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ECONOMIC EVALUATION OF FOUR GAS PLAYS AND RANKING ANALYSIS OF FEDERAL OIL AND GAS LEASES, NORTHWESTERN COLORADO

by

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ABSTRACT

This thesis concentrates upon two types of economic evaluations. (1) The ranking of available Federal leases not on a known geologic structure, and (2) the evaluation of four gas plays in northwestern Colorado using before-tax, after-tax and risk analysis methods.

The BLM distributes Federal leases of the above type by simultaneous filing, which is similar to a lottery. Given that there is a varying element of chance involved and there are leases with differing potential profits, the rank ordering of these leases can be accomplished through 'expected net present value' per filing (you are allowed to file only once per lease, but may file on as many leases as desired).

The evaluation of the four gas plays uses two production curves, which bracket past production, except for the Cozzette, Corcoran and Rollins sandstones, which are evaluated on the basis of only one curve. A success probability of .65 is used in the risk analysis portion.

The Dakota Group appears to have the most consistently high project rates of return. The Lewis sand has a range from extremely high rates of return to about a 4% rate of return on an after-tax basis.

Over the long run, this play could be profitable. The Cozzette, Corcoran and Rollins sandstones are satisfactory for a 30% rate of return or lower based upon after-tax analysis. The Mancos B formation is fairly profitable at the upper bound of production, but unprofitable at the lower bound of production. There appears to be some risk in developing the specific type of Mancos B gas play.

CONTENTS

ILLUSTRATIONS

TABLES

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INTRODUCTION

This thesis concentrates upon two different types of economic evaluations. The first evaluation deals with a ranking technique that can be applied to Federal non-competitive leases. The second evaluation examines the economics of four different gas plays. In order to limit the scope of this thesis, only data from northwestern Colorado will be evaluated.

Initially, this thesis describes the geology in north-western Colorado relating to four gas plays which will be evaluated. This section is meant to give a brief over-view of the geologic setting in this area. The leases to be ranked are also located in northwestern Colorado and will be identified on two of the maps designating the locations of producing oil and gas fields.

The second chapter describes the different leasing methods in Colorado. Chapter 3 describes in more detail the method of simultaneous filing. Colorado uses this system to distribute Federal lands that are not on known geologic structures. Each month, several leases are available. Chapter 4 describes a method of ranking all of these available leases in order to determine which leases have the highest potential profit.

The last chapter involves evaluating four gas plays on the basis of before-tax and after-tax analyses. Risk analysis is also included. A brief sensitivity section shows the effect of success ratios on risk analysis. Three of these plays are evaluated with respect to two curves bracketing past production. The fourth is evaluated by only one curve due to the lack of long-term producing wells.

To the best of my knowledge, there have been no theses or dissertations relating to simultaneous filing ranking analysis or economic evaluations dealing with these four gas plays.

I. GEOLOGY

Introduction

The Piceance Basin and adjoining Douglas arch of northwest Colorado (Figure 1) cover an area of 6,800 square miles, while the nearby Sand Wash Basin extends over approximately 2,100 square miles. Within these areas are located 72 gas fields with a cumulative production of 856 Bcf (billion cubic feet) gas from numerous sandstones of Cretaceous and Tertiary age (1). Considerable exploration and development drilling is being done today in these areas, and during 1977 the Piceance Basin-Douglas arch had a wildcat success ratio of 66.7%, the highest of any domestic province (2).

The Piceance Basin (Figure 2) is bordered on the southwest by the Uncompahgre uplift, on the east by the White River uplift, on the north by the Axial Basin arch, and the west by the Douglas arch which separates it from the Uinta Basin of northeast Utah. Immediately north of the Axial Basin arch is the Sand Wash Basin (Figure 3) which is bounded by the Sierra Madre uplift to the east, the Uinta uplift to the west, and the State Line ridge (Cherokee arch) to the north. All of these tectonic units were formed by the Laramide orogeny during Late Cretaceous through Eocene time, while the Uncompahgre uplift also had an earlier stage of development during the late Paleozoic (3).

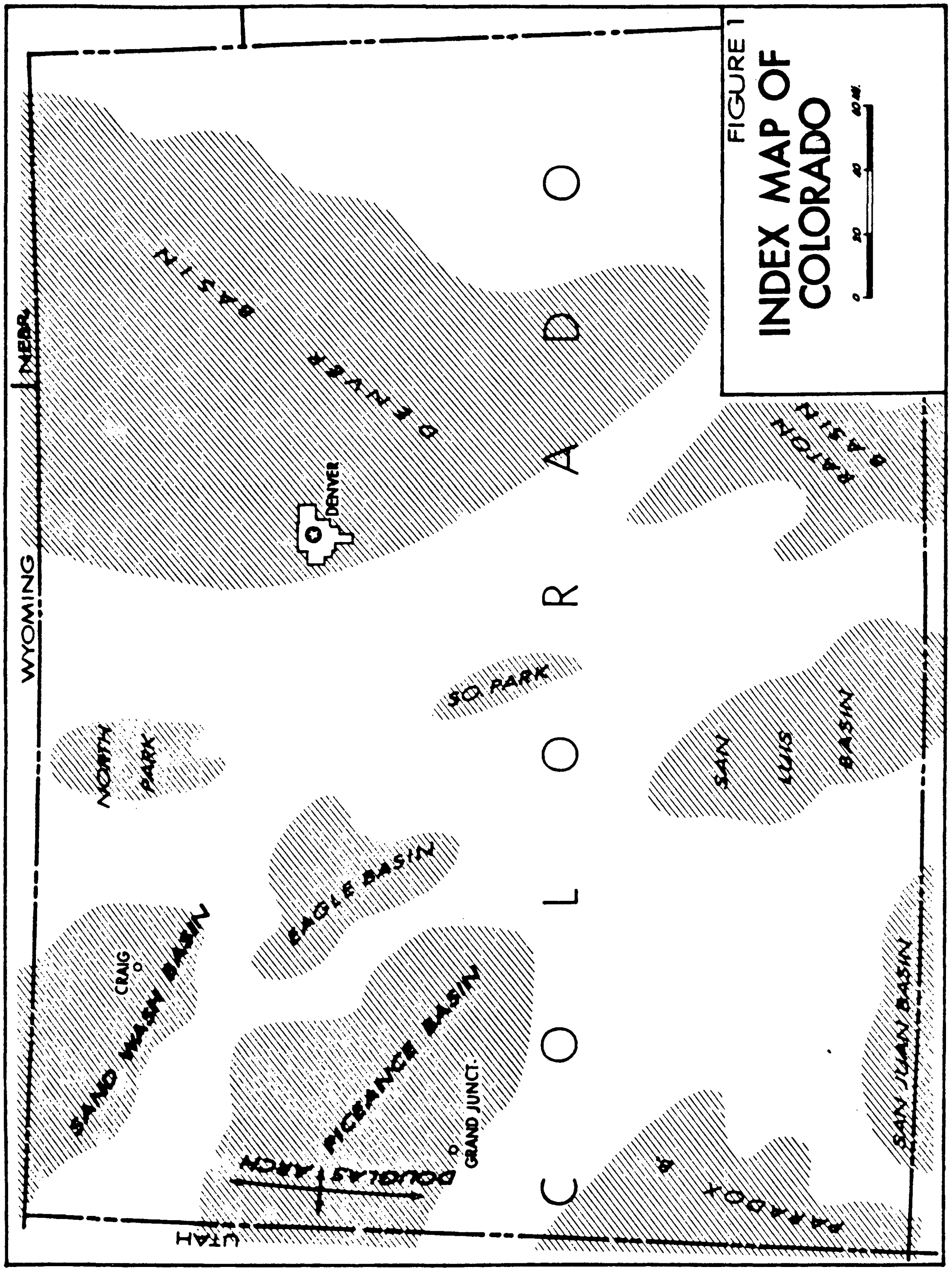

FIGURE 1
INDEX MAP OF COLORADO

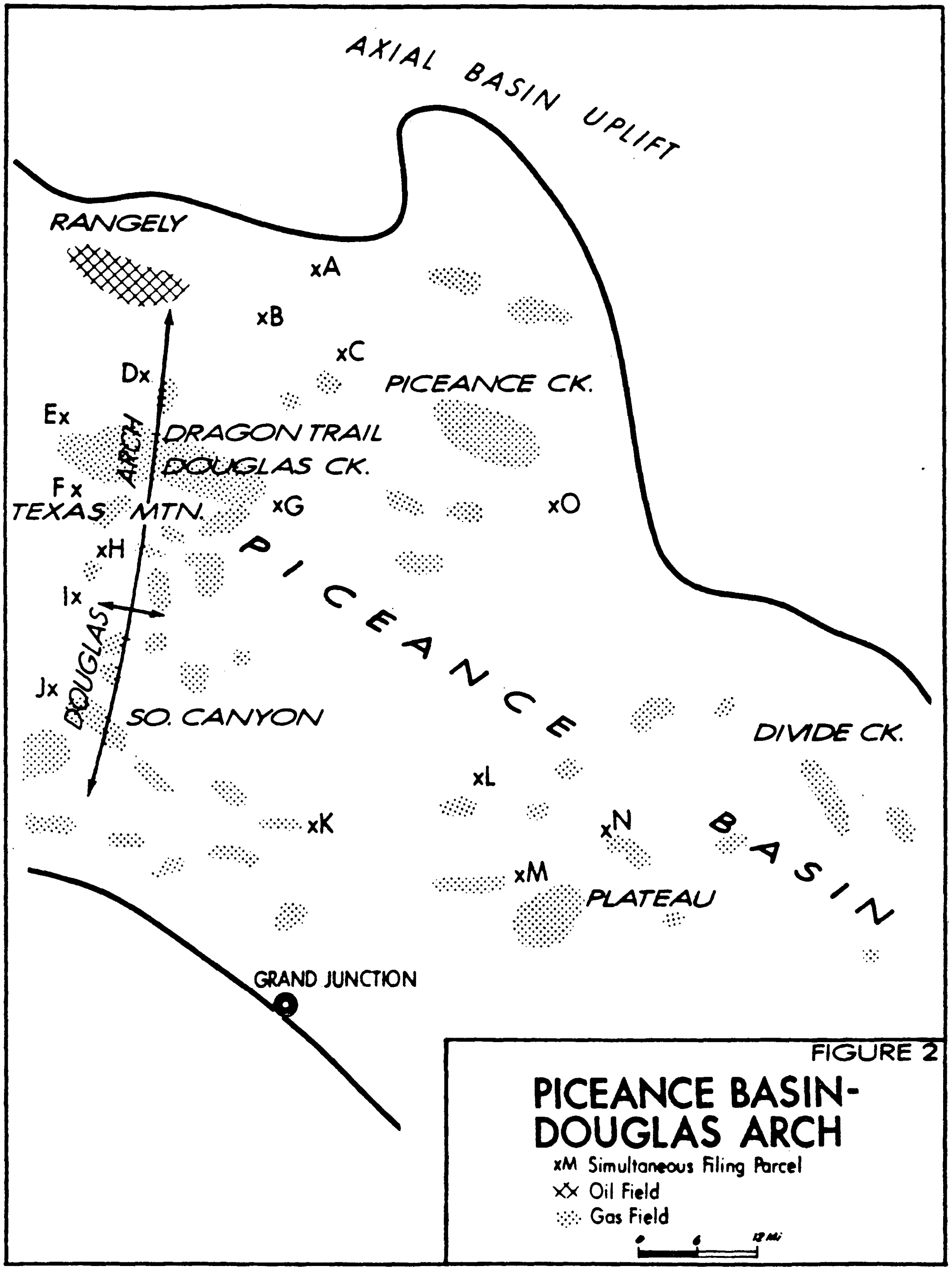

FIGURE 2
PICEANCE BASIN-
DOUGLAS ARCH

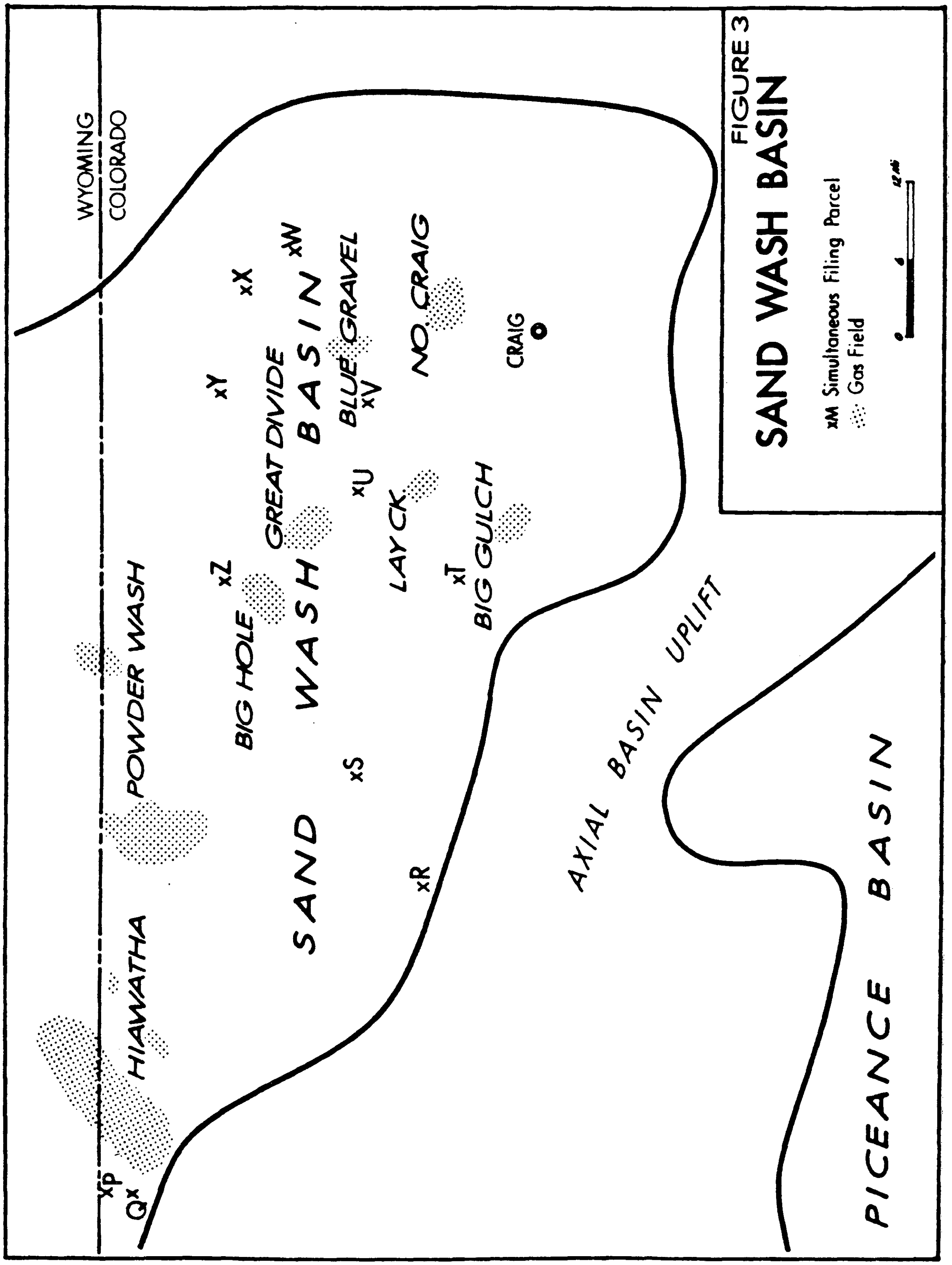

FIGURE 3
SAND WASH BASIN

Douglas Arch: Mancos B Formation

The Mancos B Formation is the most widespread producing horizon on the Douglas arch, and seven fields have produced over 132 Bcf from 149 wells in the last ten years (4). Most of this production has come from the Douglas Creek anticline, a structural feature that trends northwest across the larger Douglas arch.

