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A COMPARISON OF TWO DRILLING COST MODELS FOR
NON-ASSOCIATED NATURAL GAS IN THE PERMIAN BASIN

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science (Mineral Economics).

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ABSTRACT

This thesis uses two models to calculate drilling costs per unit of non-associated natural gas. One model relies primarily on Potential Gas Committee estimates while the other relies primarily on historical data. The models were developed by a Colorado School of Mines research group, of which the author is a member. The models are applied to data for the Permian Basin. Marginal costs, average costs, exploratory and development success ratios, the number of fields discovered and recoveries per successful well are compared from the results of the two models.

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Chapter 1

INTRODUCTION

Two models developed by a Colorado School of Mines research group are used in this study to predict the costs of extracting non-associated natural gas in the Permian Basin. One model, based primarily on subjective estimates provided by the Potential Gas Committee (PGC), will be referred to as the PGC Model, and the other, based primarily on historical data, will be referred to as the Historical Model.

The PGC data include field size parameters, total resources, drilling success ratios, and recoveries per well for many areas of the United States. The CSM research group, of which the author is a member, is analyzing these data to develop costs of extraction for oil and gas resources. This thesis uses the Permian Basin data in the category of non-associated natural gas wells. The cost of extraction for the purposes of this study is the drilling cost, in 1980 constant dollars, per thousand cubic feet (mcf) of natural gas discovered and developed.

In both models the total resource estimate for non-associated natural gas in the Permian Basin is assumed

to be accurate. Whether or not the estimate is accurate is not a crucial variable as will be explained in Chapter 5.

The models have two other features in common. The first is drilling costs per well. The analysis of costs for successful exploratory, dry exploratory, successful development, and dry development wells is assumed to be outside the scope of this study. The second is the calculation of marginal and average drilling costs. The CSM research group has developed a methodology for this calculation which is presented in Chapter 3.

The two models will be used to predict marginal and average costs of extraction for non-associated natural gas in the Permian Basin. The costs will be presented in graph form and compared to determine whether the two models produce similar results. If the shapes and the starting and ending points of the two graphs are similar, it can be assumed that the PGC data that agrees with historical data. If the graphs are not similar, the reason may be that PGC is incorporating new technologies, better industry practices, etc., into their estimates.

Chapter 2 of this thesis is a review of literature pertaining to previous oil and natural gas discovery and development models. Although there are many models, only

the four most important will be reviewed. Chapter 3 presents marginal and average costs calculated from the PGC Model. Chapter 4 presents marginal and average costs calculated from the Historical Model. Chapter 5 is a comparison of the results derived from the analysis in Chapters 3 and 4. Chapter 6 presents conclusions and suggestions for future research.

Chapter 2

REVIEW OF THE LITERATURE

2.1 Introduction

This chapter reviews literature related to oil and natural gas discovery and development models other than those used in this study. Of the four models reviewed, three tend to be analytical and one, subjective. Although there are many other discovery and development models, most follow the approaches taken by the authors reviewed here. Among other models are those developed by E. Barouch and G. M. Kaufman (1977), R. W. Jones (1978) and G. M. Kaufman, Y. B. Balcer, and D. Kruyt (1975).

2.2 The Arps and Roberts Model

One of the first widely publicized oil and gas discovery model was that of J. J. Arps and T. G. Roberts (1958). It was developed from past drilling activity and production history in a sample area of the east flank of the Denver-Julesburg Basin. A statistical correlation was prepared of the estimated ultimate recovery per field and the number of delineating dry holes per field as a function of productive area.

A mathematical relation was presented which relates the number of fields of a given size found after drilling a known number of wildcat wells to the number that existed originally, based on the assumptions of (a) random drilling, (b) pattern drilling, and (c) drilling on geophysical and geological information. Using this relation, it is possible to forecast the number of fields of a given size that will be discovered by a given number of wildcat wells.

The Denver-Julesburg Basin is a good choice for this kind of study because almost all of the production comes from the Dakota group which dates to the Lower Cretaceous Age. Not only is the accumulation of hydrocarbons similar, but there are hundreds of fields and thousands of wells. These two factors improve the validity of the statistical correlations.

The first statistical correlation was made between the productive area (A) in acres and the number of dry holes (N) needed to delineate the field.

