ was then made, utilizing the information of the largest prospect being non oil-bearing. The unsuccessful prospect was removed from further consideration. A new population of prospects was formed and the procedure of drilling its largest prospect repeated. Continued failures were assumed to occur (with new populations formed and revised U_∞'s estimated sequentially) until the U_∞ was below an economically acceptable limit.

The three major requirements of this procedure are:

1) a technique for estimating the initial set of prospects (i.e., creating the sample space),

2) a means for reassessment of reserve potential after each drilling failure, and,

3) a decision rule (a minimum acceptable U_∞) for the final acceptance or dismissal of the entire premise of the basins being petroliferous.

The crucial component is the second one, the reassessment of reserve potential after each drilling failure. To estimate the magnitude of this reassessment, an analytical, deterministic or numerical approach could be taken. Appendix IV outlines an approximate analytical solution to this problem. The major difficulty with an analytical method was that the required mathematical manipulations were unworkable. A deterministic method would be essentially an application of geological knowledge or intuition. Available geological resources did not allow examination of this approach.

A numerical and probablistic technique, the Monte Carlo simulation (or method of statistical trials), proved to be the most productive. Monte Carlo methods are generally applied to the solution of problems involving the uncertainty of various input variables. An example of this type of problem[8;9] is shown in Figure II-1. Consider a problem involving determining the value of output variable, D. To solve for D, one requires values for A, B, C. However, the values of A, B, C are subject to uncertainty, expressible as some probability function. A direct approach to this problem would be to solve for the joint probability function which governs the value of D. The Monte Carlo technique involves choosing a value for each input, A, B, C, and performing the calculations labelled ψ, to determine D. Once the probability function determining each input is described, particular values can be estimated. The exercise of choosing the inputs and determining the output, D, is repeated many times. This produces a distribution of results for D. The value of the technique is that this resulting distribution bears some relation to the fundamental joint probability function.

For our specific problem, the output variable, D, is the cumulative volume of oil bearing prospects. The inputs are the success or failure of the individual prospects.

$$D = \sum_{i=1}^{N} (\text{Prospect Volume})_i \cdot P_i(X) \qquad \text{II-1}$$

The probability of each prospect being oil bearing is modelled after a density function of the form:

$$P_i(X) = 1, \text{ for } 0 < X < 1.0 \qquad \text{II-2}$$

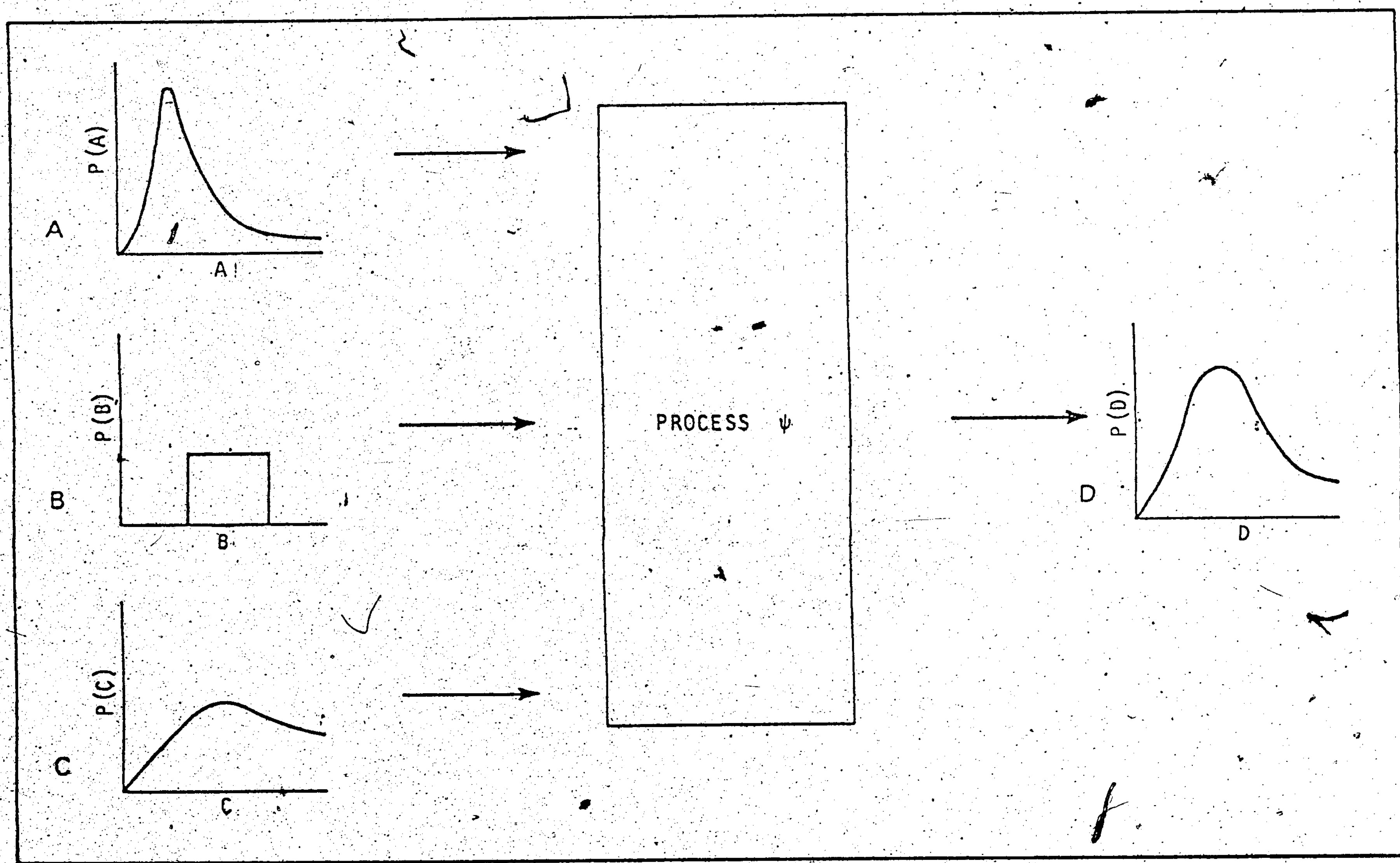

FIGURE II-1 THE MONTE CARLO PROBLEM

$$P_i(X) = 0, \text{ for } 10 > X > 1.0$$

where X is a random variable between 0 and 1. The function is a disjoint uniform distribution.

The technique makes samples of the probability function P_i to produce the output, cumulative reserve.

The actual procedure for making these samples is outlined later in this chapter.

This numerical probabilistic analog of the actual drilling of exploratory wells provides an estimate of the number of wells necessary to be drilled to bring expectations below an economic limit. This number of wells will, hereafter, be referred to as the critical failure.

II.2 Model Description

i. Basins Analysed

Included in both the Department of Energy, Mines and Resources and Canadian Society of Petroleum Geologists reports on frontier oil potential[10,11] was a summary of Canada's sedimentary basins which either contain oil or are thought to contain oil. There are 15 such basins. Of the 15, three were examined in the model, the Mackenzie-Beaufort, Sverdrup and Labrador Shelf. Of the 15, the greatest expectations have been held for these basins by industry geologists.[11] The remaining basins were not considered to have comparable potential.

ii. Sample Population

To explore an essentially virgin basin, one must first identify the significant prospects. (The term 'prospect' is defined as any geological configuration considered to be potentially oil-bearing.) The problem of identification is in two parts. In any petroliferous basin, oil is contained in two types of geological situations or traps, structural and stratigraphic. The structural prospect may be located by seismic investigation. The stratigraphic is considerably more obscure and relies upon geological judgment for its identification."

An assumption of the following exploration model is that the distribution of these prospects can be generated. This distribution would serve as the sample population.

As available information included neither seismic mapping nor detailed geological assessments, an alternate means of estimating the distribution of prospects was employed. The procedure for generating the distribution is outlined in the following steps:

1. The total volume of rock for each basin, as tabulated by the C.S.P.G. report[11] was multiplied by a factor to convert this rock volume to pore (or void space) volume. This factor was based on tabulations of the Alberta sedimentary basin rock volume to pore volume ratios as classified by stratigraphic periods[12]. These factors were derived from the work of Hitchon.

   In the C.S.P.G. analysis of oil potential for each of the frontier basins, the stratigraphic period most likely to contain oil was indicated for each of the three basins.

2. A second factor, based on the work of Ryan,[13] related pore volume to total prospect volume. (The Ryan factor was derived from comglomerated data applied over all stratigraphic periods.) This final product (pore volume x "Ryan" factor) represents the total prospect volume present in each basin.

3. By private communication with several geologists, both

academic and industrial, estimates of the number of prospects, above a minimum of 10 million barrels, were compiled. No government geologists were willing to participate. All available estimates were between 200 and 250 in number for prospects at depths less than 15 thousand feet.

4. With the total size and number of prospects estimated, the members of the distribution were generated. These members were forced to conform to a log-normal distribution (a distribution where the logarithm of the variable is normally distributed). Refer to Hald[14] for a complete analysis of the properties of the distribution. A trial-and-error solution was utilized; generating a set of log-normally distributed prospects whose size and number equalled the previously estimated values. (See Appendix 5 for computer listing.)

Assumptions made in this development were:

1) all prospects generated could be reached and drilled, ignoring any constraints as to location or depth.

2) The ability to order the prospects from biggest to smallest was not questioned.

3) The set of prospects generated was considered to be exhaustive and no major errors in geologic judgment occurred. (An example of geologic opinion ignoring significant structural or stratigraphic conditions was the failure of the industry to drill Devonian reefs prior to 1947. The Devonian had been considered too deep for oil occurrence.)

iii. Model Procedure

The rationale for the model used to simulate an exploration program was predicated heavily upon the apparent log-normality of oil pools or oil prospects. (Dickie[15] has shown that Jurassic and Cretaceous pools found in Alberta were not log-normally distributed, but simply highly skewed in their distribution.) Despite the lack of theoretical justification, the log-normal distribution was used to describe this skewness. Other authors[2,10] have also resorted to the log-normal distribution as a description of oil pool distribution.

Log-normality implies that the major portion of the total reserve is found in a few large pools. Consequently, the largest prospects ought to be investigated initially followed by successively smaller prospects in subsequent drilling attempts. If all prospects were eventually drilled the order would be from the largest to smallest. (The practical difficulties of achieving this drilling order were ignored. An example of a practical constraint would be in reaching prospects located in the deep offshore of the Beaufort Sea.) The largest prospects would represent the largest potentialities for crude oil, assuming that all prospects are equally likely before any drilling has occurred.

The aim of the model is to relate reserve expectations to drilling failures and to estimate at what point the expectations are below an economic limit.

Initial expectations can be placed at any level consistent with a company's geologic judgment. However, the process of revising prior expectations in expedited by this pattern of drilling.

The model expresses the relationship between reserve expectation and drilling failure by the following Monte Carle-type simulation procedure:

1. The ratio of the number of successes expected to the number of attempts made the success ratio is chosen. Before any drilling attempts and results, the value of this ratio is no more reliable than opinions of the geologists upon which it is based. The value used in this model came from data based on recent drilling programs in the Northwest Territories. (See Ref. 16) This particular value (one in 10) is biased towards the experience of the Norman Wells play.

2. The expected value of the cumulative reserve is determined for the total set of prospects (200 in number). The occurrence of oil in each prospect is simulated by the value of a randomly generated digit. A random digit, between zero and ten, represents a failure if its value is between 1.0 and 10.0 and represents a success if its value is between 0.0 and 1.0. Depending upon the value of the random digit, each prospect is evaluated as to its being oil-bearing or not. If the prospect was oil-bearing the oil-reserve volume was equalled to the prospect volume.

3. The prospects which are oil-bearing are totalled to give a single estimate of the cumulative reserve.

4. Steps 2 and 3 were repeated 100 times giving 100 estimates of the cumulative reserve expectable from the 200 prospects.

5. The 100 estimates were averaged. This numerical average represents the a priori expectation of oil potential for the basin.

6. A drilling attempt is presumed to be made on the largest prospect resulting in a failure (i.e. no oil was found). This largest prospect is removed from the remaining set of prospects, and steps 2 through 4 are repeated, generating a new expectation as to cumulative reserve. This revised expectation incorporates the exclusion of the largest prospect.

7. Step 6 is repeated with the largest-remaining prospect excluded. For each successive drilling failure, a revised expectation of oil reserve is made.

8. Steps 2 through 7 are repeated until all prospects are eliminated, and a curve is generated relating drilling failure to reserve expectation.

9. Steps 1 through 8 are applied to each of the frontier basins. Figures II-2, II-3 and II-4 summarize the results.

Throughout this procedure, the success ratio was not revised despite drilling failures; its value remained invariant at 1:10. (See Appendix V for computer listing.)

iv. Decision Rule

The purpose of this section was to answer the question of how many wells were needed to be drilled before a basin would be rejected as being below an economically acceptable reserve in its oil potential. To answer that question the curve of drilling failure versus reserve expectation (Figs. II-2, II-3 and II-4) was generated. A decision rule (what is the minimum acceptable reserve?) is also required. This requires the introduction of economic considerations.

The decision rule determines the point along the curve of

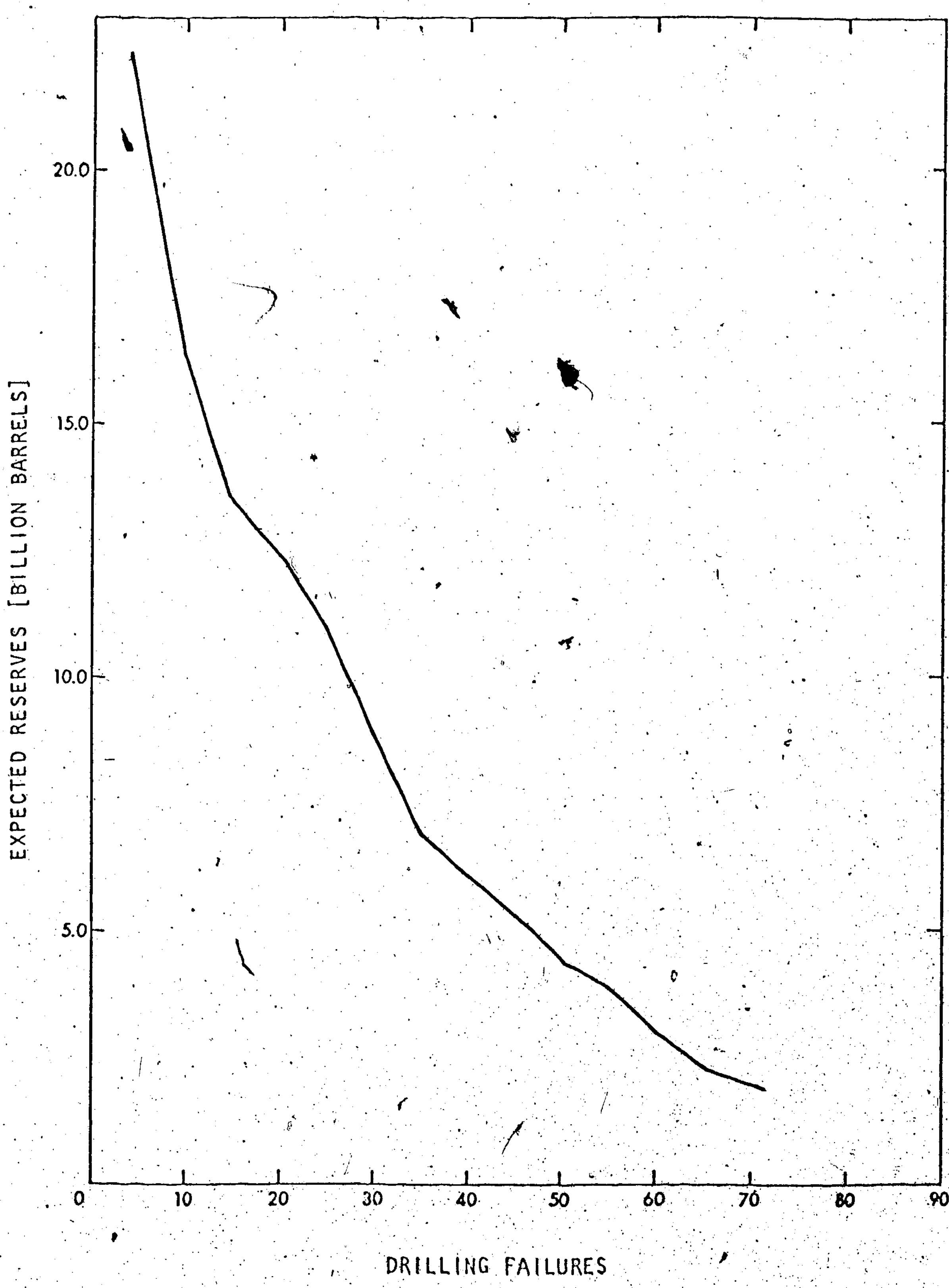

FIGURE II-2 DRILLING FAILURES VS EXPECTATION, MCKENZIE-BEAUFORT BASIN

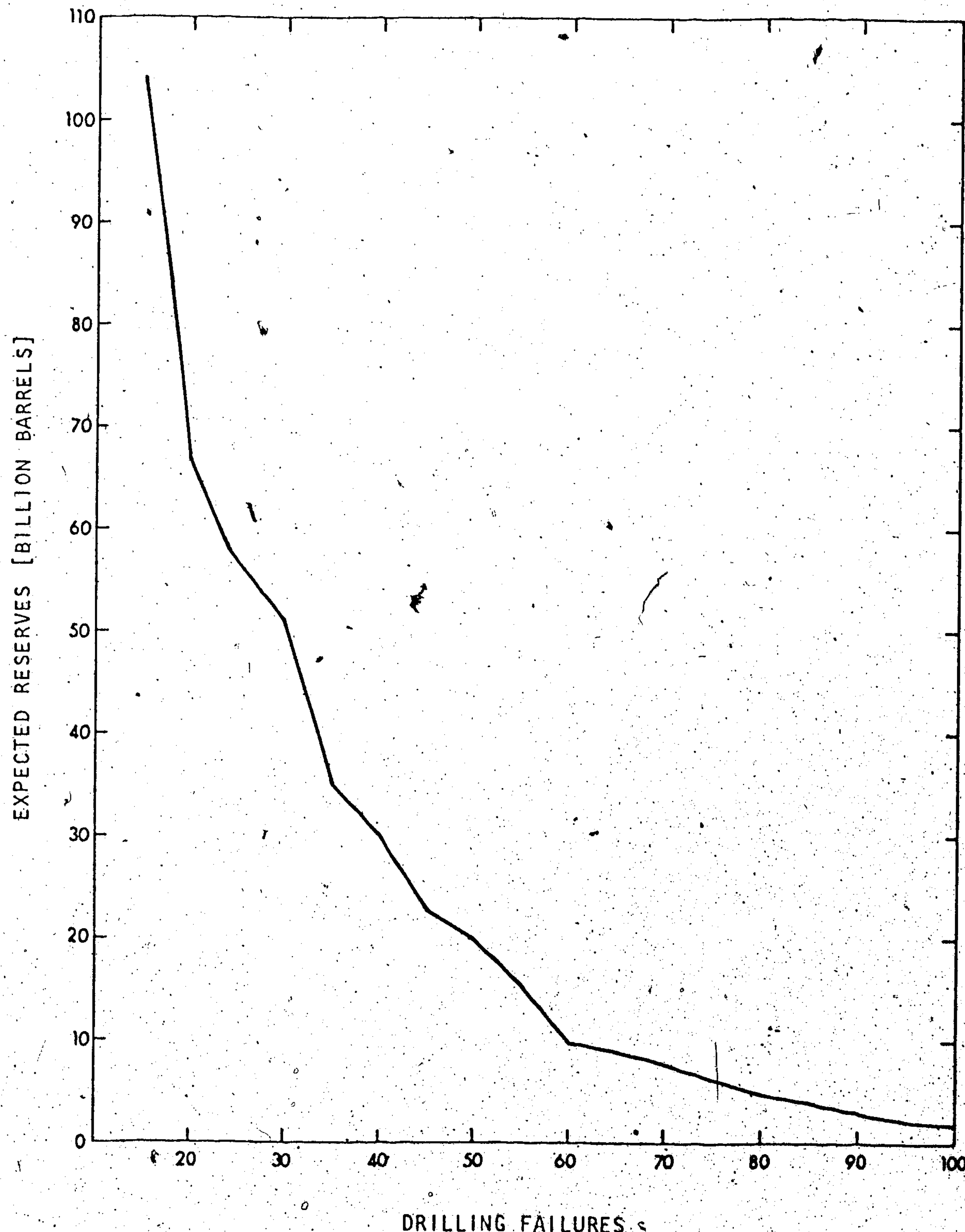

FIGURE II-3 DRILLING FAILURES VS EXPECTATIONS, SVERDRUP BASIN

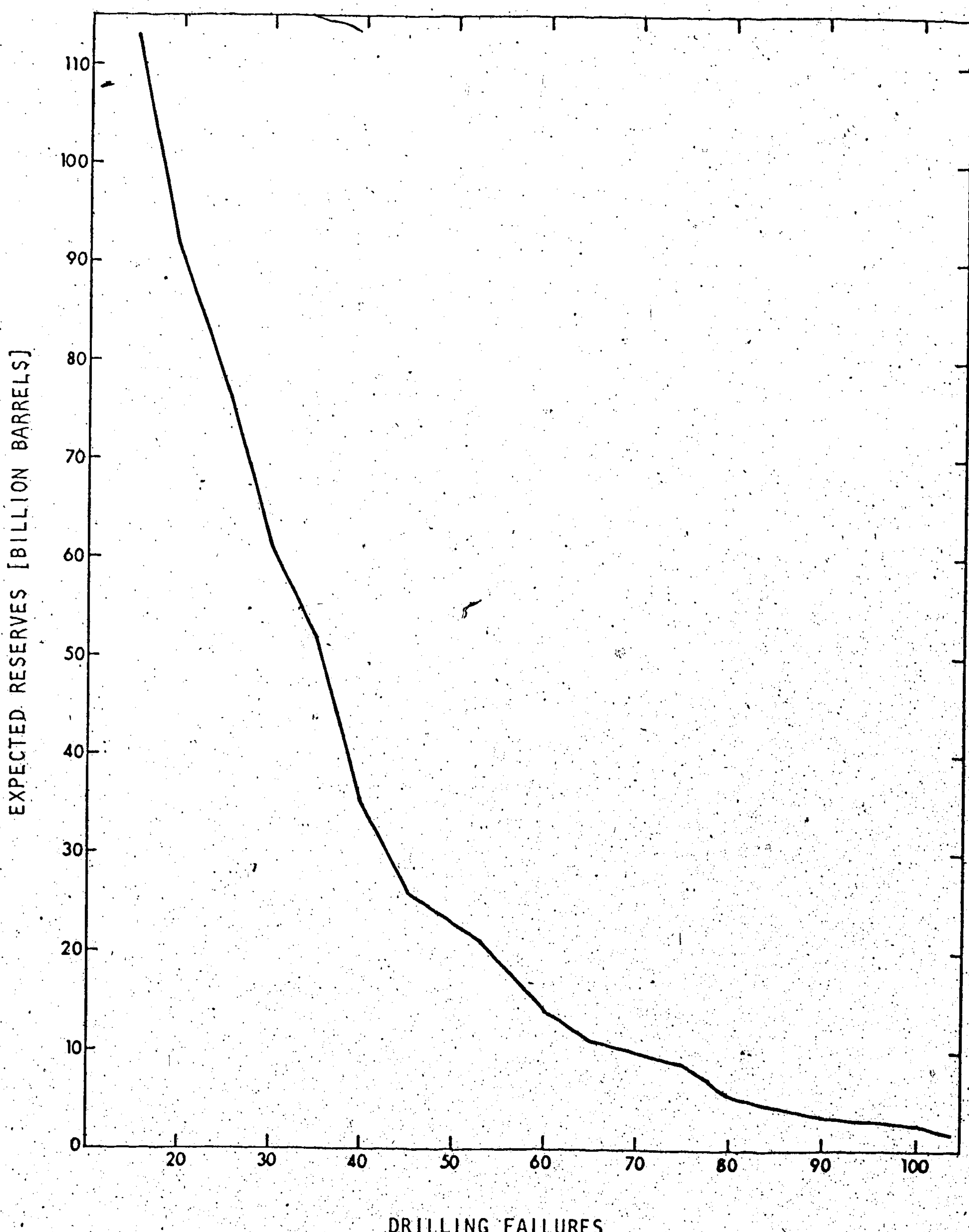

FIGURE II-4 DRILLING FAILURES VS EXPECTATIONS, LABRADOR BASIN failures versus expectations at which point the decision to no longer accept continued failures is made. Any discoveries past this point would not be economically viable.

A variety of methods and criteria for determining this decision rule are possible. The choice depends upon the corporate attitude towards risk, necessary rates of return, available capital and other factors contributing to the utility function of a participating company.

The criterion accepted for the threshold used in this model was that of requiring reserves to be of sufficient magnitude so as to support a transportation system. The transportation system would deliver the reserve to a southern market over a period of 20 years. In attempting to answer this threshold question, one faces a variety of assumptions and uncertain variables. These pertain to costs, routes, building techniques, financing, etc. The goal was not for precision but a relative order of magnitude. The details of the pipeline versus reserve study are presented in Appendix A.

The result of Appendix A placed the threshold between 2 billion to 3 billion barrels based on a Mackenzie Delta-Edmonton pipeline. The same figure for the threshold volume was used for the other basins other than the Mackenzie-Beaufort. Published reserve-threshold estimates were within 20 per cent of the model's estimates[5]. (See Table II-1)

This minimum-acceptable reserve marked the number of failures the explorer ought to accept before deciding to abandon a basin.

v. Results

A summary of the results of this chapter is presented in Table II-2.

TABLE II-1

COMPARISON OF THRESHOLD RESERVE ESTIMATES

COMPANY	MACKENZIE DELTA–BEAUFORT SEA Threshold Estimates (Billion barrels)
This work	2.0 to 3.0
Canadian Petroleum Association	2.5
Gulf Oil Canada Ltd.	2.5
Imperial Oil Limited	0.5 to 1.0
Independent Petroleum Association of Canada	2.0
Amoco Canada Petroleum Company Ltd.	2.2 to 2.6
Canada-Cities Service Ltd.	2.2
Mobil Oil Canada Ltd.	2.0 to 2.5
Shell Canada Limited	2.0

Source - NEB(5)

TABLE II-2

BASIN CRITICAL FAILURES

BASIN	WELLS REQUIRED (two wells per prospect)
Beaufort-Mackenzie	144
Sverdrup	202
Labrador	206

In order to assure that a particular prospect does not contain oil, it is industry practice to drill it twice. This practice increases the validity of the information from drilling tests.

The details of depth of drilling, onshore and offshore location, type of feature (salt dome, fault, syncline, reef, etc.) and the area pertaining to each feature were not incorporated. Such details would be useful as they would provide for greater accuracy in establishing drilling costs and the physical practicability of drilling a particular feature.