The stratigraphy of the upper Cretaceous Mancos B Formation is a complex of interbedded claystone, siltstone, and fine sandstone formed in a marine environment. The Mancos B is 'sandiest' at Douglas Creek anticline where it is 500 feet thick and appears to be east-west trending. Northward the Mancos B changes rapidly to a shaly facies. In cores at Douglas Creek anticline, individual sandstone beds are seldom more than one foot thick and the interbedded claystones range from fractions of an inch to several inches in thickness. The sandstone is very fine to fine-grained and poorly sorted. As yet no productive limits are known other than those dictated by economics. Increased drilling activity is extending the known producing area southward on the Douglas arch as well as down the flanks to the east and northwest (5).

South Piceance Basin: Cozzette, Corcoran and Rollins Sandstones

Nine fields in the southern Piceance Basin produce gas from the Cozzette and Corcoran sandstones. Apparently structure has little effect on accumulation of hydrocarbons within these sandstones since commercial gas has been discovered from the deepest parts of the area to high on the flanks. The Divide Creek field is the only one which produces from a closed anticlinal structure; however, the only apparent effect of structure was in fracturing the Cozzette and Corcoran reservoirs, thus increasing their porosity and permeability. The lensitic nature of these sandstones and their proximity to source beds at the time of hydrocarbon migration would be effective in trapping hydrocarbons (6). Drilling depths to the Cozzette and Corcoran range from 2,500 to 8,000 feet and individual sandstone reservoir thickness is from 10 to 40 feet.

The Corcoran, Cozzette, and Rollins (ascending sequence) are littoral sandstones and associated lagoonal deposits of the lower Mesaverde Group of upper Cretacous age which are separated by tongues of Mancos Shale. When traced in an eastward direction, each member grades from paludal coal-bearing facies to offshore bars and marine shale (7).

Douglas Arch-South Piceance Basin: Dakota Group

There are 17 fields producing from Dakota Group sandstones in the Douglas arch and south Piceance Basin area. These fields include South Canyon, Texas Mountain, Garmesa, Bar X, and Prairie Canyon which have a combined production of 34 Bcf.

The lower Cretaceous Group can be subdivided into the Cedar Mountain Formation and the overlying Dakota Sandstone, both of which are present throughout most of the Piceance and Sand Wash Basins. The Cedar Mountain Formation usually consists of a basal conglomerate or conglomeratic sandstone and an overlying red to green to gray mudstone unit. The initial deposits of this unit were laid down upon a stream-dissected surface of Jurassic Morrison mudstone, with conglomerates and coarse sands deposited in the stream valleys while the adjacent ridges were being eroded (8). The channel-fill sandstones formed in these valleys have been productive where draped over structural highs (9). The relatively thick units of mudstone with minor lenses of sandstone and limestone cover the channel-fill sandstones.

The upper unit of the Dakota Group is the Dakota Sandstone which is about 100 feet in thickness and consists of three lithologically distinct parts. The divisions are a basal conglomeratic sandstone, a middle unit of carbonaceous shale and mudstone with some coal, and an upper unit of one or more sandstones up to 15 feet in thickness which grade eastward into marine shales. The upper unit sands of the Dakota Sandstone are of littoral marine origin which parallel the old northwest-trending strandlines, are about one mile in width, and were laid down during the westward transgression of the Mancos sea. Both the conglomeratic sands and bar or beach sands of littoral marine origin are gas productive from combination structural and stratigraphic traps (10).

The thickness of the Dakota Group is 200 feet at Douglas Creek field where gas accumulations are localized by structural closure. At other fields such as Baxter Pass and Gilliam Draw, the Dakota Group is gas bearing due to stratigraphic entrapment (11). In Krey's study (12) of the Grand Valley area northwest of Grand Junction, it is pointed out that most producing wells and dry holes have been drilled on known anticlines with 50 to 450 feet closure; however, the Dakota-Morrison sandstones are highly lenticular and offset wells may produce from different formations or from a different horizon in the same formation. Gas production is not solely dependent upon structural closure.

Sand Wash Basin: Lewis Formation

Several wildcat tests are presently being drilled in the Sand Wash Basin with the upper Cretaceous Lewis Formation the primary pay objective at depths of 5,000 to 9,000 feet. The Lewis Formation is 2,000 to 2,500 feet thick and consists of dark grey marine shale with lensing sand beds occurring in the upper half of the formation (13).

The sand bodies themselves are complex, varying from very thin interbedded silt and shale sequences to massive clean sands 60 feet thick. The Lewis sand bodies are believed to be of varying origin; generally the uppermost sands are believed to be of littoral marine or lagoonal origin, the next lower sand zone is a complex of near shore bar developments and the lowest sand zones are believed to be far offshore marine bars or shoal complexes (14). The sand bodies vary rapidly, and at the North Craig gas field an 80-foot effective sand pay zone disappears in half a mile. The North Craig field is definitely a stratigraphic trap consisting of a sand zone which contains several distinct clean sand and silty interbeds entirely enclosed by shale. Since the Lewis sands individually vary rapidly but nevertheless are present in widespread zones, it is certain that additional gas reserves will be found on the east side of the Sand Wash Basin in this formation. It is anticipated that most of the traps discovered will be of a stratigraphic nature (15).

Asquith (16) notes that Lewis and Mesaverde production in the area is primarily gas, and most reserves found to date are in stratigraphic traps. The Mesaverde Group and the overlying Lewis Shale record a major cycle of marine regression and transgression. These upper Cretaceous strata were deposited in response to shifting deltas and associated patterns of marginal marine and marine sedimentation. Various types of sandstone deposits produce gas and oil in numerous fields around the margins of the Red Desert, Washakie (Wyoming) and Sand Wash Basins. The deeper parts of these basins are essentially unexplored and, given an adequate economic environment, substantial volumes of gas and oil could yet be discovered.

II. TYPES OF LEASES

There are basically three types of leases for mineral rights. They are fee leases, State leases and Federal leases. Fee leases apply to individually-owned mineral rights. An example of a fee lease would be railroad or other rights-of-way (17). State leases apply to mineral rights owned by the State government. Federal leases apply to Federally-owned mineral rights. There are two types of federal leases: (1) for land containing a known geologic structure (KGS), which is obtained through competitive bidding, and (2) for land not containing a KGS, which is obtained through non-competitive bidding. The U.S. Geological Survey (USGS) considers a geologic structure producing oil or gas to be a KGS (18). The USGS determines the extent of the KGS.

The above mentioned leases apply only to mineral rights. Only oil and/or gas may be extracted.

Fee Leases

There is no specific leasing process for fee leases. The current mineral rights owner and the prospective lessee decide upon a mutually-satisfactory lease. A typical lease allows the lessee a certain number of years to explore for and develop minerals for a certain price paid to the owner. The owner usually retains a royalty covering all minerals extracted from his land by the lessee. This royalty is typically 12½% of all extracted minerals. A majority of the leases in the Denver-Julesburg Basin in Northeastern Colorado are fee leases.

State Leases

The State Board of Land Commissioners (SBLC) administers approximately four million acres of Colorado's State mineral lands (19). The SBLC holds monthly auctions for specific leases. Any individual interested in leasing certain acreage may make a written or verbal request to include that acreage in the auction, so long as the land is not currently leased. This request in no way binds the individual to lease the land (20). The SBLC may also make a motion to include a lease in the auction (20). A lease usually covers one section (640 acres), although there is no maximum or minimum acreage.

The 'minimum' bid for a lease is the first years' $1 per acre rental fee. Any 'dollar-value' bid received instead of the 'minimum' bid is considered a bonus bid. This bonus bid is to be paid in addition to the first years' $1 per acre rental fee. The remaining years' rental fee is $1 per acre per year (20). All rental fees and bonus bids go to the State government for educational and institutional purposes (21). The highest bidder wins the five-year lease and must pay $6 plus $1.50 per 160 acres as application and lease fees (20). There is no limit to the amount of State acreage an individual may hold (22).

The five-year lease may be extended another five-year term by virtue of production from or the presence of a shut-in gas well on the leased land (22). If at the end of the primary term (first five-year term) the lease is not otherwise entitled to extension, the lease may be extended five years at the SBLC option; however, no lease may be extended beyond ten years unless there exists drilling or re-working operations, production, or the presence of a shut-in gas well (22). Extension of a lease continues past the tenth year for so long as production continues in paying quantities (22).

Three methods exist to dispose of State leases: (1) complete or partial surrender by written request of the lessee, (2) failure to pay annual rental fee and (3) assignment of all or part of the leased land to another individual (23).

If production results on State leases, one-eighth of the gross value of all production goes to the State government as a royalty. The State is not liable for any taxes and no deduction may be taken for any tax in computing the royalty. Cost of marketing or processing the oil and/or gas produced may not reduce the State royalty (24).

Federal Leases

Competitive Bidding

Federal land on a known geologic structure is parcelled and made available for lease by the USGS. These leases will contain up to 640 acres (25). The winner of each five-year lease is determined through a competitive sealed-bidding process (26). The Bureau of Land Management (BLM) receives the sealed bids and handles the actual bidding process; however, the USGS does assist the BLM by determining (1) whether each bid exceeds the minimum acceptable amount for the lease and (2) the highest of these acceptable bids (27).

The winning bid is considered to be a 'bonus bid' and is paid in addition to the two-dollar-per-annum rental fee. For example, a $50 bonus bid indicates actually $52 per acre is paid for the first years' lease and $2 per acre is paid annually for the remaining four years of the lease (28).

If oil production is established on the leased land, the government receives a minimum royalty or 12½%. If the well averages over 110 bbls per day, the government receives increased royalties dependent upon the average daily production (29). Table 1 outlines these royalty rates.

Table 1

Royalty Rates

Over	Not Over	Royalty
110 bbls	130 bbls	18%
130	150	19
150	200	20
200	250	21
250	300	22
300	350	23
350	400	24
400	---	25

If gas production results on the leased land, the government receives a minimum royalty of 12½%. If the well averages over 5,000,000 cubic feet daily, the royalty increases to 16 2/3% (29).

If the royalty is less than the $1 per acre lease fee, the difference between the two must be paid in addition to the royalty. In other words, the government must receive at least $1 per acre per year after production begins (30).

After five years, the mineral rights revert to the Federal government and will be available for lease again sometime in the future. The lease can be extended for two years and so long thereafter as oil and gas are produced in paying quantities (31). Other reasons for extension are listed in Title 43 of the Code of Federal Regulations in section 3107.

There are several methods available for disposing of a lease. (1) A written request to the BLM to terminate a lease can be submitted at any time (32). (2) The lease may be terminated by simply failing to pay the annual rental fee (33). (3) The lease may be transferred to another individual (34). There are no set guidelines for this type of transfer; however, the BLM must receive notification of any transfers and approve them (34). Generally, the potential lessee buys the lease from the original leasor and assigns the leaser an overriding royalty (ORR) on any future oil and gas production. This ORR typically falls in the neighborhood of five percent. (Note: the owner of the mineral rights receives a 'royalty'; a lessee of the mineral rights who sells the lease to another individual receives an 'overriding royalty'.)

Special note should be taken of the 17½% limit of the total royalty and overriding royalty applying to oil production. The one exception occurs when the contract specifically states the ORR <u>over</u> the 17½% maximum will be discontinued when the production of oil averages 15 bbls per day or less (35). The government feels this limit of ORR will enable oil companies to maintain a small profit even when production of oil is down to marginal levels, thereby encouraging these oil companies to continue production. If the total royalty and overriding royalty were higher than the 17½%, the government feels the oil companies would not even 'breakeven' on their monthly operating costs and would then cease production. By continuing the oil production, the oil companies will (1) increase the much-needed domestic oil supply and (2) continue paying royalties to the government.

There exists no maximum total of royalty and overriding royalty applying to gas production (35).

Non-competitive Bidding

The BLM distributes this type of lease using the Simultaneous Oil and Gas Filing System. Each month the USGS determines the specific areas available for leasing and their respective boundaries, with a maximum allowable acreage per lease of 2560 acres. Any individual interested in a certain lease fills out a filing form (complete with a ten-dollar filing fee per lease) and mails it to the BLM. The ten-dollar filing fee is retained as a service charge (36). Filings must be received by the BLM before 10:00 A.M. on the first Monday following the posting of the available leases. A drawing is held approximately one week later and is open to the public. Three filing forms are drawn for each lease. The individual whose form was drawn first wins the lease, if the form is filled out appropriately; if not, then the individual whose form was drawn second wins the lease, if the form is filled out appropriately, and so on.

