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ECONOMIC ANALYSIS OF GEOPRESSURED
RESOURCES: SITE SPECIFIC CONSIDERATION
OF GEOPRESSURED METHANE GAS AT BRAZORIA

Final Report for the Period March 1, 1980--February 28, 1981

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University of Pennsylvania
Philadelphia, Pennsylvania

MASTER

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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- FINAL REPORT -

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University of Pennsylvania
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ABSTRACT

As part of its program for accelerating the commercialization of geothermal energy, the U.S. Department of Energy has sponsored a research project at the University of Pennsylvania dealing with the economic viability of geothermal geopressured resources in the United States.

The ultimate commercialization of geothermal geopressured resources, of course, depends largely upon its economic viability and the willingness of the resource producing firms to invest in the resource. The current project is aimed first at narrowing the range of uncertainties in economic information of geopressured resource in light of the recently collected data on the Brazoria Fairway. Secondly, the project has developed a basic analytical framework for determining the investment potential of the geopressured resource at Brazoria. Thirdly, the project quantitatively evaluates the relative effectiveness of a number of financial incentives and other public policy initiatives designed to accelerate the commercialization of geopressured resources.

This document reports on final results of this project including: (1) a review of current estimates of important resource parameters at the Austin Bayou Project, (2) initial cash flow simulations of development of the Austin Bayou Prospect, (3) sensitivity analysis of these simulations and evaluation of the uncertainties' impact on measures of profitability and investment decision analysis, and (4) a brief review of the well-testing program.

PREFACE

This document summarizes a preliminary investigation by a University of Pennsylvania Research team into the potential commercialization of geopressured geothermal resources. This project is part of an on-going research program dealing with a variety of issues in the commercialization of new energy technologies at Pennsylvania.*

A particularly important problem in past studies of the commercial potential of geopressured resources has been the lack of a current and consistent set of data on geopressured resource characteristics. Hence, the purpose of this report is twofold: (1) to review the current compilation of resource data for a specific geopressured resource area (the Brazoria Fairway) and (2) to use these data in a preliminary investigation of the economics of developing this area. This latter step is the first stage in evaluating alternative financial incentives or other public policy initiatives for their relative effectiveness in accelerating commercialization of the resource.

The authors gratefully acknowledge the cooperation during the course of this research of Keith Westhusing of the DOE Geopressured Office in Houston; David Frederick and Myron Dorfman of the Center for Energy Studies and Robert McDonald of the Department of Petroleum Engineering at the University

*The Energy Technology Commercialization Project is a collection of research activities being carried out at the University of Pennsylvania.

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1. INTRODUCTION

Shortages of conventional oil and gas, stringent environmental standards on the use of coal, and the uncertain future of nuclear power have all prompted widespread interest in the development of alternative energy sources in the United States, including geothermal resources. A quite promising category of U.S. geothermal resources is geopressured geothermal energy which refers to subsurface sedimentary rock formations where energy exists coincidentally in forms of methane gas, heated water, and hydraulic pressure. Geopressured resources have been judged to constitute significant energy resources in certain regions of the U.S. The extent of the contribution depends, however, on the willingness of private firms or resource producers to invest in this resource. We refer to the process by which new technologies are introduced and established in the market as commercialization.

A fundamental goal of the U.S. Department of Energy (DOE) geopressured geothermal research and development program is to accelerate the rate of commercialization by providing technical assistance and economic incentives, if warranted, to the industry. As a part of this on-going program, the U.S. Department of Energy is currently sponsoring a reservoir testing program designed to reduce the uncertainty about a number of important reservoir parameters, e.g. reservoir

performance, methane solubility, and development well costs. The Austin Bayou Prospect (ABP), the focus of this study, is one of the sites which DOE selected for further testing after careful consideration. Information from the ongoing testing at ABP is utilized in this report.

1.1 Purpose and Scope of Current Work

Four interacting factors influence decisions to invest in new technologies: (1) the costs and returns of investing in new technologies, which are seldom known with certainty, (2) the characteristics of the decision environment faced by a potential resource producer, (3) the risks that the first two factors engender for a resource producer, and (4) a resource producer's attitude towards risk. The ultimate goal of our research effort is to integrate these factors in a formal model and investigate the effectiveness of various public policy initiatives in accelerating a technology's deployment by the private sector. However, this report does not incorporate producer attitudes towards risk in a detailed manner, although research is currently underway to build a sophisticated decision model (see Section 6). The present report displays the uncertainties faced by a resource producer in the form of a probability distribution and investigates the sensitivity of the probability distribution to both resource and public policy parameters. A simple adjustment for risk has been incorporated to

illustrate how venture attractiveness can be viewed in risk-adjusted terms.

1.2 Organization of Report

This document reports the current phase of our research effort. Section 2 contains a review and critique of the existing literature. In Section 3 we discuss the resource characteristics of the Austin Bayou Prospect based on interviews with the testing program's researchers and DOE personnel. Section 4 discusses economic assumptions on which our stochastic cash flow model is built. Results from a large number of sensitivity runs are presented in Section 5. Section 6 contains a brief introduction to decision models. Conclusions from this research effort are discussed in Section 7.

2. REVIEW OF PAST STUDIES

In recent years, there have been several studies dealing with the economics of developing and producing geopressured resources. Notable among these studies are those completed by the National Petroleum Council (NPC, 1980) and the Electric Power Research Institute (EPRI, 1980). Frederick et al. (1979) of the Center for Energy Studies reviewed the range of commercialization incentives applicable to geopressured ventures.

Both the NPC (1980) and EPRI (1980) studies were conducted well before recent expert interpretations of data were available from the U. S. Department of Energy (DOE) design well in Brazoria County, Texas. Table 2.0.1 presents the parameter estimates that were used by early researchers. It is clear from Table 2.0.1 that the degree of uncertainty in available data is quite high.

2.1 The National Petroleum Council Study

The NPC (1980) study initially requested by then Energy Secretary Schlesinger in June 1978 had several fundamental objectives, including:

- To study a number of promising geopressured prospects in detail, estimating the following:
 - Reservoir performance
 - Drilling programs
 - Production and water disposal methods
 - Geothermal and hydraulic energy potential
 - Producing rates and recoverable reserves

Table 2.0.1

Resource Parameter Estimates: Austin Bayou Prospect

Source	Porosity (%)	Areal Extent (mi ²)	Permea- bility (md)	Compress ibility (10 ⁻⁶ psi ⁻¹)	Methane Content (cf/bbl)	Expected Production (10 ³ bbl/day)	Pay Thickness (ft)
Gregory, 1979	20	16	2-10	-	25-45	20-40 (20 yrs)	840
Lewin, 1980 Assoc.	16	15	15	-	25	20 (22 yrs)	700
EPRI, 1980	20	16	15	1.21x10 ⁻⁵	40	13.1 (n.a.)	230
National Petroleum Council, 1980	16	18	20	-	40	30 (25 yrs)	715

- The costs and economics of field development

Based upon the study of these prospects, to predict the addition of ultimate recovery and production rate per year to the year 2000 as a function of gas price for a base case with discounted cash flow rate of return of 10 percent and example cases with rates of 15 and 20 percent.

The conclusions reached in the study are presented below:

It is possible to develop commercial production of gas from geopressured brines at gas prices ranging from \$4.00 to \$9.00 per thousand cubic feet (MCF) with a 10 percent rate of return (ROR) from selected areas of the Gulf Coast. For a maximum gas price of \$9.00 per MCF and a 10 percent ROR, the projected gas production would be 81 million cubic feet per day (MMCF/D) by the year 2000 for the most optimistic case. The ultimate gas recovery for this case would be 568 billion cubic feet (BCF).

Large-scale gas production is highly unlikely prior to the year 2000 for the following reasons:

- The extremely high capital investment and operating expense per unit of gas production leaves little margin for dry holes or poor reservoir performance.
- The low solubility of gas in brine makes the value of each barrel of brine very low (5¢ to 45¢ per barrel). This in turn requires that each well be capable of producing at high rates for many years.
- The low recovery efficiency of approximately 3 percent of the gas in-place and the highly faulted nature of the geopressured sands greatly limit the size of the resource available for exploitation.
- The existence of numerous elements of mechanical and geological risk makes large-scale gas production unlikely.

The assertion that there is "little margin for dry holes or poor reservoir performance" seems to indicate the study committee's judgement that a rate of return of 10 percent is not commensurate with the risks involved.

Figure 2.1.1

Monte Carlo Simulation Output: Austin Bayou Prospect
Source NPC (1980)

The presence of "numerous elements of mechanical and geological risk" is a well established fact. The crux of the problem is whether these risks can be translated to meaningful financial uncertainty from a potential resource producer's standpoint. An attempt was made, however, by the NPC (1980) committee to incorporate this by means of a Monte Carlo simulation model. Figure 2.1.1 represents the output of such an exercise for the Austin Bayou Prospect. From Figure 2.1.1 we can say that at \$6/MCF, there is a 50 percent chance of earning a rate of return of 10 percent. Such a characterization is not as complete as specifying a probability distribution. Moreover, it stops short of answering the question of concern in our research, i.e., given the risks, can we expect positive investment decisions by rational, risk-averse resource producers?