Using least squares regression analyses, the relation was found to be

$$N = 0.76 A^{0.345}$$

Similarly, the relation between the ultimate recovery (U) and the productive area (A) was found to be

$$U = 530 A^{1.275}.$$

The authors then developed an equation to determine how many fields of a given size will be found after drilling a specific number of wildcats. Their final equation is as follows:

$$F_w = F_o (1 - e^{-CAW/B})$$

where

- W = number of wildcats drilled
- A = area of field
- C = a constant depending on the exploration method used (random drilling, pattern drilling, etc.)
- F_o = number of fields of a given size originally existing in the basin
- F_w = number of fields of a given size found after drilling w wildcats

For random drilling, C = 1, where B equals the total extent of the basin. The chance of finding a field of size

A is proportional to the ratio of the total area of all fields of such size remaining and the area of the unexplored basin. For pattern drilling, C still equals 1, but depending on the spacing in the pattern, the chance of finding a field the size of the spacing is a certainty. For instance, if the entire basin is drilled and the spacing is one wildcat well for every square mile, no field of area one square mile or larger can go undiscovered. For drilling with the help of geophysical and geological data, the authors contend that for the Denver-Julesburg Basin, $C = 2$, that is, drilling with geological and geophysical data is twice as efficient as random or pattern drilling. The authors defend this number by stating U.S. drilling statistics showing that success ratios for wildcat wells drilled on geological and geophysical data are about 2.75 times the success ratio for wildcat wells drilled for nontechnical reasons. They contend that $C = 2$ instead of 2.75 because of the nature of the traps in the Denver-Julesburg Basin. This is reasonable because the Denver-Julesburg Basin has many more stratigraphic traps than structural traps. Stratigraphic traps could not be found by the geophysical and geological techniques existing in 1958 when this model was developed.

One of the very good points of this model is that the

equations and the methodology are simple but powerful. Another good aspect of this model is that it is based on objective historical. A model based on historical data, however, cannot take into account new technologies. With the rapid rate of technological change this could invalidate any model based on historical data.

2.3 The Fisher Model

Franklin Fisher, author of another early discovery model (1964), uses three equations to predict the annual number of wildcats drilled, success ratio, and the average size of predicted discoveries. Fisher says exploration takes place at the extensive margin (frontier areas) or at the intensive margin (partially explored areas). The extensive margin tends to yield a few large discoveries. and the intensive margin tends to yield small, less risky discoveries.

The most significant relationship in Fisher's model 1 is the average size of new discoveries. This relationship is

$$\ln(S_t) = \ln(S_0) + \beta_1 \ln(S_{t-1}) + \beta_2 \ln(F_{t-1}) - \beta_3 \ln(N_{t-1}) - \beta_4 \ln(P_t)$$

where S_t = the average size of oil fields discovered in period t

- F_{t-1} = the previous period's oil and gas success ratio
- N_{t-1} = the average size of natural gas fields found in the previous period
- P_t = the deflated price of oil in period t (constant 1947-1949 dollars)
- 's = positive constants

Thus, based on the equation, the average size of new oil field discoveries is directly related to the size of fields discovered in the previous period and to the previous period's success ratio, and is inversely related to the average size of natural gas fields discovered in the previous period and the current price of oil. The main reason for this relationship is that Fisher believed that increases in prices tend to move exploration to partially explored areas from frontier areas. Fisher gives no reason for including the previous year's success ratio or the average size of gas fields discovered in the previous year.

In Fisher's study, an increase of 1% in the real price of crude oil in the short run produced only a 0.31% increase in new discoveries. In other words, the study showed that the short-run price elasticity of supply is equal to 0.31, meaning that oil and gas discoveries are governed by factors other than price. Perhaps one of these factors is that oil and gas are not infinite resources. If this study were

repeated today, it would probably be found that the price elasticity has become even smaller than 0.31 because of further exhaustion of oil and gas resources.

Again this model is good because it relies on historical data rather than on subjective judgment. The main problem with the model is with the direction of causality between discovery size and success ratio.

2.4 The White et al. Model

In a paper by D. A. White and others (1975) a model is presented that relies more heavily on geological interpretation than do the previous models discussed. White's model combines three methods of assessing future oil and gas potential: (1) projecting the growth of existing fields, (2) entrapolating the oil-equivalent barrels discovered per wildcat foot in partly drilled sedimentary rocks, and (3) geologically analyzing undrilled sedimentary rocks.

The results are presented by a probability curve representing the final summation of the three approaches outlined above. An example of one of these probability curves appears in Figure 2.1.