The winner must pay to the BLM $1 per acre for the first year's lease rental within two weeks of being notified by certified letter that he or she won the lease. A returned filing form indicates you did not win the lease. The lease extends for ten years, subject to annual rental payments of $1 per acre (28). An extension may be obtained for five years and so long thereafter as oil or gas production continues in paying quantities (31).

The same methods of disposal exist for this type of lease as for the competitive-bidding lease.

The royalty paid to the government remains a flat 12½% on oil production, and royalty for gas remains 12½% for 5,000 MCF (MCF denotes thousand cubic feet) average daily gas production or less or 16 2/3% for over 5,000 MCF average daily gas production (29).

III. SIMULTANEOUS FILINGS

Several restrictions exist for simultaneous filings. The following chapter presents these restrictions. Advantages as well as disadvantages of this leasing system will be discussed.

Restrictions

The BLM stipulates that an individual, association, corporations, or other entity may file only once per lease (37). If there is any collusion involved between interested parties that results in a greater probability of successfully obtaining a lease, or interest therein, all offers filed by either party will be rejected (37). Similarly, if an agent or broker files an offer to lease for the same lands in behalf of more than one party, with the requirement that a winning party give a portion of the proceeds to the agent or broker, the agent or broker has increased his probability of success. All offers filed by this agent or broker will be rejected (37).

The BLM limits the amount of Federal land in any one state in which an individual may hold direct or indirect interest to 246,080 acres at one time (38). This limit also applies to corporations. If an individual or corporations violates this provision, the lease or interest in violation of the limit will be cancelled or forfeited to the government. If the lease or interest is not subject to cancellation or forfeiture, it shall be sold to the highest bidder (39).

All parties with interest in a lease, if issued, must sign separate statements indicating the extent and nature of the interest as well as one statement describing the nature of the agreement between them (40).

Mineral leases may be issued only to (a) citizens of the United States; (b) associations of United States citizens organized under the laws of the United States, or any state thereof, which are authorized to hold such interests; (c) corporations organized under the laws of the United States or any state thereof; or (d) municipalities (39).

Aliens may not acquire or hold any interest in leases, except they may own or control stock in corporations holding leases if the laws of their country do not deny similar privileges to citizens of the United States (39).

A mineral lease will not be issued to a minor, but oil and gas leases may be issued to legal guardians or trustees of minors in their behalf (39).

Advantages and Disadvantages

Probably the most significant reasoning for using this type of Federal leasing is that smaller oil companies have a chance to acquire mineral rights to these leases. If a competitive-bidding system is employed, generally the larger oil companies will attain the leases because they can affort to pay higher prices for the lease than smaller oil companies.

However, one problem with simultaneous filing is that it strongly resembles a lottery, which is illegal in the State of Colorado. The uncertain legal foundations may cause problems in the near future. The Securities Exchange Commission (SEC) may invalidate this current system and require a new system be initiated.

The greatest disadvantage is the abuse of this leasing system. Many people have recently become involved in simultaneous filing for the purpose of investment. The intent is to win a lease and then sell the lease to an oil company while retaining an overridding royalty. The oil company accepts responsibility for the annual rental fee. Because many of these people have no geological or geophysical insight to the available land, consulting firms specializing in these areas are frequently retained. This is perfectly legal if the consulting firm does not retain a portion of the interest won by their clients. However, some of these consulting firms do retain an interest in the leases won, which means they have increased their probability of success. This type of firm encourages people to become their clients, which future increases the firm's probability of success as well as increasing the volume of people filing on leases. As more people become interested in simultaneous filings, the probability of success decreases for people filing, with the exception of the firms indicated previously. Individual firms of this nature may file for as many as 200 people.

The difficulty in controlling this type of abuse is in proving this illegal form of contract exists. Recently, one firm was prosecuted in New Mexico for having interest in more than one filing offer per lease (40). This situation would probably improve if more firms of this nature could be caught.

IV. SIMULTANEOUS FILING RANKING

Introduction

Each month the BLM posts the Federal leases available for filing. There have been as many as 200 parcels per month upon which to file in the past. If a person filed upon all of these parcels, $2,000 could be spent in filing fees for one month. Some individuals may desire to file upon only a certain number of leases. The question is, given a choice of several leases, which ones would be the best to file upon?

Three variables must be considered to rank these alternative leases: (1) the size of each lease, (2) the potential resale price of the land, and (3) the number of filing applicants per lease.

Data Acquisition

The size of the lease is included on the monthly list posted by the BLM. The potential resale price for land in northwestern Colorado has been provided by several knowledgeable landmen, geologists and geophysicists. The number of filing applicants per lease must be estimated

The BLM publishes a monthly report containing the number of applicants and the winners. These past numbers may be used to help estimate the number of potential filers for different areas. When looking at these past results, the size of the lease should be considered. Many people will not file unless the lease acreage exceeds 500 acres. Thus, two values for the number of applicants in one location may vary greatly if the acreage is large for one lease and small for another lease. If possible, applicants for leases of sizes comparable to the lease being evaluated should be selected for determining current number of applicants.

Another consideration is the age of the data. Interest in an area can change very rapidly, depending upon drilling results. For example, if the gas-water or oil-water contact is found in extending a producing field, all land downstructure of the contact will not be of interest (with respect to this producing formation). This results in few people filing in this area. Conversely, if oil or gas is found, the interest in that area will increase, resulting in an increase of filing applicants.

Relative location of past lease data to the currently available lease is important. If a trend exists, the best past lease data for estimation purposes is in the same structural position as the current lease. The closest information to the available lease will also be the best.

The best estimate of the number of applicants will be obtained by using (1) the most current data, (2) data from leases of similar size to current lease, and (3) data from closest leases in a similar structural position to the current lease.

It would not be feasible to expect a formula weighting the past data to approximate the expected number of applicants. The variations described above causing this number to alter are non-quantitative. There are too many variable factors people use in deciding which leases to file upon. As previously mentioned, some people have a lower limit regarding size of the acreage. Some people will only file on leases within a certain distance from production, some will file on leases with the most favorable geological conditions for oil or gas. The many methodologies used to determine leases to file upon present too great a problem to quantify. This problem is further complicated by generally a lack of concentrated current (within one year) data.

Due to these problems, the best quantitative approach appears to be selecting or averaging the most current data which satisfies the greatest number of conditions established two paragraphs above.

For this thesis, 26 recently available leases will be ranked. The actual number of applicants for these leases will be used. A sensitivity analysis for the number of applicants will also be included.

Ranking Method

Ranking of the selected leases will be accomplished using expected present value. The expected net present value (ENPV) can be considered as a desirability rating. ENPV indicates the amount of money you can expect to make per filing over the long run. The higher this value is, the more profitable the lease is. In the long run, more money will be made on the leases with a high ENPV, so these are the leases upon which to file. This method of ranking will incorporate risk analysis and net present value.

Net value equals revenue minus cost. Revenue is derived from the sale of the lease and is equal to the acreage multiplied by the sales price per acre. The costs are the first year's rental fee of $1 per acre and the $10 filing fee.

Risk analysis includes the use of probability of success or failure of winning a lease. Probability of success is one out of the number of filing applicants. The probability of failure is the number of applicants minus one over the number of applicants.

The ENPV combines the probability of success or failure with the net present value through multiplication. There are two parts to this formula; ENPV of success, and ENPV of failure. If you are successful, the revenue is the sales revenue, and the costs are the \$1 per acre rental fee and \$10 filing fee. If you fail to win the lease, there is no revenue, and the cost is the \$10 filing fee. The total ENPV applies the probability of success and the probability of failure to the respective present values generated. The total ENPV formula used in the following calculations is:

$$\frac{(\text{sales revenue} - \text{rental fee} - \$10)}{(\text{applicants})} - \frac{(\text{applicants} - 1) \times (\$10)}{(\text{applicants})}$$

Note that because the filing fee is constant, this method will rank mutually exclusive as well as non-mutually exclusive alternatives.

Data and Calculations

Figures 1 and 2 in the Geology section indicate the locations of the 26 leases being ranked. Table 2 contains the provided data and computes the ENPV for each lease. Note parcels A through O are on Figure 1 and parcels P through Z are on Figure 2.

The five most profitable leases are parcels S, R, F, E, and L, respectively. Note that all parcels except Q have positive ENPV, which indicates all but Q will be profitable investments over the long run. For example, if

Table 2

Simultaneous Filing Ranking Analysis

Parcel	Acreage	Selling Price	Applicants	ENPV
A	1396.83	$15.00	934	$ 10.94
B	2325.28	15.00	815	29.94
C	376.83	15.00	436	2.10
D	458.19	50.00	919	14.43
E	440.00	50.00	511	32.19
F	2390.34	60.00	1984	61.09
G	558.25	60.00	807	30.81
H	240.00	60.00	609	13.25
I	160.00	60.00	327	18.88
J	1547.93	20.00	1185	14.82
K	1040.00	15.00	815	7.87
L	2037.68	15.00	692	31.22
M	1044.15	20.00	974	10.37
N	1482.58	20.00	1034	17.24
O	1200.00	15.00	589	18.53
P	538.98	25.00	771	6.77
Q	80.00	25.00	434	-5.56
R	2080.00	20.00	363	98.90
S	2555.68	25.00	252	233.44
T	640.00	25.00	554	17.73
U	320.00	50.00	608	15.79
V	640.00	30.00	827	12.44
W	2240.00	20.00	1153	26.91
X	391.05	20.00	633	1.74
Y	282.88	40.00	470	13.47
Z	782.30	30.00	1259	8.02

you file 934 times on parcels similar to A, you will probably win once and make a total profit of \$10.94 x 934, or \$10,215. Table 3 shows the relative ranking of the parcels.

In order to show the sensitivity of this ranking technique to the number of applicants, the expected net present value will be calculated again with the applicants increased and decreased by 20%. Table 4 contains these results.

Parcels S, R, and F with 20% over-estimation of applicants continue to be higher than all other parcels with the accurate applicant estimates. The extreme high desirability ratings will probably not be altered enough by inaccurate applicant estimates to effect decision making regarding lease filing. The majority of the parcels fall fairly close together in the middle range of desirability. The variation in desirability due to an inaccurate estimate of applicants can cause many wrong lease choices in this range. For example, if the correct number of applicants is used, B (ENPV = 29.94) has a more favorable ranking than W (ENPV = 26.91). However, if the correct number of applicants is used for W (ENPV = 26.91), but the number of applicants for B is overestimated by 20%, (ENPV = 21.95), then W will be incorrectly ranked above B. Similarly, if the correct

Table 3

Rank Order of Simultaneous Filing

Parcel	ENPV
S	$233.44
R	98.90
F	61.09
E	32.19
L	31.22
G	30.81
B	29.94
W	26.91
I	18.88
O	18.53
T	17.73
N	17.24
U	15.79
J	14.82
D	14.43
Y	13.47
H	13.25
V	12.44
A	10.94
M	10.37
Z	8.02
K	7.87
P	6.77
C	2.10
X	1.74
Q	-5.56

Table 4

Sensitivity Analysis of Number of Applicants

Parcel	ENPV if 20% High on Applicants	ENPV if Correct Applicants	ENPV if 20% Low on Applicants
A	$ 6.75	$ 10.94	$ 15.13
B	21.95	29.94	37.93
C	-0.31	2.10	4.52
D	9.54	14.43	19.32
E	23.75	32.19	40.63
F	46.86	61.09	75.30
G	22.65	30.81	38.97
H	8.60	13.25	17.90
I	13.10	18.88	24.64
J	9.86	14.82	19.78
K	4.30	7.87	11.44
L	22.98	31.22	39.46
M	6.30	10.37	14.44
N	11.79	17.24	22.69
O	12.82	18.53	24.22
P	3.42	6.77	10.14
Q	-6.44	-5.56	-4.68
R	77.10	98.90	120.64
S	184.72	233.44	282.08
T	12.18	17.73	23.28
U	10.63	15.79	20.95
V	7.95	12.44	16.93
W	19.53	26.91	34.29
X	-0.60	1.74	4.09
Y	8.78	13.47	18.16
Z	4.42	8.02	11.62

number of applicants is used for B (ENPV = 29.94), but the number of applicants is under-estimated by 20% for W (ENPV = 34.29), then W will be incorrectly ranked above B. These calculations indicate the leases in the average desirability range are very sensitive to the accuracy of the number of applicants. Therefore, the ranking of these leases will only be as good as the data used in calculating these rankings.

Two additional calculations can be performed to further comprehend the sensitivity of ENPV ranking to applicants. Parcel S is ranked above parcel R. What percent error in the estimated applicants for S need be present in order to rank R above S? Trial and error calculations using the ENPV equation for S equal to 98.90 yields the minimum number of applicants for S required to cause the above situation. This number can then be converted to a percentage change from the correct number of applicants. For this example, a 30% or higher over-estimation of applicants for S will cause R to be ranked the same or higher than S, respectively.

Similarly, the percent error in the estimated applicants for R required to rank R above S can be calculated. Trial and error calculations using the ENPV equation for R set equal to 233.44 can be used to determine the maximum number of applicants for R required to cause the above situation. For this example, a 51% or higher under-estimation of applicants for R will cause R to be ranked the same or higher than S, respectively.

Table 5 provides these two types of comparisons for each two adjacently-ranked parcels. The percentage over-estimation of applicants indicates the percentage required to rank the two adjacently-ranked parcels the same. Therefore, to alter the ranking, the applicants would actually need to be over-estimated slightly more than the percentage in the table. Likewise, the percentage under-estimation needs to be slightly higher than the percentage in the table to alter the ranking.

The sensitivity of ENPV ranking to the number of applicants is again confirmed by Table 5. Many errors in ranking can occur by an applicant over-estimation or under-estimation of just a few percent.