2.2 The Electric Power Research Institute Study

The EPRI (1980) study was primarily a review of previously published research, and was not an independent assessment of specific sites. Nonetheless, the EPRI study did make some economic assessments, but no effort was made to incorporate uncertainty in the financial model. Rather, the approach was to use point estimates. Unlike the NPC study (1980), however, the EPRI (1980) study did not use an exogenous price; instead, the price required to earn a pre-determined rate of return was computed. Since the market price for new gas is not likely to be influenced to any degree by the production of geopressured gas, this appears

to be a poor assumption. The report concludes, for example, that at the S.E. Pecan Island Prospect, a "one-well" development scenario is preferable to a "twelve-well" scenario because the required price of gas is lower in the former. Clearly, it is conceivable that at a higher price the "twelve-well" scenario may be more attractive to a resource producer.* Indeed this is an important question for policy makers, since decisions made by private resource producers concerning development strategies will influence the contribution that geopressured methane can make in the transition to more abundant sources.

2.3 The Center for Energy Studies Report

The report referred to here, Frederick et al. (1979), provides an excellent history of the development of interest in geopressured resources. The report also provides a fairly complete list of commercialization options applicable to geopressured ventures. The study, however, applies only a limited quantitative analysis to potential investment decisions by resource developers. The possible impacts of various project risks on profitability criteria such as the net present value of profits are discussed qualitatively in some detail. The work also suggests that a multiattribute utility framework might be appropriate for quantitatively evaluating geopressured ventures under conditions of uncertainty (c.f. p. 29).

*The cost assumptions become crucial here. For instance, there may be increasing returns to scale for on-surface methane separation.

2.4 A Critique of Past Studies

There are a number of shortcomings in the methods used and, consequently, in the conclusions of past studies of the economics of geopressured methane. These shortcomings are summarized below:

- Both the NPC (1980) and EPRI (1980) studies link profitability to rate of return.* The use of this measure is particularly inappropriate in arriving at judgments on the choice between mutually exclusive development strategies as for instance, in the choice between a one-well and multi-well development scenario.
- Almost every study that was reviewed by us recognized the presence of risks. Very few studies, however, incorporated consideration of risk.

In addition to cost and geological risks which both translate to profitability risks, there was no recognition in the literature of the uncertainties faced by resource producers because of a long lead time. Such uncertainties, which turn on political events, regulatory barriers, etc., can and do influence producer decisions. In fact, in the considerations of risky projects we need to keep in mind a number of different adjustments that a producer has to make: adjustments for relatively well defined risks such as geologic and cost risks; adjustments for the time

*Since the rate of return is a "rate" as distinct from an "absolute benefit," seemingly small variations in this rate are quite important. It is for this reason that bankers use basis points (one hundredths of one percent) as a measure.

resolution of uncertainty and adjustments for the uncertainties of a long lead time. It is possible, in some circumstances, to express all these adjustments in terms of a higher discount rate. It is conceptually better, however, to account for each of these factors explicitly and separately.

Many studies calculated a "required price" at which the resource is economically viable. Few studies attempted to estimate "how much" resource could be expected at the required price.

The NPC (1980) study, however, did compute additions to reserves at different prices and rates of return. From the conclusions made by the study group, however, it is not clear whether these additions to reserves can be expected after allowing for the risks faced by a potential producer.

As mentioned above, the risks involved in geopressured projects are an integral part of the resource producer's calculations. These calculations can certainly be expected to be sensitive, to a degree, to public policy initiatives such as investment tax credits, shorter tax lives for investments, depletion allowances, etc. None of the studies reviewed by us has addressed this question in a precise and quantitative framework.

3. RESOURCE CHARACTERISTICS OF THE BRAZORIA SITE

The Frio Formation of the Texas Gulf Coast contains a number of fairways or potentially brine rich areas. Bebout et al. (1977), in a comprehensive study of this formation, examined the potential of a number of fairways, and concluded that the Brazoria Fairway was the most promising prospect in Texas for commercial exploitation (see Figure 3.0.1 for location). Within the fairway, Bebout et al. (1977) identified the Austin Bayou Prospect (ABP) as an excellent target for a Department of Energy (DOE) design well. A DOE design well was completed in 1979 and a number of tests have now been completed. In section 3.3, we will discuss results from the well testing program.

Section 3.1 presents a brief description of crucial reservoir parameters. Section 3.2 discusses deliverability of reservoirs and presents an overview of reservoir models which permit us to translate reservoir characteristics into production scenarios. Section 3.4 describes the major assumptions about the reservoir at ABP that form the basis for cash flow simulations.

3.1 Reservoir Parameters

In the context of geopressured resources, a reservoir is the name given to a number of interconnected, highly permeable sandstone bodies that are surrounded by impermeable shale (see Figure 3.1.1). Geopressured reservoirs are currently considered to be essentially

Figure 3.0.1
 Potential geothermal fairways, Frio Formation
 Texas Gulf Coast

CROSS-SECTION

PLAN

Figure 3.1.1

Cross section and plan view of a hypothetical geopressed reservoir

"closed systems"* with relatively well-defined boundaries.

The drainage area or the area of the aquifer that can effectively be drained is an important reservoir parameter. The drainage area and the effective thickness of the brine-bearing sands, together determine the volume of the reservoir.

The fraction of the reservoir that contains brine is determined by another important reservoir parameter, porosity.

Finally, it is technologically feasible, at the present time, to produce no more than some fraction of the total volume contained in a reservoir. This fraction depends on the product of reservoir permeability and sand thickness (the KH product), and also on reservoir rock compressibility.

In general, these parameters are not known with certainty. Thus, it is appropriate to model them as random variables. Therefore, we can write:

$$\tilde{Q} = \tilde{A} \times \tilde{h}_{\text{eff}} \times \tilde{\phi} \times \tilde{\eta} \times \tilde{\zeta} \quad (3.1)$$

$\tilde{Q}$ = total volume of recoverable brine in barrels

$\tilde{A}$ = drainage area in square miles

$\tilde{h}_{\text{eff}}$ = effective sandstone thickness in miles

$\tilde{\phi}$ = porosity in percent

$\tilde{\eta}$ = extractive coefficient in percent

= f (permeability, $\tilde{h}_{\text{eff}}$, compressibility)

$\tilde{\zeta}$ = conversion coefficient, bbl/mile³

*That geopressed reservoirs can be characterized in this manner is not, however, a completely settled issue. There is speculation, for instance, that if the surrounding shale is not totally impermeable, it might be incorrect to characterize the reservoir as "closed." There is no evidence that this phenomenon (called "shale dewatering") does occur. It will be assumed here that it does not.

3.2 Deliverability

The term deliverability is used to describe technologically feasible production paths over time. Obviously, it is possible to deplete a given reservoir in a number of ways. However, the following constraints must be met:*

1. The total volume of brine produced over the life of the reservoir should not exceed Q .

2. The flow through a single well must not exceed q_{max} , which depends on the internal diameter of the well bore and the sonic velocity.

3. The well is capped when the annual after tax cash flow from reservoir production becomes negative.

4. The production over time should be such that the pressure in the reservoir always remains above a minimum threshold pressure.

At the time of choosing a production path over time, Q is known with certainty. Thus, we can ensure that the first constraint is met.

Since the diameter of the well bore is chosen before production begins, and is determined by engineering constraints, the second constraint simply places a limit on the amount of brine that can be extracted through a single well.†

The resource producer will decide to stop producing from a well if its contribution to annual after-tax cash flow is

*In the case of hydrothermal resources, this aspect of the problem has been formalized (see Blair et al., 1980a).

†All the studies reviewed by us assume a 5½" tubing for the well.

negative. In terms of a cash flow model, this shortens the life of the project.

The fourth constraint concerning reservoir pressure is not easily verified, since complex reservoir models are required to predict pressure. We shall now briefly discuss reservoir models.

3.2.1 Reservoir Models

A reservoir model is a mathematical representation of the physical processes that are postulated to occur within a reservoir. In this case of geopressured reservoirs, transient and steady state solutions are obtained to the radial diffusivity equation, and these solutions are used to predict reservoir behavior. Reservoir models can be classified as either analytical or numerical simulation.

Analytical models usually assume that the reservoir is homogeneous in its properties, and well defined in its geometry. The values of different parameters in the model are either estimated from the geology of the reservoir or measured by field tests. These parameter values are then substituted into the steady state and transient solutions to obtain deliverability estimates. The reservoir model does not predict how the reservoir will be exploited or even how it should be exploited. It does, however, provide information on the different ways that it can be exploited. It is for this reason that reservoir performance should be viewed as a constraint. For instance, it might be technologically impossible to deplete a reservoir from a single

well of fixed bore in two years. It might be possible, on the other hand, to deplete it in either five or ten years. The choice of a particular production path will, of course, depend on economic factors.

Numerical simulation models are capable of accounting for non-homogeneity in reservoir properties. Thus they are also useful in exploring the implications of different drive phenomena. Advanced numerical simulation models, for instance, permit investigation of "new technologies" such as reinjection (see Garg, 1979). MacDonald (1980a) is currently investigating the possible impact of shale dewatering on overall recovery. Numerical simulation models are very expensive to run, and the cost of performing a large number of Monte Carlo runs would be prohibitive.

The EPRI (1980) study concludes that for purposes of aggregate prediction, analytical models are adequate.

3.3 Data From the Brazoria Design Well

Pleasant Bayou #1, the first well ever drilled in the search for geopressured resources, was drilled at the Austin Bayou Prospect, Brazoria County, Texas under DOE sponsorship. This well was abandoned because of technical difficulties, but a second well, Pleasant Bayou #2, was successfully completed at a point not far from the initial site.