If the authors have estimated the input parameters correctly, the true oil and gas potential will fall

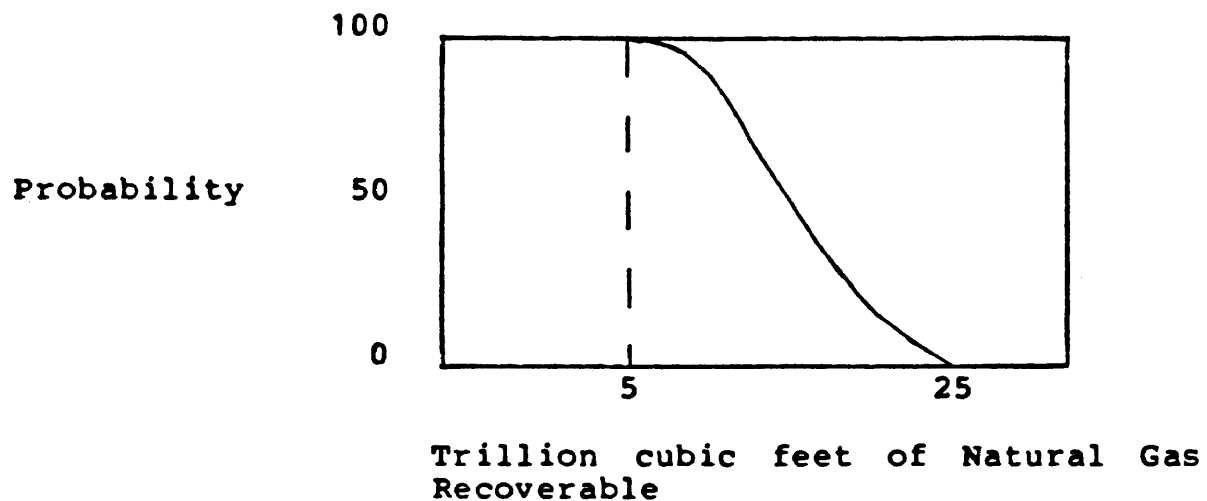


Figure 2.1

Example Probability Curve for White's Model

Source: Adapted from D.A. White, R.W. Garret, G. R. March, R. A. Baker, H. M. Gehman, Methods of Estimating the Volume of Undiscovered Oil and Gas Resources, 1975.

somewhere on the curve. With all such subjective estimates there is always a chance that one of the authors of this model had more input than the others. Instead representing the opinion of a group of experts, the model may represent the opinion of only one person.

2.5 The Drew, Schuenemeyer, and Root Model

L. J. Drew, J. H. Schuenemeyer, and D. H. Root (1980) produced a model that is similar to the Arps and Roberts Model. They contend that Arps and Roberts have a good model, but that it is useful only when a considerable amount of information is available from extensively explored areas such as the Denver-Julesburg Basin. If only limited information is available, then the Drew, et al. model may be used.

The area of influence of an exploratory well is a major component of the Drew Model (Singer and Drew, 1976). In this concept, field size determines the number of exploratory wells. If the first well is dry, the second well is drilled at a location at least a field size away from the first. The larger the field, the larger the exploration area eliminated from the basin. This is similar to the reasoning of Arps and Roberts, that pattern drilling will

find oil and gas fields that are the size of the pattern spacing. The Drew model says that the undiscovered fraction of deposits in a basin declines progressively as the unexplored area decreases. The model is stated as follows:

$$f(w) = 1 - (1 - A/B)^C \text{ for each deposit of size } A$$

where A = deposit size under consideration

f(w) = fraction of deposits discovered when A acres have been searched by W cumulative wells

B = effective basin size

C = exploration efficiency

where C is 1 for random drilling, and C is 2 for the case when 75% of the deposits are discovered by searching 50% of the basin area.

Essentially, this model is the same as the Arps and Roberts model except for the following differences: (1) the value for C is estimated for each deposit size from the historical data (Arps and Roberts assumed a constant C for all field sizes), and (2) the effective basin size B is determined from historical data (Arps and Roberts determined B subjectively). The most important asset of this model is that it extends the usefulness of the Arps and Roberts model to include new frontier areas. The main problem with this

model is that C must be determined for each field size. Drew, Schuenemeyer, and Root determined C for each field size from historical data.

Chapter 3

UNIT COSTS USING POTENTIAL GAS COMMITTEE ESTIMATES

In this chapter a method is developed for determining drilling costs per unit of resource based primarily on PGC data. Next, the method is applied to PGC estimates for the Permian Basin.

3.1 The Method

The method to be used relies extensively on PGC estimates incorporating PGC field size data, the lognormal distribution, other PGC estimates, and marginal and average costs.

3.1.1 PGC Field Size Data

The method used for calculating drilling costs per unit of resource of non-associated natural gas relies heavily on estimates made by members of the PGC in regard to field sizes and total reserves in the Permian Basin. Field size is defined as the volume of gas in a geologic structure that can be produced economically. Data on the smallest expected field size, the mode, and the largest field size are provided by the PGC.