Table 5

Percentage Over-estimation and
Under-estimation Required to Alter Ranking

Ranking	Applicants % Over-estimation	Applicants % Under-estimation
R over S	S by 30%	R by 51%
F over R	R by 53%	F by 35%
E over F	F by 69%	E by 41%
L over E	E by 2%	L by 2%
G over L	L by 1%	G by 1%
B over G	G by 2%	B by 2%
W over B	B by 8%	W by 8%
I over W	W by 28%	I by 22%
O over I	I by 1%	O by 1%
T over O	O by 3%	T by 3%
N over T	T by 2%	N by 2%
U over N	N by 6%	U by 5%
J over U	U by 4%	J by 4%
D over J	J by 2%	D by 2%
Y over D	D by 4%	Y by 4%
H over Y	Y by 1%	H by 1%
V over H	H by 4%	V by 3%
A over V	V by 7%	A by 7%
M over A	A by 3%	M by 3%
Z over M	M by 13%	Z by 12%
K over Z	Z by 1%	K by 1%
P over K	K by 7%	P by 6%
C over P	P by 39%	C by 28%
X over C	C by 3%	X by 3%
Q over X	X by165%	Q by 63%

V. ECONOMIC EVALUATION

Introduction

There are four types of gas plays that will be evaluated:

1. Stratigraphic traps in the Douglas arch area producing from the Mancos B Formation (Figure 1)
2. Stratigraphic traps in the south Piceance Basin, which produce from the Cozzette, Corcoran or Rollins sandstones (Figure 1)
3. Stratigraphic or a combination of structural and stratigraphic traps in the Douglas arch area which produce from the Dakota Group (Figure 1)
4. Stratigraphic traps in the Sand Wash Basin producing from the Lewis Formation (Figure 1)

For each of these four areas, the economic evaluation includes before-tax and after-tax analyses. The evaluation also includes a section on sensitivity analysis of land prices, minimum rates of return (ROR), risk, and depreciation. Actual production data from each area has been plotted and appears before the four individual area's evaluation section. Two production decline curves have been selected for each of three areas in an attempt to bracket production ranges.

An evaluation will be presented for both curves. The south Piceance Basin will only be evaluated with respect to one curve due to a lack of production data for long-term producing wells.

An attempt has been made to consider all costs for land, drilling, completion, operation, taxes, depletion and depreciation in the evaluations. Several landmen, geologists, geophysicists, and engineers have provided typical values for these costs. These people have been indicated in the acknowledgements at the beginning of this thesis. Due to the proprietary nature of several of these values, references will be included only when the data is not confidential.

These evaluations require several assumptions. Specifically, these assumptions regard risk, acreage involved in a drilling project, well spacing, drilling and completion times, maximum allowable Federal gas prices, operating costs, royalty, taxes, depreciation, and depletion. A brief discussion of each of the necessary assumptions follows.

For the purpose of continuity, this thesis assumes the drilling program for each area requires the purchase of 2,000 acres. The data section included earlier in this thesis contains typical land prices for each area (see page 30).

A 320-acre well spacing will be assumed for production involving the Dakota Group the Lewis Formation, and the

Mancos B Formation. This allows six wells to be drilled on the 2,000 acres. Therefore, the cost of 333 acres will be assessed to each well drilled in these areas. Due to low permeability in the Cozzette, Corcoran, and Rollins sandstones, a 160-acre spacing will be used. Therefore, the cost of 165 acres will be assessed to each well drilled in this area.

Drilling, completion and production generally require three months. For simplicity in the evaluations, this thesis assumes drilling begins January 1, 1979, and production begins April 1, 1979. The estimate of partial production for this first year will be 3/4 of the first complete year of production from the production curve used. All land, drilling and completion costs will be incurred at the beginning of 1979, and the operating costs and income from production for each year will be accounted for at the end of that year.

Congress recently passed a Federal gas pricing bill (4) entitling gas producers to a maximum of \$2.09 per MCF (heating value 1,000 BTU) commencing November 1, 1978. This base price may be increased or decreased for gas with higher or lower BTU potential, respectively. This alteration is accomplished through the use of a ratio of the potential BTU to 1,000 BTU. For example, the base price for 1,150 BTU gas would be (1,150 BTU / 1,000 BTU) x \$2.09

per MCF or $2.40 per MCF. The base price escalates 3.7% per year plus the inflation rate, which is determined by the Consumers' Price Index, until April 1, 1981. The price will then escalate 4.2% per year plus the inflation rate until January 1, 1985. Federal gas pricing controls will then be lifted. Congress expects the inflation rate to vary between 7% and 8% per year. These figures and dates apply to 'new' gas which is defined as being at least 2½ miles from any existing gas production or at least 1,000 feet deeper than existing gas production within 2½ miles (41). It should be stressed that these are the maximum allowable Federal gas prices. The price also depends upon the region and the pipeline availability.

In order to simplify this pricing technique, it is assumed that all production will be 'new' gas. Further, inflation will be 8.3% until April 1, 1981, and 7.8% after April 1, 1981. This allows the usage of a constant 12% per year price escalation throughout the evaluation, assuming prices continue to escalate 12% after elimination of price controls. Gas producers sell gas for the $2.09 per MCF base price in 1979, unless otherwise stated. It will also be assumed that the pipeline hookup will be supplied by the gas company currently established in that area.

Several people involved with drilling in these four areas indicate operating costs (OC) for gas wells will be approximately $5,000 per well for 1978. In the past, OC have escalated roughly 3% per year. It will be assumed they will continue to escalate at this rate.

Because several wells are drilled as joint efforts, it would be difficult to determine what overhead costs to assign. These costs will not be included in the evaluations.

Oil and gas leases are normally subject to 12½% royalty plus various amounts of overriding royalty that may be as much as 5%. The remaining 82½% of total production constitutes 100% of the working interest (WI) which is responsible for paying all costs of drilling, completion, and production. Anyone with an economic interest in the production is responsible for paying State and local taxes on their percentage of total production. Therefore, the oil company pays approximately 5% State and local taxes in Colorado on the working interest share of production.

The owner of an economic interest in oil or gas wells may recover their cost through Federal tax deductions for depletion over the economic life of the property (42). Percentage depletion is a specified percentage of working interest, but the deduction for depletion under this method cannot exceed 50% of taxable income from the gas well after all deductions except the deduction for depletion (43).

Percentage depletion can be used only by small oil and gas producers. Table 6 indicates the allowed percent depletion rate and the definition of small oil and gas producers for each year.

Table 6

Percentage Depletion for
Small Oil/Gas Producers

Year	Percent Depletion Rate, %	Small Oil/Gas Producer Maximum Annual Production Oil		Gas
1978	22	1400 bbl/day	or	8,400 MCF/day
1979	22	1200 "	or	7,200 "
1980	22	1000 "	or	6,000 "
1981	20	1000 "	or	6,000 "
1982	18	1000 "	or	6,000 "
1983	16	1000 "	or	6,000 "
1984	15	1000 "	or	6,000 "

The years after 1984 will use the same rates listed for 1984. If both oil and gas are produced, gas production may be converted to equivalent oil production using 6.0 MCF gas = 1 bbl oil (44). These evaluations assume percentage depletion for small gas producers unless otherwise stated.

During the drilling and completing of a well, all expenses are considered as either tangible or intangible costs.

Examples of intangible drilling costs are road and location cost, drilling expense, cement, testing, coring, logging, professional services, mud materials, fuel, water, and bits. Examples of intangible completion costs are completion unit, cement, perforating, logging, completion tools, and professional services. Intangible costs are expensed the year during which they occur.

Tangible drilling costs are generally restricted to surface casing and intermediate casing. Examples of tangible completion costs are physical equipment items such as production casing, tubing, wellhead equipment, line pipe, tanks, treaters, and separators. It will be assumed tangible costs qualify for depreciation over the life of the project, which shall be ten years. The common project length enables economic comparisons between the different areas.

The majority of all costs of a well to the casing point (or dry hole basis) are intangible expenses. The percentage of intangible costs decreases for a completed well due primarily to the large amount of tangible equipment costs. Table 7 was derived from three current drilling projects for gas wells, and indicates over 97% of all costs to the casing point are intangible expenses, while percent intangibles of a completed well range from 70 to 78%.

Table 7

Percent Intangible Costs

Well	Percent Intangibles of all Costs to Casing Point	Percent Intangibles of all Costs Through Completion
1	97.7%	70.0%
2	97.6%	76.2%
3	97.7%	78.3%

In the economic evaluations, the assumption has been made that 95% of the costs to the casing point are intangible and the balance are the depreciable tangible costs for a dry hole. For a completed well, 75% of all costs are intangible and the balance are the depreciable tangible costs.

Double declining balance (DDB) switching to straight-line (SL) will be used for depreciation calculations. A comparison will be made between SL and DDB switching to SL showing DDB switching to SL is the most advantageous. A 50% effective tax rate will be used.

Douglas Arch: Mancos B Formation

The production data plotted in Figure 4 was taken from the Dragon Trail field located in T2 and 3S, R102W (Figure 4). One oil company had completed well costs for two current wells in this area of $190,000 and $250,000. Another oil company had a completed well cost of $215,000 (45). Depth

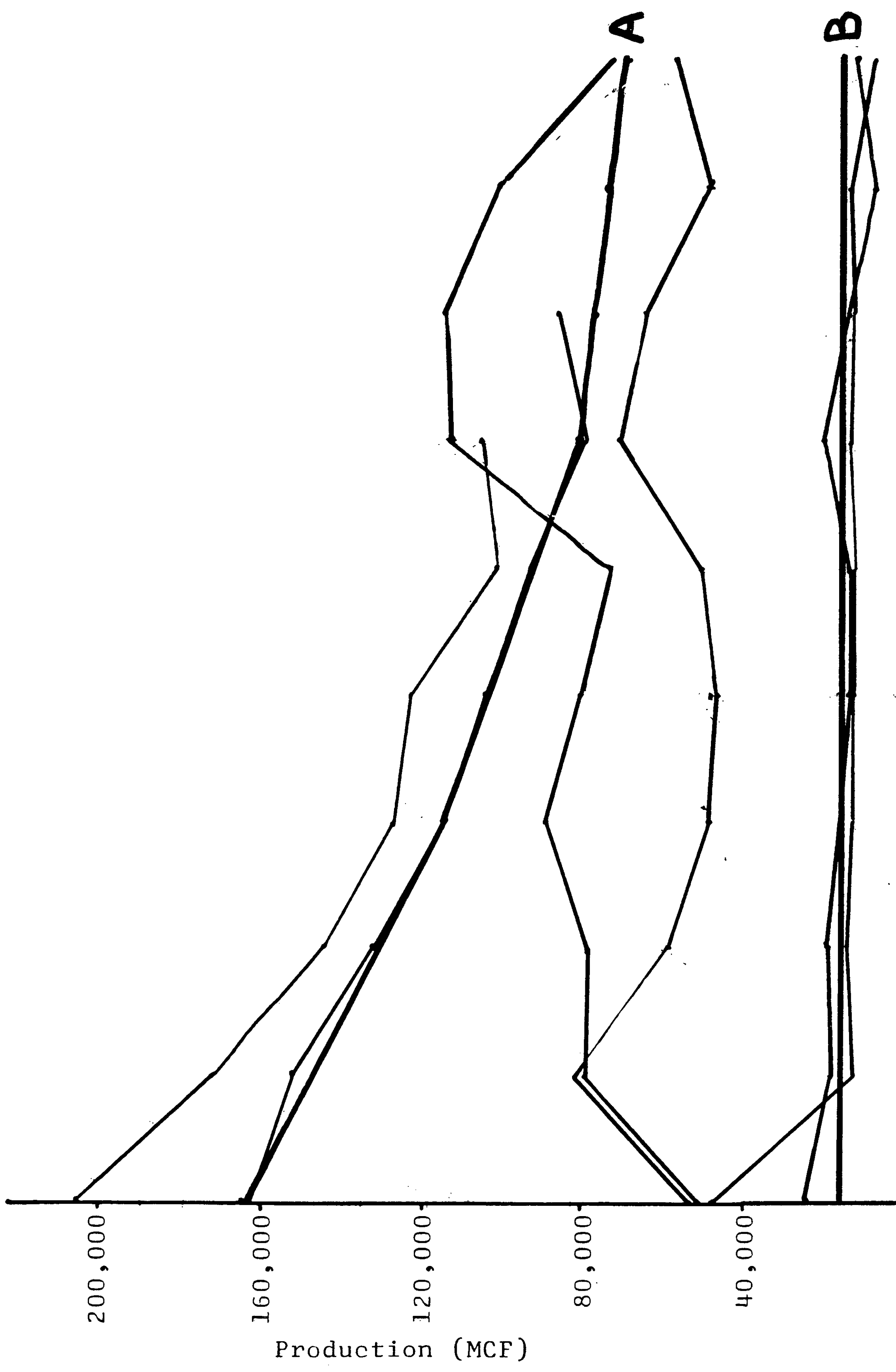

Figure 4. Mancos B Formation Production Data

to pay ranges from 3500 to 4000 feet for these three wells. This economic analysis uses the $215,000 completed well cost, with $120,000 being incurred to the casing point and $95,000 resulting from the actual completion. The heating value of this gas is 1,200 BTU. The base price will therefore be $2.51 per MCF.

Curve A Evaluation

The $(F/P_{i,n})$ factor is called the 'single payment compound-amount factor'. This factor is used to calculate a future sum, F, that is equivalent to a present sum, P. For the symbolism used, the first letter in the symbol will designate what is being calculated, and the second letter designates that from which it is being calculated. The 'i' designates the number of interest compounding periods (46). For example, $2.51 is the 1979 price for gas. The 1980 gas price can be derived from ($2.51) x $(F/P_{12,1})$. Table 8 contains the values of the $(F/P_{i,n})$ factors for a 12% annual escalation.

Table 8

$(F/P_{i,n})$ Factors for 12% Escalation

n	1	2	3	4	5	6	7	8	9
$F/P_{12,n}$	1.120	1.254	1.405	1.574	1.762	1.974	2.211	2.476	2.773

Table 9 shows the production, and production revenue for each of the ten years. The first year's production was calculated as 3/4 of 163,000 MCF, yielding 122,250 MCF. Working interest was determined by subtracting 17½% in royalty and ORR from the production revenue.