The purpose of the design well was to (1) establish the areal extent of the reservoir, its flow characteristics, its gas-water ratio, etc.; and (2) investigate the presence or absence of " aquifer recharging" by shale dewatering.

We shall not discuss the investigations that are currently underway on shale dewatering,* since our assumption is that the reservoir is bounded by impermeable shale. We shall refer to Stage 1 of the testing program (which lasted from early November to late December of 1979), and Stage 2 (which lasted from September 3 to October 31 of 1980). If we exclude the two days of production that occurred immediately after the well was perforated, all the production from Pleasant Bayou #2 has occurred in Stage 1 and 2.

3.3.1 Performance and Areal Extent of the Austin Bayou Prospect

The reservoir at the Austin Bayou Prospect (which is often referred to as the C-sand reservoir) is 30 miles long in the Southwest-Northeast direction along the major growth fault which bounds the reservoir. The width of the reservoir perpendicular to this growth fault is not uniform, and averages about 5 miles (see Figure 3.3.1).

One of the early controversies in assessing the potential of geopressured reservoirs, centered around the areal extent (and consequently the drainage area) of these reservoirs. Some investigators calculated "minimum required reservoir sizes" for economic viability, and concluded, on the basis of comparisons with petroleum reservoirs, that extraordinarily large reservoirs would be necessary for commercial exploitation (see Doscher et al., 1979). Clearly, since geopressured

*MacDonald of the University of Texas is one of the prominent investigators.

Figure 3.3.1

Net sand thickness, C-sand Frio Formation, Brazoria County
Source: MacDonald and Dorman (1980)

reservoirs are not geological traps as petroleum reservoirs are, this conclusion is misleading. Yet questions remain as to whether geopressed reservoirs are fragmented by cross faults (perpendicular to the growth faults), which would make the effective drainage area very small (see EPRI, 1980). In a very recent paper on the ABP, MacDonald and Dorfman (1980) have this to offer: "The sand reservoir body may be fragmented by cross faulting perpendicular to the main fault. However, the effects of this cross faulting on reservoir continuity must await the results of flow testing over extended production periods." In other words, while cross faulting can create barriers to the flow of brine within a sandstone body, it need not be a sealing fault. Indeed some reservoir simulation studies indicate that assigning relatively low permeabilities to some points in the reservoir does not drastically affect overall recovery, necessarily.

During Stage 1 of the testing program, Pleasant Bayou #2 produced at an average rate of 13,000 bbl/day over a ten day period. At one point in the testing program, the flow rate was increased to 23,000 bbl/day.

During Stage 2 also, the average flow rate was about 13,000 bbl/day. One important constraint on sustained testing at high flow rates has been the limited capacity of the available disposal well, Pleasant Bayou #1. In Stage 2, the flow rate was maintained at 19,000 bbl/day for 67 hours.

3.3.2 Formation Permeability at ABP

The data available from the build up and draw down tests at ABP has enabled investigators to compute a formation permeability based on the latest available information. MacDonald and Dorfman (1980) conclude that "the formation permeability is in the neighborhood of 200 md." This is in sharp contrast to the range of estimates mentioned in the EPRI (1980) study.

3.3.3 Methane Solubility at ABP

The methane solubility of geopressured brines (expressed in CF/bbl) depends on brine temperature, pressure, and salinity. Early studies of geopressured resources theoretically estimated the saturation level of methane at the anticipated temperature, pressure, salinity, etc. (see, for instance, Dow Chemical, 1976). The results from the Brazoria design well and a number of other wells of opportunity have, however, revealed that the salinity of geopressured brines is significantly higher than these early estimates. In Stage 2 of the testing program at Brazoria, a solubility of 20 CF/bbl was observed with an additional 9-12 CF/bbl in the water down stream of the separator (MacDonald and Dorfman, 1980 ; Westhusing, 1980).

3.4 Prospect Specific Assumptions for ABP: The Base Case

Sustained testing at ABP will, of course, eliminate the uncertainty about reservoir performance. Based on the extensive testing that has occurred so far, the following

triangular probability distribution functions were assigned for the base case run:

	Min	Most Likely	Max
Effective Drainage Area (in square miles)	10	16	20
Effective Sand Thickness (in feet)	200	250	300
Reservoir Porosity	0.15	0.17	0.2
Extractive Coefficient*	0.03	0.045	0.05
Methane Solubility (in CF/bbl)	23	25	27

*It is difficult to directly assign a probability distribution for the extractive coefficient. This fraction is a function of the KH product and the reservoir rock compressibility. Earlier estimates for ABP had varied from 1 to 4% (see EPRI, 1980 ; Lewin Associates, 1980).

4. FINANCIAL ANALYSIS MODEL

4.1 Introduction

In exploiting natural resources, the resource producer seldom has complete and perfect information. Geological studies, and even physical and chemical tests cannot completely eliminate the uncertainty about a region, area, or reservoir. Such efforts can, however, reduce the uncertainty about resources, which in turn would result in more credible and reliable economic data. This is the case for oil and gas deposits, as well as for geopressured resources.

In Section 3, we discussed the characteristics of the resource at ABP based on the latest information available. These uncertainties in resource characteristics combined with the uncertainties in costs make the venture risky from the standpoint of a resource producer. For instance, while the total volume of a reservoir may be large, low permeability (which contributes to a low extractive coefficient) may make the overall deliverability marginal. If in addition, the well cost turns out to be high, the project as a whole may turn out to be unprofitable. At the time of making investment decisions, the resource producer does not know with certainty if all or some of these events will or will not occur. Expected value is not a good guide since the resource producer has

to take into account the fact that the outcome could be very unfavorable. In order to characterize the situation faced by a resource producer, we need to obtain a probability distribution of the outcomes (in terms of profitability) that could result from a venture. We do this by the use of a Monte Carlo cash flow simulation. We shall begin with some basic concepts of profitability.

4.2 Measuring Profitability

4.2.1 Measuring Profitability Under Certainty

Let us begin with the assumption that we know with certainty the pattern of costs and benefits that will accrue from a venture. It is widely accepted in the literature that discounted cash flow (DCF) indices are superior measures of the profitability of a candidate project (see Dean, 1950 ; Bierman et al., 1971 ; Weston et al., 1978). Two commonly used measures of profitability that employ discounted cash flows are the net present value (NPV) and the internal rate of return (IRR).

The net present value is the present value discounted at the cost of capital minus the initial cost outlay of the venture. This relationship is expressed in (4.1):

$$NPV = \sum_{t=1}^N \frac{F_t}{(1+K)^t} - C \quad (4.1)$$

where F_t , $t = 1, 2, \dots, N$ is the net cash flow in year t .

K is the cost of capital. (under certainty, the risk-free rate).

C is the initial cost outlay of the venture .

The internal rate of return is defined as the discount rate at which the present value of the net cash flows from the venture minus the initial cost outlay is equal to zero. Therefore, we have to solve for r in

$$\sum_{t=1}^N \frac{F_t}{(1+r)^t} - C = 0 \quad (4.2)$$

where F_t , $t = 1, 2, \dots, N$ is the net cash flow in year t

C is the initial cost outlay of the venture

r is the internal rate of return

Both NPV and IRR formulations make implicit assumptions regarding the rate of reinvestment of project revenues. The NPV formulation assumes that these revenues are reinvested at the cost of capital; the IRR formulation assumes reinvestment at the IRR. Both formulations may be inappropriate, therefore, in evaluating projects of extended duration. Alternatively, we might include a priori judgements about future reinvestment opportunities, on the basis of which we could determine a terminal value of project revenues and use that value to determine a modified net present value (NPV*) and a modified internal rate of return (IRR*), as suggested by Weston et al. (1978) and expressed in (4.3) and (4.4)

* The modified rate of return is also referred to as the financial management rate of return (FMRR); See Messner and Findlay (1975).

$$NPV^* = \frac{\sum_{i=1}^N F_i (1+r_i)^{N-i}}{(1+K)^N} - C \quad (4.3)$$

$$\text{Solve for } r^* \text{ in, } \frac{\sum_{i=1}^N F_i (1+r_i)^{N-i}}{(1+r^*)^N} - C = 0 \quad (4.4)$$

where F_i = net cash flow in year i

r_i = pre-specified reinvestment rate; in general a
function of time

C = cost of initial outlay

K = cost of capital to the firm (under certainty, the
risk-free rate)

r^* = modified internal rate of return

NPV^* = modified net present value

Both the NPV and IRR are measures of profitability. In project selection, the following rules are appropriate for a firm that maximizes stockholder wealth (see Weston et al., 1978 ; Bierman and Smidt, 1971).

(1) In choosing projects from a known set of independent projects, the firm should accept all projects with an NPV^* greater than zero, which is equivalent to accepting all projects with an IRR^* greater than K .

(2) In choosing one project from a number of mutually exclusive projects as, for instance, in choosing between a

two-well or four well development plan, the firm should choose the project with the highest NPV*. In this case, choosing a project with the highest IRR* does not necessarily maximize stockholder wealth.

(3) In choosing from a known set of independent projects but with limited capital, the firm should maximize NPV* subject to the capital constraint (see Bernhard , 1969).

(4) If the firm is faced with (i) a capital constraint and (ii) is unsure of its opportunity set, it is appropriate to set up a cut-off rate of return, and then choose among the projects that qualify on the basis of the rules indicated in (1), (2), and (3). (See Blair and Venkateshwara, 1980 ; Cozzolino, 1980).