Within the Permian Basin, the PGC has divided the total resource into probable, possible, and speculative subdivisions. Within each subdivision the resources are further broken down by depth in 5,000-foot increments. Thus, the PGC provides the smallest expected field size, the mode, and the largest expected field size for different depth increments within the subdivisions of possible and speculative. For probable gas, it is assumed that the fields have already been discovered and only development of these fields is needed. Thus, the PGC does not give field-size parameters for the probable natural gas, only depth. Tables 3.1, 3.2, and 3.3 are examples of how this data is presented.

Table 3.1 Example Probable Natural Gas Data

<u>Depth of Increment (ft)</u>	<u>Potential Resource (BCF)</u>	<u>Size of Expected Fields</u>		
		<u>Largest (BCF)</u>	<u>Mode (BCF)</u>	<u>Smallest (BCF)</u>
0 - 5,000	200	-	-	-
5,000 - 10,000	400	-	-	-
10,000 - 15,000	400	-	-	-
15,000 - 20,000	800	-	-	-

Source: Prepared by author

Table 3.2 Example Possible Natural Gas Data

Depth of Increment (ft)	Potential Resource (BCF)	Size of Expected Fields		
		Largest (BCF)	Mode (BCF)	Smallest (BCF)
0 - 5,000	0	-	-	-
5,000 - 10,000	500	100	20	5
10,000 - 15,000	1,000	300	50	10
15,000 - 20,000	4,000	750	100	30

Source: Prepared by author

Table 3.3 Example Speculative Natural Gas Data

Depth of Increment (ft)	Potential Resource (BCF)	Size of Expected Fields		
		Largest (BCF)	Mode (BCF)	Smallest (BCF)
0 - 5000	1000	20	10	4
5000 - 10000	500	50	20	5
10000 - 15000	2000	100	40	10
15000 - 20000	4000	200	75	30
20000 - 25000	1000	400	100	40

Source: Prepared by author

3.1.2 The Lognormal Distribution

Using the field size parameters given by the PGC, field size distributions may be determined. A field size distribution gives the number of fields and their size that may be expected at different depths and within the different subdivisions of possible and speculative. The field size distributions used in this study separate the total range (from the smallest expected field size to the largest expected field size) into categories used in the Energy Information Administration/Department of Energy (EIA/DOE) study, shown in Table 3.4. Within a field size category, it is assumed that there are an integer number of fields.

Using the PGC field size parameters and a lognormal statistical fit, a field size distribution is determined. The lognormal distribution is used because it describes a number of normally distributed variables that are multiplied together (Hines and Montgomery, 1980). In the case of a natural gas reservoir, the normally distributed variables are surface area, thickness of the reservoir, porosity of the rock, and gas saturation within the rock. In simulation analysis, triangular distributions are used for these variables because the triangular distribution is easier to use and it approximates a normal distribution (Newendorp, 1975).

Table 3.4 Field Size Ranges and Categories

<u>Category</u>	<u>Field Size Range (BCF)</u>		
1	0	-	0.0312
2	0.0312	-	0.0625
3	0.0625	-	0.125
4	0.125	-	0.25
5	0.25	-	0.5
6	0.5	-	1
7	1.0	-	2
8	2.0	-	4
9	4.0	-	8
10	8.0	-	16
11	16.0	-	32
12	32.0	-	64
13	64.0	-	128
14	128.0	-	256
15	256.0	-	512
16	512.0	-	1024
17	1024.0	-	2048
18	2048.0	-	4096
19	4096.0	-	8192
20	8192.0	-	16384

Source: Energy Information Administration/Department of Energy

The lognormal distribution for field sizes can be described with mean (μ) and variance (σ), and the relationship of these two variables to the smallest expected field size, the mode, and the largest expected field size. The relationships are presented in the following equations.

$$\text{Ln (mode)} = \mu - \sigma^2 \quad (3.1)$$

$$\text{Ln (largest)} = \mu + 3\sigma \quad (3.2)$$

$$\text{Ln (smallest)} = \mu - 3\sigma \quad (3.3)$$

Since there are 3 equations and only 2 unknowns, only equations (3.1) and (3.2) are used to solve for μ and σ . Three σ is used for the deviation from the mean to the largest expected field size because this study is done using a 99% confidence interval. The 99% confidence interval means that the PGC is 99% confident that at least one field will be found that is as large as the largest expected field size estimate. The smallest expected field size estimate is considered to be an economic cutoff.