Figure II-5 shows various organizations' estimates of petroleum potential for the Mackenzie-Beaufort basin as a function of cumulative exploratory wells drilled. The general form of the curve is similar to that of Figure II-2, 3, 4, a decreasing expectation with increased drilling effort. The number of exploratory wells drilled (as given by Oilweek[23]) is somewhat higher than the necessary number estimated in this model (144). The number of wells per prospect could have been greater than two. Nevertheless, the two figures (Figure II-2 and II-5) directionally are very similar. The point at which a definitive industry decision on the future of oil potential of the Beaufort-Mackenzie basin is imminent. The threshold and the expectation are approaching each other.

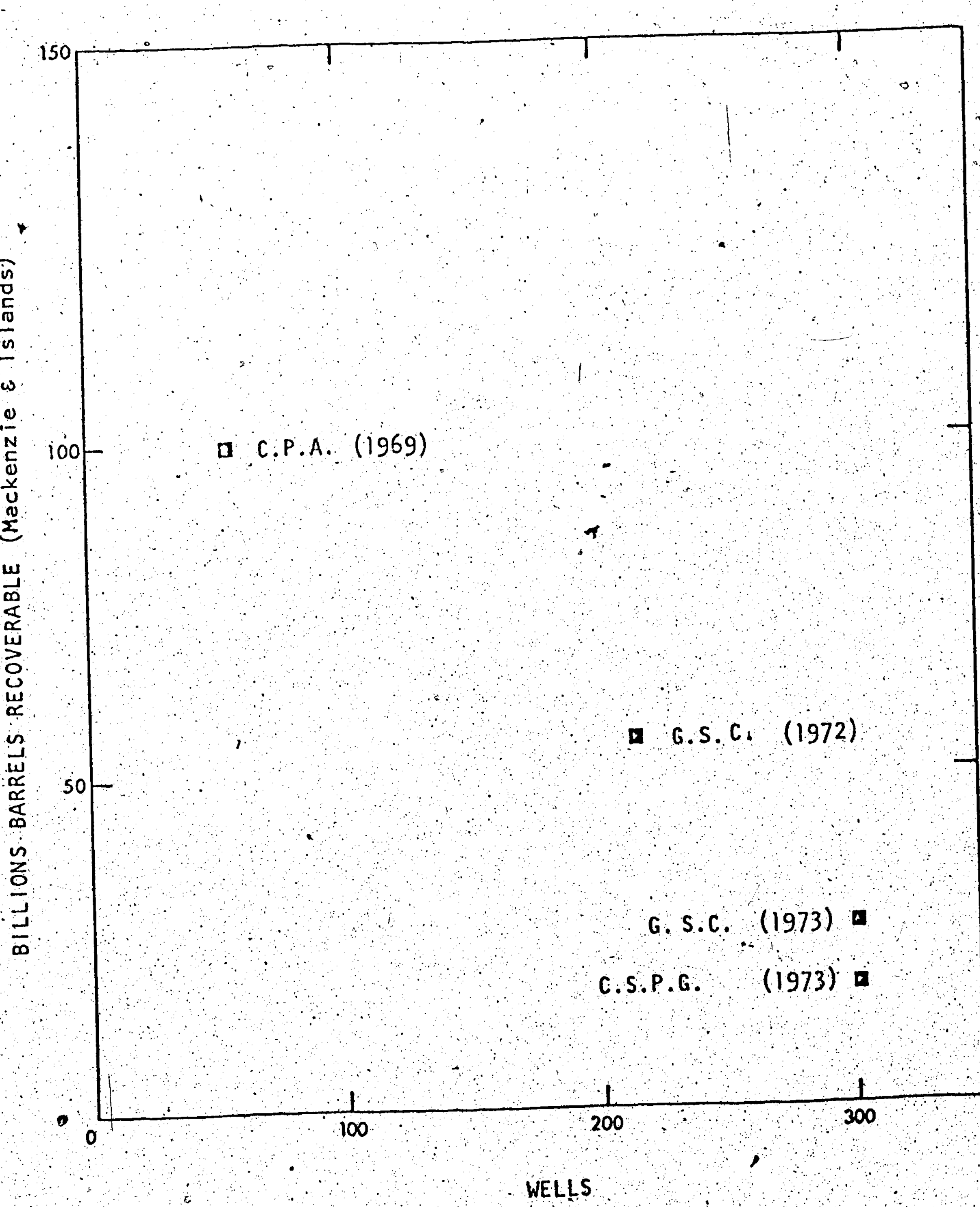

FIGURE II-5 WELLS VS EXPECTATIONS

II.3 Direct Market Price Sensitivity on Exploration

The implication of the two questions stated in the introduction of this chapter was to preclude the possibility of a direct price sensitivity (as defined in Chapter I), as affecting the exploration phase. The current price is related to exploration primarily as a component of the explorer's total income, i.e., current price times production from currently held reserves equals crude-oil-production-derived income. The important exercise was that of determining the income needed to finance the necessary exploration program and the crude oil price required to produce such income.

Exploration is predominantly income-dependent; whether that income be derived from the sale of natural gas, gasoline or hamburgers; borrowed capital or equity investment. The present study conceives the oil industry as primarily dependent on income derived from the sale of crude oil.

The available market price obtainable for a newly discovered crude would not be the crucial factor in its being discovered. Having the income to drill the well to find the new source is the critical issues. Increasing the market price will have only a secondary effect on the discovery process. A possible price sensitivity on exploration would manifest itself by reducing the threshold reserve and extending the number of wells necessary to determine the critical failure.

In Figure II-6, transportation cost is plotted against possible pipeline diameters. As pipeline size is increased, capacity similarly increases and the per-barrel transportation cost is reduced. To maintain a pipeline at maximum possible throughput, a certain reserve is required. Figure II-7 shows the relationship between pipeline size and required reserve.

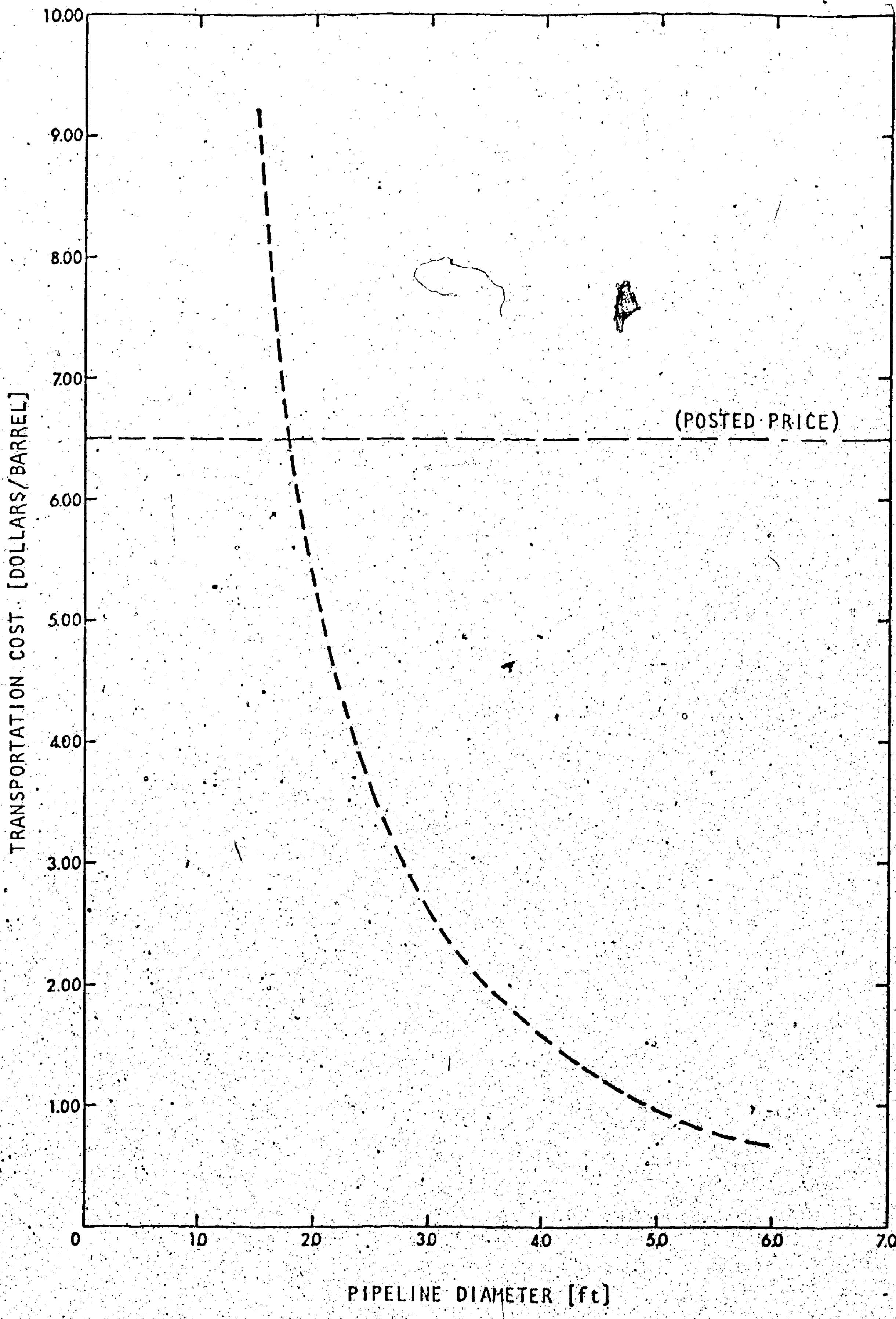

FIGURE II-6 TRANSPORTATION VS DIAMETER

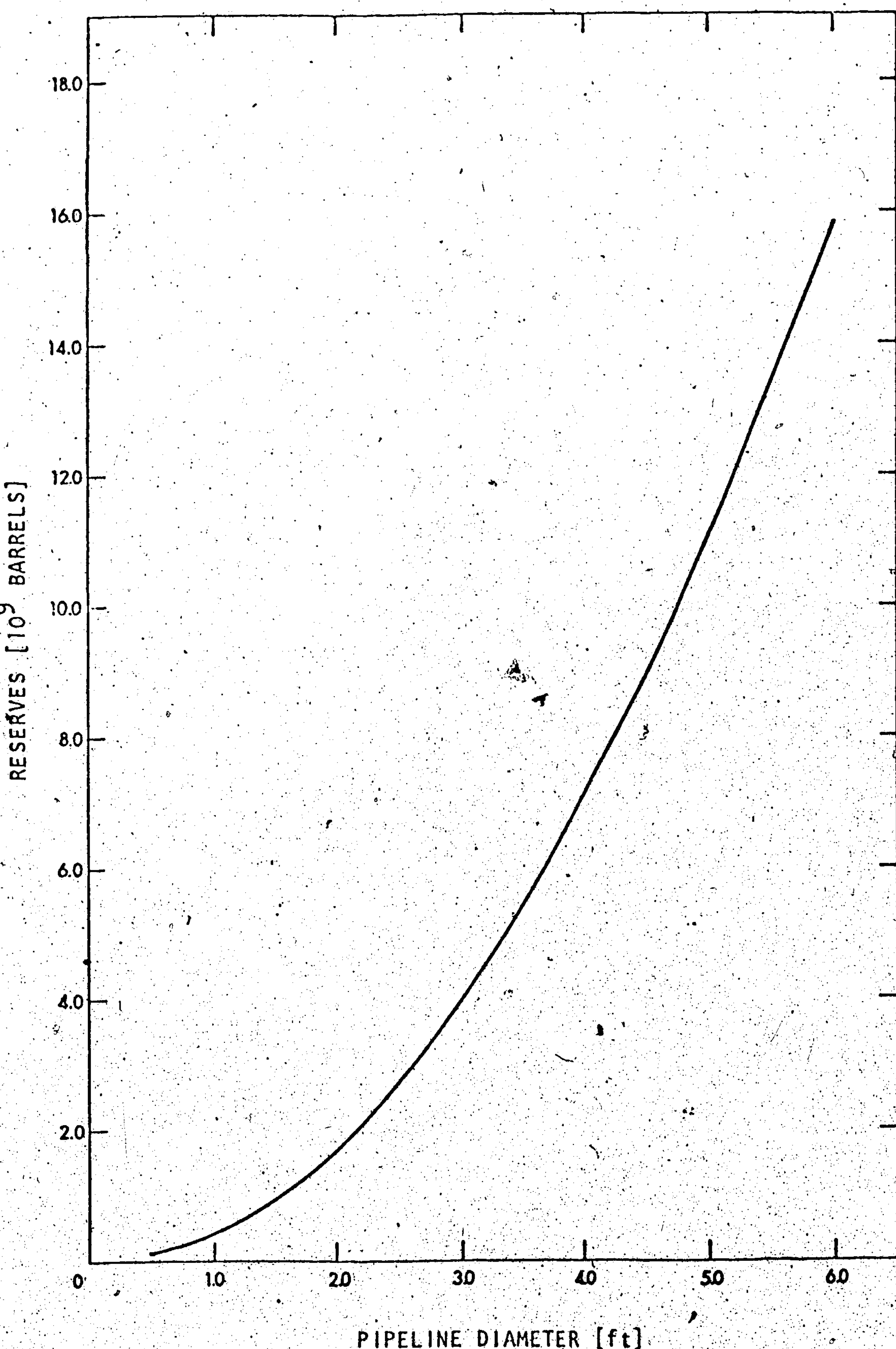

FIGURE II-7 THRESHOLD RESERVES VS PIPELINE DIAMETER

Once a market price is set (such as $6.50/bbl.), one can calculate the break-even size of pipeline, i.e., where market price equals transportation cost. With a pipeline-size chosen on this basis, a required threshold reserve is also specified. For the case of $6.50/bbl. oil, a two-foot diameter pipeline is economic and an approximately 2-billion-barrel reserve is required.

If one had increased the market price, presumably the pipeline size and threshold could be reduced. If the threshold is substantially smaller than 2 billion barrels, it will affect the value for the number of wells required, critical-failure value, and ultimately, the income requirements. The sharp increase of the transportation cost for pipeline of less than two-foot diameter reduces the effect of market price on required pipeline size, however. An increase in price to $10.00/bbl. requires a break-even pipeline-size of 1.5-foot diameter. The corresponding reserve for 1.5-foot diameter pipeline is 1 billion barrels. A price of [illegible] equired a pipeline of 1.75-foot diameter and a reserve of [illegible] barrels. The sensitivity of market price on threshold wa[illegible]sidered significant for market prices over the range of $6.00/bbl. [illegible]

If oil [illegible]t prices roll back to the $2.50-to-$4.00/bbl. range, the threshold [illegible]rve becomes markedly sensitive.

II.4 Discussi[illegible] of Reassessment Procedure

The exploration process, presented in this simulation, consisted of a sequence of decreasing reserve expectations caused by successive drilling failures. Had a significant discovery occurred the economic analysis would have become one for the development, not exploration, phase.

The mechanism whereby this downward reassessment occurred was by the successive elimination of the largest prospects. A complementary procedure would have been to reduce the value of the success ratio after each failure.

To predict an actual company's reassessment process would be more a matter of behavioral psychology than of operations research. The task was to describe each company's utility function.

Different companies will doubtless react differently when faced with similar results. The extremes of reactions would be those of unremitting confidence (i.e., every prospect is expected to be a success and is eliminated only by an unsuccessful well) and one-shot pessimism (i.e., drill one unsuccessful well and write off the potential of the entire basin). The former is never considered; the latter rarely, (for example, the exploration of the Hudson Bay basin).

The usual industrial practice would be to make a re-evaluation of the success ratio. This parameter would characterize corporate optimism or pessimism. The fundamental uncertainty would be of the true value of the success ratio.

The ratio will be known conclusively when all prospects are drilled. The a priori knowledge and conviction in a particular assessment are matters of geologic opinion. Each participating company makes an estimate of the success ratio and acts according to its individual conviction, whether that implies early abandonment, long-term commitment, or never embarking on such a program. The company with the closest estimate to the true value acquires a competitive advantage, as evidenced by the experience of Imperial Oil in 1947. The uncertainty makes decision-making difficult and insecure.

Error in reserve estimations and undue faith or pessimism cause one of two errors:

1) wasted exploration dollars, or,

2) abandonment of a significant oil basin.

These errors are analogous to Type I and II errors of hypothesis testing theory:

1) Type 1 - reject a hypothesis which is really true (rejection error)

2) Type II - acceptance of a hypothesis which is really false (acceptance error)[18]

If the primary objective of the participants is to maintain Canadian self-sufficiency in oil supply, the rejection error is the more serious. With the assumption of the invariant success ratio, the probability of this error is reduced. The invariant success ratio increases the number of wells drilled and the greater the number of wells, the more exhaustively is the basin explored.

To avoid the rejection error, reassessment took place only by the elimination of the largest-sized remaining prospect. The value of one in 10 for success ratio was not changed throughout the iterations of the simulation.

Alternate schemes of reassessing the success ratio are as numerous as participants in frontier exploration. The invariant success ratio is consistent with an objective of self-sufficiency. (See Appendix B for a means of success-ratio reassessment based upon the beta distribution. The results use a constant success ratio and the results from the beta-distribution case were not significantly different. See Appendix B).

The dependence of critical failure on the assumed value of the success ratio was not significant. (See Figure II-8) Along the abscissa is the parameter, α. This parameter is a measure of one's relative confidence or belief in a particular value of the success ratio. (See Appendix B for further discussion of the beta distribution and its parameters, α and β.) For the range of confidences, the values of critical failure for each of the three success ratios are within 10 per cent of each other. The value of the critical failure is not significantly affected by the choice of the parameter, α, within the range indicated.

The results of this chapter provided an estimate of the number of wells required to be drilled in the frontier basins to determine whether they contained economically significant oil. The issue of income sensitivity must be resolved by applying these exploration requirements to the cash-flow projections of the oil industry. The exercise will be to solve for the income requirement necessary to finance this exploration level. The assumption will be made that the source of income will come solely from the sale of crude-oil production and the crude-oil price will be adjusted to create the income necessary.

[INCOME = CURRENT PRODUCTION X PRICE]

The term 'price' referred to that portion of the market or posted price which is the producer's share.

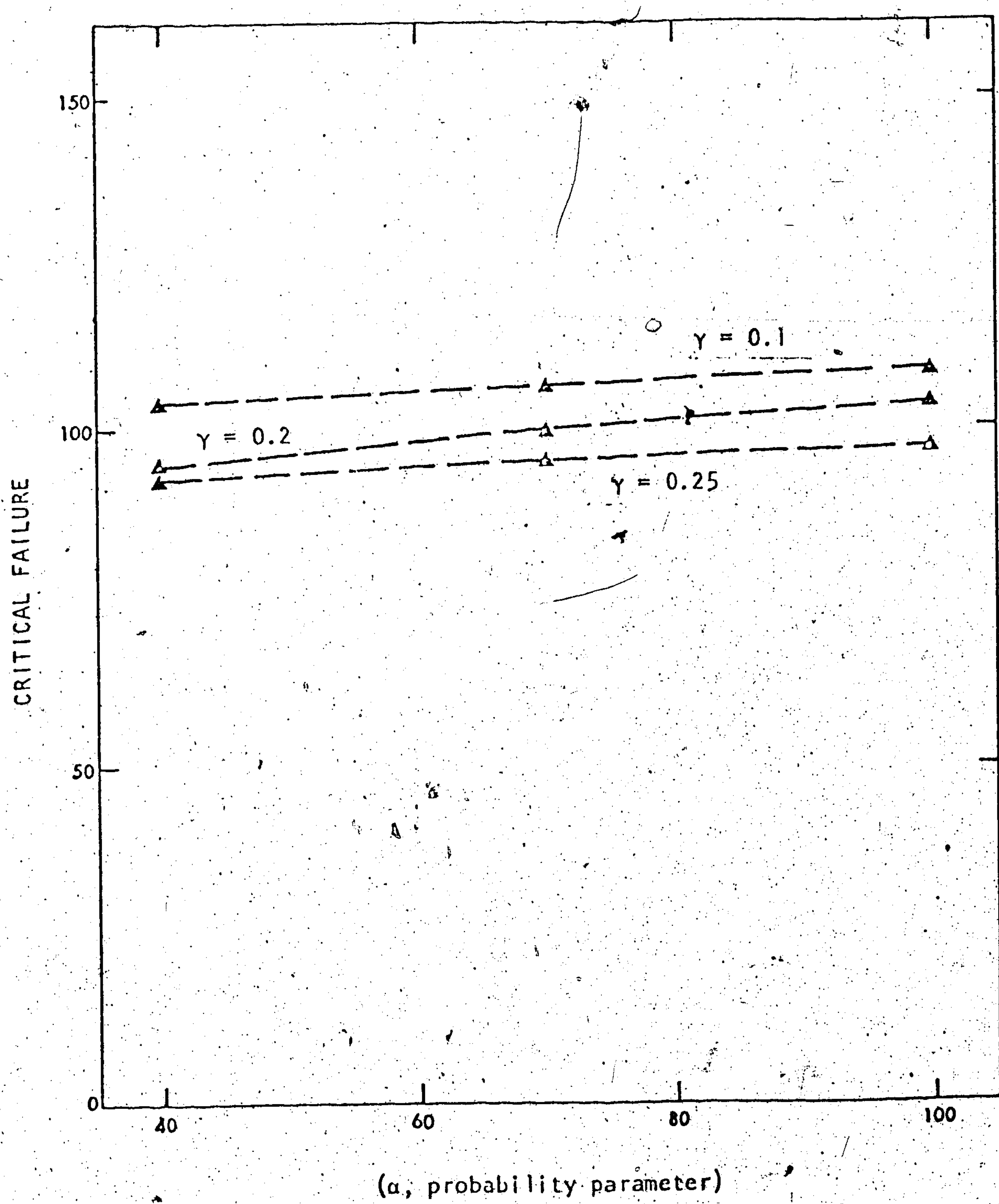

FIGURE II-8 BETA DISTRIBUTION VARIABLE (γ), SUCCESS RATIO, - CRITICAL FAILURE STATISTIC SENSITIVITY

CHAPTER THREE

INCOME SENSITIVITY MODEL

III.1 Introduction

A cash-flow model of the entire Canadian oil-producing industry was developed to determine an income sensitivity. The model solved for the oil price necessary to provide the income to sustain the exploration required (as determined by the work of Chapter Two), while imposing various fiscal scenarios. The two major assumptions of this model were:

1) the conglomeration of disparate companies, and,

2) the absence of diversified or external income.

The justification for the first is pragmatic, while for the second a matter of emphasis.

The exploration model developed in Chapter Two was based upon a set of 200 prospects, located in each of the three frontier basins, which would be drilled up to the point necessary to prove the existence of economically significant reserves of oil. No comment was made as to which companies or consortia would finally carry out this exploration. In reality, virtually all of the "majors" and many smaller-sized oil companies have held interest in,or completed,drilling programs amongst these prospects. Each participant would have some portion of the 200 structures. The decision analysis developed in Chapter Two would then have to be applied to each participant.

The task, involved in modelling this multi-participant situation, beyond identifying who the participants were and describing their individual cash flows, would be to allocate to each participant a portion of the 200 prospects. This information was available from some government departments, but its application to the decision analysis would be a formidable task.

The 200 prospects will be explored exhaustively by the entire industry. The decision regarding any basin will be a collective one. The choice of a conglomerated approach was the most practical and pragmatic when approached from the viewpoint of the limited resources available to a single student.

The assumption of a single, internal source of additional revenue, the sale of crude-oil, was made in order to isolate the effect of crude-oil price on income. The alternate petroleum-revenue sources (natural gas, natural-gas liquids and sulphur) were included in the revenue entry, but held constant at 1974 prices.

The conclusions of this chapter may be interpreted as the maxima of a set of possible solutions. Each member of that set would be consistent with an assumed financial structure and the role of crude-oil price within that structure. The model presents a scenario where crude-oil production revenue is the major component of industry revenue. This scenario emphasized the relationship between crude-oil price and the financing of exploration programs.

III.2 *Model Procedure*

1. The internal cash flows of the entire Canadian oil industry were modelled using the data provided by the Canadian Petroleum Association. These data, annually presented in the C.P.A. Statistical Yearbook[16], are a compilation of industry expenditures in exploration, production and refinery operations. [The companies constituting the C.P.A. represent primarily the larger oil producers. The smaller independents have organized into a similar, though separate, organization; Independent Petroleum Association of Canada, (I.P.A.C.). The two groups evolved out of opposing market interests among large and small producers in the early

1960s.]

2. The crude-oil production of the industry followed the projection established by Ryan[6]. This projection spanned the decade from 1973 to 1985. Revenue was calculated by the product of crude-oil price and production plus natural-gas revenue. The natural-gas production projection came from the Imperial Oil submission to the National Energy Board[27]. Natural-gas price was calculated on a crude equivalent B.T.U. basis.

3. Industry operating expenses and capital expenditures were correlated to production levels.

4. An annual exploration expenditure was assumed initially to be $100 million per year.

5. One of three fiscal scenarios was chosen. The first of these three is described by those tax laws applicable until the fall budget of 1974. The significant features of these laws were that royalty payments and a depletion allowance were deductible from taxable income for calculating federal income tax. In the second scenario the royalty payments are no longer deductible, while maintaining the depletion allowance deduction. The third scenarios removed both royalty payment and depletion allowance as acceptable deductions.

6. A price of crude-oil assumed to be $1.00/bbl. and the after-tax cash flow calculated for each year from 1975 to 1985.

7. The price was increased at $1.00/bbl. increments until the after-tax cash flow was maintained at positive levels over the 10 year span. Three price levels, each corresponding to the particular fiscal scenario, were generated, and associated with the assumed annual exploration expense.

8. The procedure from Steps 4 to 7 was repeated but with the exploration expense increased by $100 million per year. The routine

continued until exploration reached a $1 billion-per-year expense.

9. The final result was a set of three curves, each corresponding to the particular fiscal scenario, of exploration expense versus price, where the price represents the minimum price necessary to maintain a positive after-tax cash flow (See Figures III-1,2) See Appendix V for computer listing.

III.3 *Interpretations of Results*

The work of Chapter Two was superimposed on the industry cash-flow curves. For each basin, the maximum number of wells required to be drilled had been calculated. The results were summarized in Table II-7. The cost of exploratory wells was multiplied by the number of wells necessary to determine the total exploration expense required in each of the three basins. Using the same 10 years, 1975-1985, as the time available for exploration of these basins, the annual exploration expense was calculated as:

1. Mackenzie-Beaufort	58	MM $/yr
2. Sverdrup	139	MM $/yr
3. Labrador	163	MM $/yr

[The source of the cost data for the exploratory wells was private communication with a professional geologist. These cost data are summarized in Table III-1. No adjustments were made for depth or offshore structures in these data.]

If it were assumed that all three basins could be explored simultaneously, the financial commitment would be roughly $360 million per year for 10 years.