Table 9

Curve A Production and Revenue

Year	Production (MCF)	Revenue Formula	Production Revenue	Working Interest
1979	122,250	122,250($2.51)	$306,847	$253,149
1980	146,667	146,667($2.51)($F/P_{12,1}$)	$412,310	$340,155
1981	130,333	130,333($2.51)($F/P_{12,2}$)	$410,228	$338,438
1982	114,000	114,000($2.51)($F/P_{12,3}$)	$402,027	$331,672
1983	103,000	103,000($2.51)($F/P_{12,4}$)	$406,926	$335,714
1984	92,000	92,000($2.51)($F/P_{12,5}$)	$406,881	$335,677
1985	81,000	81,000($2.51)($F/P_{12,6}$)	$401,334	$331,101
1986	76,000	76,000($2.51)($F/P_{12,7}$)	$421,770	$347,960
1987	71,600	71,600($2.51)($F/P_{12,8}$)	$444,977	$367,106
1988	67,300	67,300($2.51)($F/P_{12,9}$)	$468,423	$386,499

Operating costs for future years can be calculated using ($F/P_{i,n}$) factors with a 3% annual escalation. Table 10 indicates the ($F/P_{i,n}$) values.

Table 10

$F/P_{i,n}$ Factors for 3% Escalation

n	1	2	3	4	5	6	7	8	9	10
$F/P_{3,n}$	1.03	1.061	1.093	1.126	1.159	1.194	1.23	1.267	1.305	1.344

Using the $(F/P_{3,n})$ factors and the 1978 operating cost of \$5,000, the future operating costs are calculated in Table 11. Note that these costs will be the same for all of the economic evaluations.

Table 11

Annual Operating Costs

Year	OC Formula	OC
1979	$\$5000(F/P_{3,1})$	\$5150
1980	$\$5000(F/P_{3,2})$	\$5305
1981	$\$5000(F/P_{3,3})$	\$5465
1982	$\$5000(F/P_{3,4})$	\$5630
1983	$\$5000(F/P_{3,5})$	\$5795
1984	$\$5000(F/P_{3,6})$	\$5970
1985	$\$5000(F/P_{3,7})$	\$6150
1986	$\$5000(F/P_{3,8})$	\$6335
1987	$\$5000(F/P_{3,9})$	\$6525
1988	$\$5000(F/P_{3,10})$	\$6720

Before-Tax Analysis

Figure 5 incorporates all cost and revenue on a cash flow diagram. 'C' denotes cost and 'Prod Rev' denotes production revenue. Resulting cash flow (CF) is listed under each year. Cash flow for before-tax analysis is the net income realized. The location of the year indicates the beginning of the year. All values on the diagram are in dollars. The land cost of \$16,650 was arrived at using a selling price of \$50 per acre.

	1979	1980	1981	1982	1983	1984
C_{land}	16,650					
C_{drill}	120,000					
$C_{complete}$	95,000					
OC		5,150	5,305	5,465	5,630	5,795
Prod Rev		253,149	340,155	338,438	331,672	335,714
CF	-231,650	247,999	334,850	332,973	326,042	329,919

	1985	1986	1987	1988	1989
OC	5,970	6,150	6,335	6,525	6,720
Prod Rev	335,677	331,101	347,960	367,106	386,449
CF	329,707	324,951	341,625	360,581	379,729

Figure 5. Before-tax cash flow diagram for curve A

To evaluate the present value of these future cash flows, these future values will be converted to present values using $(P/F_{i,n})$ factors. This net present value (NPV) will be determined using 15% and 30% minimum rates of return. If the NPV is positive, this indicates the revenues will more than cover the costs at a rate of return which is at least as great as the minimum rate of return (47). This would be a satisfactory investment. Table 12 contains the $(P/F_{i,n})$ factors for rates of return (ROR) of 15% and 30% (48).

Table 12

$(P/F_{i,n})$ Factors for 15% and 30% ROR

n	$P/F_{15,n}$	$P/F_{30,n}$
1	0.8696	0.7692
2	0.7561	0.5917
3	0.6575	0.4552
4	0.5718	0.3501
5	0.4972	0.2693
6	0.4323	0.2072
7	0.3759	0.1594
8	0.3269	0.1226
9	0.2843	0.0943
10	0.2472	0.0725

The NPV equation for minimum ROR (i^*) equal to 15% is:

$$NPV = -231,650 + 247,999(P/F_{15,1}) + 334,850(P/F_{15,2}) + 332,973(P/F_{15,3}) + 326,042(P/F_{15,4}) + 329,919(P/F_{15,5}) + 329,707(P/F_{15,6}) + 324,951(P/F_{15,7}) + 341,625(P/F_{15,8}) + 360,581(P/F_{15,9}) + 379,729(P/F_{15,10}) = \$1,379,318$$

The NPV equation for $i^* = 30\%$ is:

$$NPV = -231,650 + 247,999(P/F_{30,1}) + 334,850(P/F_{30,2}) + \ldots + 379,729(P/F_{30,10}) = \$735,347$$

The positive NPV for both of the minimum rates of return indicates this project will be satisfactory for both minimum rates of return.

The project ROR can be found by trial and error calculations of NPV using different rates of return. The project ROR occurs when NPV is zero. For this evaluation before tax, project ROR is 124%.

Risk analysis can be made to determine whether the project would be suitable over the long run for many repeated investments of the same type. This will be done by calculating the expected NPV, which is the average NPV that would be realized if many investments of this type were repeated. A negative expected NPV would indicate an unfavorable investment.

If 'p' denotes probability of success (of finding gas), the expected NPV (ENPV) is:

p x (income) - p x (completion cost) - all other costs.

For $i^* = 15\%$ and $p = .65$:

$$\begin{aligned} \text{ENPV} &= .65(247{,}999(P/F_{15,1}) + 334{,}850(P/F_{15,2}) + \ldots \\ &\quad + 379{,}729(P/F_{15,10})) - .65(95{,}000) - 136{,}650 \\ &= \$848{,}729 \end{aligned}$$

For $i^* = 30\%$ and $p = .65$:

$$\begin{aligned} \text{ENPV} &= .65(247{,}999(P/F_{30,1}) + 334{,}850(P/F_{30,2}) + \ldots \\ &\quad + 379{,}729(P/F_{30,10})) - .65(95{,}000) - 136{,}650 \\ &= \$430{,}148 \end{aligned}$$

The ENPV is positive for each minimum ROR, which indicates a potentially favorable investment for many investments of this type over the long run.

The expected ROR for the project can be calculated by trial and error using the above ENPV equation and solving for the 'i' value that makes ENPV = 0. This expected ROR is 95%.

After-Tax Analysis

Assuming a producing completed well, 75% of the well costs are expensed and 25% of the well costs are depreciated over ten years. Well costs are $215,000, with $161,250 being expensed at the beginning of 1979 and $53,750 being depreciated.

Using DDB switching to SL depreciation method (48), Table 13 shows the annual depreciation. The adjusted basis is the depreciable cost minus total depreciation taken. Annual depreciation is the rate times the adjusted basis for DDB and a constant ¼ times the adjusted basis in year 6.

Table 13

DDB Switching to SL Annual Depreciation

Year	Method	Rate	Adjusted Basis	Annual Depreciation
1979	DDB	2/10	53,750	10,750
1980	DDB	2/10	43,000	8,600
1981	DDB	2/10	34,400	6,880
1982	DDB	2/10	27,520	5,504
1983	DDB	2/10	22,016	4,403
1984	DDB	2/10	17,613	3,523
1985	SL	1/4	14,090	3,523
1986	SL		10,567	3,523
1987	SL		7,045	3,523
1988	SL		3,522	3,523

The percent depletion is calculated as a specific percentage of the working interest (WI). Table 14 lists these annual percentages. The maximum allowable depletion is 50% of the taxable income before depletion. If the percent depletion of working interest is greater than 50% of the taxable income before depletion, then only the 50% maximum depletion may be taken.

Table 14

Curve A Percentage Depletion

Year	Annual Percentage Depletion
1979	$55,693
1980	74,834
1981	67,688
1982	59,701
1983	53,714
1984	50,352
1985	49,665
1986	52,194
1987	55,066
1988	57,967

For after-tax analysis, cash flow is net income plus depletion, depreciation, drilling expense, and loss forward (49). Because this evaluation is from an oil company viewpoint, royalty paid is not considered in the cash flow.

Table 15 shows the cash flow for each year. In determining NPV, these annual cash flows as well as the costs incurred for land, drilling, and completion must be included.

Notice the percentage depletion on Table 15 is always considerably less than the maximum allowable de-

Year	Jan. 1 1979	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
WI		253,149	340,155	338,438	331,672	335,714	335,677	331,101	347,960	367,106	386,449
Drill Expense	-161,250										
OC		-5,150	-5,305	-5,465	-5,630	-5,795	-5,970	-6,150	-6,335	-6,525	-6,720
Depreciation		-10,750	-8,600	-6,880	-5,504	-4,403	-3,523	-3,523	-3,523	-3,523	-3,523
Taxable Income Before Depletion	-161,250	237,249	326,250	326,093	320,538	325,516	326,184	321,428	338,102	357,058	376,206
% Depletion		-55,693	-74,834	-67,688	-59,701	-53,714	-50,352	-49,665	-52,194	-55,066	-57,967
Max. Depletion		118,624									
Loss Forward		-161,250									
Taxable Income	-161,250	20,306	251,416	258,405	260,837	271,802	275,832	271,763	285,908	301,992	318,239
50% Effective Federal + State Tax Rate		-10,153	125,708	-129,202	-130,418	-135,901	-137,916	-135,881	-142,954	-150,996	-159,119
Net Income	-161,250	-10,153	125,708	129,202	130,418	135,901	137,916	135,881	142,954	150,996	159,119
Drill Expense	161,250										
Loss Forward		161,250									
Depletion		55,693	74,834	67,688	59,701	53,714	50,352	49,665	52,194	55,066	57,967
Depreciation		10,750	8,600	6,880	5,504	4,403	3,523	3,523	3,523	3,523	3,523
CF	0	237,851	209,142	203,770	195,623	194,018	191,791	189,069	198,671	209,585	220,609

Table 15

After-Tax Analysis Curve A

DDB Switching to SL Depreciation

pletion. Therefore, the percentage depletion is subtracted from the 'taxable income before depletion'. Although the maximum depletion has been included on Table 15, it has not been used in the cash flow determination.

For the given cash flows and costs incurred on January 1, 1979, the NPV for $i^* = 15\%$ is:

$$-231{,}650 + 237{,}851(P/F_{15,1}) + 209{,}142(P/F_{15,2}) + \ldots + 220{,}609(P/F_{15,10}) = \$808{,}659$$

The NPV for $i^* = 30\%$ is:

$$-231{,}650 + 237{,}851(P/F_{30,1}) + 209{,}142(P/F_{30,2}) + \ldots + 220{,}609(P/F_{30,10}) = \$418{,}549$$

Both net present values are positive, indicating the project is satisfactory with respect to either minimum ROR. The ROR for the project is 95%.

Risk analysis for after-tax evaluation will be different from before-tax evaluation. In after-tax evaluation, there is a 65% chance of finding gas and a 35% chance of drilling a dry hole. If a dry hole results, 95% of the drilling expense may be expensed at the beginning of 1979, which results in a tax savings if it is assumed there is other income to subtract this drilling expense loss from.

The Federal tax rate is 50%; therefore, a tax savings will be generated equal to:

$$(.50) \times (.95) \times (\$120,000) = \$57,000$$

There is a 35% chance this tax savings will be generated. Thus, a general formula for ENPV would be:

p(Cash Flows) - p(Completion Cost) + (1-p)(95% Drilling Cost)(.50) - Other Costs

This calculation assumes the depreciable equipment equal to 5% of the drilling expense to be negligible.

Risk analysis for both minimum rates of return in conjunction with a .65 success ratio follows. ENPV for $i^* = 15$ equals:

$$.65(-95,000 + 237,851(P/F_{15,1}) + 209,142(P/F_{15,2}) + \ldots + 220,609(P/F_{15,10})) + .35(.50)(.95)(\$120,000) - 136,650 = \$497,751$$

ENPV for $i^* = 30$ equals:

$$.65(-95,000 + 237,851(P/F_{30,1}) + 209,142(P/F_{30,2}) + \ldots + 220,609(P/F_{30,10})) + .35(.50)(.95)(\$120,000) - 136,650 = \$244,179$$

This evaluation indicates a potentially satisfactory investment over the long run for both a 15% and 30% minimum ROR. The expected project ROR is 80%.

In order to see the difference in depreciation methods, this after-tax analysis has been completed a second time using SL depreciation. The annual depreciation is 1/10 of \$53,750, or \$5,375.

Table 16 displays the economics using SL depreciation. Using the cash flows shown for each year and costs initially incurred, the NPV for $i^* = 15\%$ is:

$$-231{,}650 + 235{,}159(P/F_{15,1}) + 207{,}529(P/F_{15,2}) + \ldots + 221{,}536(P/F_{15,10}) = \$806{,}353$$

The NPV for $i^* = 30\%$ is:

$$-231{,}650 + 235{,}159(P/F_{30,1}) + 207{,}529(P/F_{30,2}) + \ldots + 221{,}536(P/F_{30,10}) = \$415{,}898$$

Note the decrease in NPV for this type of depreciation. For a minimum ROR of 15%, DDB switching to SL depreciation resulted in a 837,321 NPV whereas SL depreciation resulted in a 806,353 NPV. For a 30% minimum ROR, DDB switching to SL depreciation yields a 435,765 NPV whereas SL depreciation yields a 415,898 NPV. With DDB switching to SL, the depreciation is higher than SL for the first four years. Apparently, the sooner the depreciation can be taken, the better. Therefore, DDB switching to SL depreciation will be used for the remainder of this paper.