Using the PGC data (smallest expected field size, the mode, and the largest expected field size) and equations (3.1) and (3.2), together with the lognormal distribution, a field size distribution may be found. A numerical example

is offered for clarity. This example takes the mode and the largest expected field size and solves for the mean and variance using equations (3.1) and (3.2). Using the log-normal distribution, probabilities are then assigned to each of the EIA/DOE field size categories. Finally, using these probabilities, the total reserves, and the EIA/DOE field size categories, a field size distribution is found.

Example:

Estimates given by the PGC

Type of Resource:	Speculative
Depth Increment:	0 - 5000 ft.
Total Resource:	2000 BCF
Largest Expected Field Size:	100 BCF
Mode:	25 BCF
Smallest Expected Field Size:	10 BCF

Using equations (3.1) and (3.2), the mean (μ) and the standard deviation (σ) of the lognormal distribution are found by solving simultaneously the equations

$$\ln(25) = \mu - \sigma^2$$

and

$$\ln(100) = \mu + 3\sigma.$$

The solution is $\mu = 3.384$ and $\sigma = 0.4069$.

If natural logarithms of the field size ranges (X) are calculated, then this lognormally distributed variable becomes a normally distributed variable. Then, using the transformation

$$z = [\ln(x) - \mu] / \sigma$$

(Hines and Montgomery, 1980), z is a normally distributed random variable with a mean of 0 and a standard deviation of 1. This allows a distribution function to be defined:

$$F(x) = P[\ln(X) \leq \ln(x)] = P \quad z \leq [\ln(x) - \mu] / \sigma .$$

By picking different x's, the probability that $X < x$ can be calculated. In order to demonstrate this procedure, refer to the previous example. Let

$$P_A = P[\ln(X) < \ln(x_A)] \text{ and } P_B = P[\ln(X) \leq \ln(x_B)]$$

where x_A equals the lower field size in the range and x_B equals the upper field size in the range. Then the values of Z_A and Z_B can be found from a normal probability density table. Table 3.5 shows the results for the example.

Table 3.5 Probability Calculations for Different Field Size Ranges

<u>Field Size Range (BCF)</u>	<u>ln(Field Size Range)</u>	<u>Z_A</u>	<u>Z_B</u>	<u>P_A</u>	<u>P_B</u>	<u>P_B - P_A</u>
10 - 15	2.303 - 2.708	-2.657	-1.661	.00391	.0485	.0446
15 - 35	2.708 - 3.555	-1.661	-4.202	.0485	.663	.6145
35 - 70	3.555 - 4.248	.4202	2.123	.663	.983	.32
70 - 100	4.248 - 4.605	2.123	3.000	.983	.998	.015

In order to find the field size distribution, equation (3.4) is used to calculate the total number of fields (Kent et al., 1982).

$$N \sum_{i=1}^I F_i P_i = T \quad (3.4)$$

where

N = total number of fields

P_i = P_B-P_A in Table 3.5 within the ith range

F_i = field size assigned to the ith range

T = total resource

I = number of field size categories, equals 4 in this example

The field size assigned to the i th range (F_i) is usually the average of the upper and lower bounds for the range. The exception to this is where one of the PGC estimates of field sizes is inside one of the field size ranges. In these cases F_i is assumed to be the PGC estimate instead of the average. For instance, in the example the smallest expected field size is 10 BCF. Therefore, F_i will be equal to 10 BCF rather than 12.5 BCF which is the average for the range 10 BCF - 15 BCF.

Using equation (3.4) and Table 3.5, the total number of fields is found by solving the equation:

$$N \times (10 \times .0446 + 25 \times .6145 + 52.5 \times .32 + 100 \times .015) = 200 \text{ for } N.$$

N is calculated to be 58.64. Since the number of fields is considered to be an integer, this number is rounded to 59. By multiplying 59 by each P_i , the number of fields in the i th category is found. These numbers are also rounded to give integers. Table 3.6 summarizes the results for the example.

Figure 3.1 is a plot of field sizes versus the frequency of fields within a field size range using the data from Table 3.6. Note that the graph resembles a lognormal distribution.

Table 3.6 Field Size Distribution Calculations for the Example

Field Size (BCF)	P_i	Number of Fields = 59 x P_i	Resource for i^{th} Range = Field Size x Number of Fields
10.0	.0446	3	30.0
25.0	.6145	36	900.0
52.5	.32	19	997.5
100.0	.015	1	100.0
TOTALS	.9941	59	2027.5