In order to implement the decision rules indicated, the cash flow model is set up to generate both the NPV* and IRR* for candidate geopressured projects.

The decision rules that we have discussed so far do, in principle, carry over to project selection under risk so long as appropriate adjustments are made for risk. We shall now turn to this topic.

4.2.2 The Discount Rate as an Adjustment Mechanism

A common approach to account for risk is the use of risk-adjusted discount rates, i.e., for a risky project we could rewrite (4.1) as

$$\text{NPV}_{\text{adjusted}} = \sum_{t=1}^N \frac{\bar{F}_t}{(1+K)^t} - C \quad (4.5)$$

where, NPV_{adjusted} = risk-adjusted net present value

$\bar{F}_t$ = expected value of net cash flow in year t

K' = risk-free rate + risk premium

C = initial outlay

The crucial question, of course, is the determination of the risk premium. At the theoretical level, a number of approaches have been developed to provide empirical estimates for risk premium (see Weston and Brigham, 1978). These models view the project from the individual stockholder's point of view.*

Several considerations suggest that a risk-adjusted discount rate is inappropriate for our problem:

(1) We are concerned here with the decisions about a single investment project; it is highly unlikely that a firm can generate an appropriate discount rate for individual projects. This should be distinguished from the firm's weighted average cost of capital.

In practice, firms that use higher discount rates to account for risk, classify projects arbitrarily into risk classes (see Johnson, 1970, for a discussion).

(2) We are also concerned here with decisions made by firms that are completely owned and operated by individual

* It is assumed that each stockholder has a fully diversified portfolio.

entrepreneurs. For such firms, investors cannot signal, through the market, an appropriate discount rate for projects (see Grayson, 1960).

(3) It is evident from equation (4.5) that the initial outlay is treated as certain. In commercialization decisions, however, the initial outlay is seldom known with certainty, and is a major component of project riskiness.

In addition, there are a number of circumstances where the formulation in (4.5) leads to serious inconsistencies (see Robichek and Meyers, 1965, for a discussion).

4.2.3 The Utility Function Approach

Another way to account for risk is the use of utility functions. A utility function is a means of representing a consistent set of preference for gambles. If some fundamental axioms of behavior under risk are accepted (see Savage, 1954 ; Luce and Raiffa, 1957 ; Arrow, 1971 for expositions), it can be shown that a utility function (that is unique up to a positive linear transformation) does exist, and it possesses the property that in ranking lotteries the individual should be guided solely by expected utility. Application of the theory permits us to rank lotteries in a manner that is consistent with individual preferences. The theory also enables us to determine for each lottery a quantity known as the "certainty equivalent" or "risk-adjusted value". The individual is indifferent between receiving the lottery or receiving the "certainty equivalent" with certainty.

Let us assume that we can determine a utility function that adequately represents the behavior of a firm. Then, for projects with risky cash flows, the firm can generate a probability distribution of net present value (based on discounting at the risk-free rate)*, and determine a corresponding certainty equivalent. Since the firm can now treat uncertain projects as if they were projects with certain net present values equal to the certainty equivalent, the decision problem is considerably simplified. Thus, in choosing between mutually exclusive projects, the firm chooses the project with a higher certainty equivalent. Moreover, in choosing among independent projects, it accepts all projects whose certainty equivalent (or "risk-adjusted value") is greater than zero. The theoretical elegance and consistency of this approach has been recognized in the literature on capital budgeting (see Robichek and Meyers, 1965 ; Mao, 1969 ; Weston and Brigham, 1978).

4.2.4 State-of-the World Uncertainty

There is strong reason to believe that in choosing between two projects that have the same certainty equivalent net present value, firms prefer the project that has a "relatively better" distribution of cash flows over time.

*When risk is being accounted for by the use of utility functions it is important not to include margins for risk in the discount rate, for this would amount to double counting risk. It should also be pointed out that the firm's weighted average cost of capital includes a market determined margin for risk (see Wiig and Hax, 1977; Newendorp, 1975).

The primary reason for this appears to be a lack of credibility in the cash flow distribution for distant periods. Subjective probability distributions of cash flows are based to an extent, on the premise that the state-of-the world will not change drastically. In the energy sector, for instance, political events, OPEC decisions and sharply changing environmental and regulatory policies can and do influence the "state-of-the world". To a private firm, changes in the "state-of-the world" can provide windfall gains or losses, although the magnitude is often limited in both states. If credible subjective probabilities could be assigned to different "states-of-the world", we could include these assessments in the generation of cash flow distributions. Typically, however, it is not easy even to list the possible changes in the state-of-the world, much less assign probabilities to different events. Thus, we have a situation of "classic uncertainty" as distinct from "risk" (see Knight, 1922).

A working hypothesis about behavior under such circumstances is that firms do make judgements about future events, and in so doing, hold beliefs about the near future with greater confidence than beliefs about the distant future. In evaluating projects, therefore, the firm is concerned not only with the net present value, but also with the fraction of early cash flows from the project (for which the probability distribution are "more credible").

The frequent use of the payback period or similar measures as an indicator of "riskiness" attests to the importance of this phenomenon.

Uncertainty about the "state-of-the world" is particularly relevant to decisions made by private firms to invest in new energy technologies. The length of such projects is long, thereby making cash flow projections difficult and, as we have already discussed, projects in the energy sector are very susceptible to political and regulatory "shocks".

In order to account for state-of-the world uncertainty, we define a proxy measure called the "safety index" (SI):

$$SI = \sum_{i=1}^n \frac{W_i F_i}{C} \quad (4.6)$$

where

F_i = net cash flow in year i

C = initial outlay

W_i = $i = 1, 2, \dots, n$ are weights

$W_i > W_{i+1}$ for all i

4.3 Cash Flow Modeling Assumptions

In this section, we will discuss the major assumptions of the stochastic cash flow model.

4.3.1 Land Acquisition and Project Development

It is assumed that from the time of land acquisition, it will take five years for commercial production to begin.

During this period, geological and geophysical surveys are conducted, the resource is confirmed, environmental studies are conducted, and development wells and on-site surface facilities are completed. Figure 4.3.1 indicates the phases of project development.

4.3.2 Resource Production

It is assumed that the resource producer does not produce any hydraulic energy.* It is also assumed that the resource producer separates the methane from the brine with on-surface separators, and reinjects the brine into a shallow aquifer of depth ranging from 3000 to 4000 feet.

For every Monte Carlo trial, the model determines a total recoverable volume, Q , as a function of many random variables (see Section 3.1 and 3.2), and a production path is then assigned. For purposes of cash flow modeling, it is assumed that there is a constant flow rate in the early years followed by a steady decline. Figure 4.3.2 depicts some typical production paths.

4.3.3 Annual Operating Revenues

If prices could be forecast reasonably accurately, determining operating revenues would be very straight forward. We could simply write

$$REV_i = P_i Q_i \quad (4.7)$$

* It is now clear that the total quantity of hydraulic energy that can be produced is insignificant (see Garg, 1979).

Figure 4.3.1
Phases of Project Development

Figure 4.3.2
Typical Production Paths

where

REV_i = revenue in i^{th} year of project

P_i = price in i^{th} year of project

Q_i = production in i^{th} year

Forecasting prices for future oil and gas has, however, always been a difficult task, even before the events of 1973 (see Grayson , 1960). Indeed there is an important relationship between decisions on "how much" to produce in year i , and the expected price in year i . The usual approach to this problem is to choose a production path so that production is maximized in the early years. It is often argued that since future cash flows are discounted heavily, this procedure is consistent with maximizing resource producer profit. However, if the price of the resource is escalating at a rate higher than the discount rate, this claim is not valid. Another important issue is the magnitude of the price itself. Some models treat the price received by the resource producer as a random variable. Although it is difficult to forecast future prices precisely, the current model, treats the price as an exogenous variable known with certainty and escalating at a constant rate. The procedure is appropriate for our problem principally because our purpose is to study the impact of higher prices on resource producer decisions. Moreover, the price of methane will not be influenced appreciably by the production of geopressured

methane. In addition to price risk, the resource producer faces varying degrees of uncertainty about future OPEC policies, regulatory policies etc., and we have discussed the question of making adjustments for these factors in Section 4.2.4.

The current model includes a provision for a "thermal credit" which can, of course, be set equal to zero. The assumption here is that the resource producer sells the heat from the brine at some pre-determined price. Whether the heat is used to produce electricity or whether it is used to process heat is of no direct consequence to the producer. (For a discussion of the prospects for process heat utilization see Frederick et al., 1979).

To summarize, the current model determines operating revenues from the following equation:

$$REV_i = 365 \times P_{og} (1+g_g)^i \times S \times Q_i + 365 \times P_{ot} (1+g_t)^i \times Q_i \quad (4.8)$$

where

- REV_i = Revenues in i^{th} year
- P_{og} = Initial gas price (\$/MCF; input variable)
- P_{ot} = Initial thermal price (\$/bbl; input variable)
- S = Solubility (MCF/bbl; random variable)
- Q_i = Production in year i (bbl/day; random variable)
- g_g = Gas price escalation rate
- g_t = Thermal price escalation rate.

4.3.4 Cost Assumptions

The current model uses a narrow subjective triangular probability distribution of costs built around the most likely cost, M (see Figure 4.3.4). Cost uncertainty is an important source of project riskiness, especially in the cash flow sense, since major costs are incurred at the start of the project.