To maintain this level under the first fiscal scenario, required

TABLE III-1

BASIN DRILLING COSTS

BASIN	COST (MM $/WELL)
Mackenzie-Beaufort	4.0
Sverdrup	7.0
Labrador	8.0

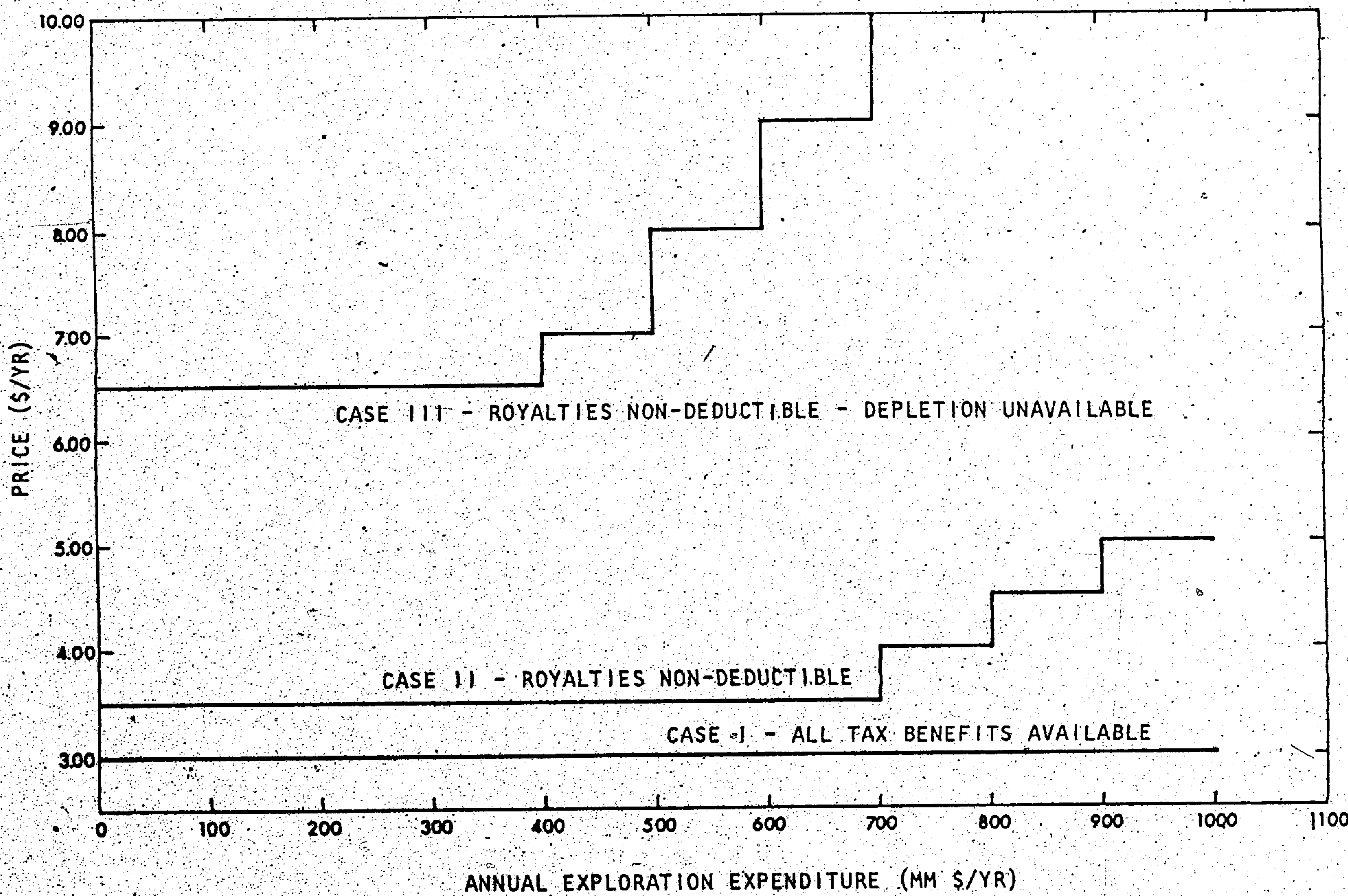

FIGURE III-1 INDUSTRY INCOME SENSITIVITY (0-1000 MM $/YR RANGE)

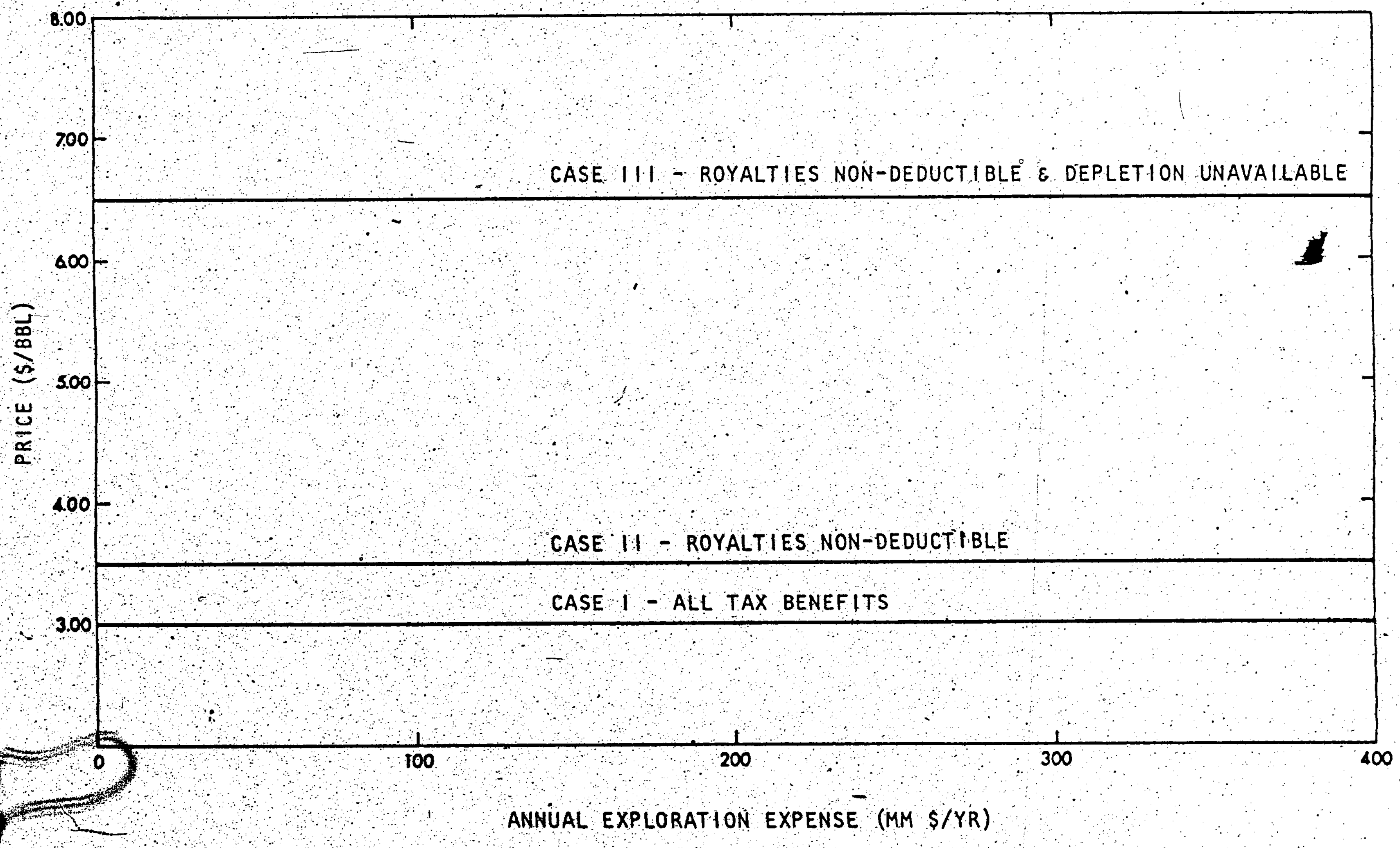

FIGURE III-2 INDUSTRY INCOME SENSITIVITY (0-400 MM $/YR RANGE) a price of $3.00/bbl. This tax scheme, law until the fall of 1974, would have allowed the industry adequate cash flows at current prices (i.e. $3.00/bbl. as company share) to continue exploration to virtually any level. The critical constraint in exploration in order to complete the program within the decade would then be logistical rather than financial.

The second case produced an upward translation of the previous curve of between $.50 to $1.00/bbl. from case one for identical exploration expenditure to $3.50 to $4.00/bbl. The $360-million level required a price of $3.50/bbl. The third scenario caused yet greater increases in price with the $360-million level requiring $6.50/bbl.

The present tax laws as formulation in the proposals of the Turner budget of November, 1974, come closest to those of scenario two (with the promise of "earned" depletion, i.e., exploration effort must be sufficiently high before depletion allowance may be claimed). For the range of between $100 million to $300 million per year in exploration expense, the price required was essentially constant for a given fiscal scenario. The significant increase in required price took place between fiscal scenarios.

The prices indicated in Figure III-2 represent only the minimum necessary to maintain positive cash flows. No allowance for a greater return on investment was made. Exploration is more sensitive to fiscal and royalty policies than the actual cost of exploration. Cash flow is reduced drastically by the dual effect of high royalty (40%) and royalty being considered non-deductible expenses. The industry could have sustained the burden of the royalty and frontier exploration, (scenario one), if former tax concessions had continued to exist. The present combination makes the industry's ability to complete required program of exploration doubtful.

III.4 Effect of Drilling Funds

To assess the effect of outside income from drilling funds, the same exercise as outlined in Section III was carried out, with the addition of $160-million annually to industry revenue. This would represent either direct investment or simply speculation for the purpose of American income tax. The $160-million/yr. figure is the 10-year average (1959-1969) of such income to the Canadian industry from American sources as tabulated by Statistics Canada[23].

The effect of this additional income was to reduce the required price of fiscal scenario two to $2.00 to $3.00/bbl. for the $360-million per year exploration level. The required price of scenario three was also reduced to $5.50/bbl. (See Figure IV-3)

Such funds do make significant contributions to company revenues; however the likelihood of their continued availability is not high, based upon discussions with industry officials. Changes in American tax laws and the lack of significant Canadian discoveries have caused their decline and disappearance.

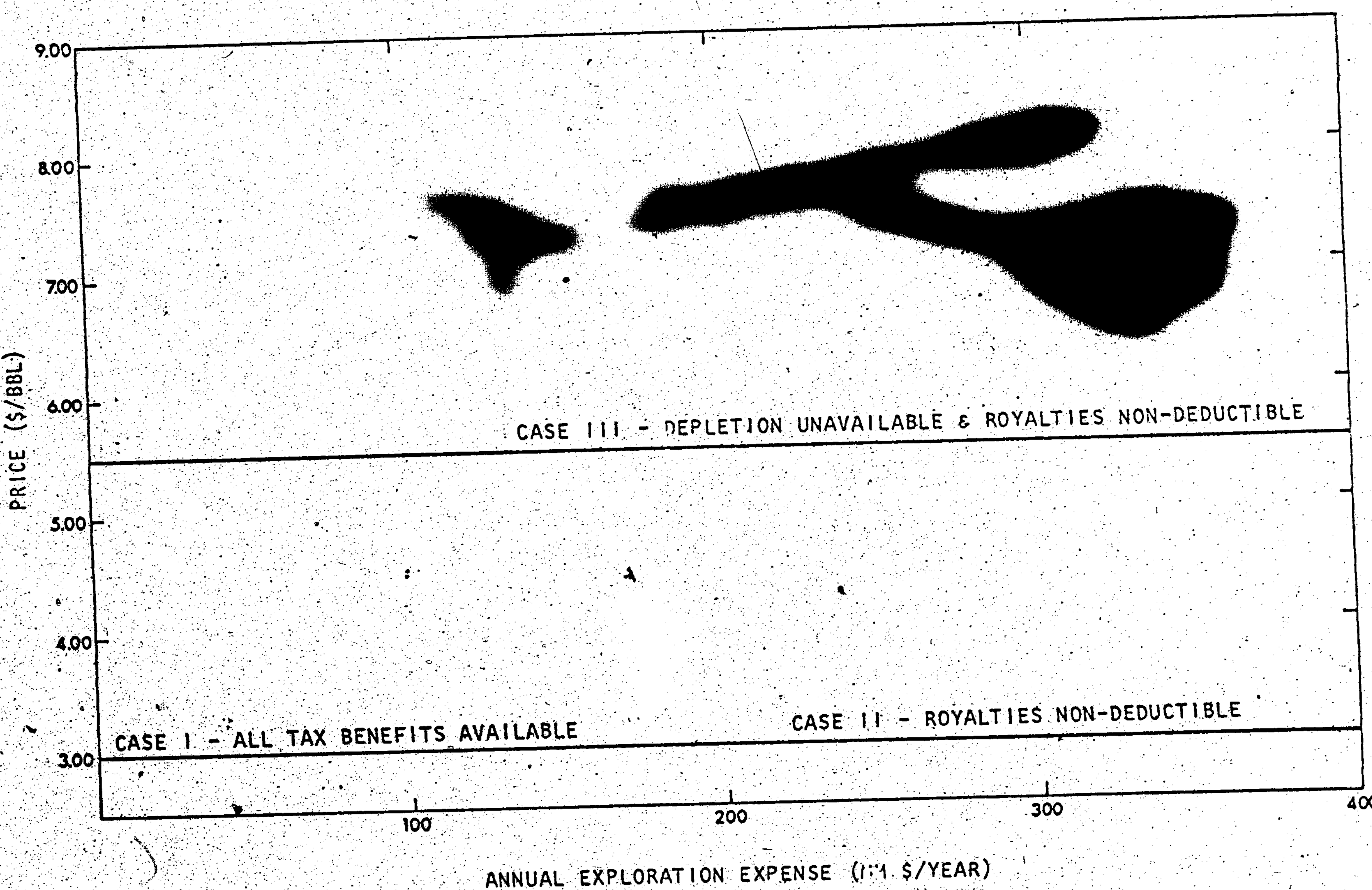

FIGURE III-3 INDUSTRY INCOME SENSITIVITY INCLUDIN[illegible]ING FUNDS

CHAPTER FOUR

INDUSTRY FINANCIAL STRUCTURE

IV.1 Introduction

The previous chapter produced a projection of crude-oil prices necessary to finance various levels of exploration expenditure. Those results were based on two major assumptions:

1) industry aggregation, and,

2) a single source of additional revenue.

The validity of those results and assumptions is examined by applying a similar cash-flow analysis, as that outlined in Chapter Three, to specific oil companies. Imperial Oil Ltd., Dome Petroleum Ltd., and Chieftain Development Ltd. were individually analysed. These companies were considered representative of the three major industry groups or types of oil company:

1) an integrated oil company ("major"),

2) middle-sized independent producers, and,

3) small independent speculators.

The following sections describe the cash flows, sensitivities of cash flow to various fiscal scenarios, and the source of funds of each of these three groups. The same analysis formed the basis of the cash-flow model for the entire industry presented in the last chapter.

Each of these analyses is based on the annual reports of the three companies. This exercise was intended to indicate the limitations of the results of the previous chapter.

IV.2 . The Integrated Oil Company

The term 'integrated oil company' designates a company engaged not only in exploration and production but also in the refining, marketing and distribution phases of the oil industry. These companies can complete within their own capabilities and operations the whole process, from the discovery of frontier petroleum to the final sale of the refined product. Such companies (e.g. Exxon, Shell, Gulf, Texaco, etc.) are giants not only within the oil industry but also of the entire corporate world. Their activities are global in nature. They move to those areas whose prospects are not only highest in oil reserve but also in fiscal and competitive advantage.

The effects of crude-oil-price increases are imbedded within their integrated structure, and are ultimately manifested by the prices of refined products. [Crude oil is sold within the organization. The crude-oil price is a transfer payment; not an entity subject to external consumer pressure. Attempting to investigate the component of crude-oil price in final consumer prices is a task beyond the scope of this work. Assessing production costs past the refinery level to specific products is a non-trivial problem for any investigator[18].]

Crude-oil supplies are simultaneously purchased and sold with only a portion of the majors' total supply being actually refined within their own system. For the case of Imperial, the levels of purchases and sales are approximately equal[19]. The crude oil produced from its own reserves can be interpreted either as a saving in external purchases or the actual crude's contributing to crude-oil revenues as cited in company annual reports. If external sales and purchases remain roughly in equal proportion, an interpretation of the extent to which crude-oil price and internal production are an actual component to company revenue and cash flow can be made. For Imperial, this interpretation has validity.

The proportion of direct crude-oil revenue to total revenues from all operations has remained constant between 20 per cent to 30 per cent,[19] other revenue being derived from the sale of petroleum products, natural gas, petrochemicals and other non-energy-related investments. The comparatively low proportion of direct crude-oil revenue to total revenue marks the strength of the major as its revenues are diversified.

It could be argued that crude-oil-price changes will cause corresponding changes in refined products, thereby diminishing the positive effect of diversification. The significance of that diversification, however, is more clearly demonstrated by the response of Imperial, in its cash-flow position, to various fiscal scenarios. It is the ability of the major to overcome certain fiscal conditions that makes it more stable than smaller non-integrated companies in the entire industry.

The exercise carried out to demonstrate such responses was to model the cash flows of Imperial to three separate fiscal scenarios, all of which have either existed as law or have been proposed at some time. The first of the three scenarios exists as the base case for the remaining two. The characteristics of the base case are as follows:

1) exploration expenditure dedictible at 100 per cent,
2) royalties deductible from taxable income, and,
3) depletion allowance of 33 per cent of net taxable income available as a deduction.

The remaining details of the tax formula are no different from those applying to any corporation (capital-cost allowance, tax rate of 50 per cent, deferred-tax credit usable if available, etc.). The second scenario involved having royalties (payable to provincial governments) being no longer deductible. The third involved having both depletion allowance and royalty deductions unavailable.

Throughout all three scenarios, the assumption was made that no reserve of deferred-tax credits accumulated in previous years, to be applied against present income, was available. The annual reports indicate the payment of income tax since the middle of the 1950s. The natural evolution of oil companies is from early exploration losses (interpretable as future tax savings) to production-based profits (interpretable as taxable income). Only companies without significant production income and continuing exploration remain in a negative tax position.

The details of the actual cash-flow model are shown in the listing in Appendix V. The other revenues, operating expenses, depreciation and exploration streams of the cash-flow calculation were correlated to crude-oil production as projected to 1990. The basis for the production curve was founded on two factors:

1) Imperial's share of the total Canadian production had averaged 15 per cent of the total Canadian production over the period of 1950 to 1972. This percentage was assumed to remain constant until 1990, and,

2) The decline of total Canadian production followed the projection established by Ryan[6].

All cash flows of a oil company can ultimately be related to the fundamental natural resource of the industry, crude oil.

Finally, a certain portion (13 per cent) of Imperial's production is subject to royalty payments to freehold lease holders rather than the provincial government. The difference in royalty rates (42.5 per cent to government, 16 per cent to freeholders) is significant.

The object of the exercise was to calculate the crude oil price at which a positive after-tax cash flow for each fiscal scenario could be maintained. The object was to examine the sensitivity of the necessary price over the three scenarios. The results are shown in Figure IV-1, 2, 3.

On these graphs are plotted the after-tax cash-flows from 1974 to 1984. The form of the curves is common to each, that is, a parabolic shape. The reason for this shape is that both capital and exploration expenditures peak with production in the late 1970s causing the greatest strain on revenue. One could argue that companies would not allow themselves to reach low cash-flow positions and would make the necessary cut-backs or corrections. This analysis investigates the response of increasing crude-oil price to achieve the same purpose.

The results showed that the second and third scenarios would necessitate price increases if positive cash flows were to be maintained. The over-all price change between the three cases was only between $2.00 to $2.50/bbl. The first case showed that at virtually any price (i.e., $3.00 per barrel and upwards), Imperial would maintain a positive cash flow.

The second case required a crude-oil price of between $3.00 to $4.00/bbl. The effect of losing the royalty deduction was to increase taxable income. A price of $3.00/bbl. in scenario one for 1977, for example, meant a $38-million per-year cash flow. With scenario two, in 1977, the cash flow was a minus $18-million, the only difference being in fiscal conditions between the two cases.

The third case was the most severe. A price of nearly $6.50/bbl.