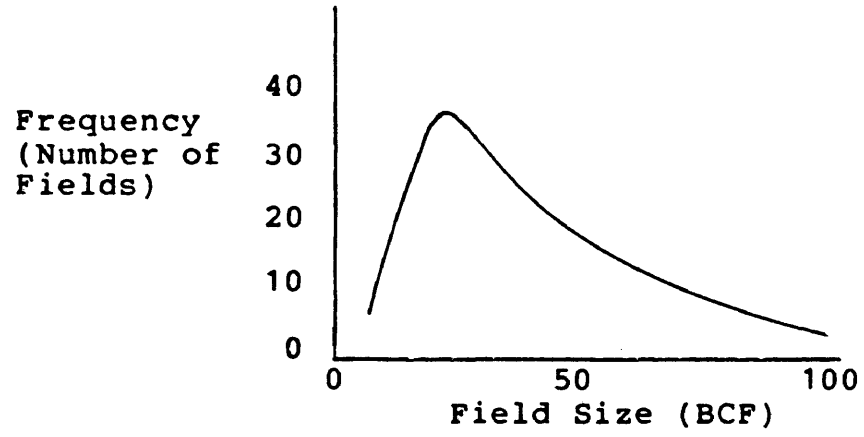


Figure 3.1 Lognormal Field Size Distribution

3.1.3 Other PGC Estimates

Once an appropriate field size distribution is found, marginal and average drilling costs per thousand cubic feet of natural gas can be found using a procedure that has been developed by the CSM research group. This procedure is described in this section incorporating the example from the preceding section.

The PGC estimates exploratory success ratios, development success ratios, and recovery per well. A success ratio is defined as the number of successful wells drilled, divided by the total number of wells drilled. A 50% success ratio would mean that half the wells drilled were successful on the average. The recovery per well is an estimate of how much natural gas a successful well will produce over its lifetime. It is assumed that for a particular field only one successful exploratory well is needed to find the field. All other wells drilled in this field are considered to be development wells.

Using the exploratory success ratio, the number of dry and successful exploratory wells needed to find a field are calculated. In the example in section 3.1.2, the one field of 100 billion cubic feet (BCF) will be used for the purposes of illustration. The other fields can be analyzed

in a similar manner. If the given exploratory success ratio is 5%, it would take 19 dry and one successful exploratory well to find the 100 BCF field.

After the field is found by the successful exploratory well, the number of successful development wells needed to develop the field to its economic optimum must be calculated. This is done by dividing the field size by the estimated recovery per well and subtracting one. One well is subtracted because the successful exploratory well takes the place of one successful development well. Figure 3.2 is an aerial view of a field showing exploratory wells and development wells. It shows why one successful development well is subtracted. In the example, if the expected recovery per well is 10 BCF, the number of successful development wells needed would be $100/10 - 1 = 9$.

The development success ratio is used to find the number of dry development wells. In the example, if the development success ratio is 90% then 9 successful development wells and one dry development well would be drilled in the 100 BCF field. As in this example, development success ratios are usually much higher than exploratory success ratios.