Year	Jan. 1 1979	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988
WI		253,149	340,155	338,438	331,672	335,714	335,677	331,101	347,960	367,106	386,449
Drill Expense	-161,250										
OC		-5,150	-5,305	-5,465	-5,630	-5,795	-5,970	-6,150	-6,335	-6,525	-6,720
Depreciation		-5,375	-5,375	-5,375	-5,375	-5,375	-5,375	-5,375	-5,375	-5,375	-5,375
Taxable Income Before Depletion	-161,250	242,624	329,475	327,598	320,667	324,544	324,332	319,576	336,250	355,206	374,354
% Depletion		-55,693	-74,834	-67,688	-59,701	-53,714	-50,352	-49,665	-52,194	-55,066	-57,967
Max. Depletion		121,312	164,738	163,799	160,333	162,272	162,166	159,788	168,125	177,603	187,177
Loss Forward		-161,250									
Taxable Income	-161,250	25,681	254,641	259,910	260,966	270,830	273,980	269,911	284,056	300,140	316,387
50% Effective Federal + State Tax Rate		12,841	127,320	129,955	130,483	135,415	136,990	134,955	142,028	150,070	158,193
Net Income	-161,250	12,841	127,320	129,955	130,483	135,415	136,990	134,955	142,028	150,070	158,193
Drill Expense	161,250										
Loss Forward		161,250									
Depletion		55,693	74,834	67,688	59,701	53,714	50,352	49,665	52,194	55,066	57,967
Depreciation		5,375	5,375	5,375	5,375	5,375	5,375	5,375	5,375	5,375	5,375
CF	0	235,159	207,529	203,018	195,559	194,504	192,717	189,996	199,597	210,511	221,536

Table 16

After-Tax Analysis Curve A

SL Depreciation

Curve B Evaluation

Curve B is a constant 15,000 MCF annual gas production. Production for 1979 is 3/4 of 15,000 MCF, which is 11,250 MCF. Table 17 indicates production, production revenue and working interest for the 10 year well life.

Table 17

Curve B Production and Revenue

Year	Production (MCF)	Revenue Formula	Production Revenue	Working Interest
1979	11,250	11,250($2.51)	$ 28,238	$23,296
1980	15,000	15,000($2.51)($F/P_{12,1}$)	42,168	34,789
1981	15,000	15,000($2.51)($F/P_{12,2}$)	47,213	38,951
1982	15,000	15,000($2.51)($F/P_{12,3}$)	52,898	43,641
1983	15,000	15,000($2.51)($F/P_{12,4}$)	59,261	48,890
1984	15,000	15,000($2.51)($F/P_{12,5}$)	66,339	54,730
1985	15,000	15,000($2.51)($F/P_{12,6}$)	74,321	61,315
1986	15,000	15,000($2.51)($F/P_{12,7}$)	83,244	68,676
1987	15,000	15,000($2.51)($F/P_{12,8}$)	93,221	76,908
1988	15,000	15,000($2.51)($F/P_{12,9}$)	104,403	86,133

All costs and operating costs will be the same for curve A as for curve B. Only the realized production revenue (working interest) will be different.

Before-Tax Analysis

The annual cash flows for curve B are contained in Table 18.

Table 18

Before-Tax Cash Flows for Curve B

Year	Cash Flow
1979	$18,146
1980	29,484
1981	33,486
1982	38,011
1983	43,095
1984	48,760
1985	55,165
1986	62,341
1987	70,383
1988	79,413

The NPV equation for $i^* = 15\%$ is:

$$-231{,}650 + 18{,}146(P/F_{15,1}) + \ldots + 79{,}413(P/F_{15,10})$$
$$= -\$26{,}565$$

NPV for $i^* = 30\%$ is:

$$-231{,}650 + 18{,}146(P/F_{30,1}) + \ldots + 79{,}413(P/F_{30,10})$$
$$= -\$121{,}155$$

The NPV for each minimum rate of return is negative, indicating this project will not be satisfactory for either minimum rate of return requirement. The project ROR is 12%. Therefore, this investment is only profitable for a minimum rate of return of 12% or less.

Risk analysis using .65 probability of success and $i^* = 15\%$ yields on ENPV of:

$$.65(23,088(P/F_{15,1}) + \ldots + 97,683(P/F_{15,10})) - .65(95,000) - 136,650 = -\$65,095$$

For $i^* = 30\%$, ENPV equals:

$$.65(23,088(P/F_{30,1}) + \ldots + 97,683(P/F_{30,10})) - .65(95,000) - 136,650 = -\$126,578$$

Again, the project is unsatisfactory for either minimum rate of return.

After-Tax Analysis

The well costs will be expensed and depreciated the same way as for curve A. The cost of $161,250 will be expensed at the beginning of 1979 and $53,750 will be depreciated DDB switching to SL over ten years. The annual depreciation was listed in Table 13. Depletion is shown in Table 19. Operating costs are listed in Table 11.

These values have been used to calculate the cash flows in Table 20. The same method was used to calculate these cash flows as for curve A. Note the large drop in cash flow for 1986. Losses may be carried forward for seven years and backward for three years. The loss forward may not be applied outside of this ten-year period. The loss had to be dropped in 1986, which eliminated

Table 19

Curve B Percentage Depletion

Year	Annual Percentage Depletion
1979	$5,125
1980	7,654
1981	7,790
1982	7,855
1983	7,822
1984	8,210
1985	9,197
1986	10,301
1987	11,536
1988	12,920

Table 20

Curve B After-Tax Cash Flows

Year	Cash Flow
1979	$18,146
1980	29,484
1981	33,486
1982	38,011
1983	43,095
1984	48,760
1985	55,165
1986	42,115
1987	53,668
1988	60,440

the tax benefits. The taxable income was negative for all years previous to 1986 due to the size of the loss carried forward, so no Federal taxes were levied.

The revenue from the production is rather small, so taxable income before depletion is small. This results in a low maximum depletion. For this evaluation the 50% maximum depletion is used for each year.

The following formula is used to generate the NPV for i^*:

$$NPV = -231{,}650 + 18{,}146(P/F_{i,1}) + \ldots + 60{,}440(P/F_{i,10})$$

For $i^* = 15\%$, the NPV is -\$42,618. For $i^* = 30\%$, the NPV is -\$126,587. This project is an unsatisfactory investment for either minimum rate of return. The project ROR is 11%.

Using risk analysis, the ENPV formula is:

$$ENPV = .65(18{,}146(P/F_{i,1}) + \ldots + 60{,}440(P/F_{1,10}) - 95{,}000) - 136{,}650 + 19{,}950$$

The \$19,950 results from the tax savings generated if a dry hole is drilled. ENPV equals -\$55,579 for an i^* of 15% and ENPV equals -\$110,159 for an i^* of 30%. Both investments are unsatisfactory.

Conclusions

Curve B is unacceptable by before-tax and after-tax analyses for both minimum rates of return. Curve A is acceptable by both analyses for both minimum rates of return. The Mancos B Formation can be a satisfactory investment if the production is greater than curve B.

South Piceance Basin: Cozzette, Corcoran and Rollins Sandstones

The production data plotted in Figure 6 is from the Plateau field located at T10S, R96W (Figure 2). An oil company has recently completed two wells in this area for $221,000 and $233,000. This analysis uses $100,000 to the casing point and $133,000 completion costs. Depth to pay in this area is approximately 4,000 feet.

Only curve A will be evaluated. Plateau is a fairly recent field with only two wells having produced for over ten years. The records state cummulative field production, but do not seperate the actual production per well. Therefore, each year's production has been divided by two to arrive at average annual production.

For some reason, in 1964, 1970 and half of 1969, only one well was producing gas. These three years' production were not divided by two. It appears that this well has a higher production rate than the other well due to the unusually high production in these three years. Curve A has not been altered to accommodate these three anomolous values because they could be the result of seasonal take or higher production from the one well.

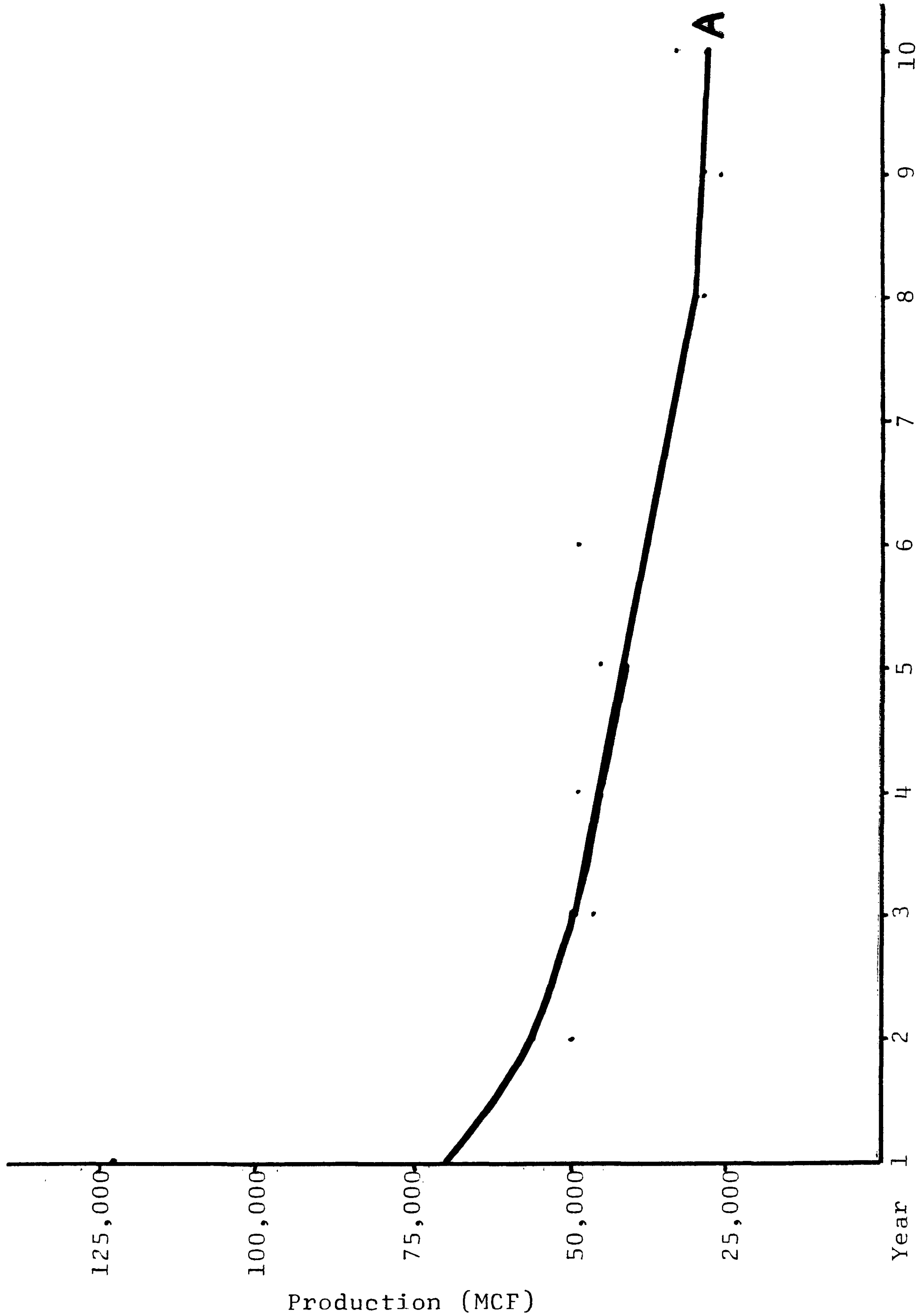

Figure 6. Cozzette, Corcoran and Rollins Sandstones Production Data

Although there is not much data available to determine the bounds of production, this gas play is being evaluated because there is increasing drilling interest in this area. This evaluation may shed some light on the potential economics of this gas play.

Curve A Evaluation

Table 21 contains the production, production revenue, and working interest. The base price is $2.09 per MCF gas. The first year's production is 3/4 of 69,000 MCF, or 51,750 MCF.

Table 21

Curve A Production and Revenue

Year	Production (MCF)	Production Revenue	Working Interest
1979	51,750	$108,157	$ 89,230
1980	56,000	131,085	108,145
1981	49,500	129,733	107,029
1982	45,600	133,902	110,469
1983	41,700	137,179	113,173
1984	37,800	139,202	114,841
1985	33,900	139,860	115,384
1986	30,000	138,630	114,370
1987	29,000	150,010	123,758
1988	28,000	162,276	133,878

Operating costs are those listed in Table 11. The cost of 165 acres at $20 per acre is $3,300.

Before-Tax Analysis

Table 22 lists the annual before-tax cash flows.

Table 22

Curve A Before-Tax Cash Flows

Year	Cash Flow
Jan. 1, 1979	-$236,300
1979	84,080
1980	102,840
1981	101,564
1982	104,839
1983	107,378
1984	108,871
1985	109,234
1986	108,035
1987	117,233
1988	127,158

The before-tax NPV equation for i^* minimum ROR is:

$$NPV = -236,300 + 84,080(P/F_{i,1}) + \ldots + 127,158(P/F_{i,10})$$

NPV = $282,889 for $i^* = 15\%$ and NPV = $74,571 for $i^* = 30\%$. Both investments will satisfy the minimum rates of return required, so they are satisfactory. The project ROR is 40%.

Risk analysis involving a .65 sueeess ratio uses the following ENPV equation:

$$ENPV = .65(-133{,}000 + 84{,}080(P/F_{i,1}) + \ldots + 127{,}158(P/F_{i,10})) - 103{,}300$$

For $i^* = 15\%$, ENPV = \$147,723. For $i^* = 30\%$, ENPV = \$12,316. This project may be potentially satisfactory for either i^* due to the positive values of ENPV.

After-Tax Analysis

Total well costs are \$233,000. The 75% of these costs to be expensed is \$174,750 and the balance to be depreciated is \$58,250.

DDB switching to SL depreciation yields the annual depreciation contained in Table 23.

Table 23

Annual Depreciation

Year	Adjusted Basis	Annual Depreciation
1979	58,250	11,650
1980	46,600	9,320
1981	37,280	7,456
1982	29,824	5,965
1983	23,859	4,772
1984	19,087	3,817
1985	15,269	3,817
1986	11,452	3,817
1987	7,635	3,817
1988	3,817	3,817

Table 24 indicates annual percentage depletion.