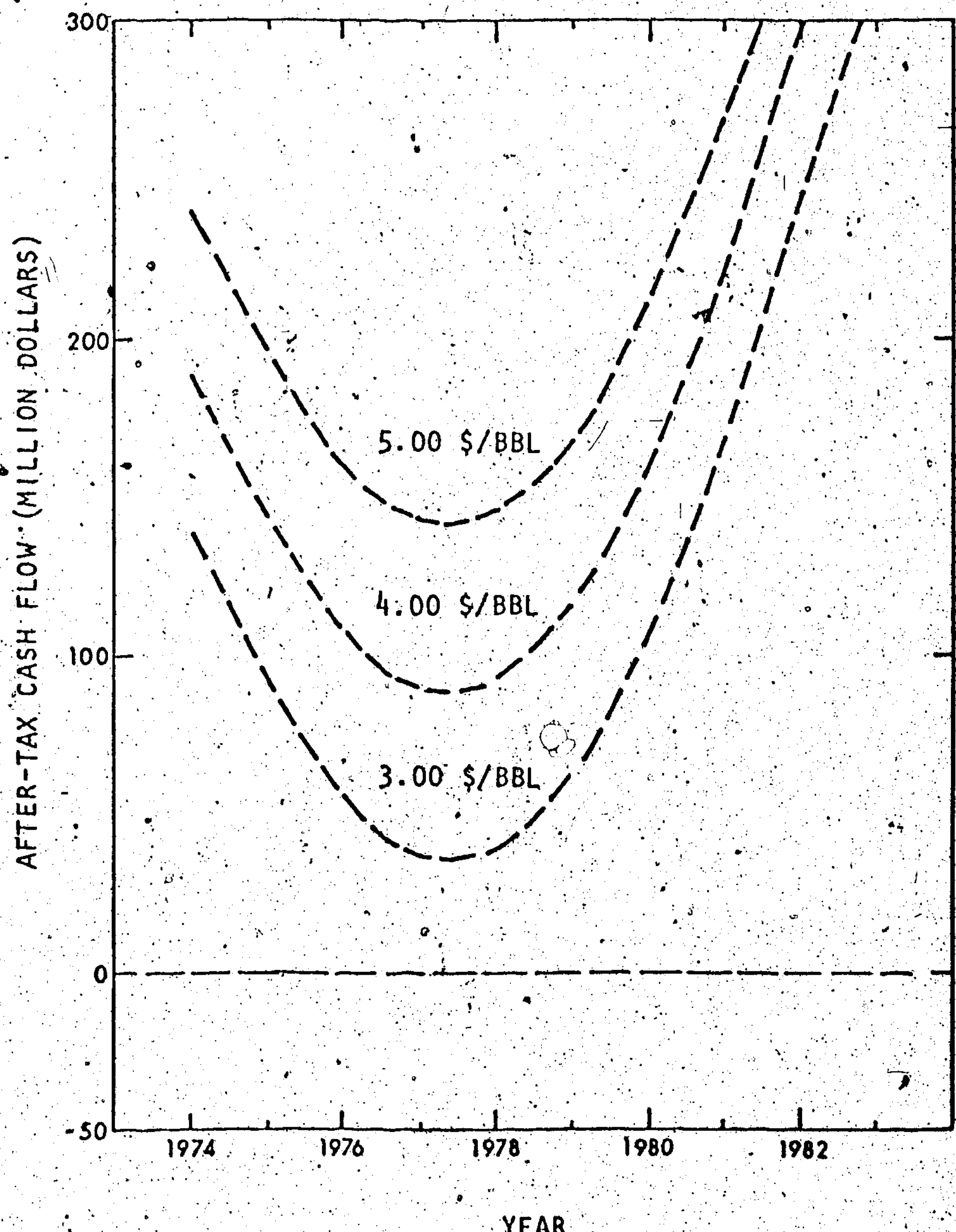

FIGURE IV-1 IMPERIAL OIL INCOME SENSITIVITY, ALL POSSIBLE TAX BENEFITS

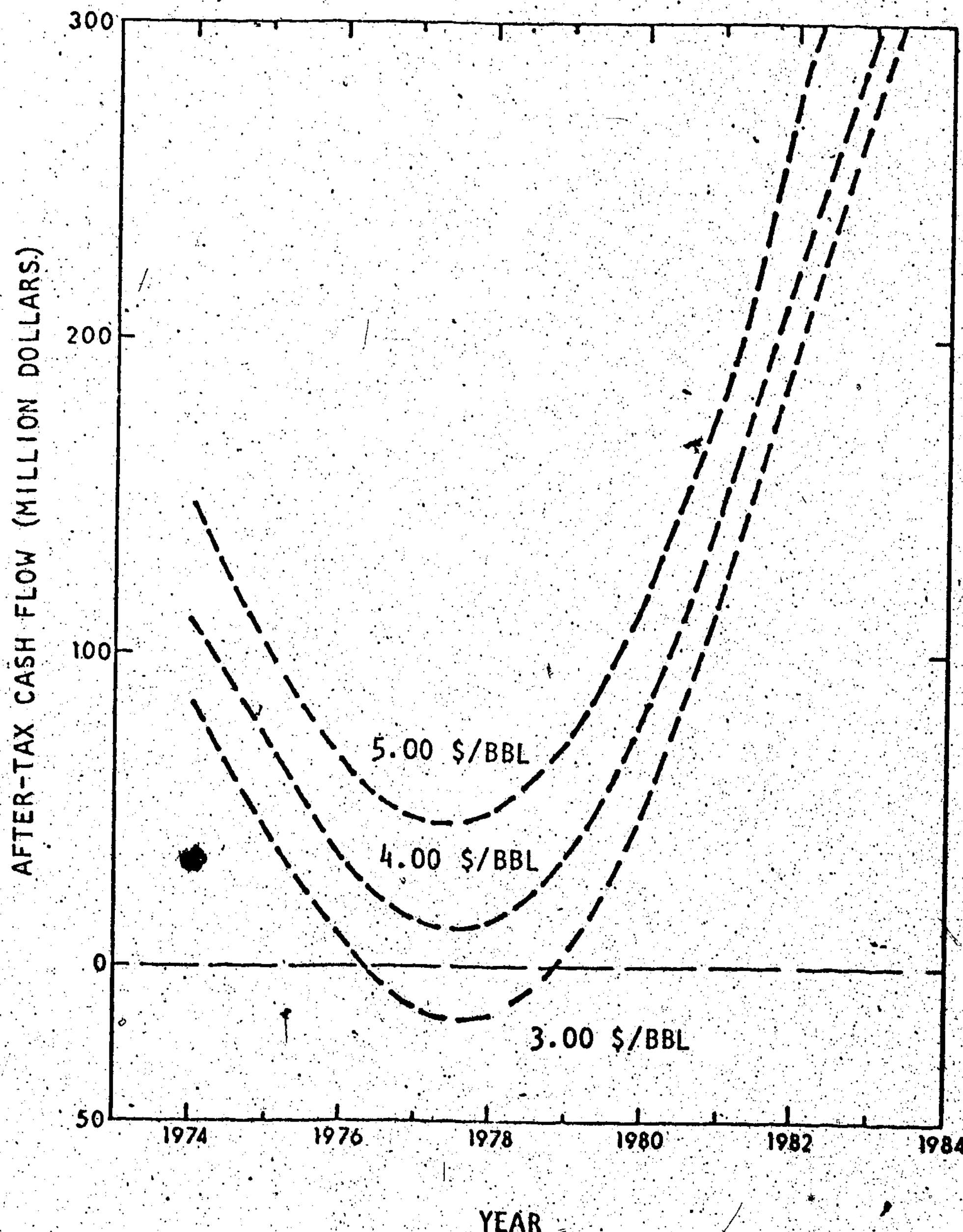

FIGURE IV-2 IMPERIAL OIL INCOME SENSITIVITY, ROYALTIES NON-DEDUCTIBLE

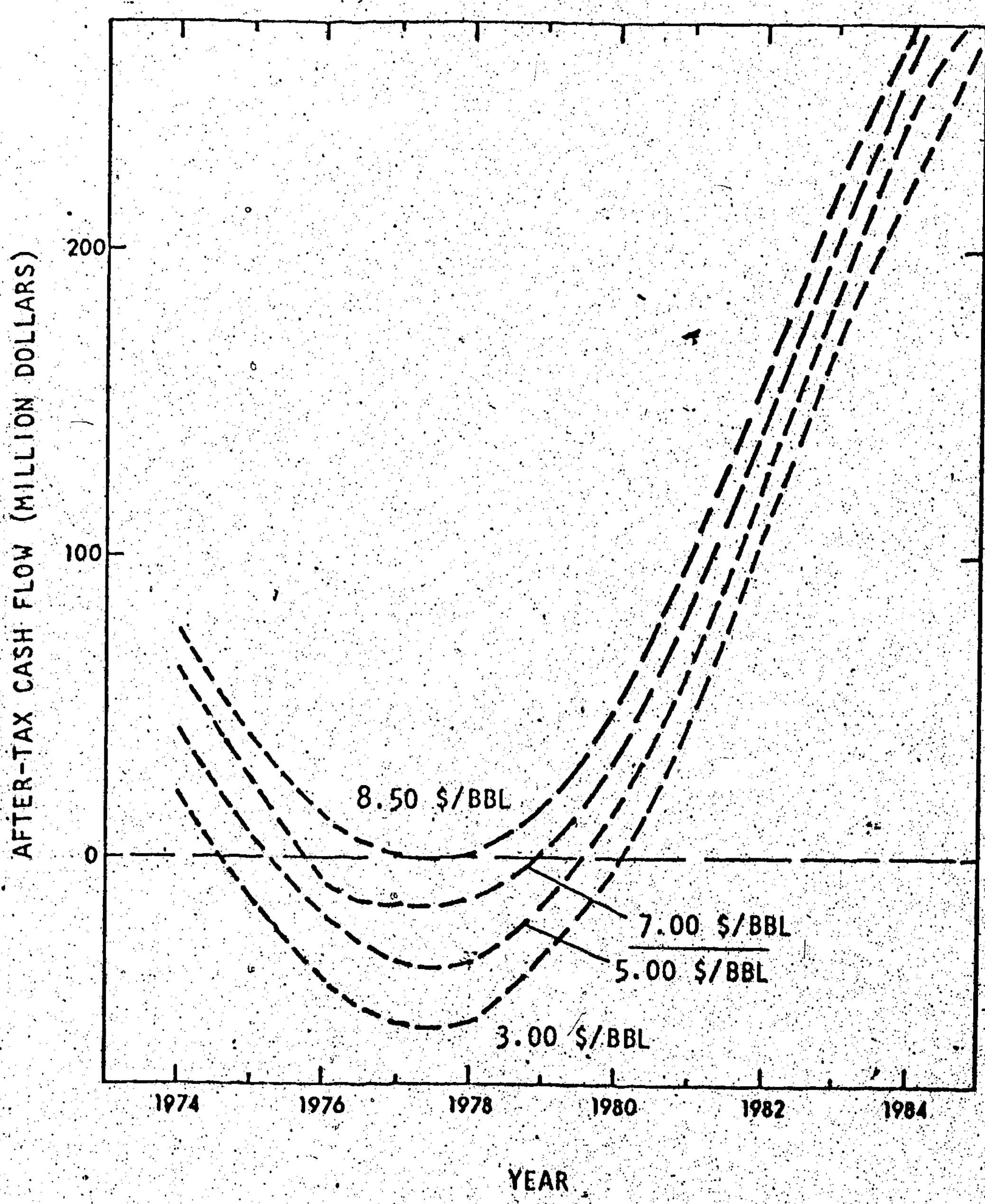

FIGURE IV-3 IMPERIAL OIL INCOME SENSITIVITY, ROYALTIES NON-DEDUCTIBLE, DEPLETION UNAVAILABLE positive after-tax cash flow for each fiscal scenario could be maintained. The object was to examine the sensitivity of the necessary price over the three scenarios. The results are shown in Figure IV-1, 2, 3.

On these graphs are plotted the after-tax cash flows from 1974 to 1984. The form of the curves is common to each; that is a parabolic shape. The reason for this shape is that both capital and exploration expenditures peak with production in the late 70's causing the greatest strain on revenue. One could argue that companies would not allow themselves to reach low cash flow positions and would make the necessary cut backs or corrections. This analysis investigates the response of increasing crude oil price to achieve the same purpose.

The results showed that the second and third scenarios would necessitate price increases if positive cash flows were to be maintained. The overall price change between the three cases was only between two to two and a half dollars per barrel. The first case showed that at virtually any price (i.e., three dollars per barrel and upwards), Imperial would maintain a positive cash flow.

The second case required a crude oil price of between three to four dollars. The effect of losing the royalty deduction was to increase taxable income. A price of three dollars per barrel in scenario one for 1977, for example, meant a 38 million dollar per year cash flow. With scenario two, in 1977, the cash flow was a minus 18 million dollars; the only difference being in fiscal conditions between the two cases.

The third case was the most severe. A price of nearly six and a half dollars per barrel was needed to maintain a positive cash flow.

The effect of the latter cases was to penalize the profit derived from crude oil production without affecting the other downstream was needed to maintain a positive cash flow.

The effect of the latter cases was to penalize the profit derived from crude-oil production without affecting the other downstream stages of the oil industry (refining, marketing, transportation, etc.). Had Imperial purchased only crude and spent nothing on exploration, the results of the three fiscal scenarios would have been identical. The fact that Imperial had only 30 per cent of its total revenue from crude-oil production kept the required price at only $5.50/bbl.

Diversification is one component in the strength of Imperial's financial position. Another advantage is its access to outside funds from its American parent. Imperial can rely on the parent to direct funds from other areas in their global network, if the prospects in Canada justify this action. This final resort of gaining funds from sources totally external to internal sources, by the intervention of the parent, gives the major the financial resources to continue exploration after other companies have exhausted their internal sources.

Ultimately the parent will come to a position similar to that of its subsidiaries (declining production, pressure for new discoveries).

IV.3 Middle Independent

Dome Petroleum Limited has been involved in exploration and production of crude oil and natural gas since the late 1940s. Its exploration expenditure has generally matched or exceeded internally generated income; consequently, the company has always been in a non-taxable position. (See Figure IV-4) It had up to 1973 accumulated deferred tax credits of approximately $100 million. The Independent's long-term debt position has steadily been increasing throughout the last decade. (See Table IV-1) Its total petroleum reserves have reached a

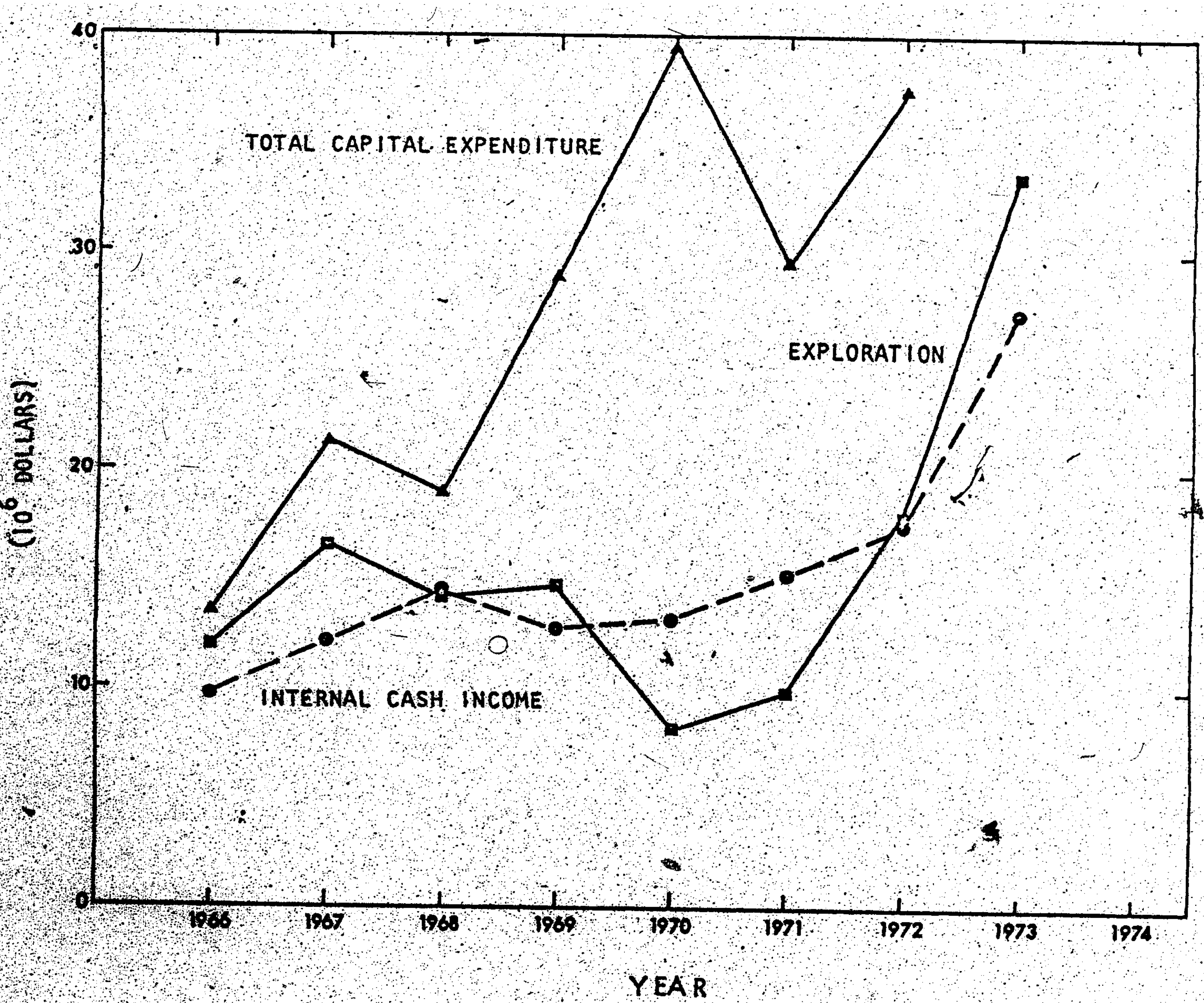

FIGURE IV-4 HISTORICAL CASH FLOW AND EXPENDITURE DOME PETROLEUM peak and now begun a decline. Though natural gas reserves have increased, sales of natural gas have remained constant. The company decision to undertake frontier exploration is evidence of their positive belief in the prospects of the frontier basins.

An analysis of the company's historical financial position indicated that this independent had always been in a negative cash flow position. Their own accounting as shown in their annual reports presented an optimistic interpretation. "Cash flow", by their definition, consisted only of revenues minus operating expenses (consumibles, general administration, and interest charges) but not deducting exploration or capital expenditures. Had these latter items been included their cash flow position would have been negative.

Table IV-1 shows the data of the past decade in the source-of-funds category. Internally generated revenue has never reached a majority position, while debt capital has ranked first. The fact that the independent has steadily attracted investors is a testimony to its management.

In analysing crude oil revenue for this company, the same three fiscal scenarios were applied to the specific cash flow model of Dome. The same technique of correlating the various streams of the cash flow model to the company crude-oil production curve was maintained. Good correlation existed between production and operating expenses, depreciation and, to a lesser extent, exploration costs. The sizable natural-gas production and market held by the company were assumed to hold constant at the 1973 level for the years in the projection.

The now-familiar assumption of relying on internally generated capital for financing exploration would seem faulty when applied against the history of this company. Yet, ultimately, investors will become scarce if financial conditions (low prices, unfavorable tax laws, etc.) and high

TABLE IV-1

SOURCE OF FUNDS FOR DOME PETROLEUM (1966-73)

	Source of Fund		
	CASH FLOW %	DEBT %	EQUITY %
1973	33.4	42.5	24.3
1972	43.6	80.2	6.0
1971	53.11	24.15	2.28
1970	25.56	68.67	1.33
1969	80.95	47.87	1.23
1968	48.76	50.62	.6
1967	80.89	42.69	1.29
1966	60.64	31.1	8.23

risks are combined, as is the case with present frontier exploration.

The results of cash-flow projection followed the general form of the previous section IV-2 (i.e., greater price changes required as fiscal policies become unfavorable). The extent of required price changes were greater for the independent than the major, as virtually all revenue is from petroleum production that is subject to royalty and tax penalty. The offsetting factor in its favor remained the one $100 million of deferred tax credits.

The results from scenario three showed that prices of $12.00-to-$15.00/bbl. were necessary if the independent were to declare a positive after-tax flow throughout the entire 10 years of projection. Surprising behavior took place in the $5.00-to-$9.00/bbl. range (See Figure IV-5) of this scenario. A price of $7.00 to $8.00/bbl. was worse than $5.00 to $6.00/bbl. because of the increased royalty and tax payable at the $7.00-to-$8.00/bbl and the rapid elimination of the deferred tax credits, whereas the $5.00-to-$6.00/bbl. range exhausted the tax credit less rapidly over the entire 10-year period. It is not until the price reaches $10.00/bbl. does the increased revenue offset the early loss of the tax credits. However, the preference of the $5.00-to-$6.00/bbl. range is only a relative one. The effect of such tax policies upon this independent is devastating. Cutbacks in exploration, or the increasing of natural-gas sales would be possible strategies for the company to adopt to help to restore some cash flow.

IV.4 *The Small Independent*

The two previous companies demonstrated the top and middle rungs of the oil-industry ladder. The "major" held not only production

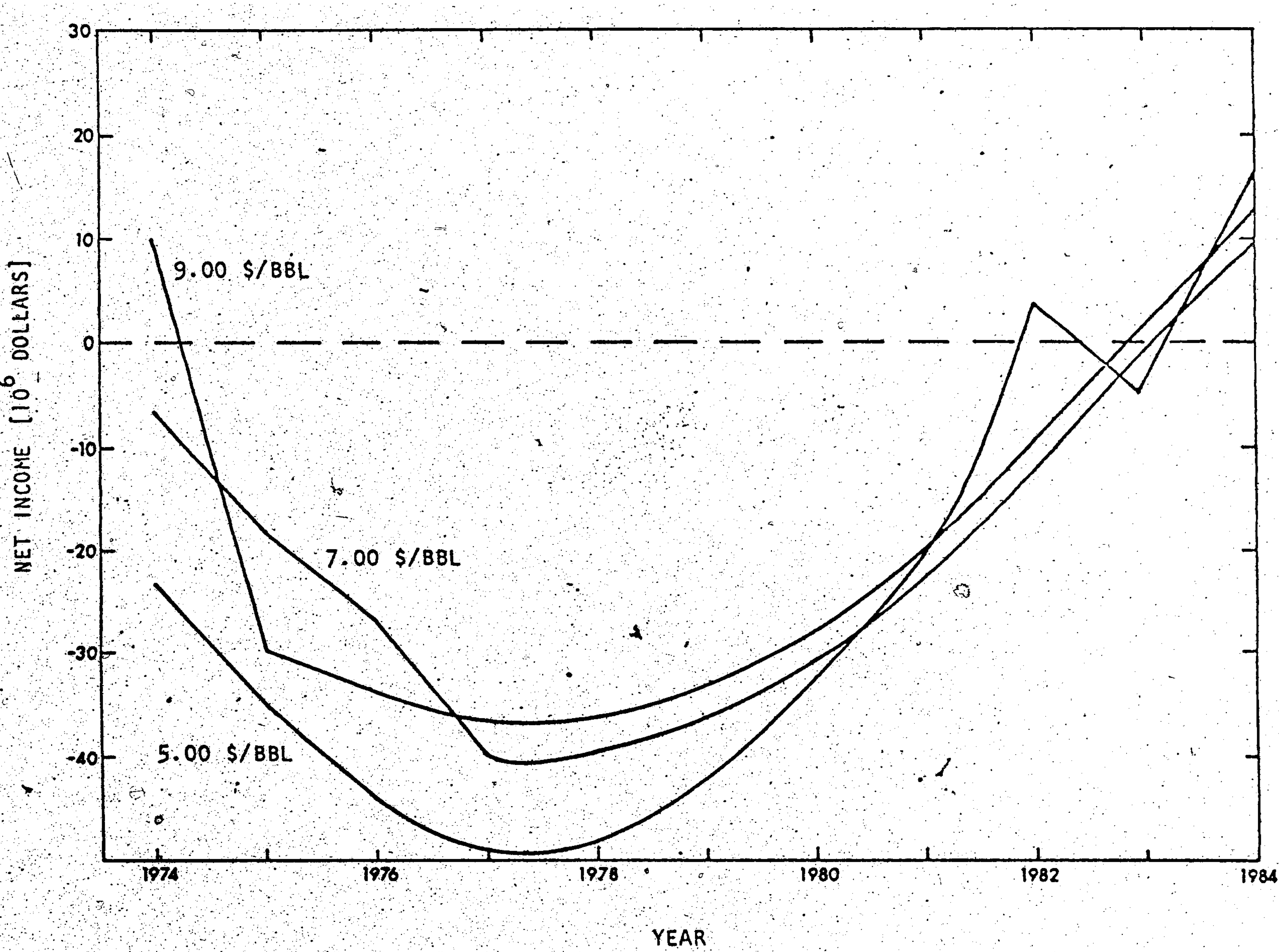

FIGURE IV-5 AFTER TAX CASH FLOW OF DOME PETROLEUM capacity but the facilities for refining and distribution of final products. The independent reached only the production phase. Both, however, did hold substantial petroleum reserves. The small independent has not yet reached that stage. Initial discovery or acquisition of petroleum production has not occurred.

This small independent, Chieftain Development Ltd., holds the exploration rights to various areas in Western Canada and the North Sea of up to 3.3 million acres. The production of crude oil in 1972 totalled 38 bbl/day; in 1973 no production was reported. (see Reference 22) The company is not in a taxable position. Only in the last two years has revenue surpassed exploration expenditures. In 1972 and 1973, large issuances of stock were made, increasing the funds available to the company. The use of such funds was in the purchase of capital (land, equipment, buildings) and revenue-earning assets. Additional loads were obtained. In previous years bond issues were used to increase funds. At that time the primary use was in exploration rather than in acquiring revenue producing assets. The ability of such a company to sustain exploration is weak in comparison to the other firms.

The effects of any of the three scenarios would not be much different since the company has yet to exhaust previous tax credits from unsuccessful exploration. The latter two scenarios would not penalize Chieftain, as they manifest themselves on the production phase specifically. This small independent has very little production. The effects of these fiscal conditions may be felt indirectly as potential returns from possible discoveries would be reduced and possible investors deterred.

This independent with limited financial resources has restricted its exploration efforts to mature, comparatively low-risk areas such as the Western Canada basin and the North Sea. Such independents are unlikely to participate in frontier exploration because of the simple lack of adequate financing.

This chapter has described three companies, each representing a certain class within the Canadian oil industry. The three shared little in common other than an interest in discovering and producing oil. None could be said to have been totally dependent upon crude oil production revenue. Either the company produced refined products and held alternate revenue earning investments, or obtained capital from external sources (borrowing, drilling funds, etc.). The examination of other companies would doubtless have presented other complications and deviations from a model of an oil company with a single source of revenue.

CHAPTER FIVE

DEVELOPMENT AND PRICE SENSITIVITY

V.1 *Introduction*

The previous chapters examined the sensitivity of exploration to income. Income was assumed to be internally generated from the sale of crude oil and natural gas. With this model of corporate cash flow, exploration could be related to price. Such prices cannot assure the discovery of oil, but only enable the drilling of the necessary wells to resolve the uncertainty as to the existence of oil in economically significant amounts.

The character of the oil-supply problem is immediately changed with the first truly significant discovery of oil. Supply is then no longer dominated by uncertainty but by the relatively deterministic elements, costs of production and well producibilities. These factors determine what price is required to facilitate the production and transportation of the resources of any oil pool to a market, given the axiom that high producibility translates into low price.

In any oil field, the constituent pools will have different producibilities (barrels per day, per well), while the cost of a given well and its ancillary gathering and transportation systems remain relatively constant, since these costs are fixed by the geographic location of the well and its logistical implications. The production of those pools of high producibility occurs at costs lower than those required for the less productive. If the price is sufficiently high, all pools will become economically viable, after which no increase in production is forthcoming regardless of further price increases. For a given oil field, once the individual pool producibilities are known or estimated, a relationship between available throughput and price can be constructed.

Establishing the price sensitivity for frontier basins is complicated by the fact that the oil pools have yet to be discovered (presuming that they are discoverable). It becomes necessary to make predictions about the total reserve and its distribution, and also assumptions regarding the magnitude and range of producibilities applicable.

Geologists can provide the predictions of the most-probable expected reserve for a particular basin. In turn, a log-normal set of pools can be hypothesized to constitute this reserve. The producibilities can also be assumed to conform to distributions based on the experience of other fully developed basins. The exercise becomes one of generating both the reserve and producibility of a given pool and calculating the required price to cover costs of production.

The problem is one of carrying out in a probablistic sense the same calculations done by a petroleum engineer in a deterministic sense. The purposes are the same, with the circumstances different (a priori versus a posteriori).

A model was developed to estimate price sensitivity in the Mackenzie-Beaufort basin, utilizing a probablistic approach, eventually producing the sensitivity curve.

II. Model Procedure

Outlined in the following steps is the procedure used to produce the sensitivity curve. Discussion of the rationale for the assumptions made through the procedure is deferred until the next section.

1. A total producible reserve for the basin is assumed (in the first case 2 billion barrels), along with the number of pools comprising this reserve (12).

2. A log-normally distributed set of pools is generated with the cumulative reserve for these pools approximately equal to the assumed reserve established in Step 1.

3. The log-normal distributions of pay thickness (rock volume of the pool divided by the area of the pool) and deliverability (expressed as barrels per day per foot of pay thickness) were constructed from the data based on largest non-reefal pools of Alberta. (See reference 3 and 24) (See Figure V-1,2 for plots of distributions)

4. A random number was then generated. With this number a member of the pay-thickness distribution was selected.

5. An identical procedure, involving another random number, selected a member of the specific deliverability distribution.

6. The product of these two parameters gave the well producibility.

(ft of pay) x (bbl/day/ft of pay) = bbl/day

7. This producibility was assigned to the first member of the set of oil pools.

8. The required yearly production for each pool determined by dividing the pool reserve by 20 years.

Required Production = Reserve (bbl)/20 yrs.

9. The number of wells necessary to fulfil the required production was determined by dividing required production by well producibility.

Number of Wells = bbl/day/(bbl/day/well)

10. The price required was calculated for the pool according to the following:

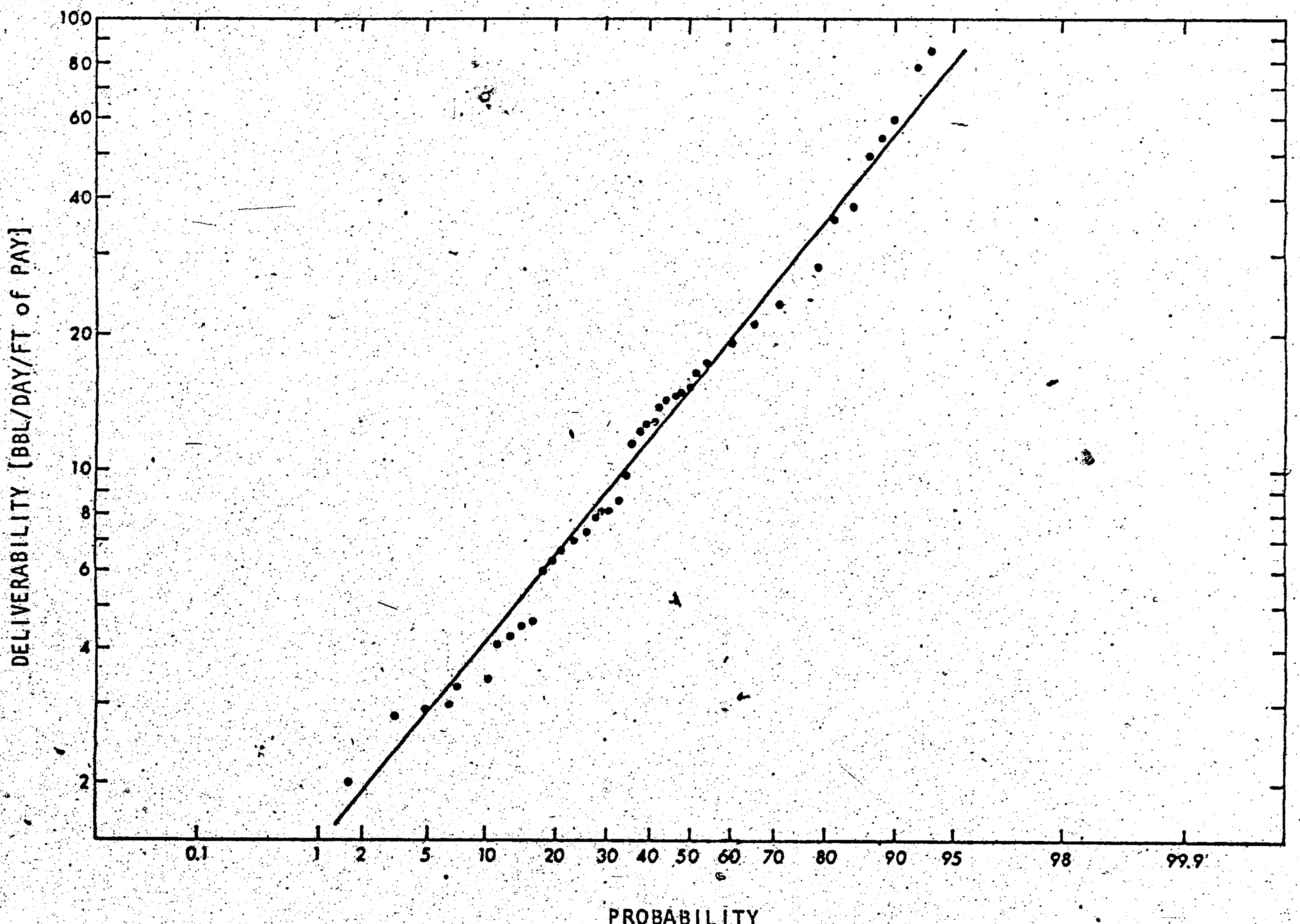

FIGURE V-1 LOG-NORMAL PLOT OF DELIVERABILITY STATISTICS

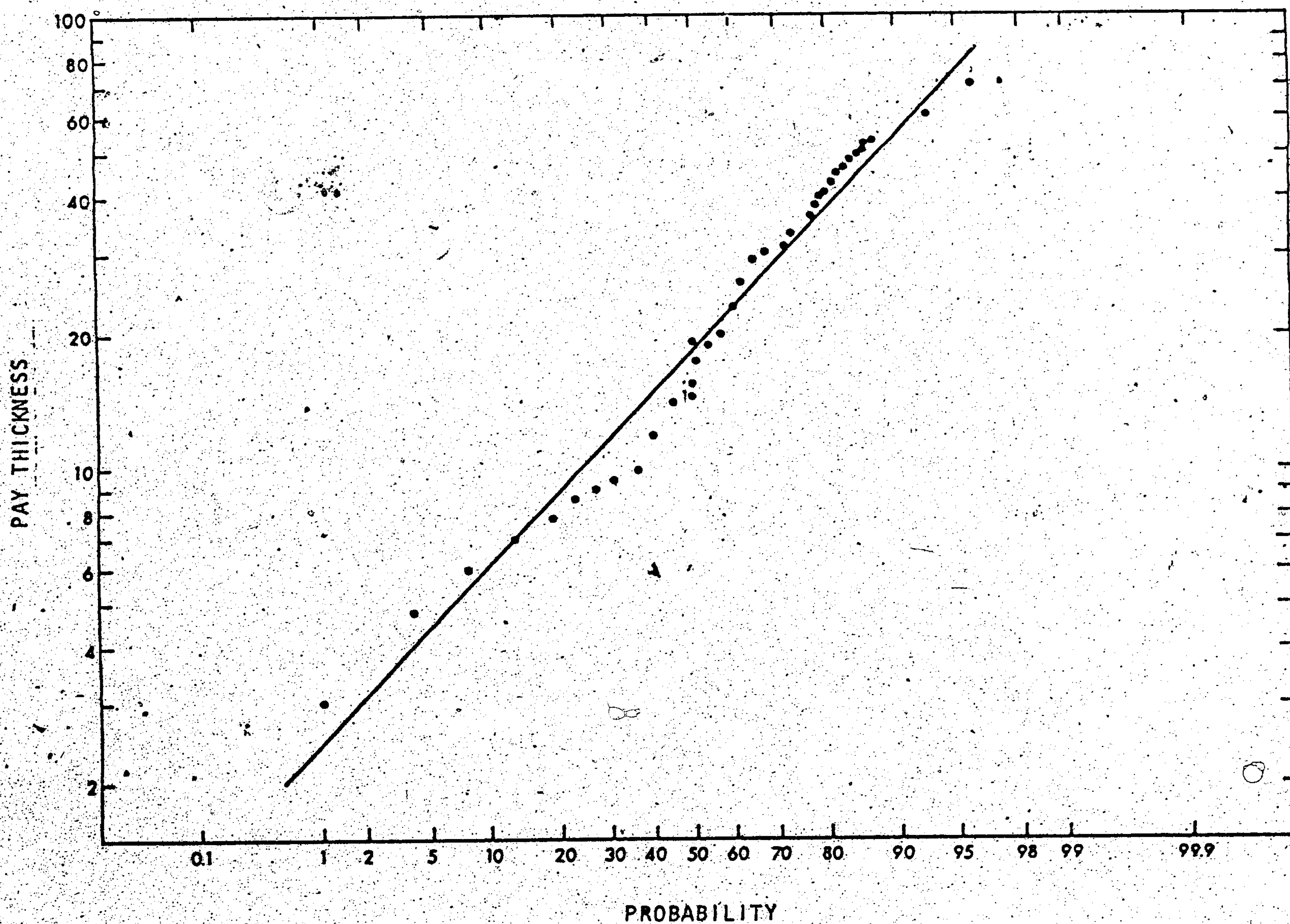

FIGURE V-2 LOG-NORMAL PLOT OF PAY THICKNESS

$$\text{Price} = \frac{[\text{Cap} + \text{Op}(P/a)\ {}^{T}_{i}] \times \text{NUM}}{\text{PROD}\ [P/a]\ {}^{T}_{i} \times \text{NUM}}$$

where Cap / original capital cost of development well ($2 million)