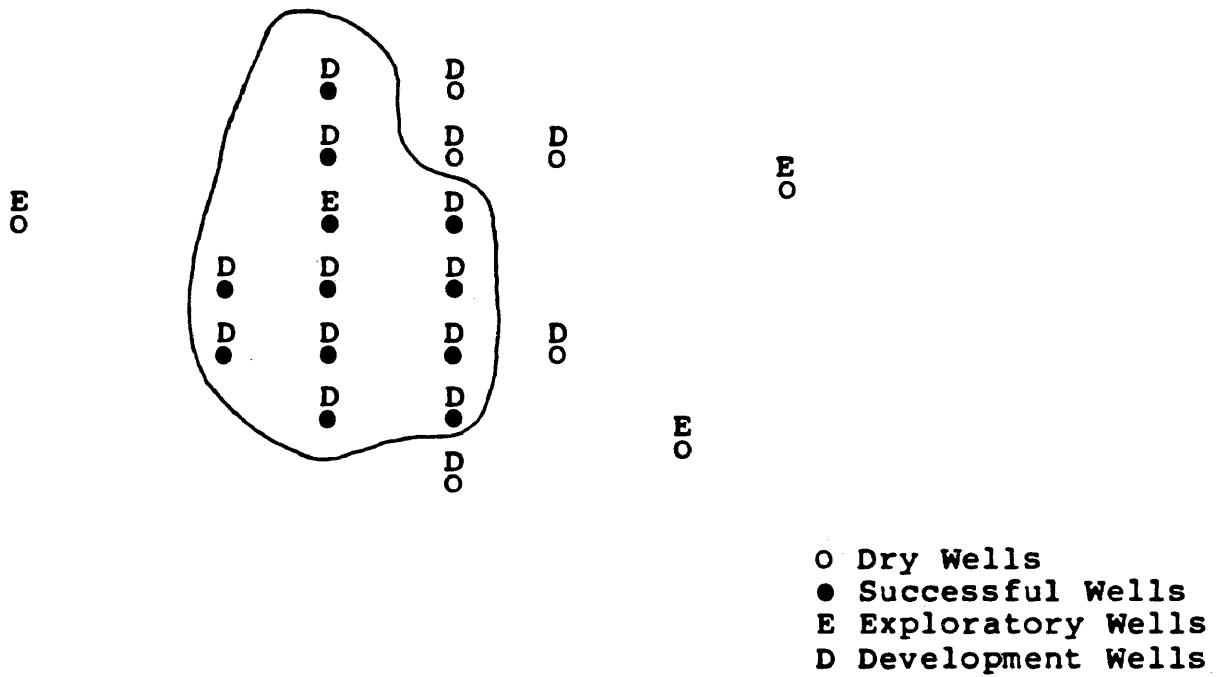


Figure 3.2 Aerial View of a Field

There are four types of wells to be considered: successful exploratory, dry exploratory, successful development, and dry development. Each type will incur a different drilling cost. Exploratory wells are generally more expensive than development wells because access to the area may not have been established and the subsurface geology not yet defined. Successful wells are generally more expensive than dry wells because of completion costs. Drilling costs per well are supplied by the CSM research group; their accuracy is beyond the scope of this study. All drilling costs are summed up and attributed to the reserves in the field. Table 3.7 shows the summation of drilling costs for the example.

Table 3.7 Total Cost to Find and Develop the 100 BCF Field in the Example

<u>Type of well</u>	<u>Number of wells</u>	<u>Cost/well (\$)</u>	<u>Total Cost-Number of wells x cost/well(\$)</u>
Successful Exploratory	1	1,000,000	1,000,000
Dry Exploratory	19	750,000	14,250,000
Successful Development	9	900,000	8,100,000
Dry Development	1	650,000	<u>650,000</u>
		Total	24,000,000

Source: Prepared by the Author

By dividing the total cost by the total reserves, the marginal cost per unit resource (MC) is calculated. In the example:

$$\$24,000,000/100,000,000 \text{ MCF} = \$0.24/\text{MCF}$$

In order to get a marginal cost curve for an entire basin consisting of many fields, an assumption must be made about the order of discovery of the fields. In this study it is assumed that the cheaper fields are found before the more expensive fields. If a plot of cumulative reserves versus marginal cost is constructed, the plot will begin at the point where cumulative reserves equals the cheapest field, and the cost will equal the cost per unit resource for the cheapest field. An example marginal cost curve is presented in Figure 3.3.

An average cost for the resource can be found by adding up the total cost for several fields and dividing this total cost by the total resource for the fields. If, in the example, an additional field of 50 BCF is introduced that would cost \$20,000,000, the average cost would be

$$(\$20,000,000 + \$24,000,000)/(100 + 50) = \$0.293/\text{MCF}.$$

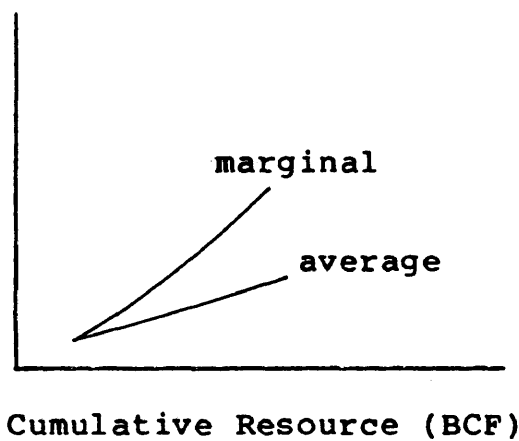


Figure 3.3 **Marginal and Average Cost Curves for Natural Gas**

Another way of looking at the average cost is to realize that it is an average of the marginal costs weighted by the reserves associated with the marginal cost. The marginal cost of the 50 BCF field is

$$\$20,000,000/50,000,000 \text{ MCF} = \$0.40/\text{MCF}.$$

The average cost of the two fields is

$$[(100 \times 0.24) + (50 \times 0.4)] = \$0.293/\text{MCF}.$$

3.2 Permian Basin Results

This section presents the PGC data for the Permian Basin and then uses the methodology presented in Section 3.1 to calculate marginal and average costs for the resources predicted by the PGC. This section will develop marginal and average cost curves to be used for comparison with the results presented in Chapter 4, Section 2.

3.2.1 Drilling Cost Data

The drilling costs used in this study were calculated by the CSM research group and are presented in Table 3.8. Historical drilling costs were obtained and least squares

regression analysis was performed to produce Table 3.8. Table 3.9 shows the equations produced by the regression analysis and some of the important statistics associated with the equations. As previously stated, the analysis of the drilling cost data is considered to be beyond the scope of this study.