Table 24

Annual Depletion

Year	Annual Percentage Depletion
1979	$19,631
1980	23,792
1981	21,406
1982	19,884
1983	18,108
1984	17,226
1985	17,308
1986	17,156
1987	18,564
1988	20,082

The after-tax cash flows have been calculated given the preceeding information. Table 25 shows these annual cash flows. The costs for land, drilling and completion must be used in addition to these cash flows to arrive at net present values.

The NPV equation incorporating these costs and cash flows is as follows:

$$NPV = -236{,}300 + 84{,}080(P/F_{i,1}) + \ldots + 75{,}528(P/F_{i/10})$$

For $i^* = 15\%$, the NPV = \$156,548. For $i^* = 30\%$, the NPV = \$15,030. The project rate of return is 33%.

Table 25

Curve A After-Tax Cash Flows

Year	Cash Flow
1979	\$ 84,080
1980	102,840
1981	91,324
1982	65,344
1983	65,129
1984	64,957
1985	65,179
1986	64,504
1987	69,807
1988	75,528

The ENPV equation used for i^* is:

$$.65(-133{,}000 + 84{,}080(P/F_{i,1}) + \ldots + 75{,}528(P/F_{i,10}))$$
$$-103{,}300 + .35(.50)(.95)(100{,}000)$$

ENPV for $i^* = 15\%$ is \$82,226. The ENPV for $i^* = 30\%$ is -\$9,760. For $i^* = 15\%$, this is a potentially satisfactory investment; however, for $i^* = 30\%$, this is not a satisfactory project.

Conclusion

The before-tax and after-tax analyses indicate this is a potentially satisfactory area for exploration. The risk analysis indicates this is a potentially satisfactory investment if 15% is the minimum rate of return required.

Douglas Arch - South Piceance Basin: Dakota Group

Figure 7 contains the production data for the Dakota Group. Curve A is the result of averaging the production for five wells in the South Canyon field (Figure 2) located at T6S, R104W. There is no way to determine the actual production for each well as only a cummulative production figure is given at Petroleum Information. All five wells began producing within a year of each other and continued production for over ten years.

Curve B records the production of one well in the Texas Mountain field (Figure 2) located at T3S, R102W.

The data for curve A tends to oscillate. This could be due to seasonal demand. The tail of the curve is almost flat due to the increased production at that time. It is possible the considerably lower gas prices in the past economically restricted production of gas. The price of gas did increase during the time plotted at the tail of the curve and could account for the higher than expected production.

Completed well costs are approximately $250,000, according to one oil company drilling in this area. Cost to the casing point is $118,100; cost for completion is $131,900 (50). Depth to pay is 6200 feet.

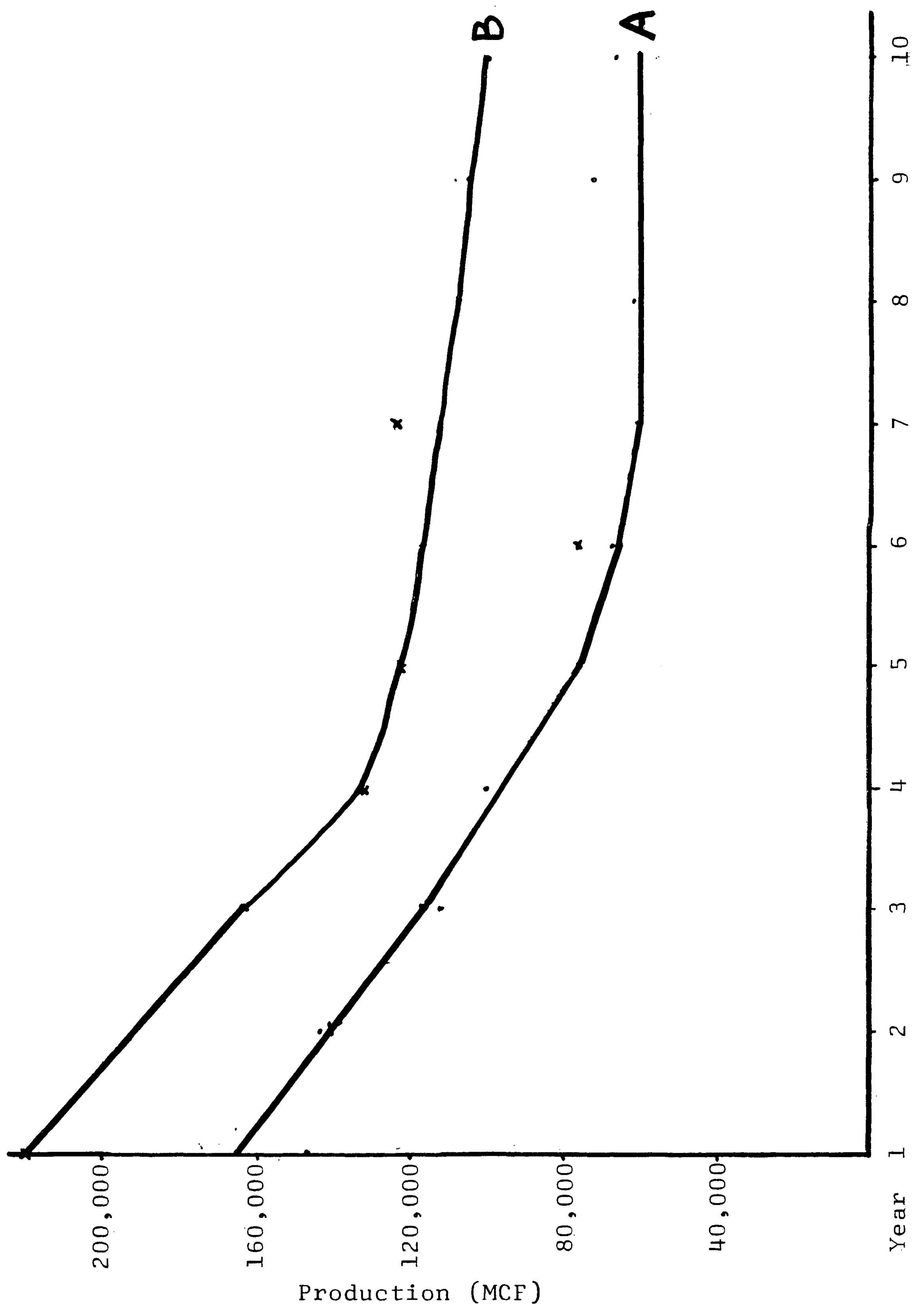

Figure 7. Dakota Group Production Data

Curve A Evaluation

Production, production revenue and working interest are shown on Table 26. The base price is $2.09 per MCF. The first year's production is 3/4 of 165,000 MCF, or 123,750 MCF.

Table 26

Curve A Production and Revenue

Year	Production (MCF)	Production Revenue	Working Interest
1979	123,750	$258,638	$213,376
1980	140,000	327,712	270,362
1981	115,000	301,399	248,654
1982	95,000	278,963	230,144
1983	75,000	246,725	203,548
1984	65,000	239,367	197,478
1985	60,000	247,540	204,220
1986	60,000	277,259	228,739
1987	60,000	310,490	256,155
1988	60,000	347,734	286,881

The cost of 333 acres land at $60 per acre is $19,980. The operating costs are the same as those in Table 11.

Before-Tax Analysis

The working interest and operating costs are combined to arrive at the cash flows. The costs for land, drilling and completion comprise the January 1, 1979, cash flow. Table 27 lists these cash flows.

Table 27

Curve A Before-Tax Cash Flows

Year	Cash Flow
Jan. 1, 1979	-$269,980
1979	208.226
1980	265,057
1981	243,189
1982	224,514
1983	197,753
1984	191,508
1985	198,070
1986	222,404
1987	249,630
1988	283,064

The before-tax net present values are derived as follows:

$$NPV = -269{,}980 + 208{,}226(P/F_{i,\ 1}) + \ldots + 283{,}064(P/F_{i,10})$$

NPV = \$868,983 for $i^* = 15\%$. NPV = \$432,172 for $i^* = 30\%$. This project will be a satisfactory investment for either minimum rate of return. The project ROR is 85%.

Risk analysis uses the following formula to determine ENPV:

$$ENPV = .65(-131{,}900 + 208{,}226(P/F_{i,1}) + \ldots + 283{,}064(P/F_{i,10})) - 138{,}080$$

For a minimum ROR of 15%, ENPV equals \$516,421. For a minimum ROR of 30%, ENPV equals \$232,584. This drilling project is potentially satisfactory for either minimum ROR according to this risk analysis.

After-Tax Analysis

75% of $250,000, or $187,500, will be expensed on January 1, 1979; 25% of $250,000, or $62,500, will be depreciated over ten years. Table 28 lists the annual depreciation.

Table 28

Annual Depreciation

Year	Adjusted Basis	Annual Depreciation
1979	$62,500	$12,500
1980	50,000	10,000
1981	40,000	8,000
1982	32,000	6,400
1983	25,600	5,120
1984	20,480	4,096
1985	16,384	4,096
1986	12,288	4,096
1987	8,192	4,096
1988	4,096	4,096

Table 29 contains annual percentage depletion.

The after-tax cash flows have been calculated for each year and appear in Table 30.

Table 29

Annual Depletion

Year	Annual Percentage Depletion
1979	$46,943
1980	59,480
1981	49,731
1982	41,426
1983	32,568
1984	29,622
1985	30,633
1986	34,311
1987	38,423
1988	43,032

Table 30

Curve A After-Tax Cash Flows

Year	Cash Flow
1979	$208,226
1980	186,627
1981	150,460
1982	136,170
1983	117,720
1984	112,613
1985	116,399
1986	130,405
1987	146,074
1988	163,644

These cash flows and initial costs combined in the following equation yield the NPV:

$$NPV = -269{,}980 + (208{,}226(P/F_{i,1}) + \ldots + 163{,}644(P/F_{i,10})$$

The NPV is \$504,564 for $i^* = 15\%$ and \$232,003 for $i^* = 30\%$. Both investment situations are satisfactory. The project ROR is 65%.

The equation used to calculate the ENPV is as follows:

$$ENPV = .65(-131{,}900 + 208{,}226(P/F_{i,1}) + \ldots + 163{,}644(P/F_{i,10})) - 138{,}080 + 19{,}634$$

For $i^* = 15\%$, the ENPV is \$299,272. For $i^* = 30\%$, the ENPV is \$122,108. Both of these investments are potentially satisfactory.

<u>Curve B Analysis</u>

Table 31 lists the production, and calculated production revenue and working interest. The first year's production is 3/4 of 220,000 MCF, or 165,000 MCF.

Before-Tax Analysis

The operating costs and working interest are combined to produce the annual cash flows shown in Table 32.

Using the cash flows from Table 32 and the initial total cost of \$269,980, the NPV equation is:

Table 31

Curve B Production and Revenue

Year	Production (MCF)	Production Revenue	Working Interest
1979	165,000	$344,850	$284,501
1980	191,000	447,093	368,852
1981	162,000	424,579	350,278
1982	132,000	387,611	319,779
1983	121,000	398,049	328,390
1984	116,200	427,916	353,031
1985	111,500	460,011	379,509
1986	107,000	494,446	407,918
1987	102,800	531,974	438,878
1988	98,700	572,023	471,919

Table 32

Curve B Before-Tax Cash Flows

Year	Cash Flow
1979	$279,351
1980	363,547
1981	344,813
1982	314,149
1983	322,595
1984	347,061
1985	373,359
1986	401,583
1987	432,353
1988	465,199

$$NPV = -269{,}980 + 279{,}351(P/F_{i,1}) + \ldots + 465{,}199 \times (P/F_{i,10})$$

For $i^* = 15\%$, the NPV is \$1,474,124. For $i^* = 30\%$, the NPV is \$768,995. A satisfactory investment results for both minimum rates of return. The project ROR is 116%.

The equation for the ENPV for a minimum rate of return of 'i' is:

$$ENPV = .65(-131{,}900 + 279{,}351(P/F_{i,1}) + \ldots + 465{,}199(P/F_{i,10})) - 138{,}080$$

For $i^* = 15\%$, the ENPV is \$949,813. For $i^* = 30\%$ the ENPV is \$451,519. A potentially satisfactory investment results for both minimum rates of return.

After-Tax Analysis

Table 33 contains the percentage depletion for each year. The depreciation and OC are the same for curve B as for curve A.

The depletion, depreciation, OC and WI have been combined to produce the after-tax cash flows in Table 34.

These after-tax cash flows and the initial costs are used to calculate NPV by:

$$NPV = -269{,}980 + 270{,}970(P/F_{i,1}) + \ldots + 270{,}041(P/F_{i,10})$$

Table 33

Curve B Percentage Depletion

Year	Annual Percentage Depletion
1979	$62,590
1980	81,147
1981	70,056
1982	57,560
1983	52,542
1984	52,955
1985	56,926
1986	61,188
1987	65,832
1988	70,788

The depletion, depreciation, OC and WI have been combined to produce the after-tax cash flows in Table 34.

Table 34

Curve B After-Tax Cash Flows

Year	Cash Flow
1979	$270,970
1980	227,347
1981	211,434
1982	189,054
1983	190,128
1984	202,056
1985	217,190
1986	233,433
1987	251,140
1988	270,041

If i^* equals 15%, then NPV equals \$891,310. If i^* equals 30%, then NPV equals \$452,198. This drilling project is satisfactory based upon a 15% or a 30% minimum ROR. The project ROR is 91%.

Risk analysis uses the following equation to calculate ENPV:

$$ENPV = .65(-131,900 + 276,120(P/F_{i,1}) + \ldots + 276,761(P/F_{i,10})) - 138,080 + 19,634$$

For $i^* = 15\%$, the ENPV = \$550,658. For i^* 30%, the ENPV = \$265,235. According to this after-tax risk analysis, this investment is potentially satisfactory for either minimum rate of return.

Conclusions

Production on or between curves A and B will yield a satisfactory return on money invested with respect to a minimum ROR of 15% or 30%. Risk analysis indicates this investment is potentially satisfactory with respect to a 15% or 30% minimum ROR.