Op / operating cost, 20% of original capital cost per year

T / time, (20 years)

i / effective rate of return (price increase - inflation) - 5%

(P/a) / discount factor, converts annuity to present worth

NUM / number of wells

11. The procedure from Step 4 to 10 is repeated but now the second pool is considered. The other pools, comprising the reserve, were in turn considered by the same process.

12. After determining the 12 prices associated with the 12 pools, a relationship of throughput versus price was drawn.

13. The entire procedure from Step 1 to 12 was repeated, resulting in another curve of throughput versus price. One hundred such curves (the number limited only by computer cost and availability) were generated.

14. The reserve level was changed to 10 and 20 billion barrels recoverable. Two additional sets of 100 curves of throughput versus price were produced. See Appendix V for computer program of this routine.

III. Discussion of Procedure

The entire procedure as previously outlined relied upon the hypothesis that the magnitudes of the pay thickness and deliverability were independent of the size of the pool with which they were associated. The validity of this assumption is not clear on purely geologic grounds; private communications with geologists did not provide any resolution.

The following result may serve as some form of justification for that hypothesis. The distributions of area, pay thickness, porosity and water saturation were generated from the same data set.

[All distributions were derived from data pertaining to the largest non-reefal pools found in the Alberta sedimentary basin, as ostensibly tabulated by the Energy Resources Conservation Board of Alberta. See Reference 3. The total number of pools in this set was 380. This amounted to the inclusion of all non-reefal pools whose areal extent was greater than 40 acres. Reefs (a particular structural trap, which in Alberta contain a substantial portion (60%) of the total oil in place) were omitted as their inclusion would have caused undue upward bias in the distributions, particularly with respect to pay thickness. The 380 pools, from which the distributions were derived, are not exhaustive of all non-reefal pools in Alberta. See Reference 3 for tabulation of data.]

With these distributions of the various reservoir parameters, an estimate of the oil in place for Alberta's non-reefal pools was made. This was done with the following routine [not unlike the previously described procedure of section two.]

1. A random number was generated and, in turn, a member of the porosity distribution.

2. Three additional random numbers produced members from the area, pay thickness and water saturation distributions.

3. The product of these four parameters gave a value for the oil in place in a single pool.

OIL IN PLACE = Area * Pay Thickness * Porosity * (1-Water Saturation)

4. Steps 1 through 3 were repeated 380 times. (380 is the number

of the significant pools of the original data set.)/

5. The oil in place in the 380 pools was totalled, representing one estimate of the cumulative reserve. The total was rounded to the nearest billion.

6. Steps 1 through 5 were repeated 200 times. A plot of cumulative reserve versus frequency of occurrence was produced. (See Figure V-3). The most frequent value was the simulation's estimate of the actual oil in place found in non-reefal pools in Alberta.

The result was a reserve of 17 billion barrels. The actual figure as reported by the E.R.C.B. was also near 17 billion barrels. The variance depended upon the accounting of miscellaneous stratigraphies.

The results showed that it is possible to independently sample from the reservoir parameter distributions, and closely approximate the tabulated oil-in-place figure. The original hypothesis was not proven or disproven by this result, but merely given some empirical support.

The other major assumption employed in the model was implicitly contained in the manner in which the 12 pools were evaluated economically. [The choice of 12 pools as opposed to any arbitrary figure was based on the results of Chapter II. Of the original 200 structures, 72 would have been drilled before the expectations fell below the threshold of 2 billion. At the point at which the threshold oil reserve was discovered or confirmed the number of oil-bearing structures for the basin would be 12.]

The model assumed that the necessary pools had been discovered, thereby assuring the reserve for a transportation system based on a 20-year life before any economic evaluation of any individual pool would take place. The only question remaining is what price would be necessary to cover the costs of the most expensive oil found in the 12 pools.

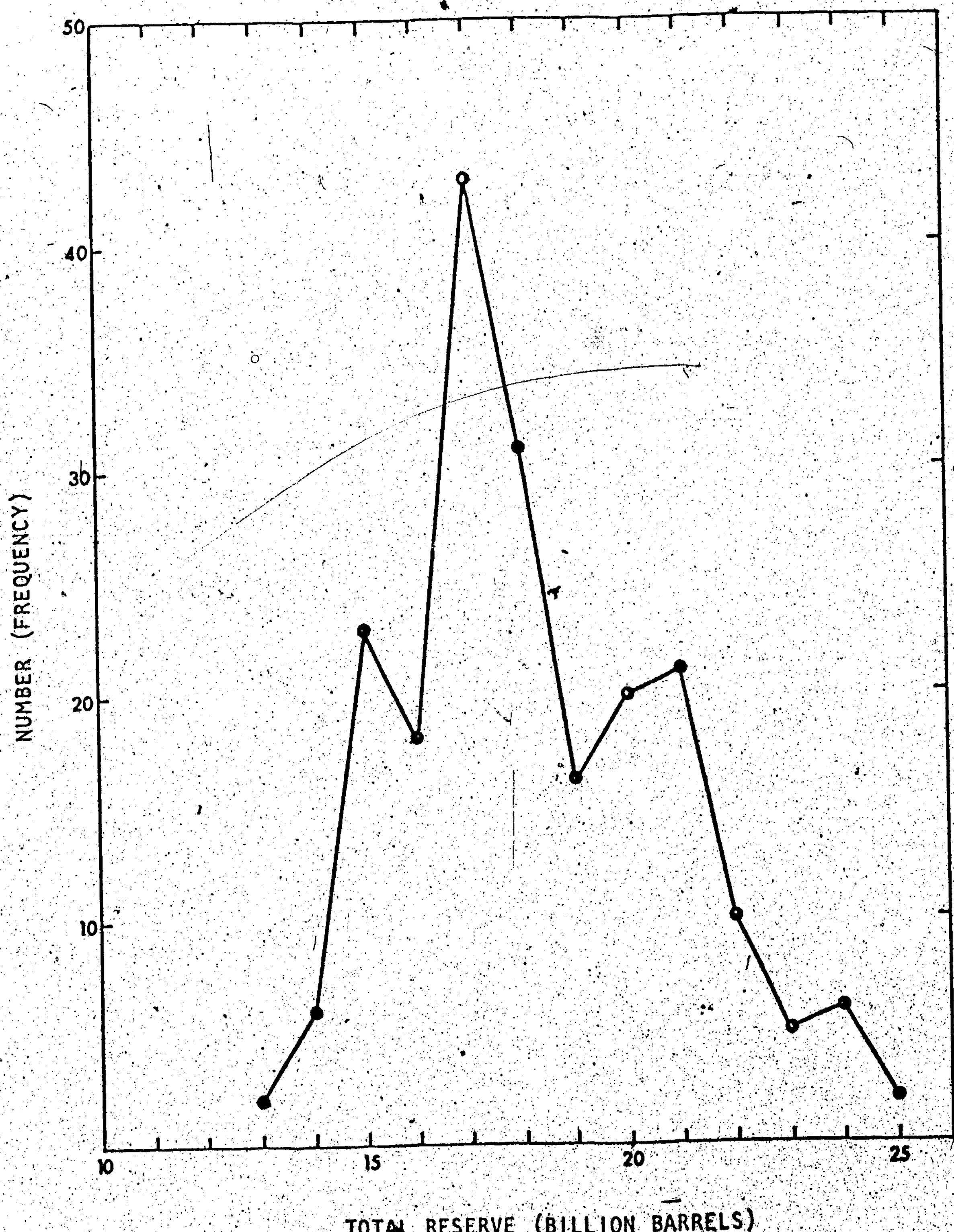

FIGURE V-3 RESERVE SIMULATION FREQUENCY CURVE

The opposite scheme of development would have involved discovering a single pool, finding it was producible at current market price and building a transportation system. The one pool would not likely contain sufficient reserve to maintain a pipeline for 20 years at full capacity, in the faith that other viable pools would be subsequently discovered to replace the original pool and maintain full capacity. This development policy has problems if the subsequent discoveries are not forthcoming. The conception of this model requires exploration up to the point where reserves are proven to justify the pipeline over a significant period of time - 20 years.

If supply is not possible it would be because market prices were not adequate, rather than a physical insufficiency. The error of lacking sufficient reserve would be avoided.

The other assumptions applied to the model development were:

1. The producibility calculated by the multiplication of the reservoir parameters was assumed to remain constant throughout the entire production life of the pool. This would require a natural water drive or similar mechanism. Other schemes involving a decline of production with time will not be explored in this section. (See Appendix C) Such declining producibilities are a more realistic model of the production of most pools. The results following from the constant delivery assumption will represent the most optimistic of all possible from a choice of production schedules.

4. The number of wells required on the individual pools was determined by simply dividing the desired production by the well deliverability. The reserve would be exhausted in 20 years. This assumed that as many wells would be put into place as are physically required and that there would be no

logistical constraints as to the ability of the industry to accomplish the construction of sufficient wells. Such logistical constraints could prove decisive.

5. The capital cost of each well, gathering system and other necessary equipment was set at $2 million. This figure was based upon published data for the Beaufort-Mackenzie basin.[25] Operating expenses associated with these capital investments were at 20 per cent of the original capital cost, based upon the historical relation between capital and operating cost in the development phase (Reference 16).

6. The assumed production life of the pools was 20 years, based primarily upon previous pipeline calculations. The sensitivity of the calculated price to producibility over various production lives was not significant. See Figure V-4. Between the 20-and 40-year lifetimes, the curves were virtually coincident.

7. The final number of iterations (or curves of throughput versus price) for each reserve level was limited to 100. The limit of 100 was due to computer availability and cost. See Appendix C for computer listing of this procedure.

IV Results

From the results of preceding simulation, the most probable available throughput (rounded to the nearest 10 million bbl./yr), for a given price was calculated. A set of 100 available throughputs was generated. The throughput with the greatest frequency was interpreted as being the most probable for the particular price level.

A similar solution was calculated for each price level from

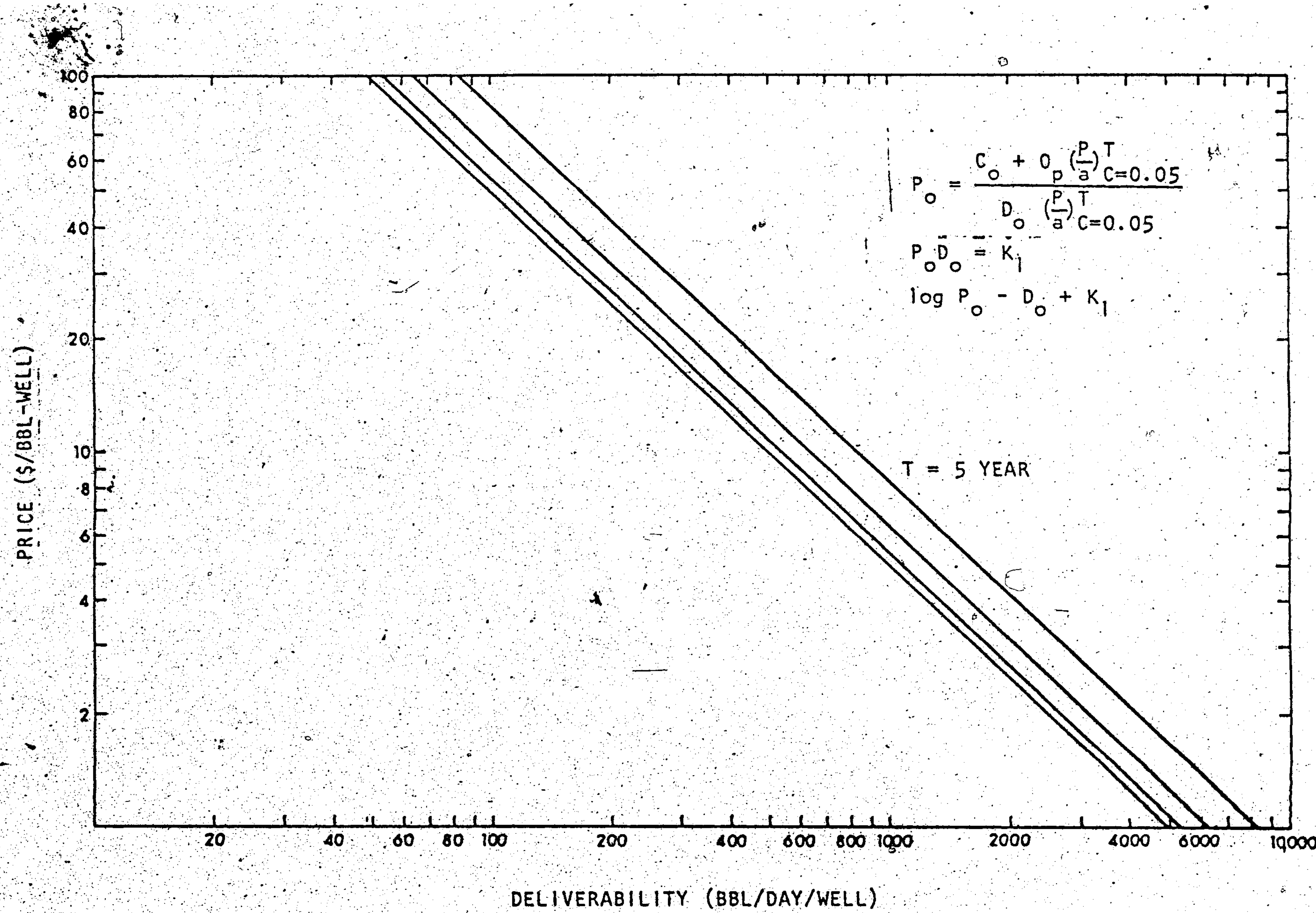

FIGURE V-4, PRICE - RESERVOIR LIFE SENSITIVITY

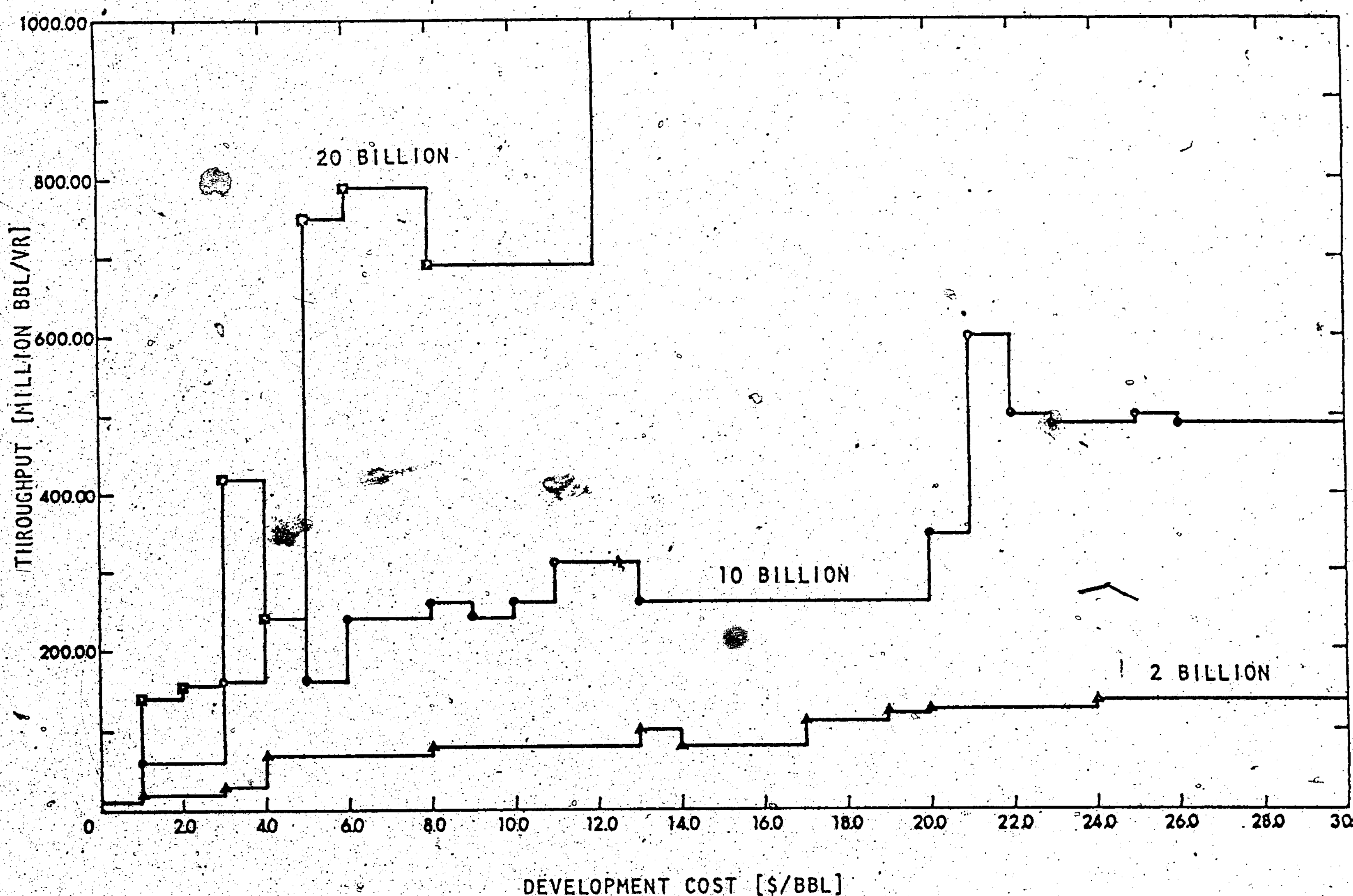

FIGURE V-5 DEVELOPMENT COST VS MOST PROBABLE AVAILABLE THROUGHPUT the 2-billion-bbl. reserve, the extra price is insignificant as the price is already at the $20.00/bbl. level, compared to the current Canadian market price of $6.50/bbl.

The pipeline-cost effect on the other cases is not critical as additional reserves exist beyond the minimum of the 2-billion-bbl. level. The additional reserve allows greater throughput, thereby reducing the "per barrel" cost of transportation.

Debate centres on the likelihood of finding the 2-billion-bbl. or 20-billion-bbl. reserve. Geologists have been relied upon to provide predictions as to petroleum potential of Canada's frontier basins. Their estimates were originally optimistic as evidenced by the 1970 C.P.A. predictions, or even C.S.P.G. estimates, in the E.M.R. 1973 report[10]. The lack of significant oil discoveries to date causes downward revision of these optimistic, original estimates. Each exploratory failure brings the possibility and inevitability of higher-priced oil an unavoidable eventuality.

It should be appreciated that the results of this chapter are based on assumptions which are highly favorable to the realization of Arctic production. The development costs shown in Figure V-5 represent a lower bound on the range of possibilities. It is significant that the costs of development in this lower-bound case would still rise to $20.00/bbl. if the total reserve is not significantly higher than the threshold volume.

Conclusions

1. Price increases above $3.00/bbl. would be required if sufficient self-generated income is to be made available to finance the levels of exploration required and if traditional tax laws pertaining to oil and gas producers are altered.
2. If the tax laws, in effect prior to the fall, 1974, federal budget, were not altered, $3.00/bbl. as a company share of the posted price, would facilitate an exploration expenditure of approximately $400 million per year. The level of expenditure would be sufficient to determine conclusively the oil potential of the Canadian frontier.
3. If the deliverabilities encountered in the pools of Alberta are applicable to the possible discoveries in the Mackenzie-Beaufort basin, significant price increases would be required.
   i) For an ultimate reserve of 2 billion barrels (equivalent to the threshold reserve), development costs are estimated to be at least $20.000/bbl.
   ii) If the ultimate reserve lies between the 10-billion-bbl. and 20-billion-bbl. level, development cost of between $2.00 to $4.00/bbl. are anticipated.
4. If pools are to be economic from frontier locations, they must contain not only sufficient reserves but also high producibilities.
5. The available market price for potential crude oil reserves has only a minor effect on their discovery.

Recommendations

1. The income tax effects on the financing of development and exploratory wells should be investigated. This would indicate any effect which reduction in the cost of wells would have on development costs of frontier oil.
2. Greater specification of prospects as to their;
   1) location, onshore-offshore
   2) depth, and,
   3) type of trap (fault, reef, syncling strat, etc.)

   This specification would allow the decision analysis of Chapter Two to be done on a stratified basis. This would possibly accelerate the reassessment process. It also allows for greater specificity as to cost and consideration of logistical constraints.
3. Improvement in data base of the industry cash flow, as presented in Chapter Four from C.P.A. publication, would allow for a more significant interpretation of the role of crude oil price on income.
4. The incorporation of various oil company utility functions as applied to frontier exploration would permit the modification of the decision analysis of Chapter Two. This would allow for the Chapter Two model to approximate more closely the actual corporate decision process.

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Appendix A. Threshold Reserve Determination

During the development of the decision analysis presented in Chapter Two an estimate of the reserve necessary to justify the construction and operation of a pipeline was required. The figure of 2 billion barrels of recoverable reserve was used.

This appendix will outline the procedure used to derive that threshold estimate. Generally, this procedure involved generating a curve of combined cost, operating and capital, (\$/bbl.) for various sized pipelines from two feet to four feet in diameter.

The economic pipeline size corresponding to a particular wellhead price was calculated. Wellhead price is the difference between the price obtainable at the refinery gate and the transportation cost involved in shipping the oil from the well to the refinery gate. The f.o.b. price at a certain point is a matter of government regulation presently set at \$6.50/bbl. The return to the producer is equivalent to the wellhead price, excluding production and royalty costs.

With the pipeline size elected on the basis of zero wellhead price, the reserve required to maintain full capacity, was calculated, assuming a 20-year production life.

A route, having Mackenzie Delta-Edmonton, Alberta, terminals, covering 1738 miles, was selected. The physical properties assumed for the oil were:

1. Max. temp. +160°F
2. Min. temp. - 48°F
3. Specific gravity - 28° API at 60°F
4. Viscosity - 12.04 cp
5. Pump discharge 850 psig

The velocity chosen for the pipeline was five feet/sec, standard industrial practice. A standard pipeline calculation followed using these physical parameters and specifications. The number of pumps, insulation costs and materials costs were calculated (see listing in Appendix V). Various other capital items were also included (roads surveying, transportation of equipment land, construction duties, etc.). All cost data were based on the unpublished work of Chen and Faris. Operating costs were based primarily on utility and manpower requirements. The total capital cost was converted to an annual equivalent capital cost and added to the operating costs.

The annual throughput a function of pipeline diameter, determined the final pipeline cost per barrel.

$$\text{Trans. Cost} = \frac{(\text{Cap/Cost})\left(\frac{a}{p}\right)\begin{smallmatrix} I=20 \\ T=20 \end{smallmatrix} + \text{OP Cost } \frac{\$}{\text{Year}}}{\text{ANNUAL PROD. } \frac{\text{BBL}}{\text{YEAR}}}$$

The results of these calculations are summarized in Figure II-4, showing transportation cost as a function of pipeline diameter, with current market price of \$6.50/bbl. assumed.

This curve demonstrated that considerable economies of scale are to be gained by constructing large-diameter pipelines. If the reserve is available, the larger the pipeline size is increased, the greater netback to be gained by producers. This economy of scale occurred because of the fact that the increase in cost attributable to increased pipeline size, primarily increased material cost, was substantially offset by the increased capacity.