The "most likely" estimate, M, for each cost item was developed on the basis of an extensive literature search, analysis of engineering estimates, and personal interviews and is shown in Table 4.3.4.

4.3.5 Financial Inputs

The model requires a number of financial and tax-related parameters as inputs. Table 4.3.5 presents the magnitude of these parameters for the base case run.

4.4 Cash Flow Simulation Model

Figure 4.4.1 shows the structure of the cash flow simulation model. For a given set of inputs, the model generates a probability distribution for the relevant investment attributes, namely, NPV^* , IRR^* , and SI. Interpreting probability distributions without a formal decision model is not very meaningful. Current research is aimed at developing an appropriate decision model (see Section 6).

Figure 4.3.4

Probability Distribution for Cost Estimates

Table 4.3.4

Geopressured Project Cost Estimates

1980 dollars

<u>Cost Category</u>	<u>Most Likely Estimate</u>
1. Land	\$25/acre (total area: 8000 acres)
2. Preliminary Geologic and Geophysical Tests	\$100,000
3. Environmental Studies	\$300,000
4. Engineering Design and Site Preparation	\$100,000
5. Exploratory Wells*	$C_e = $.5C_d$
6. Development Wells (includes completion costs for a 5.5" tubing well)	$C_d = $.00249d^{2.181}$
7. ReInjection wells (for wells between 2000 and 10,000 feet)	$C_r = \$102.8d^{1.035}$
8. Well Ratios	
Spare Well Fraction	0
ReInjection	1:3
9. Surface Facilities (includes methane separator and disposed system; exclude reinjection wells)	$C_s = \$943,200 + 32.03Q$
10. Operating Expenses	$C_o = \$320,000 + (.029)(365Q)$
11. Insurance**	0

* C_e (cost per exploratory well); C_d (cost per development well); d (depth of well in feet); C_r (cost per reinjection well); C_s (total cost of facilities); Q (brine production in bbl/day); C_o (total annual operating cost).

**No explicit insurance costs to cover against subsidence or environmental damage has been included. It appears premature to include such insurance, although the drilling contractors on the DOE sponsored design well carry insurance upto \$100 million in damage.

Table 4.3.5

Summary of Financial Parameters: Base Case

Initial Methane Gas Price	\$8/MCF
Initial Thermal Price	0
Gas Price Escalation Rate	8.5% annually +
Thermal Energy Escalation Rate	0
Cost Escalation Rate	8.0% annually +
Intangible Fraction	.70
Investment Tax Credit	10%
Effective Tax Rate*	50%
Fraction financed by producer	1.0
Opportunity Cost of Initial Outlay	9.5% ++
Project Revenue Reinvestment Rate	9.5%-10% ++
Depletion Allowance	10% +++
Tax Life	11 yrs.
Royalty Fraction	10%

* Includes federal, state and local taxes

+ This represents a nominal annual rate

++ These rates are long-term, risk free rates which, as we discussed, are appropriate for our purposes. They can be viewed as the rate at which the firm could lend money free of risk.

+++It is assumed that a depletion allowance of 10% will be available for the entire length of the project.

Figure 4.4.1

Structure of the Simulation Model

The cash flow simulation model is designed to readily generate cash flow distributions under alternative assumptions. For instance, if some fraction of the initial outlay is obtained at a relatively low interest rate because of a loan guarantee*, the model generates probability distributions for NPV*, IRR*, and SI under this scenario. Likewise, the impact on the cash flow of a change in tax life (for depreciation purposes) or an increased investment tax credit can be readily investigated.

* It is not always the case, however, that a loan guarantee lowers the interest rate (see Nasr, 1978).

5. CASH FLOW SENSITIVITY ANALYSIS

The profitability of a geopressured venture can, as was pointed out, be represented by after-tax probability distributions of the modified net present value (MNPV), the modified rate of return (MRR), and the risk payback or safety index (SI). These profitability measures are sensitive to resource parameters, financial parameters, and, prices. Public policy is often aimed at influencing producer decisions through taxes and subsidies. The stochastic cash flow model combined with a decision model enables us to identify the impact of specific incentives on producer decisions. The choice of a particular public policy initiative is, however, not easy since in addition to the impact on producer profitability, the budgetary and administrative implications of particular incentives have to be considered. Table 5.0.1 provides a summary of a number of incentive categories and their characteristics, some of which are examined in detail (see Section 5.3).

In the following section, we will present the results from sensitivity runs on a number of parameters. We shall begin with the base case run.

5.1 The Base Case

Table 4.3.5 contains the parameters that were used (in addition, of course, to the cost estimates discussed in Section 4) in the base case run.

Table 5.0.1

Commercialization Incentives: Tax Subsidies

Alternative Forms	Specific Examples	Application as a User Incentive	Evaluation
1) Income Tax Credits	<ul style="list-style-type: none"> ●Fifteen percent tax credit for conservation investment (Energy Tax Act 1978, P.L. 9) ●Thirty percent tax credit for renewable energy investment (Energy Tax Act) 	All four forms could be utilized as incentives for geopressured investment. Relative effectiveness depends on firm tax liabilities and the size of the investment	<u>Benefits</u> <ul style="list-style-type: none"> ●Tax incentives appear popular in business community ●Are simple to administer ●Promote private decision making
2) Investment Tax Credits	<ul style="list-style-type: none"> ●Ten percent investment tax credit for energy conservation equipment reducing oil or natural gas requirements (Energy Tax Act) 		<u>Costs</u> <ul style="list-style-type: none"> ●Tax incentives tend to be inequitable ●Ineffective where limited tax liability exists (small or new firms for example)
3) Tax Liability Reduction	<ul style="list-style-type: none"> ●Oil production tax exemption for small producers (Windfall Profits Tax Act) 		<ul style="list-style-type: none"> ●Difficult to trace effectiveness
4) Accelerated Depreciation	<ul style="list-style-type: none"> ●Accelerated depreciation for oil drilling equipment (U.S. Tax Code) 		<ul style="list-style-type: none"> ●Difficult to accurately calculate budget impact ●May result in "windfalls" if taxpayers would have invested regardless of tax subsidy

Table 5.0.1 (continued)

Commercialization Incentive: Credit Subsidies

Alternative Forms	Specific Examples	Application as a User Incentive	Evaluation
Low Interest Direct Loans	<ul style="list-style-type: none"> ●Rural Electrification Program provides loans for projects (REA Act) ●TVA provides interest free weatherization loans to homeowners 	Credit subsidies should prove effective assuming (1) That initial capital investment is significant (2) That capital markets display resistance because of perceived risk of technology or of potential borrower in general	<u>Benefits</u> <ul style="list-style-type: none"> ●Can reduce capital barriers ●Limited costs to the government
Subsidized Loans	<ul style="list-style-type: none"> ●Recently established Solar Energy and Conservation Bank will subsidize private institution loans (2 to 3% below market rates) to home and building owners (Energy Security Act PL 95- 		<u>Costs</u> <ul style="list-style-type: none"> ●Interferes in capital markets ●Removes risk from technology producers
Guaranteed Loans	<ul style="list-style-type: none"> ●Federal Government offers guarantees to loans ranging from student loans to urban renewal ●The Synthetic Fuels Corporation may guarantee loans for commercial scale synthetic fuels plants (Energy Security Act) 		
Indemnification	<ul style="list-style-type: none"> ●Federal indemnification of nuclear power facilities limiting liability (Price Anderson Act) ●Geothermal Insurance 		

Table 5.0.1 (continued)

Commercialization Incentive: Purchase Subsidies

Alternative Forms	Specific Examples	Application as a User Incentives	Evaluation
Purchase Guarantee	<ul style="list-style-type: none"> ●Synthetic Fuel Corporation has authority to provide purchase guarantees to synthetic fuel producers. Corporation can contract for specific amounts of fuel (Energy Security Act) 	<p>While the examples provided involve guarantees of markets and prices to suppliers, guarantees could also be made to consumers. This could be accomplished by paying the difference between market price and a guaranteed ceiling price for example.</p>	<p><u>Benefits</u></p> <ul style="list-style-type: none"> ●Reduces risk to consumers ●May prove relatively inexpensive, depending on price formula and world energy price changes
Price Guarantees	<ul style="list-style-type: none"> ●Synthetic Fuel Corporation has authority to guarantee a specified price for synthetic fuels under contract. Price level can be established in a variety of ways (Energy Security Act). 	<p>The effectiveness of these incentives depends on the importance of fuel prices and security are in investment decisions.</p>	<p><u>Costs</u></p> <ul style="list-style-type: none"> ●Establishment of price may be difficult ●Interference with prices of other energy sources.

Table 5.0.1 (continued)

Commercialization Incentive: Regulatory Subsidies

Alternative Forms	Specific Examples	Applications as a User Incentive	Evaluation
Price Regulation	<ul style="list-style-type: none"> ●Natural Gas Policy Act regulates natural gas prices in attempt to reduce impacts on certain consuming sectors as price deregulation occurs (NGPA) ●Oil Entitlements Program to reduce impacts on domestic refiners of foreign oil. 	Aside from entry restrictions, these forms of regulatory subsidies could be directed at consumers of a new technology.	<u>Benefits</u> <ul style="list-style-type: none"> ●Many of the possible regulatory actions would have low direct costs. to the government ●Highly visible
Entry Restrictions	<ul style="list-style-type: none"> ●Nuclear Licensing 		
Surcharges	<ul style="list-style-type: none"> ●Proposed gasoline surcharge to dampen demand, cause relative improvement in demand for substitutes. 		
Required level of Service	<ul style="list-style-type: none"> ●Federal requirements that utilities provide energy conservation audits (Public Utilities and Regulatory Policy Act) ●Federal requirements for utilities' use of cogeneration (Public Utilities and Regulatory Policy Act) 		

Since the resource price and the relevant opportunity costs of funds are exogenous to this model, they have to be carefully examined.