Sand Wash Basin: Lewis Sand

The production graphed in Figure 8 originates from the North Craig field (Figure 3) located in T8N, R90W. Data from two wells currently drilled has been provided. Well 1 cost \$86,200 to the casing point and cost an additional

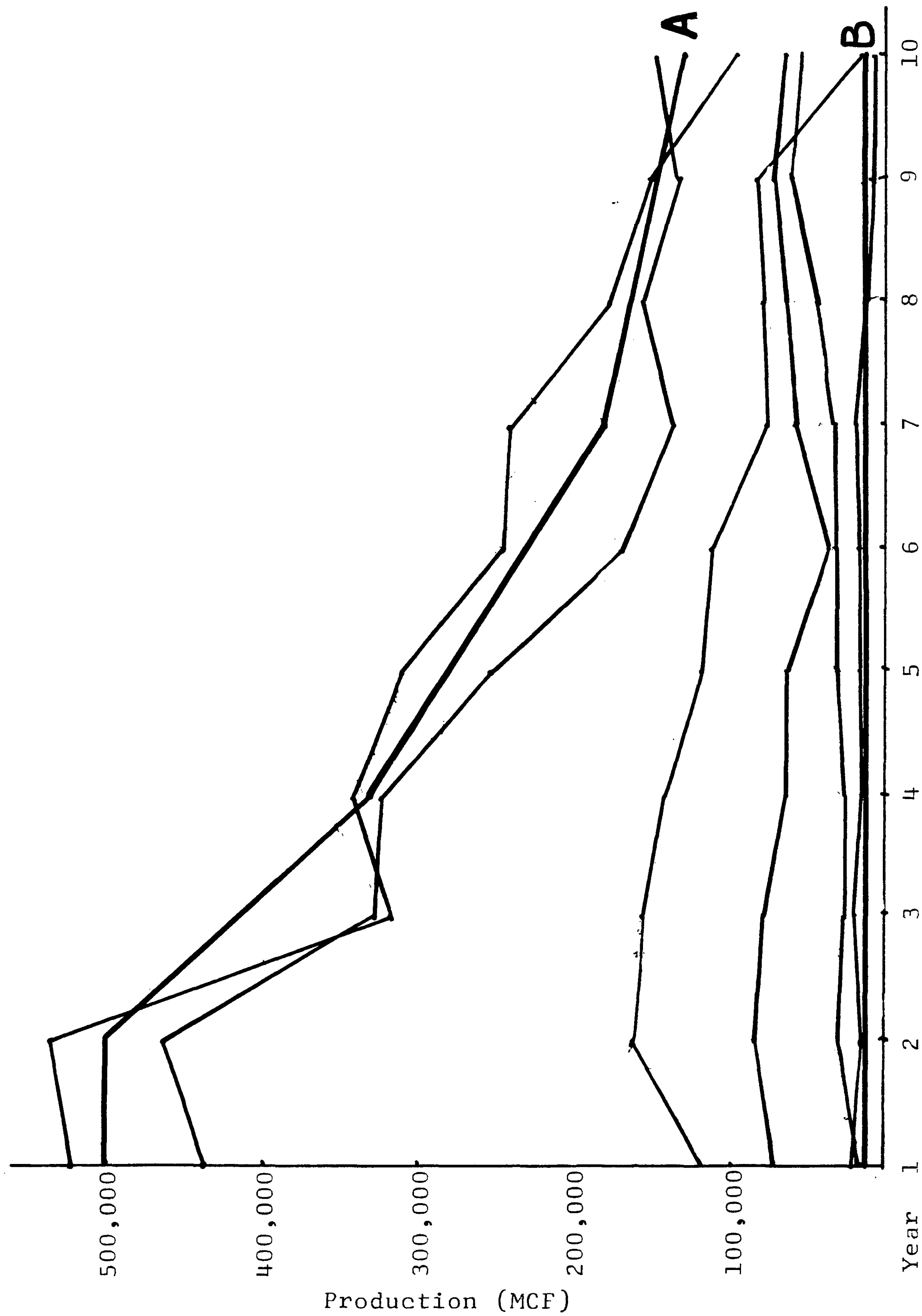

Figure 8. Lewis Sand Production Data

$93,100 for completion. The well is located in T8N, R90W and the depth to pay is 3200 feet. Well 2 cost $89,500 to the casing point and cost an additional $95,100 for completion. This well is located in T10N, 90W and is drilled to 3400 feet (51). The additional cost of well 2 could be due to the extra 200 feet drilled. Due to the proximity to currently established production, the evaluation uses well 1 cost information.

Curve A Evaluation

The first complete year's production is 500,000 MCF. Therefore, 3/4 of this value, or 375,000 MCF, will be used for the well's partial year of production in 1979. Table 35 contains the annual production, production revenue, and working interest.

Table 35

Curve A Production and Revenue

Year	Production (MCF)	Production Revenue	Working Interest
1979	375,000	$ 783,750	$646,594
1980	500,000	1,170,400	965,580
1981	415,000	1,087,657	897,317
1982	330,000	969,029	799,449
1983	280,000	921,105	759,911
1984	230,000	846,993	698,770
1985	180,000	742,619	612,661
1986	163,000	753,221	621,408
1987	146,000	755,527	623,309
1988	129,000	747,629	616,794

Assuming land costs $50 per acre, the 333 acres assessed to this well cost $16,650. Operating costs are shown in Table 11. The before-tax cash flows appear in Table 36.

Table 36

Curve A Before-Tax Cash Flows

Year	Cash Flow
1979	$641,444
1980	960,275
1981	891,852
1982	793,819
1983	754,116
1984	692,800
1985	606,511
1986	615,073
1987	616,784
1988	610,074

The drilling, completion and land costs total to $195,950. Using this initial cost and the before-tax cash flows, the NPV equation is:

$$NPV = -195{,}950 + 641{,}444(P/F_{i,1}) + \ldots + 610{,}074(P/F_{i,10})$$

For $i^* = 15\%$, the NPV is $3,557,862. For $i^* = 30\%$, the NPV is $2,170,670. These two exceptionally high net present values indicate this will be a very profitable drilling prospect. This is further confirmed by the very large project ROR of 361%.

Risk analysis uses the following before-tax formula to calculate ENPV:

$$ENPV = .65(-93,100 + 641,444(P/F_{i,1}) + \ldots + 610,074(P/F_{i,10})) -102,850$$

For $i^* = 15\%$, the ENPV = \$2,276,613. For $i^* = 30\%$, the ENPV = \$1,374,938. This before-tax risk analysis indicates this project is potentially very satisfactory with respect to either minimum ROR.

After-Tax Analysis

The cost to be expensed is \$134,475 and the depreciable cost is \$44,825. Table 37 lists the annual depreciation.

Table 37

Annual Depreciation

Year	Adjusted Basis	Depreciation
1979	\$44,825	\$8,965
1980	35,860	7,172
1981	28,688	5,738
1982	22,950	4,590
1983	18,360	3,672
1984	14,688	2,938
1985	11,750	2,938
1986	8,812	2,938
1987	5,874	2,938
1988	2,936	2,938

The percentage depletion is tabulated in Table 38.

Table 38

Curve A Percentage Depletion

Year	Annual Percentage Depletion
1979	$142,251
1980	257,488
1981	217,531
1982	174,425
1983	147,377
1984	127,049
1985	111,393
1986	112,983
1987	113,329
1988	112,144

The after-tax cash flows are included in Table 39.

Table 39

Curve A After-Tax Cash Flows

Year	Cash Flow
1979	$468,717
1980	617,772
1981	563,025
1982	492,047
1983	458,377
1984	417,363
1985	366,571
1986	371,832
1987	373,050
1988	369,298

The after-tax equation for NPV is as follows:

$NPV = -195,950 + 468,717(P/F_{i,1}) + . . .$
$+ 369,298(P/F_{i,10})$

If $i^* = 15\%$, then the NPV is \$2,195,304. If $i^* =$ 30%, then the NPV is \$1,334,587. This investment will be satisfactory for either minimum ROR. The project ROR is 258%.

Risk analysis uses the following formula to determine ENPV:

$ENPV = .65(-93,100 + 468,717(P/F_{i,1}) + . . .$
$+ 369,298(P/F_{i,10})) - 102,850 + .35(.50)(.95) \times$
$(86,200)$

ENPV for an i^* of 15% is \$1,405,231. ENPV = \$845,815 for an $i^* = 30\%$. This risk analysis indicates this project is a potentially satisfactory investment with respect to either minimum ROR.

<u>Curve B Analysis</u>

The production, production revenue and working interest are included in Table 40.

Before-Tax Analysis

The cash flows resulting from the working interest and operating costs are shown in Table 41.

Table 40

Production and Revenue

Year	Production (MCF)	Production Revenue	Working Interest
1979	7,500	$15,675	$12,932
1980	10,000	23,408	19,312
1981	10,000	26,209	21,622
1982	10,000	29,365	24,226
1983	10,000	32,897	27,140
1984	10,000	36,826	30,381
1985	10,000	41,257	34,037
1986	10,000	46,209	38,123
1987	10,000	51,748	42,692
1988	10,000	57,956	47,813

Table 41

Curve B Before-Tax Cash Flows

Year	Cash Flow
1979	$ 7,782
1980	14,007
1981	16,157
1982	18,596
1983	21,345
1984	24,411
1985	27,887
1986	31,788
1987	36,167
1988	41,093

The cash flows are used in conjunction with the initial cost of $195,950. The NPV equation is:

$$NPV = -195{,}950 + 7{,}782(P/F_{i,1}) + \ldots +$$
$$41{,}093(P/F_{i,10})$$

NPV = -94,856 for $i^* = 15\%$. NPV = -\$142,272 for $i^* = 30\%$. This drilling project is unacceptable for either minimum ROR. The project ROR is 3%, indicating a very poor investment.

This project will be even more unaccpetable with risk analysis performed. The ENPV for $i^* = 15\%$ is -\$97,654.

After-Tax Analysis

The percentage depletion is presented in Table 42.

Table 42

Curve B Percentage Depletion

Year	Annual Percentage Depletion
1979	\$1,712
1980	3,082
1981	3,237
1982	3,347
1983	3,415
1984	3,662
1985	4,183
1986	4,768
1987	5,425
1988	6,164

The after-tax cash flows are contained in Table 43.

Table 43

Curve B After-Tax Cash Flows

Year	Cash Flow
1979	\$ 7,782
1980	14,007
1981	16,157
1982	18,596
1983	21,345
1984	24,411
1985	27,887
1986	19,747
1987	22,265
1988	25,100

Using the after-tax cash flows and an initial cost of \$195,950, the NPV for 15% and 30% minimum ROR is calculated using:

$$NPV = -195,950 + 7,782(P/F_{i,1}) + \ldots$$
$$+ 25,100(P/F_{i,10})$$

For $i^* = 15\%$, the NPV = -\$106,698. For $i^* = 30\%$, the NPV = -\$146,219. This amount of production is considerably too low in order to meet a 15% or 30% minimum rate of return. The project ROR is .2%. Therefore, this project is totally unacceptable. The risk analysis would yield even more unacceptable results.

Conclusions

The range of production for the Lewis sand is very great; curve A yields an exceptionally high rate of return, whereas curve B yields a positive, but unacceptable rate of return. These results are consistent for before-tax and after-tax analyses.

SENSITIVITY ANALYSIS

Throughout this chapter, a .65 success ratio has been used. In order to determine the sensitivity ENPV to this value, the risk analysis on curve B of the Dakota Group has been calculated again using a .20 success ratio. The ENPV equation remains the same, except .20 will be used in place of a .65 and .80 will be used in place of .35. The resulting ENPV from this calculation is $100,943 for $i^* = 15\%$ and is +$21,410 for $i^* = 30\%$. The ENPV for a .65 probability of success is $532,027 for $i^* = 15\%$ and is $245,044 for $i^* = 30\%$.

The probability of success has a definite effect upon ENPV. For this area the probability of success is fairly well established; however, some areas have too little drilling to determine a fairly accurate success ratio. Therefore, several probabilities of success should be examined before making any drilling decisions.

One other sensitivity analysis will be run, which relates to the price of land affordable in order to maintain a certain minimum ROR. Using the Dakota curve A analysis, the price of land which will maintain a 30% minimum ROR is calculated by:

$$\text{Cost} = 208{,}226(P/F_{30,1}) + \ldots + 163{,}644 \times (P/F_{30,10}) - 250{,}000$$

where \$250,000 equals total drilling costs. Note, NPV = 0 at the minimum ROR. The cost allowable equals \$251,983, which is considerably more than what was paid for the land. Therefore, for Dakota production similar to curve A, the current cost of land is not unacceptable.

CONCLUSIONS

The parcels available under simultaneous filing can be ranked through the use of 'expected net present value' per parcel. The size of the parcel is known and the selling price can be determined fairly accurately; however, the estimated number of applicants can be difficult to determine. The ranking technique is rather sensitive to the number of applicants.

An additional consideration that cannot be quantified is the overriding royalty generally acquired when turning the leasing rights over to another individual. Although the ENPV may cause a lower parcel ranking, an overriding royalty on good production can greatly out-weight the returns derived through selling the lease.

The ENPV for most of the parcels indicates a profit can be made through simaltaneous filings; however, according to the law of probability, several filings would have to be made in a period of a few years to realize the profits in a reasonable time.

In evaluating the economics of the four gas plays in northwestern Colorado, it appears the Dakota

Formation is the most potentially satisfactory investment. The production-range bracket always indicated a favorable investment.

Although the Lewis sand only had a .2% project ROR after-tax for the lower bound of production, it had the highest project ROR after-tax for the upper bound of production. Therefore, this type gas play may be very profitable over the long run, but some risk will be involved.

The Mancos B formation is a satisfactory project based upon the upper bound of production; however, the lower bound of production is an unacceptable project. The range of project ROR for the two production curves is large; therefore, it may be a profitable investment over the long run.

The Cozzette, Corcoran, and Rollins sandstones show potential. The production curve evaluated satisfies a minimum ROR equal to 30% based upon after-tax analysis. This type of gas play is worth investigating for future drilling.

The new Federal gas prices did offset declining production in the later years of the project life in some cases. This may stimulate further exploration for gas.

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