The cost on a per-barrel basis was reduced, thereby increasing the wellhead price to the producer.

Figure II-5 shows the relationship between pipeline size, assumed to be full over 20 years, and the reserve necessary to maintain such throughput. As the minimum case, a pipeline size for which the wellhead price is zero was roughly the two-foot size. (This translates to a required reserve of approximately 2 billion barrels (see Figure II-5).) The minimum reserve to merely support the laying of a pipeline system is roughly 2 billion barrels. This does not allow for any costs of production or exploration or government (royalty or taxes).

The only known published estimates for threshold reserves are those found in the November, 1974, NEB report. See Table II-1. The numerical average of these estimates is practically 2 billion barrels, giving excellent agreement with the estimate developed in this work.

Appendix II. Success Ratio Reassessment by Use of the Beta Distribution

I - INTRODUCTION

During the process of exploring for oil in a virgin basin, a particular explorer's willingness to continue this exploration in spite of drilling failures can be evaluated by comparing his expectation of the basin oil potential to a threshold reserve requirement. His conception of the basin reserve will logically be reduced by drilling failure.

In Chapter Two, this reassessment of expected reserve took place by the elimination of the largest-sized structures from consideration once they had been drilled and found to be non oil-bearing. The volume of possible oil-bearing rock was reduced by each drilling failure.

A success ratio was utilized to relate the remaining prospects into an oil potential. Despite the drilling failures no reassessment was made in the value of success ratio, which was estimated a priori any drilling success or failure. The question of this section is how much is the explorer's downward reassessment of oil potential accelerated by the downward revision of the success ratio, and the elimination of unsuccessful traps.

The extent of change in the success ratio because of drilling failure is a matter of the explorer's personnel utility function. Different explorers will react differently, depending on their own conceptions of the value of the information contained in the drilling results.

One analysis applicable to describing revisions in the success ratio from drilling results, is that which utilizes the beta probability distribution. It is only one possibility. The value of any mechanism for reassessment depends on its best describing an individual's reaction to evidence.

The purpose of investigating the "beta" analysis was to determine any sensitivity between accepting an invariant or a sequentially revised success ratio on the statistic, critical failure. [Critical failure being the number of unsuccessful wells drilled before one's expectations are below the threshold reserve.]

This analysis is presented in the following sections, preceded by some theoretical review of the beta distribution.

(2). *Theory*

The process of drilling prospects is conceived to be a Bernoulli process, (i.e., a random process as a sequence of discrete trials each having one or the other of only two possible outcomes). Another example is the testing of the production of light bulbs which are either defective or good.

The probability of having x successes in n trials is given by the binomial probability distribution:

$$P_B(x|n,\gamma) = b(x;n\gamma)$$

$$= \frac{n!}{x!(n-x)!}\,\gamma^x(1-\gamma)^{n-x} \qquad \text{B-1}$$

where 1) n = number of trials

2) x = number of successes

3) γ = the probability of a success on each trial, the success ratio

The success ratio, γ, being characterized as a random variable:

$$f_\beta(\gamma|\alpha,\beta) = \frac{(\alpha + \beta + 1)!}{\alpha!\ \beta!} \gamma^\alpha (1 - \gamma)^\beta \qquad \text{B-2}$$

where f_β is a beta distribution with parameters α and β.

Assume a prior assessment of this distribution to be:

$$f_\beta(\gamma|\alpha_o, \beta_o)$$

If after a sequence of m trials, there occurs in r successes, then the posterior distribution of the parameter, γ.

$$f_\beta(\gamma|\alpha_m, \beta_m) = f_\beta(\gamma|\alpha_o + r, \beta_o + m - r) \qquad \text{B-3-A}$$

$$= \frac{(\alpha_o + \beta_o + m)!}{(\alpha_o + r)!\,(\beta_o + m - r)!} \gamma^{\alpha_o + r} (1-\gamma)^{\beta_o + m - r} \qquad \text{B-3-B}$$

The mean of the beta distribution is:

$$E(\gamma|\alpha, \beta) = \frac{\alpha + 1}{\alpha + \beta + 2} = \frac{a_o + r + 1}{\beta_o + m - r} \qquad \text{B-4}$$

For a flat prior distribution (i.e., no idea as to the possible value of γ),

$$\alpha_o = \beta_o = 0.$$

(See Reference 8,9).

III

Section II.4 discussed the significance of the success ratio reassessment method as an expression of the entrepreneur's belief in prior estimates of resource potential. The selection of appropriate beta distribution parameters can represent these beliefs. On Fig. B-1, the plot of the beta distribution density versus the random variable, γ or success ratio, has been made for several values of α and β. The degree of the spiked-ness for increasing values of alpha and beta is a measure of magnitude of revisions to expect. The sharp tall spikes (α=100, α=40) lead to gradual revisions; whereas, the flatter curves (α=2, α=10) cause relatively rapid changes in the original estimate.

With the use of Equation III-3-A and Equation III-4, a revised estimate of the success ratio can be calculated. The magnitude of the revision will depend upon particular values of the parameters α_m and β_m or qualitatively by the relative spiked-ness as shown in Fig. B-1. Compare the following results for revised success ratio:

1) $\gamma = 0.25, \alpha_o = 1, \beta = 4$, 0 success in 10 trials,

Revised success ratio	$\frac{1}{4}$	$\frac{1}{5}$	$\frac{1}{6}$	$\frac{1}{7}$	$\frac{1}{8}$ ...
Number of trials	1	2	3	4	5 ...
γ	.25	.2	.166	.142	.125

2) $\gamma = 0.25, \gamma = 100, \beta = 400$, 0 successes in 10 trials

Revised trials	$\frac{100}{400}$	$\frac{100}{401}$	$\frac{100}{402}$	$\frac{100}{403}$	$\frac{100}{404}$ ...
Number of trials	1	2	3	4	5 ...
γ	.25	.2493	.2487	.2481	.2475

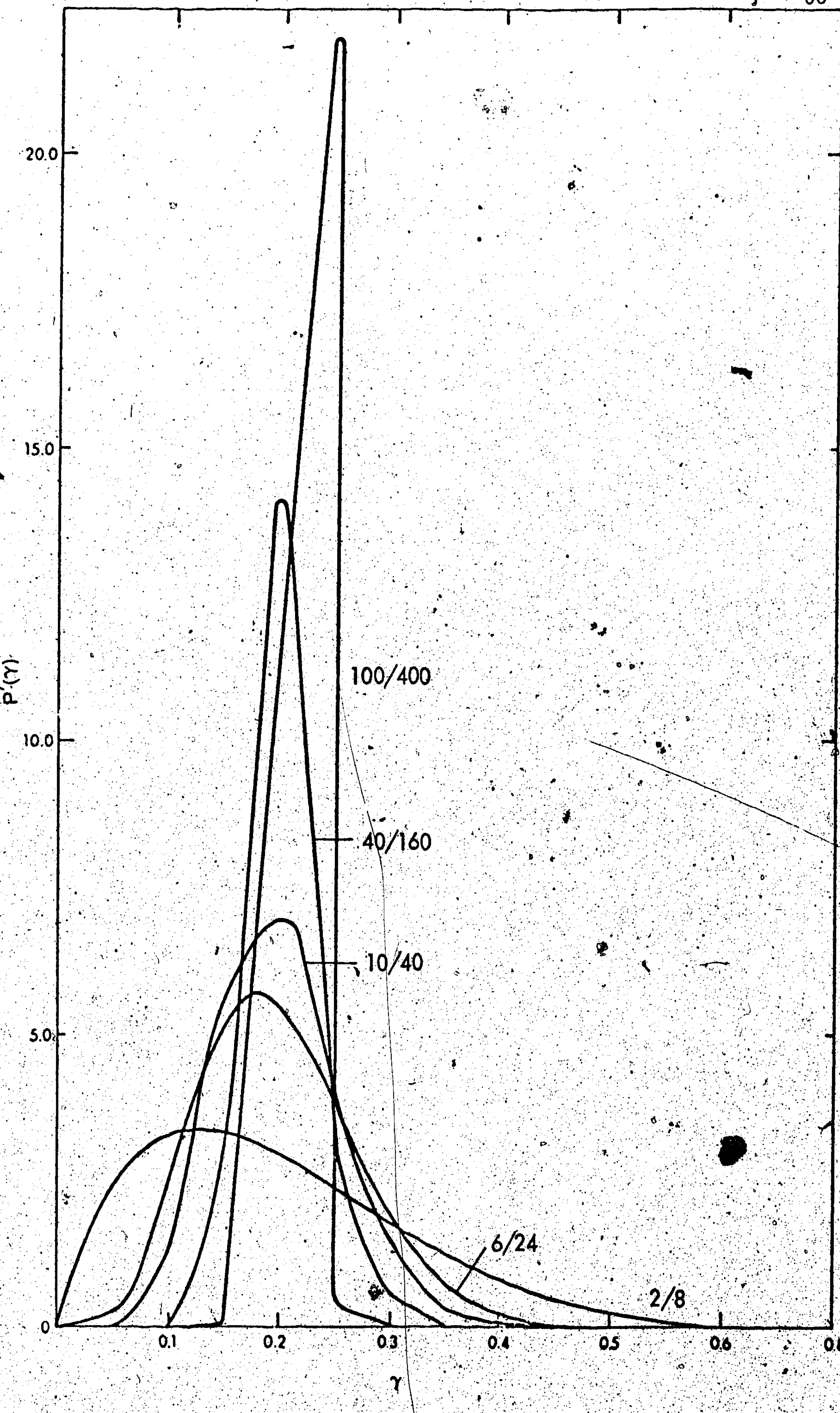

FIGURE B-1 THE BETA PROBABILITY DENSITY FUNCTION P(γ)

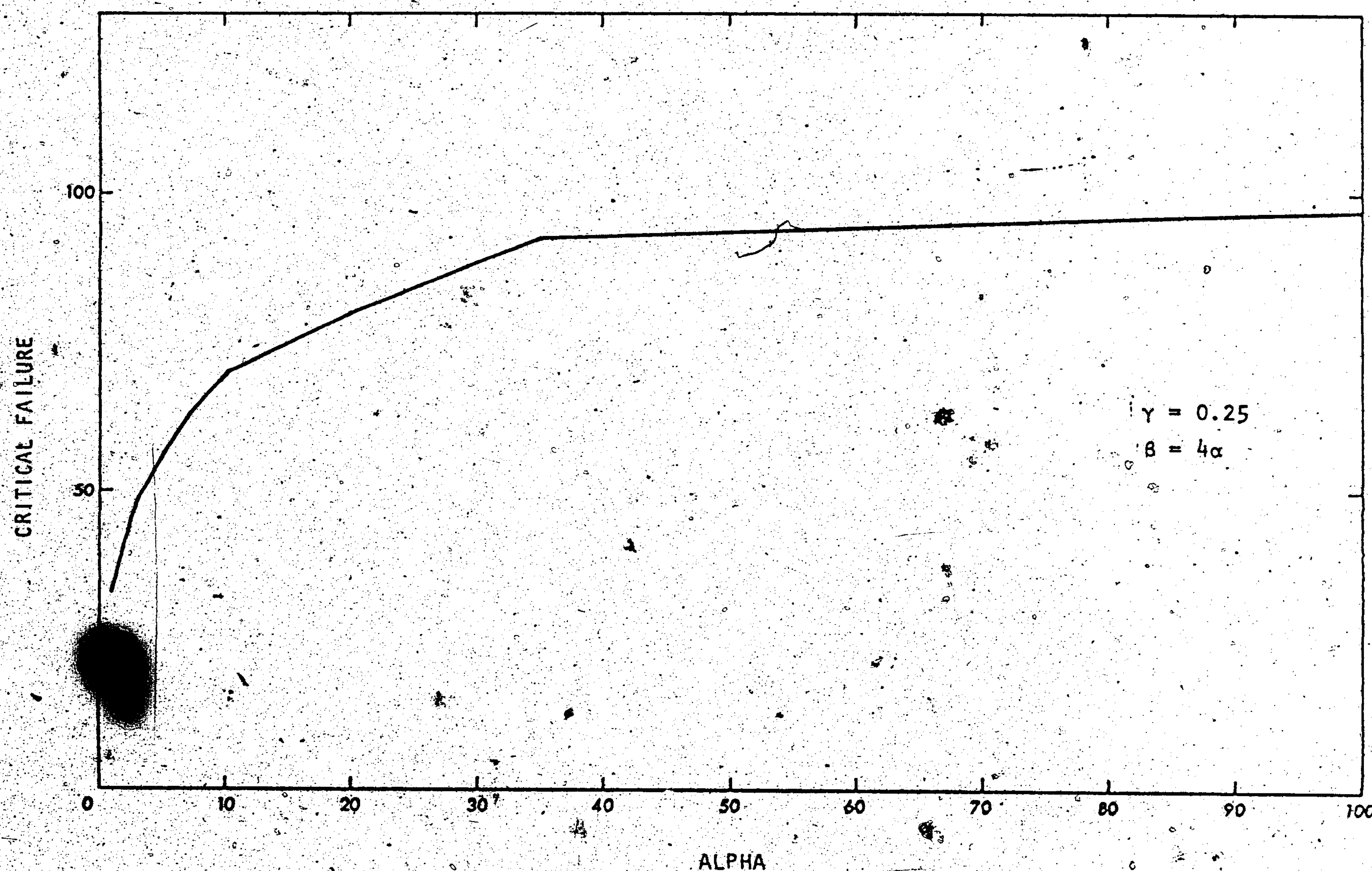

FIGURE B-2 BETA DISTRIBUTION PARAMETER (α)
- CRITICAL FAILURE STATISTIC SENSITIVITY

The α and β then characterize the degree of belief in a particular success ratio, rapid pessimism versus stubborn optimism; case two approximated the invariant success ratio.

The effect of the choice of the parameters, α and β, on the critical failure is shown in Figure B-11. Using Labrador Basin prospects with an initial success ratio of 0.25, the critical failure was determined identically to the procedure outlined in Chapter Two except after each drilling failure a revision in the success ratio took place, according to the parameters α and β.

For α and β equalling one and 10 respectively, the critical failure was 60. With α and β equalling 100 and 1,000, the critical failure, 102. The degree of prior belief was crucial to the final value of the critical failure.

The difference between an invariant success ratio and a beta distribution revised success ratio, was dependent on the choice of the parameters α and β.

IV

The purpose of this appendix was to compare the difference between an invariant and revised success ratio on the critical failure. The crucial decision became that of choosing appropriate beta distribution parameters.

The following procedure was used to determine basis for selecting a particular α and β:

1) A range for the value of the success ratio was chosen: $0.2 < \gamma < 0.3$, representing a total deviation of 40% from a median value of 0.25 for success ratio.

2) With 0.2 and 0.3 as limits, the beta distribution was integrated:

$$P_{\beta}(\gamma) = \int_{0.2}^{0.3} \left(\frac{\alpha + \beta + 1}{\alpha!\ \beta!}\right)!\ \gamma^{\alpha} (1 - \gamma)^{\beta}\ d\gamma$$

The value of this integral was the probability of γ lying between 0.2 and 0.3.

3) The parameters (α, β) were adjusted, but γ always equalling 0.25, and the value the above integral evaluted. The results are shown in Table II-1.

TABLE B-1

BETA PROBABILITY DISTRIBUTION SENSITIVITY

α*	Value of Integral - Probability
1	0.04
2	0.06
10	0.14
20	0.20
30	0.25
40	0.28
50	0.31
60	0.34
70	0.36
80	0.39
90	0.41
100	0.43

*β being always four times α..

For α equalling 20, one was expressing a confidence of only 20 per cent that the actual value of the success ratio would be within the accepted .2 to .3 range.

From Table II-1, if a degree of confidence of only 30 per cent were to be asserted in prior beliefs, the beta distribution requires an α of 80 and β of 200. From Figure II-1, having distribution parameters at these typical values ($\beta > 200$, for a γ of 0.25) the success ratio would be effectively invariant to drilling failure. The assumption is made that a typical explorer would claim at least 30 per cent confidence in his prior estimate of the success ratio, based upon his available geologic expertise.

[The final question is that of the sensitivity of critical failure to actual value of the success ratio. Figure B-1 demonstrates the variance in the statistic, critical failure, to success ratios between 0.1 and 0.25. (This range was that found in published estimates of success ratio.) (References 16,25). As α's ranged from 40 to 100, the three estimates of critical failure remained within 10 per cent of one another.]

In summary, using a success ratio revised by using the beta distribution and accepting a minimum of 30 per cent confidence in a priori estimates, the critical failure was ~~not~~ significantly different from initially assuming an invariant success ratio to drilling failure.

Appendix C. The Case of Declining Recovery With Production

The following is an attempt to describe the production from a given pool with a decline rate proportional to remaining reserve.

In general, the reservoir pressure, P, is a unique function of the cumulative production.

$$P = P_o - a(CP)^n \qquad \text{CP - cumulative production}$$

If CP = 0, then $\qquad P = P_o \qquad$ P - reservoir pressure

If CP = U_∞, then P = 0, and

a,n - decline parameters

$$0 = P_o - a\,U_\infty^{\,n}$$

$$\therefore\ a = \frac{P_o}{U_\infty^{\,m}}$$

$$P_o = P_o[1 - (\frac{CP}{U_\infty})^n] \qquad \text{C-3}$$

Substituting Equation III-3 into Equation III-1,

$$Q = \frac{K}{\mu} P_o[1 - (\frac{CP}{U_\infty})^n] \qquad \text{C-4}$$

but,

$$Q = \frac{dCP}{dt} \qquad \text{C-5}$$

Combining Equation III-5 and III-4 and separating variables,

$$\frac{U_\infty}{U_\infty} \cdot \frac{dCP}{[1 - (\frac{CP}{U_\infty})^n]} = \frac{KP_o}{\mu}\,dt \qquad \text{C-6}$$

Define,

$$\xi = \frac{CP}{U_\infty} \qquad \text{C-7}$$

Equation III-6 reduced to:

$$\frac{d[\frac{CP}{U_\infty}]}{[1 - (\frac{CP}{U_\infty})^n]} = \frac{d\xi}{1 - \xi^n} = \frac{KP_o}{U_\infty \mu}\, dt \qquad \text{C-8}$$

There is no general analytical form for this integral.

Assume pressure decline directly proportional to cumulative production, i.e.,

$$n = 1$$

Integrate:

$$\int \frac{d\xi}{1 - \xi} = -\ln\,(1 - \xi) = \frac{KP_o}{U_\infty \mu}\, t + C_1 \qquad \text{C-9}$$

At $t = t^*$, where t^* is the time at which decline begins,

$\xi = \xi^*$, the cumulative production at commencement of decline,

$$-\ln\,(1 - \xi^*) - \frac{KP_o}{\mu_\infty \mu}\; t^* = C_1$$

Substituting,

$$-\ln\,(1 - \xi) + \ln\,(1 - \xi^*) = \frac{KP_o}{U_\infty \mu}\,(t - \tau^*) \qquad \text{C-10}$$

$$\ln \frac{(1 - \xi)}{(1 - \xi^*)} = -\frac{KP_o}{U_\infty \mu}\,(t - \tau^*)$$

$$(1 - \xi) = (1 - \xi^*)\exp\left(-\frac{KP_o}{U_\infty \mu}\,(t - \tau^*)\right) \qquad \text{C-11}$$

The boundary conditions are checked:

1) at $t \rightarrow \infty$, $1 - \xi = 0$ $\quad \therefore CP = U_\infty$

2) at $t - \tau^* = 0$, $1 - \xi = 1 - \xi^*$

$$1 - \xi = 1 - \frac{CP}{U_\infty} \rightarrow \text{or} \ \frac{U_\infty - CP}{U_\infty} = \frac{RR}{U_\infty}$$

where RR is remaining reserve.

$$\frac{RR}{U_\infty} = \frac{RR^*}{U_\infty} \exp\left(-\frac{KP_o}{U_\infty \mu}(t - \tau^*)\right) \qquad \text{C-12}$$

where RR^* is the remaining reserve at $t = \tau^*$.

$$\frac{\partial RR}{dt} = -RR^* \cdot \frac{KP_o}{U_\infty \mu} \exp\left(-\frac{KP_o}{U_\infty \mu}(t - \tau^*)\right)$$

if $RR^* = U_\infty$, $\tau^* = 0$, $\frac{KP_o}{\mu} = D_o$, initial delivery.

$$Q = -D_o \exp\left(-\frac{D_o}{U_\infty} t\right) \text{ for each well.}$$

The economic consequence of such a delivery scheme is to increase the number of wells over time to maintain a desired production rate.

In the determination of development cost, presented in Chapter Five, annual production was assumed constant throughout the producing life of the pool. The production schdule, as shown in Equation III-9, would replace the constant producability assumption. If the value of (D_o/U_∞) is sufficiently low, i.e., $\{(\frac{D_o}{U_\infty}) < 0.01\}$, the difference in the final development cost is not significant.

Using a $(D_o/U_\infty) = 0.01$, the comparison of deliverabilities is shown in Table C-1.

TABLE C-1

COMPARISON OF DELIVERABILITY SCHEDULES

YEAR	CONSTANT DEL. ($D_o = 1$)	EQUATION III-9 SCHEDULE
1	1	1
2	1	0.98
3	1	0.97
4	1	0.961
5	1	0.953
6	1	0.942
7	1	0.9325
8	1	0.9233
9	1	0.914
10	1	0.905

The total, if assuming constant deliverability instead of a declining delivery, is less than 10 per cent.

Appendix D. Analytical Determination of Critical Failure

The objective of Monte Carlo simulation of exploration presented in Chapter Two was to determine the critical failure. The critical failure was the number of failures an explorer would tolerate before his reserve expectations were below the threshold level. The simulation approach was strictly numerical.

In analytical approach to the same problem is presented in this appendix. Instead of assuming a success ratio and sampling the lognormal prospect distribution numerically, as a first approximation, in an analytical approach, we assumed that all prospects are potentially oil-bearing. The aim will be to express a given reserve, $R(\overline{X})$, as a function P_o, number of pools.

[Note: the attempt to solve for the real situation of some prospects being not oil-bearing proved to be mathematically intractable.]

Assume the cumulative oil reserve is represented by

$$R(\bar{x}) = \frac{N}{\sqrt{2\pi}T} \int_{\bar{x}}^{\infty} x \, e^{-(\ln x - \ln \xi)^2/2T^2} \frac{dx}{x} \qquad \text{D-1}$$

Assume that the number of pools discovered is given by:

$$P_o(\bar{x}) = \frac{N}{\sqrt{2\pi}T} \int_{\bar{x}}^{\infty} e^{-(\ln x - \ln \xi)^2/2T^2} \frac{dx}{x} \qquad \text{D-2}$$

$\frac{\partial R}{\partial P_o}$ is essentially the slope of a curve of reserve versus pools (or drilling failures)

$$\frac{\partial R}{\partial P_o} = \frac{\partial R}{\partial \bar{x}} \frac{1}{\left(\frac{\partial P_o}{\partial \bar{x}}\right)} \qquad \text{D-3}$$

$$\frac{\partial R(\bar{x})}{\partial \bar{x}} = \frac{N}{\sqrt{2\pi}T} \left[\bar{x} \, e^{-(\ln \bar{x} - \ln \xi)^2/2T^2} \frac{dx}{\bar{x}}\right] \qquad \text{D-4}$$

$$\frac{\partial P_o}{\partial \bar{x}} = \frac{N}{\sqrt{2\pi}T} e^{-(\ln \bar{x} - \ln \xi)^2/2T^2} \frac{dx}{\bar{x}} \qquad \text{D-5}$$

In alternate form,

$$\frac{\partial R}{\partial \bar{x}} = f(\bar{x}), \quad \frac{\partial P_o}{\partial \bar{x}} = \frac{f(\bar{x})}{\bar{x}} \quad \text{and}$$

$$\frac{\partial R}{\partial P_o} = \frac{f(\bar{x})\bar{x}}{f(\bar{x})} = \bar{x} \qquad \text{D-6}$$

The objective is to express $R(\bar{x})$ as a function of P_o. To discover a reserve of size $R(\overline{x})$, how many pools must be found?

$$P_o = \frac{N}{\sqrt{2}\pi T}\int_{\overline{x}}^{\infty} e^{-(\ln \overline{x} - \ln \xi)^2/2T^2}\,\frac{dx}{x} \quad \text{or}$$

$$\frac{N_T}{\sqrt{2}\pi T}\int_{\overline{x}}^{\infty} e^{-(\ln x - \ln \xi)^2/2T^2}\, d\ln x \qquad \text{D-7}$$

By substituting variables,

$$u = \frac{\ln x - \ln \xi}{\sqrt{2}\,T} \qquad \text{D-8}$$

Differentiate (D-7):

$$\sqrt{2}\,T\,du = d(\ln x)$$

$$P_o(u) = \frac{N}{\sqrt{2}\pi T}\sqrt{2}\,T\int_{\overline{u}}^{\infty} e^{-u^2}\,du \quad \text{or}$$

$$= \frac{N}{\sqrt{\pi}}\int_{\overline{u}}^{\infty} e^{-u^2}\,du \qquad \text{D-9}$$

By means of assyntotic expansion (see Kreyzig, Reference 26),

$$P_o \simeq \frac{N}{\sqrt{\pi}}\cdot\frac{1}{2}\frac{e^{-\overline{u}^2}}{u}$$

$$P_o\,\overline{u} \simeq \frac{N}{2\sqrt{\pi}}\,e^{-\overline{u}^2}$$

$$\frac{2\sqrt{\pi}}{N}\,P_o\,\overline{u} \simeq e^{-\overline{u}^2} \qquad \text{D-10}$$

This expansion is applicable for sufficiently large $\overline{x}$. Taking the logarithm of D-9,

$$\ln P_o + \ln\left[\frac{2\sqrt{\pi}}{N}\right] + \ln \bar{u} + \bar{u}^2 = 0 \qquad \text{D-11}$$

In general, $\ln \bar{u} << u^2$, if $\bar{u} > 1$. D-9 is approximately equal to:

$$\ln P_o \frac{2\sqrt{\pi}}{N} = -\bar{u}^2 \qquad \text{or}$$

$$\bar{u} = \sqrt{-\ln P_o \frac{2\sqrt{\pi}}{N}} \qquad \text{D-12}$$

By definition

$$\bar{u} = \frac{\ln \bar{x} - \ln \xi}{\sqrt{2}\, T}$$

If

$$\bar{u} = \frac{\ln \bar{x} - \ln \xi}{\sqrt{2}\, T} = \sqrt{-\ln P_o \frac{2\pi}{N}},$$

$$\ln \bar{x} = 2T \sqrt{-\ln[P_o \frac{2\pi}{N}]} + \ln \xi \qquad \text{and}$$

$$\bar{x} = e^{\sqrt{2}\, T \sqrt{-\ln(P_o \frac{2\pi}{N})}}\, e^{\ln \xi} \qquad \text{or}$$

$$\bar{x} = \xi\, e^{\sqrt{2}\, T \sqrt{-\ln(P_o \frac{2\pi}{N})}} \qquad \text{D-13}$$

From Equation D-6,

$$\frac{\partial R(x)}{\partial P_o(x)} = \bar{x} = \xi\, e^{\sqrt{2}\, T \sqrt{-\ln\{\frac{2}{N} P_o\}}},$$

and with the assumptions,

1) $\ln \left\{\frac{\ln \bar{x} - \ln \xi}{\sqrt{2}\, T}\right\} < < \left\{\frac{\ln \bar{x} - \ln \xi}{\sqrt{2}\, T}\right\}^2$

2) $\frac{2\pi}{N} P_o < 1$,

$$\frac{dR}{dP_o} = \xi\, e^{A}\sqrt{-\ln BP_o} \qquad \text{D-14}$$

where

$$A = \sqrt{2}\, T\, \xi$$

$$B = \frac{2\pi}{N}$$

Now, Equation D-14 is differentiated. Let

$$BP_o = \emptyset \qquad \text{D-15}$$

Therefore,

$$dP_o = \frac{d\emptyset}{B} \qquad \text{D-16}$$

By substituting Equation D-15 and D-16 into Equation V-14,

$$\frac{BdR}{d\emptyset} = e^{A}\sqrt{-\ln \emptyset}$$

By cross-multiplying and back substitution,

$$\frac{B}{\xi}\frac{dR}{d\emptyset} = \frac{2\pi}{N_T\xi}\frac{dR}{d\emptyset} = e^{A(\sqrt{-\ln \emptyset})} \qquad \text{D-17}$$

Separating variables,

$$\frac{2\pi}{N_T\xi}\, dR = e^{A\sqrt{-\ln \emptyset}} \qquad \text{D-18}$$

let $\quad u = \sqrt{-\ln \emptyset} \qquad$ D-19

Therefore,

$$u^2 = -\ln^2 \text{ and } \emptyset = e^{-u^2} \qquad \text{D-20}$$

By differentiating D-20,

$$d\phi = e^{-u^2} \; (-2u \; du) \qquad \text{D-21}$$

Back substituting D-21 into D-18,

$$\frac{2\pi}{N\xi} dR = e^{Au} e^{-u^2} (-2u \; du) \qquad \text{or}$$

$$+\frac{\pi}{N\xi} dR = e^{-u^2 + Au} u \; du \qquad \text{D-22}$$

Completing the square of the exponent,

$$-u^2 + Au = -(u^2 - Au + \frac{A^2}{4}) + \frac{A^2}{4}$$

$$= -(u - \frac{A}{2})^2 + \frac{A^2}{4} \qquad \text{D-23}$$

Substituting Equation D-23 into Equation D-21,

$$+\frac{\pi}{N\xi} dR = e^{-(u - \frac{A}{2})^2} e^{A^2/4} u \; du \qquad \text{D-24}$$

Defining the simplifying constant, β,

$$\beta = u - A/2 \text{ or } u = \beta + \frac{A}{2} \qquad \text{D-25}$$

By differentiating D-25, $d\beta = du$ D-26

Back substitute Equation D-25, D-26 into Equation D-24,

$$+\frac{\pi}{N\xi} e^{-A^2/4} dR = e^{-\beta^2} \beta d\beta + \frac{A}{2} e^{-\beta^2} d\beta \qquad \text{D-27}$$

Integrating both sides of D-27,

$$+\frac{\pi}{N\xi} e^{-A^2/4} R = \int_{\bar{\beta}}^{\infty} e^{-\beta^2} \beta d\beta + \frac{A}{2} \int_{\bar{\beta}}^{\infty} e^{-\beta^2} d\beta \qquad \text{D-28}$$

Integrating the first term of R.M.S. of D-28,

$$\int_{\beta}^{\infty} e^{-\beta^2} \beta d\beta = \int_{\bar{\beta}}^{\infty} e^{-\beta^2} d(\beta^2) = e^{-\bar{\beta}^2}$$

By integrating the second term of L.M.S. of D-28,

$$I1 = \int_{\bar{\beta}}^{\infty} e^{-\beta^2} d\beta \sim \frac{1}{2}\frac{1}{\bar{\beta}} e^{-\bar{\beta}^2}$$

by the assymptotic expansion assumptions (see Kreyzig).