We have already discussed our reasons for treating the price as a non-random exogenous variable. For the base case run, we have chosen an escalation rate that is slightly higher than the cost escalation rate. This appears reasonable in light of the consensus among experts that large natural gas reserves remain to be found in the continental United States at prices that are higher than the current average price. In fact, the escalation rate for costs could possibly exceed the escalation rate for resource price in the case of geopressured methane. This possibility will be examined in greater detail in Section 5.4.3.

It is important to bear in mind that the opportunity costs that are relevant to our model are long-term, risk-free rates. Thus, we could regard the long-term (as distinct from the fluctuating, transient) rate for government securities to be the relevant opportunity cost. In Table 4.3.5 the opportunity cost of initial outlays is the risk-free rate at the time of project initiation. The project revenue reinvestment rate is a vector of future long-term risk-free rates. Risk can be accounted for completely and explicitly in the decision model by using appropriate utility functions. In the present report, we illustrate the use of a risk-adjusted

net present value or "risk-adjusted value" by using a simple utility function for net present value.* In the case of the other measures, namely, modified rate of return (MRR), and safety index (SI) only the probability distribution are presented.

Results from the base case formulation run are presented in Table 5.1.1. The results show that a firm (or developer) could lose as much as \$2.5 million on this venture or make a profit as high as \$12.5 million. The question that the risk-adjusted value answers is whether this lottery is worth accepting. The risk-adjusted value shows that the venture is worth about \$1.1 million in after-tax profits. This, of course, is far smaller than the expected value of about \$4.9 million. Table 5.1.1 also shows the maximum, minimum and average values for the modified rate of return (MRR) and the safety index (SI). Again, the large risks involved are evident.

5.2 Sensitivity to Resource Parameters

As was discussed, a number of investigators have raised questions on the "effective size" of geopressured reservoirs because of sealing faults within the reservoir. In addition, as the NPC (1980) report points out, the resource is "thin": a price of \$8.00/MCF (our base case value) translates to

* The utility function is: $\frac{1}{r} (1 - e^{-rx})$ (5.1)

where $r = 1 \times 10^{-6}$

and x = increase in net assets in million

Table 5.1.1

Results for Base Case Run

	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87

20¢/bbl when the methane solubility is 25 CF/bbl. Although petroleum reservoirs are usually much smaller than geopressured reservoirs, it is important to note that new oil can, in comparison, fetch upwards of \$35/bbl.

Another important limitation of geopressured resources is the limit placed on resource extraction by reservoir permeability. Estimates of the ratio of brine extracted to brine-in-place vary from 0.01 to 0.04 or 0.05 (see Lewin Associates, 1980; EPRI, 1980; MacDonald et al., 1979).

In order to study the sensitivity of after-tax profitability to variations in these resource parameters, a number of Monte Carlo simulations were performed, the results of which are discussed below.

5.2.1 Reservoir Drainage Area

Table 5.2.1 shows the results from a sensitivity analysis. Case 5.2.1a shows that if the minimum reservoir size is reduced to 5 square miles while the most likely and maximum values remain unchanged, the value of the venture to a resource producer drops dramatically. It is still possible, as the maximum NPV shows, to earn a profit of about \$12.5 million; however, it is now possible to lose as much as \$3.3 million. In risk-adjusted terms, the venture now represents a loss of about \$800,000.

Case 5.2.1b represents a case where the minimum and maximum values of drainage area are smaller, with the same mode. Such a change in probability distribution could come

Table 5.2.1

Sensitivity to Reservoir Drainage Area

Drainage Area (square miles)	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE													
Min Max Mode	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
10 20 16													
CASE 5.2.1a													
Min Max Mode	-3.3	12.58	3.17	3.75	-0.806	0.06	0.15	0.11	0.023	0.80	4.9	2.50	1.02
.5 20 16													
CASE 5.2.1b													
Min Max Mode	-0.525	12.58	5.82	2.74	2.89	0.09	0.15	0.127	0.012	1.47	4.9	3.20	0.75
14 18 16													

about as a result of more research on reservoir characteristics. Here again, the simulation shows a maximum profit of about \$12.5 million. The maximum loss is, however, only about \$500,000. The venture is, therefore, more attractive than the base case as is reflected by a risk-adjusted value of \$2.8 million.

5.2.2 Methane Solubility

Three cases of methane solubility were compared to the base case (see Table 5.2.2 for details).

In Case 5.2.2a, a leftwards shift in the probability distribution of methane was considered. As can be seen from Table 5.2.2, this reduces the maximum profit on the venture from \$12.5 million in the base case to \$7.0 million. The maximum loss also increases, though not as sharply. The venture, as a whole declines steeply in attractiveness as indicated by a risk-adjusted value of about - \$930,000.

Case 5.2.2c, on the other hand, represents a significant improvement in resource quality. The attractiveness of this venture is very high as indicated by a risk-adjusted value of over \$6.0 million.

5.2.3 Extractive Coefficient

The current simulation model treats the extractive coefficient as a random variable. Since the extractive coefficient depends, to a great extent, on the permeability, this sensitivity run throws light on the influence of permeability. The results are shown in Table 5.2.3.

Table 5.2.2

Sensitivity to Methane Solubility

Methane Solubility (CF/bbl)	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE													
Min Max Mode													
23 27 25	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.2.2a													
Min Max Mode													
19 21 20	-3.97	7.01	1.29	2.36	-0.934	0.051	0.13	0.10	0.017	0.64	3.52	2.04	0.647
CASE 5.2.2b													
Min Max Mode													
28 32 30	-0.64	18.05	8.64	3.94	3.16	0.09	0.165	0.14	0.015	1.42	6.27	3.89	1.07
CASE 5.2.2c													
Min Max Mode													
35 40 38	2.19	26.6	14.3	5.11	6.21	0.11	0.18	0.15	0.0146	2.07	8.38	5.31	1.38

Table 5.2.3

Sensitivity to Extractive Coefficient

Extractive Coefficient (%)	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE													
Min Max Mode													
0.03 0.05 0.045	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.2.3a													
Min Max Mode													
0.04 0.05 0.045	-1.0	12.96	6.19	3.07	2.45	0.086	0.15	0.128	0.014	1.34	5.16	3.3	0.83
CASE 5.2.3b													
Min Max Mode													
0.025 0.045 0.035	-3.18	10.78	2.48	2.75	-0.212	0.062	0.146	0.11	0.017	0.81	4.49	2.29	0.75

In Case 5.2.3a, the minimum fraction extracted was increased from 0.03 to 0.04. As the results show, this has the impact of sharply reducing the maximum loss, while it does not increase the maximum profit as much. Given the risk-averse behavior of producers, this loss reduction is quite significant, as reflected by a risk-adjusted value of \$2.45 million.

In Case 5.2.3b the distribution was shifted to the left. This sharply reduces venture attractiveness. In risk-adjusted terms, the venture now represents a loss of over \$200,000.

5.3 Sensitivity to Financial Parameters

We shall now examine the impact of a number of financial parameters on the profitability of a venture.

5.3.1 Sensitivity to Investment Tax Credit

The current cash flow model assumes that there is always enough unrelated income against which a tax credit can be claimed. Thus, we see that the impact of a tax credit is to shift the entire probability distribution to the right (see Figure 5.3.1A). Another important feature of the investment tax credit is that its impact is felt at the very beginning of the project, i.e., it effectively lowers the initial outlay. For this reason, the investment tax credit is sometimes referred to as a "front-end incentive" (Booz Allen, Inc., 1979).

Figure 5.3.1A

Impact of Tax credit on net present value

Table 5.3.1
Sensitivity to Investment Tax Credit

	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE 10%	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.3.1a 20%	-2.12	12.94	5.27	3.19	1.43	0.07	0.15	0.125	0.016	1.05	5.16	3.11	0.91
CASE 5.3.1b 30%	-1.78	13.3	5.60	3.19	1.75	0.077	0.16	0.128	0.016	1.09	5.44	3.27	0.96
CASE 5.3.1c 40%	-1.44	13.65	5.93	3.20	2.08	0.08	0.16	0.131	0.016	1.16	5.75	3.44	1.01

Figure 5.3.1B

Variation of expected value and risk-adjusted value with investment tax credit

Case 5.3.1a, 5.3.1b and 5.3.1c in Table 5.3.1 represent tax credit rates 0.2, 0.3 and 0.4 respectively. As can be seen from Figure 5.3.1B, the investment tax credit shifts both the expected value and the risk-adjusted value uniformly upwards. With an investment tax credit rate of 0.4, the after tax risk-adjusted value of the venture is \$2.08 million. (This should be compared with a base case risk-adjusted value of \$1.09 million.)