Equation D-28 reduces to:

$$+\frac{\pi}{N\xi} e^{-A^2/4} [+R(\bar{P}_o)] = e^{-\bar{\beta}^2} + \frac{A}{2}(\frac{1}{2}) \frac{e^{-\bar{\beta}^2}}{\bar{\beta}} \quad \text{or}$$

$$\frac{\pi}{N\xi} e^{-A^2/4} R(\bar{x}) = e^{-\bar{\beta}^2} [\frac{A}{4}\frac{1}{\bar{\beta}} + 1] \qquad \text{D-29}$$

Back substitute $\beta = u - \frac{A}{2}$ into D-29,

$$\frac{\pi(R(\bar{x}))}{N_T\xi} = e^{-(u - A/2)^2} e^{A^2/4} [\frac{u}{u - A/4}] \qquad \text{D-30}$$

as $[\frac{A}{4}\frac{1}{\beta} + 1] = [\frac{A}{4(u - \frac{A}{2})} + 1]$

Back substitute into $\emptyset$, $u = \sqrt{-\ln \emptyset}$,

$$\frac{\pi(R(\bar{x}))}{N\xi} = e^{-u^2} e^{Au} \{\frac{u}{u - A/4}\} \quad \text{, and}$$

$$= \emptyset\, e^{A\sqrt{-\ln \emptyset}} \left\{\frac{\sqrt{-\ln \emptyset}}{\sqrt{-\ln \emptyset} - A/4}\right\} \qquad \text{D-31}$$

If $\frac{A}{4} << \sqrt{-\ln \emptyset}$, then

$$\frac{\pi R(\bar{x})}{N\xi} \sim \phi\, e^{A\sqrt{-\ln \phi}} \qquad \text{D-32}$$

Back substituting in terms of P_o from ϕ,

1) $\phi = \beta P_o$, $\beta = 2\pi/N$

2) $\phi = \frac{2\pi}{N} P_o$

$$\frac{\pi}{N} \quad \frac{1}{\xi} R(\bar{x}) = \frac{2\pi}{N} P_o\, e^{A\sqrt{-\ln \frac{2}{N} P_o}}, \qquad \text{or}$$

$$R(\bar{x}) \simeq 2\xi\, P_o\, e^{\sqrt{2}\, T \sqrt{-\ln \frac{2\pi}{N} P_o}} \qquad \text{D-33}$$

This development was based on two major assumptions:

1) all drilling attempts were successes and,

2) only the very large pools of the entire population were discovered.

There conditions were imposed to make the mathematics tractable. Neither assumption is particularly realistic. Attempts to introduce the consideration of success or failure into the exercise made it impossible in terms of an analytic solution.

APPENDIX E

Computer Listings

Contained in the following pages are listings of routines and procedures referred to in Chapter 1 through 5. The programs have been given titles and are arranged in order of appearence in the text.

TABLE E-1

TITLE	CHAPTER	DESCRIPTION
1. Exploration Sensitivity	2	This program constructs the curve of drilling failures versus reserve expectations.
2. Cash Flow Sensitivity	3	This program constructs the curve of required crude oil price versus exploration intensity for the Canadian petroleum producing industry.
3. Imperial Oil Sensitivity	4	This program demonstrates the sensitivity of Imperial Oil Ltd. to certain fiscal scenarios.
4. Dome Sensitivity Loop	4	This program demonstrates the sensitivity of Dome Petroleum Ltd. to certain fiscal scenarios.
5. Reserve Generation Loop	5	This routine constructs a reserve of log-normally distributed oil pools and orders them according to size.
6. Price Sensitivity Loop	5	This routine demonstrates the relationship between development costs and available production for Mckenzie-Beaufort reserves.
7. Alberta Reserve Estimate	5	This program estimates Alberta's non-reeful initial oil in-place reserve by a Monte Carlo simulation.

8. Pipeline Calculation	Appendix A	This program constructs the curve of pipeline cost versus pipeline diameter.

EXPLORATION SENSITIVITY

```
C     THIS PROGRAM INITIALLY CONSTRUCTS A SET OF TWO HUNDRED
C     STRUCTURES, LOG-NORMALLY DISTRIBUTED.

      REAL N
      REAL MEAN
      REAL LGTOT
      REAL MIN
      REAL LGMIN
      REAL NO(40)
      REAL LMEAN(300)
      REAL LOG(300)
      DIMENSION OIL(300)
      DIMENSION PSOIL(300),OILMX(300)
      DIMENSION TOIL(40),AV(40)
      DIMENSION ETA(300),ABERR(300)
      DEFINE FILE 1(280,8,U,IDISK)
      READ(1'1)TOT,N,MIN,M,IX
      READ(1'2) STEP,LGTOT,MEAN,IREC,NUMTO
      L=1
      STEP=0.1
      LGTOT=(1.0/2.303)*ALOG(TOT)
      MEAN=TOT/N
      LMEAN(L)=(1.0/2.303)*ALOG(MEAN)
      LGMIN=(1.0/2.303)*ALOG(MIN)

      ETA(1)=-0.5+(1.0/(N+1.0))
      ETAMN=-0.5+((N/2.0)/(N+1.0))
80    B=(LMEAN(L)-LGMIN)/(ETAMN-ETA(1))
      A=LGMIN-(B*ETA(1))
      DO 100 I=1,M
      ETA(I)=(I/(N+1.0)-0.5)
      LOG(I)=A+B*ETA(I)
100   CONTINUE
      SUM=0.0
      DO 200 I=1,M
      SUM=10.0**(LOG(I))+SUM
200   CONTINUE
      TOL=10000000.0
      ERROR=TOT-SUM
      ABERR(L)=ABS(ERROR)
      IF(ABERR(L)-TOL)40,40,60
40    WRITE(1'3) ABERR(L),LMEAN(L),A,B
      GO TO 110
60    IF(L-1)45,45,55
45    K=L
      L=L+1
      LMEAN(L)=LMEAN(K)-STEP
      GO TO 80
55    BILL=ABERR(K)-ABERR(L)
```

EXPLORATION SENSITIVITY ...(CONT'D)

```
      IF(BILL-0.0)75,65,65
65    K=L
      L=L+1
      LMEAN(L)=LMEAN(K)-STEP
      GO TO 80
75    STEP=STEP/10.0
      K=L-2

      L=L+1
      LMEAN(L)=LMEAN(K)-STEP
      GO TO 80

C     A SIMULATION OF EXPLORATION IS CONDUCTED WITH THE
C     LARGEST STRUCTURES INITIALLY ANALYZED AND RESERVE
C     ASSESSMENTS SEQUENTIALLY GENERATED.

110   KOL=20
      TOP=1.0
      BOT=10.0
51    SR=TOP/BOT
      SURD=1.0-SR
504   DO 900 M=1,KOL
      NO(M)=0.0
      TOIL(M)=0.0
      J=0
      AV(M)=0.0
      DO 800 I=1,NUMTO
      CALL SUSPN(16,1)
      IDUM=1
      DO 700 K=1,IDUM
      CALL SWITH(ISWT)
      IF(ISWT) 11,506,11
11    CALL PEACH(IX,IY,YFL)
      ZO=YFL
      IF(YFL-SURD)14,15,15
14    OIL(K)=0.0
      GO TO 16
15    OIL(K)=LOG(1)
      NO(M)=NO(M)+1
16    CONTINUE
      IF(OIL(K)-0.0)21,21,22
22    TOIL(M)=TOIL(M)+(10.0**(OIL(K)) )
      AV(M)=AV(M)+OIL(K)
      J=J+1
21    CONTINUE
      IX=IY
      PSOIL(I)=OIL(K)
700   CONTINUE
800   CONTINUE
      OILMX(M)=0.0
```

EXPLORATION SENSITIVITY ...(CONT'D)

```
      DO 17 K=1,NUMTO
      IF(PSOIL(K)-OILMX(M))17,17,18
18    OILMX(M)=PSOIL(K)
17    CONTINUE
      AV(M)=AV(M)/J
900   CONTINUE
      TOTMX=0.0
      DO 620 M=1,KOL
      TOTMX=TOTMX+OILMX(M)
620   CONTINUE
      AVMX=10.0**(TOTMX/KOL)
      CUOIL=0.0
      DO 610 M=1,KOL
600   CUOIL=TOIL(M)+CUOIL
610   CONTINUE
      AVOIL=CUOIL/KOL
      AVCUM=0.0
      DO 630 M=1,KOL
      AVCUM=AV(M)+AVCUM
630   CONTINUE
      AVG=10.0**(AVCUM/KOL)
      NOT=0
      DO 61 M=1,KOL
      NOT=NOT+NO(M)
61    CONTINUE
      NOVA=NOT/KOL
      WRITE(1'IREC)NUMTO,AVMX,AVG,AVOIL,NOVA,SR
      IREC=IREC+1

      NUMTO=NUMTO-1
      IF(AVOIL-2000000000.0)92,92,94
92    GO TO 505
94    GO TO 51
506   WRITE(1'2) STEP,LGTOT,MIN,IREC,NUMTO
      CALL EXIT
      END
```

CASH FLOW SENSITIVITY

```
C      THIS ROUTINE CALCULATES THE PRICE OF CRUDE OIL
C      NECESSARY TO CREATE SUFFICIENT INDUSTRY CASH FLOW TO
C      SUSTAIN VARIOUS LEVELS OF EXPLORATION , EXPENDITURE
C      UNDER A CERTAIN FISCAL SCENARIO.

       REAL NATGS(100)
       REAL NTINC(100)
        REAL INTAX(100)
       DIMENSION ARTIC(100)
       DIMENSION TOTDP(100),DEDUC(100),DEPLE(100),TXINC(100)
       DIMENSION PROD(100),ANPRO(100),OPEXP(100),REVCO(100)
      *,GROSS(100)
       DIMENSION ROYAL(100),SECOV(100),DEPDL(100),REMAI(100)
      *,CURDP(100)
       DIMENSION ATCF(100),DISAT(100)
       WRITE(6,17)
   17  FORMAT(14X,'    ROYALTIES NON-DEDUCTABLE AND DEPLETION
      * ALLOWANCE UN
      2AVAILABLE',///,6X,' EXPLORATION EXPENSE',10X,'
      * REQUIRED PRICE',//
      2/)
       ARTIC(I)=50000000.0
   77  COMSH=3.00
       COMSH=3.00
       ROY=0.425
       PRCNT=ROY*100.0
       RATE=0.10
       PERCT=RATE*100.0
       TOT=0.0
  997  DO 555 I=23,40
  555  TOTDP(I)=0.0
       M=0
       DO 999 I=23,35
       PROD(I)=-0.04417+(I*0.05911)+((I**2.0)*0.000429)+((I*
      **3.0)
      1*0.00005503)+((I**4.0)*(-0.0000025))
       ANPRO(I)=365.0*1000000.0*PROD(I)
       NATGS(23)=2.5
       NATGS(24)=2.62
       NATGS(25)=2.7
       NATGS(26)=2.8
       NATGS(27)=2.9
       NATGS(28)=2.95
       NATGS(29)=3.0
       NATGS(31)=3.0
       NATGS(32)=2.9
       NATGS(33)=2.8
       NATGS(34)=2.6
       NATGS(35)=2.5
```

CASH FLOW SENSITIVITY ...(CONT'D)

```
      NATGS(I)=NATGS(I)*1000000000000.0
      NATGS(I)=NATGS(I)*0.5/1000.0
      REVCO(I)=COMSH*ANPRO(I)
      REVCO(I)=COMSH*ANPRO(I)+(NATGS(I))
      REVCO(I)=REVCO(I)+160000000.0
      ROYAL(I)=(0.425*0.87*REVCO(I))+(0.16*0.13*REVCO(I))
      OPEXP(I)=((-8.361)+(348.0*PROD(I))+(-380.4*PROD(I)*
     **2.00)
     1+(224.6*(PROD(I)**3.0))
      OPEXP(I)=OPEXP(I)*1000000.0
      GROSS(I)=REVCO(I)-OPEXP(I)
      SECOV(I)=(-2.312+(21.72*PROD(I))+(-10.87*(PROD(I)**2))
     1+(6.888*(PROD(I)**3.0)))
      DEPDL(I)=(-12.292+(210.8*PROD(I))+(-167.3*(PROD(I)*
     **2)))
     1+(106.7*(PROD(I)**3.0))
      REMAI(I)=DEPDL(I)
      DO 40 J=23,I
      CURDP(J)=REMAI(J)*0.3
      REMAI(J)=REMAI(J)-CURDP(J)
      TOTDP(I)=TOTDP(I)+CURDP(J)
40    CONTINUE
      DEDUC(I)=((TOTDP(I)+SECOV(I))*1000000.0)
      DEDUC(I)=DEDUC(I)+ARTIC(I)
      NTINC(I)=GROSS(I)-DEDUC(I)
      IF( NTINC(I)- 0.0) 240,240,45
45    DEPLE(I)=0.0
      TXINC(I)=NTINC(I)-DEPLE(I)
      INTAX(I)=0.5*TXINC(I)
240   ATCF(I)=NTINC(I)-INTAX(I)-ROYAL(I)
      N=I-23
      DISAT(I)=ATCF(I)*(1.0/((1.0+RATE)**N))
      GO TO 993
993   CONTINUE
      IF(ATCF(I)-0.0)998,998,996
996   M=M+1
      IF(M-12)999,994,994
999   CONTINUE
998   COMSH=COMSH+0.50
      GO TO 997
994   WRITE(6,995)ARTIC(I),COMSH
995   FORMAT(6X,F17.2,20X,F6.2)
      ARTIC(I)=ARTIC(I)+100000000.0
      IF(ARTIC(I)-1000000000.0)77,77,78
78    CALL EXIT
      END
```

IMPERIAL OIL SENSITIVITY

```
C     THIS ROUTINE EXAMINES THE SENSITIVITY OF IMPERIAL OIL
C     LTD.'S CASH FLOW TO A SPECIFIC FISCAL SCENARIO.

      INTEGER YEAR
      REAL INTAX(100)
      REAL NTINC(100)
      DIMENSION PRO(100),ANPRO(100),COREV(100),OTHRV(100)
     *,TOTRV(100)
      DIMENSION CALEN(100)
      DIMENSION DEPRE(100),OPEXP(100),GROSS(100),ROYAL(100)
     *,ATCF(100)
      DIMENSION DEDUC(100),DEPLE(100),TXINC(100)
      DIMENSION FEROY(100),CWROY(100)
      DIMENSION DISAT(100)
      DIMENSION EXPLO(100)
      DIMENSION COMSH(100)
      DIMENSION PROD(100)
      DO 1000 K=1,5
      TOT=0.0
      READ(5,9) COMSH(K)
 9    FORMAT(F6.2)
      WRITE(6,15) COMSH(K)
 15   FORMAT('/',' THE COMPANY SHARE OF THE POSTED PRICE OF
     * CRUDE OIL IS
     1',F6.3,' DOLLARS PER BARREL ')
      ROY=0.425
      PRCNT=ROY*100.0
      WRITE(6,35)PRCNT
 35   FORMAT('/',' ROYALTY RATE    ',F6.3,' PER CENT ')
      RATE=0.10
      PERCT=RATE*100.0
      WRITE(6,55)PERCT
 55   FORMAT('/',' INTEREST RATE ',F6.3,' PER CENT')
      DO 555 I=23,35
      YEAR=1950+I
      WRITE(6,65)YEAR
      CALEN(I)=1950+I
 65   FORMAT('////',I4)
      PROD(I)=-0.04417+(I*0.05911)+((I**2.0)*0.000429)+((I*
     **3.0)
     1*0.00005503)+((I**4.0)*(-0.0000025))
      PRO(I)=0.145*PROD(I)
      ANPRO(I)=PPRO*365.0*1000000.0
      WRITE(6,10) ANPRO(I)
 10   FORMAT('/',' ANNUAL PRODUCTION OF CRUDE OIL AND N.G.
     * L. TOTALS
     1  ',F17.2,' BARRELS')
      OTHRV(I)=(11.8+(3120*PRO(I))+(18040.0*(PRO(I)**2.0)) )
     **1000000.0
```

IMPERIAL OIL SENSITIVITY...(CONT'D)

```
      COREV(I)=ANPRO(I)*COMSH(K)
      WRITE(6,20) COREV(I)
20    FORMAT('/',' CRUDE OIL REVENUE IS      ',F17.2, '
     * DOLLARS')
      TOTRV(I)=COREV(I)+OTHRV(I)
      WRITE(6,30) OTHRV(I)
30    FORMAT('/',' COMPANY REVENUE FROM ALL OTHER SOURCES IS
     *     ',F17.2,
     1' DOLLARS')
      WRITE(6,40) TOTRV(I)
40    FORMAT('/',' TOTAL COMPANY REVENUE IS      ',F17.2,'
     * DOLLARS')
      OPEXP(I)=(3.46+(2262.0*PRO(I))+(-39940.0*(PRO(I)*
     **2.0))
     1 +(259300.0*(PRO(I)**3.0)))*1000000.0
      GROSS(I)= TOTRV(I)-OPEXP(I)
      WRITE(6,50) OPEXP(I)
50    FORMAT('/',' TOTAL OPERATING EXPENSES  ARE      ',F17.2
     *,' DOLLARS')
      WRITE(6,60) GROSS(I)
60    FORMAT('/',' GROSS INCOME IS      ',F17.2,' DOLLARS')
      DEPRE(I)=(0.1841+(4.1*PRO(I))+(2278.0*(PRO(I)**2.0)))
     **1000000.0
      WRITE(6,70) DEPRE(I)
70    FORMAT('/',' TOTAL DEDUCTION AVAILABLE FOR CAPITAL
     * COST ALLOWANCE
     1 IS      ',F17.2,' DOLLARS')
      CWROY(I)=0.87*0.425*ANPRO(I)*COMSH(K)
      WRITE(6,81) CWROY(I)
81    FORMAT('/',' ROYALTY FROM CROWN LANDS IS      ',F17.2,'
     * DOLLARS')
      FEROY(I)=0.13*0.12*ANPRO(I)*COMSH(K)
      WRITE(6,82) FEROY(I)
82    FORMAT('/',' ROYALTY FROM FREEHOLD LANDS IS      ',F17.2
     *,' DOLLARS')
      ROYAL(I)=FEROY(I)+CWROY(I)
      WRITE(6,80) ROYAL(I)
80    FORMAT('/',' ROYALTY EXPENSE IS      ',F17.2,' DOLLARS')
      EXPLO(I)=100000000.0
      WRITE(6,90) EXPLO(I)
90    FORMAT('/',' EXPLORATION EXPENDITURE IS .      ',F17.2,'
     * DOLLARS')
      DEDUC(I)=EXPLO(I)+DEPRE(I)+ROYAL(I)+0.0
      WRITE(6,110) DEDUC(I)
110   FORMAT('/',' TOTAL DEDUCTIONS            ',F17.2,'
     * DOLLARS')
      NTINC(I)=GROSS(I)-DEDUC(I)
      IF(NTINC(I)-0.0) 240,45,45
45    DEPLE(I)=0.333*NTINC(I)
      WRITE(6,120) NTINC(I)
```

IMPERIAL OIL SENSITIVITY...(CONT'D)

```
120   FORMAT('/',' NET INCOME                  ',F17.2,' DOLLARS')
      WRITE(6,130) DEPLE(I)
130   FORMAT('/',' DEPLETION ALLOWANCE            ',F17.2,'
     * DOLLARS')
      TXINC(I)=NTINC(I)-DEPLE(I)
      WRITE(6,140) TXINC(I)
140   FORMAT('/',' TAXABLE INCOME          ',F17.2,' DOLLARS')
      IF (TOT-0.0) 160,160,235
160   INTAX(I)=0.5*TXINC(I)
      WRITE(6,210) INTAX(I)
210   FORMAT('/',' INCOME TAX PAYABLE          ',F17.2,'
     * DOLLARS')
      ATCF(I)=NTINC(I)-INTAX(I)
      WRITE(6,220) ATCF(I)
220   FORMAT('/',' AFTER TAX CASH FLOW         ',F17.2,'
     * DOLLARS')
      N=I-23
      DISAT(I)=ATCF(I)*(1.0/((1.0+RATE)**N))
      WRITE(6,230) DISAT(I)
230   FORMAT('/',' PRESENT WORTH OF THIS YEAR''S CASH
     * FLOW    ',F17.2,
     1' DOLLARS')
      GO TO 555
235   IF(TOT-TXINC(I)) 265,255,255
240   TOT=TOT-NTINC(I)
      WRITE(6,242) NTINC(I)
242   FORMAT('/',' NET INCOME                  ',F17.2,' DOLLARS')
      NTINC(I)=NTINC(I)
      WRITE(6,245) NTINC(I)
245   FORMAT('/',' NET INCOME MINUS ROYALTY EXPENSE ',F17.6
     *,' DOLLARS')
      GO TO 259
255   TOT=TOT-TXINC(I)
      WRITE(6,256) NTINC(I)
256   FORMAT('/',' NET INCOME          ',F17.2,' DOLLARS')
      NTINC(I)=NTINC(I)-ROYAL(I)
      WRITE(6,257) NTINC(I)
257   FORMAT('/',' NET INCOME MINUS ROYALTY EXPENSE ',F17.6
     *,' DOLLARES')
259   WRITE(6,250) TOT
      WRITE(6,250) TOT
250   FORMAT('/',' ACCUMULATED DEFERRED TAX SAVINGS    '
     *,F17.2,' DOLLARS'
     2 1)
      GO TO 555
265   TOT=0.0
      INTAX(I)=0.5*(TXINC(I)-TOT)
      WRITE(6,270) INTAX(I)
270   FORMAT('/',' INCOME TAX PAYABLE ',F17.2,' DOLLARS')
      ATCF(I)=NTINC(I)-INTAX(I)-ROYAL(I)
```

IMPERIAL OIL SENSITIVITY...(CONT'D)

```
      WRITE(6,280) ATCF(I)
280   FORMAT('/',' AFTER-TAX CASH FLOW          ',F17.2,'
     * DOLLARS')
555   CONTINUE
      READ(5,551)M
551   FORMAT(I1)
      DO 200 I=23,35
      WRITE(5,552)CALEN(I),ATCF(I)
552   FORMAT(E13.6,E13.6)
200   CONTINUE
1000  CONTINUE
      CALL EXIT
      END
```

DOME SENSITIVITY LOOP

```
C     THIS PROGRAM EXAMINES THE SENSITIVITY OF DOME
C     PETROLEUM IN THIER CASH FLOW POSITION TO VARIOUS
C     FISCAL SCENARIOS.

      INTEGER YEAR
      REAL INTAX(100)
      REAL NTINC(100)
      REAL NGPRI
      REAL NGPRO
      REAL NGREV
      DIMENSION PRO(100),ANPRO(100),COREV(100),OTHRV(100)
     *,TOTRV(100)
      DIMENSION DEPRE(100),OPEXP(100),GROSS(100),ROYAL(100)
     *,ATCF(100)
      DIMENSION DEDUC(100),DEPLE(100),TXINC(100)
      DIMENSION FEROY(100),CWROY(100)
      DIMENSION DISAT(100)
      DIMENSION EXPLO(100)
      DIMENSION COMSH(100)
      DIMENSION PROD(100)
      DO 1000 K=1,10
      TOT=100000000.0
      READ(5,9) COMSH(K)
9     FORMAT(F6.2)
      WRITE(6,15) COMSH(K)
15    FORMAT('/',' THE COMPANY SHARE OF THE POSTED PROCE OF
     * CRUDE OIL IS
     1',F6.3,' DOLLARS PER BARREL ')
      ROY=0.425
      PRCNT=ROY*100.0
      WRITE(6,35)PRCNT
35    FORMAT('/',' ROYALTY RATE      ',F6.3,' PER CENT ')
      RATE=0.10
      PERCT=RATE*100.0
      WRITE(6,55)PERCT
55    FORMAT('/',' INTEREST RATE ',F6.3,' PER CENT')
      DO 555 I=24,35
      YEAR=1950+I
      WRITE(6,65) YEAR
65    FORMAT('////',I4)
      PROD(I)=-0.04417+(I*0.05911)+((I**2.0)*0.000429)+((I*
     **3.0)
     1*0.00005503)+((I**4.0)*(-0.0000025))
      PRO(I)=0.02*PROD(I)
      PPRO=PRO(I)/0.837
      ANPRO(I)=PPRO*365.0*1000000.0
      WRITE(L810) ANPRO(I)
10    FORMAT('/',' ANNUAL PRODUCTION OF CRUDE OIL AND N.G.
     * L. TOTALS
```

DOME SENSITIVITY LOOP ...(CONT'D)

```
    1  ',F17.2,' BARRELS')
       NGPRI=0.70
       NGPRO=140.0
       NGREV=((NGPRI/1000.0)*(NGPRO*1000000.0*365.0))/0.837
       WRITE(6,25) NGREV
 25    FORMAT('/',' REVENUE FROM NATURAL GAS SALES',F17.6,'
    *  DOLLARS')
       MISC=1500000.0
       OTHRV(I)=MISC+NGREV
       COREV(I)=ANPRO(I)*COMSH(K)
       WRITE(6,20) COREV(I)
 20    FORMAT('/',' CRUDE OIL REVENUE IS      ',F17.2, '
    *  DOLLARS')
       TOTRV(I)=COREV(I)+OTHRV(I)
       WRITE(6,30) OTHRV(I)
 30    FORMAT('/',' COMPANY REVENUE FROM ALL OTHER SOURCES IS
    *       ',F17.2,
    1' DOLLARS')
       WRITE(6,40) TOTRV(I)
 40    FORMAT('/',' TOTAL COMPANY REVENUE IS      ',F17.2,'
    *  DOLLARS')
       OPEXP(I)=(-1.082+(2048.0*PRO(I))+(-329900.0*(PRO(I)*
    **2.0))
    21+(10410000.0*(PRO(I)**3.0)))*1000000.0
       GROSS(I)= TOTRV(I)-OPEXP(I)
       WRITE(6,50) OPEXP(I)
 50    FORMAT('/',' TOTAL OPERATING EXPENSES  ARE      ',F17.2
    *,' DOLLARS')
       WRITE(6,60) GROSS(I)
 60    FORMAT('/',' GROSS INCOME IS      ',F17.2,' DOLLARS')
       DEPRE(I)=(-).1042+(238.9*PRO(I))+(-32330.0*(PRO(I)*
    **2.0))
    1+(1091000.0*(PRO(I)**3.0)))
       DEPRE(I)=DEPRE(I)*1000000.0
       WRITE(6,70) DEPRE(I)
 70    FORMAT('/',' TOTAL DEDUCTION AVAILABLE FOR CAPITAL
    *  COST ALLOWANCE
    1  IS      ',F17.2,' DOLLARS')
       CWROY(I)=0.87*0.425*ANPRO(I)*COMSH(K)+0.87*0.25*NGREV
       WRITE(6,81) CWROY(I)
 81    FORMAT('/',' ROYALTY FROM CROWN LANDS IS      ',F17.2,'
    *  DOLLARS')
       FEROY(I)=0.13*0.12*ANPRO(I)*COMSH(K)+0.13*0.12*NGREV
       WRITE(6,82) FEROY(I)
 82    FORMAT('/',' ROYALTY FROM FREEHOLD LANDS IS      ',F17.2
    *,' DOLLARS')
       ROYAL(I)=FEROY(I)+CWROY(I)
       WRITE(6,80) ROYAL(I)
 80    FORMAT('/',' ROYALTY EXPENSE IS      ',F17.2,' DOLLARS')
       EXPLO(I)=0.0
```

DOME SENSITIVITY LOOP ...(CONT'D)

```
      EXPLO(I)=EXPLO(I)*1000000.0
      WRITE(6,90) EXPLO(I)
90    FORMAT('/',' EXPLORATION EXPENDITURE IS      ',F17.2,'
     * DOLLARS)
      DEDUC(I)=EXPLO(I)+DEPRE(I)
      WRITE(6,110) DEDUC(I)
110   FORMAT('/',' TOTAL DEDUCTIONS              ',F17.2,'
     * DOLLARS')
      NTINC(I)=GROSS(I)-DEDUC(I)
      IF(NTINC(I)-0.0) 240,45,45
45    DEPLE(I)=0.0
      WRITE(6,120) NTINC(I)
120   FORMAT('/',' NET INCOME              ',F17.2,' DOLLARS')
      WRITE(6,130) DEPLE(I)
130   FORMAT('/',' DEPLETION ALLOWANCE           ',F17.2,'
     * DOLLARS')
      TXINC(I)=NTINC(I)-DEPLE(I)
      WRITE(6,140) TXINC(I)
140   FORMAT('/',' TAXABLE INCOME          ',F17.2,' DOLLARS')
      IF (TOT-0.0) 160,160,235
160   INTAX(I)=0.5*TXINC(I)
      WRITE(6,210) INTAX(I)
210   FORMAT('/',' INCOME TAX PAYABLE            ',F17.2,'
     * DOLLARS')
      ATCF(I)=NTINC(I)-INTAX(I)-ROYAL(I)
      WRITE(6,220) ATCF(I)
220   FORMAT('/',' AFTER TAX CASH FLOW           ',F17.2,'
     * DOLLARS')
      N=I-23
      DISAT(I)=ATCF(I)*(1.0/((1.0+RATE)**N))
      WRITE(6,230) DISAT(I)
230   FORMAT('/',' PRESENT WORTH OF THIS YEAR''S CASH FLOW
     *  ',F17.2,
     1' DOLLARS')
      GO TO 555
235   IF(TOT-TXINC(I)) 265,255,255
240   TOT=TOT-NTINC(I)
      WRITE(6,242) NTINC(I)
242   FORMAT('/',' NET INCOME            ',F17.2,' DOLLARS')
      NTINC(I)=NTINC(I)-ROYAL(I)
      WRITE(6,245) NTINC(I)
245   FORMAT('/',' NET INCOME MINUS ROYALTY EXPENSE ',F17.6
     *,' DOLLARS')
      GO TO 259
255   TOT=TOT-TXINC(I)
      WRITE(6,256) NTINC(I)
256   FORMAT('/',' NET INCOME          ',F17.2,' DOLLARS')
      NTINC(I)=NTINC(I)-ROYAL(I)
      WRITE(6,257) NTINC(I)
257   FORMAT('/',' NET INCOME MINUS ROYALTY EXPENSE ',F17.6
```

DOME SENSITIVITY LOOP ...(CONT'D)

```
     *,' DOLLARS')
259   WRITE(6,250) TOT
      WRITE(6,250) TOT
250   FORMAT('/',' ACCUMULATED DEFERRED TAX SAVINGS  ',F17.2
     *,' DOLLARS')
2     1)
      GO TO 555
265   TOT=0.0
      INTAX(I)=0.5*(TXINC(I)-TOT
      WRITE(6,270) INTAX(I)
270   FORMAT('/',' INCOME TAX PAYABLE ',F17.2,' DOLLARS')
      ATCH(I)=NTINC(I)-INTAX(I)-ROYAL(I)
      WRITE(6,280) ATCF(I)
280   FORMAT('/',' AFTER-TAX CASH FLOW          ',F17.2,'
     * DOLLARS')
555   CONTINUE
1000  CONTINUE
      CALL EXIT
      END
```

RESERVE GENERATION LOOP

```
C      THIS SUBROUTINE GENERATES TWELVE POOLS OF A CUMULATIVE
C      RESERVE OF TWO TO THREE BILLION BARRELS. IT THEN
C      ASCRIBES POOL PRODUCIBILITY TO EACH POOL. FINALLY,
C      IT ARRANGES THE POOLS IN ORDER OF LARGEST RESERVE.

       SUBROUTINE SORT (IX,POL,X,Y,SUM)
       REAL MAX
       DIMENSION POL(30),X(30),Y(30)
       DIMENSION PORO(350),POOL(350),DEL(350),PAY(350)
      *,WAST(350),AREA(350
      1)
       DO 10 I=1,350
       AM=2.72
       S=0.9
       CALL GAUSS(IX,S,AM,V)
       AREA(I)=10.0**(AREA(N))
       AREA(N)=V
 10    CONTINUE
       DO 12 N=1,350
       AVER=1.188
       VAR=0.695
       CALL GAUSS(IX,VAR,AVER,V)

       DEL(N)=10.0**V
 12    CONTINUE
       DO 13 I=1,350
       AV=1.07
       S=0.332
       CALL GAUSS(IX,S,AV,V)
       PAY(I)=10.0**V
 13    CONTINUE
       DO 14 L=1,350
       AV=0.13
       S=0.0048
       CALL GAUSS(IX,S,AV,V)
       PORO(L)=V
 14    CONTINUE
       DO 15 J=1,350
       A=0.2621
       S=0.0066
       CALL GAUSS(IX,S,A,V)
       WAST(J)=V
 15    CONTINUE
       SUM=0.0
       DO 4000 I=1,350
       POOL(I)=AREA(I)*PAY(I)*43560.0
       POOL(I)=0.178*POOL(I)
       POOL(I)=0.60*(1.0-WAST(I))*PORO(I)*POOL(I)
       SUM=POOL(I)+SUM
```

RESERVE GENERATION LOOP ...(CONT'D)

```
4000 CONTINUE
     WRITE(6,42)SUM
42   FORMAT('  THE RESERVE IS',F17.1,' BARRELS')
     N=16
     KUM=0.0
     NUR=12
74   MAX=0.0
     DO 72 I=1,350
     IF(MAX-POOL(I))73,73,72
73   MAX=POOL(I)
     J=I
72   CONTINUE
     POL(N)=POOL(J)
     X(N)=DEL(J)
     Y(N)=PAY(J)
     PORO(N)=PORO(J)
     WAST(N)=WAST(J)
     N=N+1
     POOL(J)=0.0
     KUM=KUM+1
     IF(KUM-15)74,75,75
75   CONTINUE
     RETURN
     END
```

PRICE SENSITIVITY LOOP

```
C     CALCULATION OF MCKENZIE-BEAUFORT DEVELOPMENT COSTS
C     THIS ROUTINE INITIALLY TAKES THE TWELVE ORDERED POOLS
C     GENERATED IN THE SUBROUTINE,SORT, AND CALCULATES A
C     DEVELOPMENT COST FOR EACH POOL. THIS CALCULATION IS
C     REPEATED ONE HUNDRED TIMES.

      INTEGER COST(30)
      DIMENSION PUT(100)
      DIMENSION NUM(30),COS(30),POOL(30),DEL(30),PAY(30)
     *,CUMDL(30),DELIV
     1(30),DELI(30),DES(30),FRAC(30),POL(30),THRU(30)
      DIMENSION INT(100)
      T=20.0
      FAC=(((1.0+0.05)**T)-1.0)/(0.05*((1.0+0.05)**T))
      A=0.05
      CO=240000.0
      OP=0.2*CO
      KAR=1
 131  IX=29211
      DO 1000 K=1,100
      CALL SORT(IX,POL,DEL,PAY,SUM)
      DO 76 I=16,30
      POOL(I)=POL(I)
  76  CONTINUE
      DO 97 I=16,30
      DELI(I)=PAY(I)*DEL(I)
  97  CONTINUE
      DO 77 I=16,30
      FRAC(I)=POOL(I)/SUM
  77  CONTINUE
      TOT=0.0
  22  DO 18 I=16,30
      DELI(I)=DEL(I)*PAY(I)
      DELIV(I)=DEL(I)*PAY(I)*365.0
      DES(I)=POOL(I)/T
      POP=POP+DES(I)
      NUM(I)=(DES(I)/DELIV(I))+1
      COST(I)=(CO + (OP*FAC))/(DELIV(I)*FAC) +1
  41  COS(I)=COST(I)*NUM(I)*DELIV(I)
      CUMDL(I)=NUM(I)*DELIV(I)
  21  TOT=CUMDL(I)+TOT
  18  CONTINUE
      TOTAL=0.0
      DO 111 I=16,30
      TOTAL=COS(I)+TOTAL
 111  CONTINUE
      DEV=TOTAL/TOT
      VEL=5.0
      THRUT=0.0
```

PRICE SENSITIVITY LOOP ...(CONT'D)

```
      DO 81 I=16,30
      THRUT=THRUT+(DELIV(I)*NUM(I))
      THRU(I)=THRUT
      DELIV(I)=THRU(I)
 81   CONTINUE
      PUT(K)=0.0
      DO 123 I=16,30
      IF(COST(I)-KAR)121,121,123
 121  PUT(K)=CUMDL(I)+PUT(K)
 123  CONTINUE
      WRITE(6,124)PUT(K)
 124  FORMAT(6X,F17.2)
 1000 CONTINUE

C     THE ROUTINE NOW ORDERS THE RESULTS OF THE ONE HUNDRED
C     TRIALS AND DETERMINES THE MOST PROBABLE THROUGHPUT
C     (BBL/YR) FOR A GIVEN ALLOWABLE DEVELOPMENT COST.

      DO 9 M=1,100
      INT(M)=0
 9    CONTINUE
      N=1
      K=N+1
      A=0.0
      B=10000000.0
 36   DO 32 I=1,100
      IF(PUT(I)-A)30,29,29
 30   GO TO 32
 29   IF(PUT(I)-B)31,31,32
 31   INT(N)=INT(N)+1
 32   CONTINUE
      IF(B-1000000000.0)33,33,35
 33   A=A+10000000.0
      B=B+10000000.0
      N=N+1
      GO TO 36
 35   DO 1005 M=1,100
      WRITE(6,1006)INT(M)
 1006 FORMAT(30X,I8)
 1005 CONTINUE
      NUMT=0
      DO 1003 M=1,100
      IF(NUMT-INT(M))1002,1002,1003
 1002 NUMB=M
      NUMT=INT(M)
 1003 CONTINUE
      LIM1=NUMB
      LIM2=NUMB-1
      XLIM1=1000000.0*LIM1
      XLIM2=1000000.0*LIM2
```

PRICE SENSITIVITY LOOP ...(CONT'D)

```
      WRITE(6,137)XLIM1,XLIM2
137   FORMAT(10X,F17.1,10X,F17.1)
      HAL=NUMT/2
      DO  20 M=1,100
      IF(M-NUMB)20,20,23
23    IF(INT(M)-HAL)24,24,20
24    NUMP=M
      GO TO 25
20    CONTINUE
25    LIM3=NUMP
      LIM4=NUMP-1
      XLIM3=1000000.0*LIM3
      XLIM4=1000000.0*LIM4
      WRITE(6,737)XLIM3,XLIM4
737   FORMAT(3X,F17.1,4X,F17.1)
      KAR=KAR+1
      IF(30-KAR)132,131,131
132   CALL EXIT
      END
```

ALBERTA RESERVE ESTIMATE

```
C     THIS PROGRAM ESTIMATES THE TOTAL IN-PLACE RESERVE OF
C     THE ALBERTA BASIN BY MAKING RANDOM SAMPLES FROM THE
C     DISTRIBUTIONS OF POROSITY, WATER SATURATION, AREA AND
C     PAY THICKNESS.

      REAL MEAN
      DIMENSION REA(380)
      DIMENSION PORO(380),WAST(380)
      DIMENSION PAY(380),AREA(380),BBL(380)
      IX=81
      WRITE(6,47)
 47   FORMAT(' THE OIL IN PLACE IS',15X,15X,' BARRELS')
      DO 108 LUM=1,20
      SUM=0.0
      TOT1=0.0
      TOT=0.0
      DO 2000 M=1,380
      AM=1.07
      S=0.332
      CALL GAUSS(IX,S,AM,V)
      PAY(M)=V
      PAY(M)=10.0**(PAY(M))
 2000 CONTINUE
      DO 3000 N=1,380
      AM=2.72
      S=1.00
      CALL GAUSS(IX,S,AM,V)
      AREA(N)=V
      REA(N)=AREA(N)
      TOT=AREA(N)+TOT
      AREA(N)=10.0**(AREA(N))
 3000 CONTINUE
      DO 5000 K=1,380
      AM=0.13
      S=0.0048
      CALL GAUSS(IX,S,AM,V)
      PORO(K)=V
 5000 CONTINUE
      DO 6000 L=1,380
      AM=0.26921
      S=0.0066
      CALL GAUSS(IX,S,AM,V)
      WAST(L)=V
 6000 CONTINUE
      WRITE(6,50)
 50   FORMAT(///,5X,' NUMBER',10X,' PAY THICKNESS(FT)',4X,'
     1 AREA(ACRES)',6X,' RESERVOIR(BARRELS)')
      MEAN=TOT/380
```

ALBERTA RESERVE ESTIMATE...(CONT'D)

```
      DO 4000 I=1,380
      DEV=(REA(I)-MEAN)**2.0
      TOT1=DEV+TOT
      BBL(I)=AREA(I)*PAY(I)*43560.0
      BBL(I)=0.178*BBL(I)
      BBL(I)=(1.0-WAST(I))*PORO(I)*BBL(I)
      SUM=SUM+BBL(I)
 4000 CONTINUE
      WRITE(6,43) SUM
 43   FORMAT(22X,E12.4)
      VAR=TOT1/379.0
      SD=VAR**0.5
      KUM=0
 107  NUM=380
      RESMX=0.0
      DO 101 I=1,NUM
      IF(BBL(I)-RESMX)101,101,102
 102  RESMX=BBL(I)
      J=I
 101  CONTINUE
      WRITE(6,51)J,PAY(J),AREA(J),BBL(J)
 51   FORMAT(5X,I5,10X,F17.2,10X,F17.2,10X,F17.2)
      BBL(J)=0.0
      KUM=KUM+1
      IF(KUM-380)107,108,108
 10,  C/
 108  CONTINUE
      CALL EXIT
      END
```

PIPELINE CALCULATION

```
C     PIPELINE DIAMETER SENSITIVITY STUDY
      REAL NUM
      REAL INT
      REAL MAT
      REAL INS
      REAL INSB
      REAL INSA
      REAL INSTL
      REAL MLENC
      REAL MSFLO
      REAL LENC
      REAL INS
      REAL K
      DIMENSION DIAM(10)
      I=1
      DIAM(I)=D
      DIST=1738.0
      VEL=5.0
      PMAX=850.0
      PMIN=195.0
      DELP=PMAX-PMIN
      DENSI=55.3
      VISC=12.04
      FRIC=0.005
      FOB=6.50
      WRITE(6,53)FOB
 53   FORMAT(' THE F.O.B. PRICE AT EDMONTON IS IS ', F6.2,'
     * DOLLARS/
     'BARREL')
      DO 1000 I=1,6
      READ(5,10) DIAM(I)
 10   FORMAT(F6.2)
      WRITE(6,11)I,DIAM(I)
 11   FORMAT(' CASE',I2,'--------- DIAMETER EQUALS',F6.2,'
     * FEET')
      REYNO=DIAM(I)*VEL/(VISC*0.3875)
      D=DIAM(I)
      A=DELP*32.0*144.0*D
      B=2.0*DENSI*(VEL**2.0)*FRIC
      LENC=A/B
      MLENC=LENC/5280.0
      VOFLO=(3.14*((D/2.0)**2.0))*VEL
      NUM=(DIST/MLENC)+1
      NUMB=NUM
      WRITE(6,12)NUMB
 12   FORMAT(' THE NUMBER OF PUMPING STATIONS ',I3)
      DAFLO=VOFLO*3600.0*24.0/5.61
      WRITE(6,32)DAFLO
```

PIPELINE CALCULATION ....(CONT'D)

```
 32   FORMAT(' THE DAILY FLOW RATE                    ',F17.2,'
     * BARRELS')
      MSFLO=DENSI*VOFLO
      WORK=2.0*(VEL**2.0)*FRIC*LENC/D
      HP=MSFLO*WORK*0.001818/32.0
      ACHP=HP/0.85
      HPM=ACHP/MLENC
      C=(1.0/2.303)*ALOG(HPM)
      CPUMP=17.19+(C*174.2) -((C**2.0)*116.4)+((C**3.0)
     **19.49)
      CPUMP=CPUMP*ACHP
      F=0.912*(1.0/2.303)*ALOG(HPM)
      F=F+2.35
      DPUMP=10.0**F
      A=400.0
      T=(970.0*D)/(2.0*(0.8*60000.0))/D
      CPIPE=28.2*A*T*D*D
      TIN=140.0
      TOUT=80.0
      INS=1.0
 30   H1=(1.0/(2.0*3.14*(DIAM(I)/2.0)*52800.0*50.5))
      H2=(ALOG((DIAM(I)+0.04)/DIAM(I)))/(2.0*3.14*70.0
     **528000.0)
      H3=(ALOG((DIAM(I)+(INS/12.0)+0.04)/(DIAM(I)+0.04)))
     */(2.0*3.14*0.13
     1*52800.0)
      H4=1.0/(2.0*3.14*(DIAM(I)+(INS/12.0)+0.5)*52800.0)
      Q=[illegible]*3600.0*0.48*(TIN-TOUT)
      [illegible](Q*(H1+H2+H3+H4))
      [illegible]2.0)20,9,9
  9   [illegible]1.0
      [illegible]0
 20   [illegible]E

 70   [illegible]LOG((DIAM(I)+(K/12.0)+0.04)/(DIAM(I)+0.04)))/(2.0
     *[illegible]*0.13
     1[illegible]00.0)
      [illegible]LOG((DIAM(I)+(K/12.0)+0.5+3.0)/(DIAM(I)+(K/12.0)
     *+[illegible]))
     1[illegible]0*3.14*0.9*52800.0)
      [illegible]=TIN-(Q*(H1+H2+H3+H5))
      [illegible]TOB-32.0)60,50,50
 50   [illegible]K+0.5
      GO TO 70
 60   INSB=K
      INSA=INS
      CINS=(0.206*(1788.0*5280.0)*3.14*((INSA/12.0)**2.0)
     **1.20)+(0.794*
     1(1738.0*5280.0)*3.14*((INSB/12.0)**2.0)*1.20)
      CINS=69000000.0
```

PIPELINE CALCULATION ...(CONT'D)

```
      WRITE(6,18)CINS
18    FORMAT(' THE COST OF INSULATION                 ',F17.2)
      AREA=Q*25.0*((72.0-(281.0-TOA))/ALOG(72.0/(281.0
     *-TOA)))
      HLOG=0.3185*((1.0/2.303)*ALOG(AREA))+3.59
      CHEAT=10.0**HLOG
      BOIL=54300.0
      PIPE=CPIPE*1738
      WRITE(6,13) PIPE
13    FORMAT(' THE COST OF PIPE MATERIAL              ',F17.2)
      FITT=0.10*PIPE
      WRITE(6,14) FITT
14    FORMAT(' THE COST OF FITTINGS                   ',F17.2)
      CSTA=(3650000.0/18.0)*NUM
      CLAND=1140000.0
      ROW=(CLAND+CSTA)*8.42
      TRAT=300000000.0
      MAT=ROW+TRAT+FITT+PIPE+CINS
      WRITE (6,15) MAT
15    FORMAT(' THE TOTAL MATERIAL COST                ',F17.2)
      INSTL=1257600000.0
      ROAD=90000000.0
      DEL=62000000.0
      PUMP=NUM*CPUMP
      WRITE(6,19)PUMP
19    FORMAT(' THE COST OF PUMPS                      ',F17.2)
      DRIV=NUM*DPUMP
      WRITE(6,21)DRIV
21    FORMAT(' THE COST OF DRIVERS                    ',F17.2)
      BOIL=BOIL*NUM
      WRITE(6,22)
22    FORMAT(' THE  COST OF BOILERS                   ',F17.2)
      TANK=1.32*7000.0*NUM*(324.0/239.0)
      EQUIP=PUMP+DRIV+BOIL+TANK+CHEAT
      WRITE(6,16) EQUIP
16    FORMAT(' THE TOTAL EQUIPMENT COST TOTALS        '
     *,F17.2)
      COM=40000000.0
      SURVY=100000000.0
      CONT=100000000.0
      DUTY=0.20*(EQUIP)
      STAX=0.15*EQUIP
      CAP=MAT+INSTL+ROAD+DEL+EQUIP+COM+SURVY+CONT+DUTY+STAX
      WRITE(6,17)CAP
17    FORMAT(' THE TOTAL CAPITAL COST TOTALS          '
     *,F17.2)
      EFF=0.85
      GAS=16.21*ACHP*NUM
      WATER=9100.0*NUM*EFF*1.42
      LAB=(1900000.0/18.0)*NUM
```

PIPELINE CALCULATION ...(CONT'D)

```
      SUP=0.20*(LAB)
      MAIN=((4700000.0/18.0)*NUM)*(1.0+0.4)
      PAY=((0.06)*LAB)+(0.2*(LAB+SUP+ (1.0/1.4*MAIN)))
      PLDEP=(PIPE+FITT+CINS)/20.0
      EQDEP=EQUIP/20.0
      OPCO=PLDEP+EQDEP+PAY+MAIN+SUP+LAB+WATER+GAS
      WRITE(6,26)OPCO
26    FORMAT(' THE TOTAL OPERATING COSTS              ',F17.2)
      YEAR=20.0
      INT=0.20
      ANCAP=CAP*((INT*((1.0+INT)**YEAR))/(((1.0+INT)**YEAR)
     *-1.0))
      WRITE(6,27)ANCAP
27    FORMAT(' THE ANNUAL EQUIVALENT CAPITAL COST       '
     *,F17.2)
      PRICE=5.00
      REVRO=ANCAP+OPCO
      ANPRO=365.0*DAFLO
      WRITE(6,51)ANPRO
51    FORMAT(' THE ANNUAL PRODUCTION IS               ',F17.2,'
     * BARRELS')
      COST=REVRO/ANPRO
      WRITE(6,63) COST
63    FORMAT(' THE PIPELINE CHARGE IS                 ',F17.2,'
     * DOLLARS/
     1BARREL')
      RES=ANPRO*20.0
      WRITE(6,29)RES
29    FORMAT(' THE RESEVES REQUIRED TO PHYSICALLY FILL
     * PIPELINE
     1 FOR TWENTY YEARS',F17.2,' BARRELS')
      WELL=FOB-TRAN
      WRITE(6,55) WELL
55    FORMAT('THE WELL-HEAD PRICE  IS                 ',F17.2,'
     * DOLLARS/
     1BARREL')
      RETUR=WELL*ANPRO
      WRITE(6,57)RETUR
57    FORMAT(' THE RETURN TO THE PRODUCER IS          ',F17.2,'
     * DOLLARS')
1000  CONTINUE
      END
```