5.3.2 Sensitivity to Reduced Tax Lives

Compared to the investment tax credit, the impact of reducing the tax life is small (see Table 5.3.2). Even in the case of a 3 year tax life, the risk-adjusted value of the venture is about \$1.58 million (see Case 5.3.2c); in contrast, with an investment tax credit of 0.3, the risk-adjusted value is about \$1.75 million. This is because the beneficial impact of a reduced tax life is spread over the early years and is not immediately available as in the case of an investment tax credit.

Figure 5.3.2 shows the variation of the expected value and the risk-adjusted value with tax life. It is clear that this change is not linear. The reason for the non-linearity is the complex formula for sum-of-the years depreciation.

5.3.3 Special Loan Mechanisms

Special loan mechanisms are usually undertaken with either or both of the following objectives: (1) to rectify

Table 5.3.2

Sensitivity to Reduced Tax Life

Reduced Tax Life	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE 11 years	2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.3.2a 7 years	-2.27	12.65	5.04	3.17	1.26	0.074	0.15	0.12	0.016	1.02	4.91	2.97	0.86
CASE 5.3.2b 5 years	-2.12	12.71	5.15	3.15	1.40	0.076	0.15	0.12	0.015	1.04	4.91	2.98	0.86
CASE 5.3.2c 3 years	-1.93	12.89	5.35	3.15	1.59	0.078	0.15	0.12	0.015	1.06	4.93	3.0	0.86

Figure 5.3.2

Variation of expected value and risk-adjusted value with tax life

what is believed to be a misjudgement of risks by the private sector; and (2) to make capital available to a certain "special sectors" at lower-than-market rates.

In the former case, the most common mechanism is a loan guarantee. Although in theory loan guarantees are supposed to reduce the interest rate by making a default risk premium unnecessary, in practice they add to the administrative costs (see Nasr, 1978).

In the latter case, the government, in addition to providing a guarantee, agrees to pay the difference between the market rate and a pre-specified rate that the borrower has to pay. There are, in addition, instances of direct lending at lower-than-market rates by a number of federal agencies.

In the current study, the latter version was modeled. It was assumed that even in the event of a failure, the developer would not default on the loan since that would seriously damage his credit worthiness in the private sector. The borrowing rate was fixed at 8.5%, which is lower than the assumed long-term risk free rate of 9.5%. Cases 5.3.3a, 5.3.3b, and 5.3.3c represent guaranteed fractions of 25%, 50%, and 75%. The results in Table 5.3.3 show that the loan guarantee does markedly reduce the maximum loss. At the same time, the subsidy in the form of lower-than-market interest rates improves the average profitability of the project. As a consequence, the risk-adjusted value rises significantly. For example, with a 50% guarantee, the risk-

Table 5.3.3
Sensitivity to Loan Mechanisms

Guaranteed Fraction	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE 0.0	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.3.3a 25% @ 8.5%	-2.02	12.90	5.27	3.18	1.49	0.069	0.16	0.13	0.019	0.92	6.11	3.52	1.15
CASE 5.3.3b 50% @ 8.5%	-1.54	13.22	5.62	3.15	1.92	0.065	0.18	0.14	0.023	0.81	8.51	4.64	1.72
CASE 5.3.3c 75% @ 8.5%	-1.01	13.55	5.99	3.12	2.39	0.051	0.218	0.17	0.030	0.49	15.7	8.02	3.42

adjusted value rises to \$1.92 million from a base case value of \$1.09 million.

A more interesting insight into this mechanism can be gained by looking at the modified rate of return. Consider a 75% guarantee (Case 5.3.3c). The initial amount put out by the resource producer is small. If the project fails, he would still have to repay the loan. The subsidy in the borrowing rate does, however, lower the loss relative to his initial investment. From Table 5.3.3 we see that the minimum rate of return can be as low as 5%. However, if the project succeeds, the subsidy implicit in the borrowing rate translates into a very high payoff on a small initial investment. This can be seen as the maximum possible rate of return, which can be as high as 21.8%.

5.4 Impact of Prices on Producer Decisions

In investigating this important area, we will focus our attention on three distinct issues. (1) Given our base case resource parameters, we will determine a price, including thermal credits, at which the venture exhibits a positive profit after adjusting for risk in the manner described earlier. In addition, we will compute the expected supply of methane from this single reservoir over its first five years (i.e., its peak years) of production in CF/year. (2) We increase the minimum drainage area from the base case value, and calculate the price at which the venture shows a profit on a risk-adjusted basis. (3) We will discuss the

circumstances under which government policies such as investment tax credits induce the producer to deplete the resource with two or more wells, i.e., more rapidly.

5.4.1 Impact of Rising Prices on Risk-Adjusted Value

Table 5.4.1 presents the impact of a rising initial methane price on venture profitability. In all cases presented in Table 5.4.1, the escalation rates for methane and for costs remains unchanged from the base case. Figure 5.4.1 shows the impact of a higher initial gas price on the risk-adjusted value of the venture. From Figure 5.4.1, it is clear that the venture begins to show a positive risk-adjusted profit when the initial price is somewhere between \$7/MCF and \$7.25/MCF. Further, at this price the expected supply of methane from the reservoir over the first five years of production is 0.21 BCF/year. With the escalation rates fixed at base case values, it was found that there was no incentive (even at \$10/MCF) to deplete the resource more rapidly with two or more wells. In Section 5.4.3, we shall discuss the impact of changing the escalation assumptions.

Table 5.4.2 presents the impact of thermal credits on the profitability of a venture. As is clear from a comparison of Tables 5.4.1 and 5.4.2, a thermal credit of 3¢/bbl improves the risk-adjusted value considerably. There is much uncertainty, however, about the demand for process heat in the area (see Frederick, et al., 1979). For that reason, many sensitivity runs were not made.

Table 5.4.1A

Sensitivity to Initial Methane Price

Initial Methane Price	Modified Net Present Value ($\$ \times 10^6$)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE $P_o = \$8/\text{MCF}$	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.4.1a $P_o = \$5/\text{MCF}$	-5.08	2.31	-1.74	1.63	-2.8	0.029	0.11	0.077	0.017	0.39	2.35	1.27	0.45
CASE 5.4.1b $P_o = \$7/\text{MCF}$	-3.46	9.14	2.65	2.70	-0.18	0.059	0.14	0.11	0.017	0.76	4.05	2.38	0.73
CASE 5.4.1c $P_o = \$10/\text{MCF}$	-0.237	19.5	9.57	4.15	3.65	0.093	0.169	0.14	0.015	1.52	6.62	4.12	1.13

Figure 5.4.1

Impact of higher initial gas price on risk-adjusted value

Table 5.4.2B

Sensitivity to Thermal Credits

Thermal Credit	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE P _o : \$8/MCF Thermal Credit = 0.0	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.4.2a P _o : \$7.25/MCF Thermal Credit: \$0.05/bbl	-1.12	16.52	7.63	3.72	2.63	0.086	0.16	0.13	0.015	1.30	5.88	3.63	1.01
CASE 5.4.2b P _o : \$7.25/MCG Thermal Credit \$0.03/bbl	-1.99	13.91	5.86	3.37	1.63	0.077	0.155	0.13	0.016	1.1	5.23	3.19	0.91

5.4.2 Price Sensitivity of Larger Reservoirs

A number of simulations of price sensitivity were run with the assumption of a bigger average reservoir and smaller variance in reservoir size. Table 5.4.2 reveals that with an increase in average reservoir size, the venture exhibits a positive risk-adjusted profit at an initial price of a little under \$6.50/MCF. This, of course, should be compared with the base case result, which was in the neighborhood of \$7.25/MCF.

5.4.3 Price Escalation Rates and Producer Decisions

In all the sensitivity runs discussed above, the gas price escalation rate exceeded the cost escalation rate by a small amount. It was found that this assumption led to a single well development scenario even at very high prices (e.g. \$10/MCF).

An alternative scenario was posed to test the sensitivity of producer decisions to price expectations. It was assumed (i) that a larger reservoir was available and (ii) price expectations were such that the costs escalated more rapidly than the price. The new inputs as well as the results are summarized in Tables 5.4.3A and 5.4.3B. At higher prices, a two well development scenario is the producer's preferred option if the reservoir is big. On average, therefore, the two well option is preferred more frequently. This is reflected in the average supply from the reservoir over the initial five years. We see from

Table 5.4.2
Price Sensitivity of Larger Reservoirs

Area; Price	Modified Net Present Value (\$ x 10 ⁶)					Modified Rate of Return (%)				Safety Index (SI)			
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	Min.	Max.	Avg.	Std. Dev.	Min.	Max.	Avg.	Std. Dev.
BASE CASE Min Max Mode 10 20 16 Initial Price: \$8/MCF	-2.47	12.58	4.94	3.19	1.1	0.072	0.15	0.12	0.016	0.99	4.9	2.96	0.87
CASE 5.4.2a Min Max Mode 14 18 16 Initial Price: \$6/MCF	-3.25	5.69	0.986	1.90	-0.53	0.06	0.13	0.10	0.014	0.81	3.19	1.97	0.52
CASE 5.4.2b Min Max Mode 14 18 16 Initial Price: \$6.50/MCF	-2.61	7.41	2.17	2.11	0.32	0.07	0.13	0.108	0.013	0.97	3.62	2.28	0.58
CASE 5.4.2c Min Max Mode 14 18 16 Initial Price: \$7.25/MCF	-1.59	10.0	3.99	2.43	1.61	0.08	0.14	0.118	1.013	1.21	4.26	2.73	0.67

Table 5.4.3A

Price Escalation Rates and Supply

PARAMETERS

Gas Price Escalation: 0.06

Cost Escalation : 0.08

Drainage Area (square miles)

Min.	Max.	Mode
16	20	18

All Other Parameters Assume Base Case Values

	Modified Net Present Value (\$ x 10 ⁶)					Average Supply Over Initial Five Years
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	
Initial Gas Price \$7.50/MCF	-1.53	6.58	2.21	1.72	1.03	25544 bbl/day (0.23BCF/year)
Initial Gas Price \$8.50/MCF	0.002	9.85	4.41	2.06	2.82	30196 bbl/day (0.275BCF/year)
Initial Gas Price \$9.50/MCF	1.57	13.14	6.67	2.46	4.59	33454 bbl/day (0.305BCF/year)

Table 5.4.3B

Price Escalation Rates and Supply

PARAMETERS

Gas Price Escalation : 0.06

Cost Escalation : 0.08

Investment Tax Credit: 0.3

Drainage Area (square miles)

Min.	Max.	Mode
16	20	18

All Other Parameters Assume Base Case Values

	Modified Net Present Value (\$ x 10 ⁶)					Average Supply Over Initial Five Years
	Min.	Max.	Avg.	Std. Dev.	Risk Adjusted Value	
Initial Gas Price \$7.00/MCF	-1.57	6.06	1.82	1.60	0.813	29337 bbl/day (0.27 BCF/year)
Initial Gas Price \$7.50/MCF	-0.85	7.70	2.93	1.80	1.71	31568 bbl/day (0.29 BCF/year)
Initial Gas Price \$8.50/MCF	0.684	10.98	5.21	2.22	3.50	37077 bbl/day (0.34 BCF/year)

Figure 5.4.3

Impact of increased price on average supply

Figure 5.4.3 that the average supply increases with price.

A similar exercise was conducted with an increased investment tax credit. The results are summarized in Table 5.4.3B. Thus we see that if the average reservoir size is large and the escalation rate of gas prices is lower than the cost escalation rate, the investment tax credit not only makes projects more attractive but also accelerates the rate of resource depletion (see Figure 5.4.3).

6.0 DECISION MODELS

The mechanism used to arrive at the risk-adjusted value in Section 5 is based solely on the net present value. This would imply that a firm would be indifferent between two opportunities that had the same risk-adjusted value. Yet, as we have discussed in Section 4, there is strong reason to believe that private resource producers will prefer projects that have a "relatively better" cash flow pattern in the early years because of a lack of credibility in future probability distributions. We have also discussed a proxy measure of "state-of-the world" uncertainty, namely, the safety index (SI). The cash flow model has been designed to simulate a probability distribution of SI.

We shall now turn to a more general formulation of this problem. The attractiveness of a more general formulation is clear: it enables us to represent more complex preference structures simply by changing the parameters of our model.

6.1 Formulation of a Multi-Period Utility Function

Consider a utility function $U(F_1^*, F_2^*)$ where F_1^* and F_2^* are the present values (discounted at the risk-free rate) of cash flows in periods 1 and 2. The utility function $U(F_1^*, F_2^*)$ is, of course, a valid von Neumann-Morgenstern utility function in that two joint probability distributions of F_1^* and F_2^* can be ranked by expected utility. As we have discussed before, a firm may not be indifferent between two streams S and S' given by

$$S : (F_{S1}^* , F_{S2}^*) ,$$

$$S' : (F_{S'1}^* , F_{S'2}^*)$$

$$\text{where } F_{S1}^* + F_{S2}^* = F_{S'1}^* + F_{S'2}^*$$

Since F_1^* and F_2^* are present values, this absence of indifference implies a preference purely for time paths of cash flow. We can choose a utility function wherein early cash flows are preferred to later cash flows, all else being the same.

If we assume mutual utility independence between period 1 and period 2, we can write

$$U(F_1^* , F_2^*) = k_1 U_1(F_1^*) + k_2 U_2(F_2^*) + k k_1 k_2 U_1(F_1^*) U_2(F_2^*) \quad (6.1)$$

Further, if we assume stable preference over time, we have

$$U^*(F^*) = U_1(F^*) = U_2(F^*) \quad (6.2)$$

and we can write

$$U(F_1^* , F_2^*) = k_1 U^*(F_1^*) + k_2 U^*(F_2^*) + k k_1 k_2 U^*(F_1^*) U^*(F_2^*) \quad (6.3)$$

Mutual utility independence is not, however, a good working assumption for our purposes since we want to represent a preference structure where cash flows in different time periods are very likely to be interdependent.

An assumption that would be more relevant to our problem is that the future is utility independent of the past. In other words, preferences for future outcomes

are not influenced by past outcomes. Preferences for outcomes in a single period do, however, depend on the future. With this assumption we can write (see Keeney and Raiffa, 1976) :

$$U_t(X_t) = a_t(x_t) + b_t(x_t)U_{t+1}(X_{t+1}), \quad (6.4)$$

$$\text{for } t = 1, 2, 3, \dots, n$$

where X_t is the vector of n-period outcomes

$a_t(\cdot)$ is a real valued function

$$b_t(\cdot) > 0$$

and U_t is the n-period utility function.

It has been shown by Keeney and Raiffa, 1976 that (6.4) can be expressed as

$$U(X) = \sum_{t=1}^n a_t(x_t) \left(\prod_{\tau=1}^{t-1} b_{\tau}(x_{\tau}) \right) \quad (6.5)$$

where the empty product

$$\prod_{\tau=1}^0 b_{\tau}(x_{\tau}) = 1$$

Thus, (6.5) offers alternative way of modeling producer decisions.

6.2 Status of Current Research

A resource developer's decision to invest or not invest in a geopressured project is a complex process that no existing theoretical decision model can describe in complete detail. Models such as the one discussed in

Section 6.1 provide a framework within which different preference structures can be consistently represented. Two areas of research are being pursued at the present time.

(1) It is proposed to gather information on preferences from potential participants in geopressured resource development, and use this data to obtain the parameters of the model discussed in Section 6.1. This task will not only entail preferences for simple lotteries, but will also include a close examination of past corporate decisions of potential developers. Also, the nature of the risk-return tradeoff for small, independent operators will be considered. Models for studying the commercialization of hydrothermal resources have already been developed in some detail (see Blair and Cassel, 1980; Cassel et al., 1979).

(2) It is proposed to use this decision model to gain insight into alternative policies. Since the selection of policies has to balance the often conflicting objectives of rapid commercialization and economic efficiency, it is worthwhile to examine if specific policies can achieve both objectives. In the presence of risk, for instance, the design of innovative risk sharing policies suggests itself.

7. CONCLUSIONS

In this section we will summarize the implications of the sensitivity runs discussed in Section 5. Three important points must however, be borne in mind. (1) We will assume that geopressured methane is a "bridge fuel" the development of which will ease the transition to more abundant resources. As a consequence, we focus on the impact of public policy measured in terms of acceleration of resource development. The question as to whether or not this is an "optimal" path of resource depletion for the economy as a whole is a complex question that cannot be easily answered (see Dasgupta and Heal, 1979, for a theoretical discussion). (2) Our purpose here is to characterize the impact of a number of public policies on the probability distributions of profitability. The choice of a public policy instrument involves a number of considerations in addition to this impact. (3) We will refer to results derived from a utility function for net present value as "risk-adjusted results". Although these results are useful, a more complete understanding of resource producers behavior requires a multi-period utility function such as the one discussed in Section 6.

With these caveats, we will discuss the results obtained thus far:

(A) In the case of resource parameters, placing a lower bound on minimum values substantially decreases risk

and enhances venture attractiveness.

(B) A reservoir that possesses our base case parameters (which is based on the best available information for the Austin Bayou Project), presents an acceptable investment opportunity after adjustment for risks, when the initial price is between \$7.0 and \$7.25/MCF, and the price escalates at a nominal annual rate of 8.5%. At this price and with the cost escalation rate slightly lower than the price escalation rate, it is almost always better for a resource producer to deplete the reservoir with one well. Thus, the average peak supply from the reservoir is about 0.21 billion cu.ft. per year.

(C) If a credible lower bound on reservoir drainage area could be placed at 14 square miles, the attractiveness of the venture increases markedly. With a lower bound of 14 square miles, it was found that the venture presents an acceptable investment opportunity at an initial price of about \$6.50/MCF, escalating at a nominal annual rate of 8.5%.

(D) A number of public policy initiatives were considered, and it was found that in terms of making geopressured projects more attractive, investment tax credits were moderately successful. Further, it was found that a subsidized loan on some fraction of the project has the following impact: it dramatically increases the rate of return on a successful project, making it as high as

21.8%; and, in the event of a loss, the absolute loss (as distinct from the rate) is small. A subsidized loan may, therefore, be perceived by business as a low-risk way of trying a new technology.

(E) In terms of increasing the peak supply (which occurs in the early years) from a reservoir, the crucial parameter is not price, but price escalation rate. If the price escalation rate for gas is lower than the cost escalation rate and the reservoir is bigger (on average) than the base case, it is conceivable that resource producers would deplete the reservoir with two or more development wells, thereby increasing the peak supply. As was discussed earlier, the peak supply can be further increased by an investment tax credit.

It is possible to design subsidies the effect of which is equivalent to a price escalation rate that is lower than the cost escalation rate. For instance, a steadily declining cash subsidy per unit produced offered over a fixed period of time could have this impact.

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