3.2.2 PGC Data

The data used in this chapter come primarily from the PGC. These data were gathered by the CSM research group through meetings held with the PGC and represents the PGC's opinions about the quantity of non-associated natural gas resources and their distribution throughout the Permian Basin. Table 3.10 presents data for probable resources; Table 3.11, for possible resources; and Table 3.12, for speculative resources.

3.2.3 Analysis for Probable Resources

Tables 3.13-3.17 summarize the calculations necessary to find the marginal cost for probable resources. In order to find the average cost for these resources, the marginal costs for each depth increment are sorted from the lower costs to higher costs. Then average costs are calculated

Table 3.8 Permian Basin Drilling Costs
(in dollars per well)

<u>Depth Increment (ft)</u>	<u>Successful Exploratory Wells</u>	<u>Dry Exploratory Wells</u>	<u>Successful Development Wells</u>	<u>Dry Development Wells</u>
0- 5,000	\$ 133,000	\$ 89,000	\$ 104,000	\$ 85,000
5,000-10,000	478,000	250,000	420,000	261,000
10,000-15,000	1,384,000	1,144,000	1,305,000	1,057,000
15,000-20,000	3,243,000	2,821,000	3,127,000	2,494,000
20,000-25,000	6,152,000	5,279,000	5,771,000	4,571,000
25,000-30,000	9,446,000	8,519,000	8,209,000	7,288,000

Source: Colorado School of Mines Research Group

Table 3.9 Regression Results for Drilling Costs per Well

Type of Well	$\frac{x}{\text{Cost}(\$ \times 10^{-3})} = f(\text{Depth}(\text{ft} \times 10^{-3}))$	Standard Deviation	R ² adj	Degrees of Freedom
Successful Exploratory	$\ln(y) = 4.1769 + 0.2934x - .004232x^2$ (28.18) (11.36) (4.22)	0.2769	0.940	62
Dry Exploratory	$y = 375.91 - 134.06x + 15.6430x^2$ (6.77) (9.93) (22.52)	262.6	0.921	144
Successful Development	$\ln(y) = 3.8513 + 0.33096x - 0.0052096x^2$ (41.74) (15.72) (5.37)	0.3377	0.930	119
Dry Development	$y = 268.72 - 97.05x + 12.8107x^2$ (5.61) (6.60) (13.94)	210.4	0.845	135

NOTE: numbers in parentheses are t-statistics for the coefficients

Table 3.10 Data for Non-Associated Natural Gas in the Permian Basin for Probable Resources

<u>Depth Increment</u>	<u>Resource</u>	<u>Ultimate Recovery per Well (BCF)</u>
0 - 5,000	300	0.15
5000 - 10,000	4,200	1
10,000 - 15,000	2,512	2
15,000 - 20,000	7,000	5
20,000 - 25,000	1,002	10

Development Well Success Ratio = 0.70

Source: Potential Gas Committee

Table 3.11 Data for Non-Associated Natural Gas in the Permian Basin for Possible Resources

Depth Increment (feet)	Size of Expected Fields				
	Total Resource (BCF)	Largest (BCF)	Mode (BCF)	Smallest (BCF)	Ultimate Recovery per Well (BCF)
0 - 5,000	1,700	3	.6	.15	.15
5,000 - 10,000	9,000	25	5.0	1.0	1
10,000 - 15,000	8,320	30	8.0	3.0	2
15,000 - 20,000	7,000	75	15.0	5.0	5
20,000 - 25,000	6,000	150	30.0	10.0	10
25,000 - 30,000	1,000	150	30.0	10.0	10

Exploratory Well Success Ratio = 0.20
 Development Well Success Ratio = 0.70

Source: Potential Gas Committee

Table 3.12 Data for Non-Associated Natural Gas in the Permian Basin for Speculative Resources

Depth Increment (feet)	Total Resource (BCF)	Size of Expected Fields				Ultimate Recovery per Well (BCF)
		Largest (BCF)	Mode (BCF)	Smallest (BCF)		
0 - 5,000	0	--	--	--	--	
5,000 - 10,000	207	25	5	1	1	
10,000 - 15,000	800	50	10	2	2	

Exploratory Well Success Ratio = 0.10
 Development Well Success Ratio = 0.70

Source: Colorado School of Mines Research Group

**Table 3.13 Marginal Cost for Probable Resources in the
0-5,000 ft. Depth Increment**

Resource	300 BCF
Ultimate Recovery per Well	0.15 BCF
Exploratory Wells	none
Successful Development Wells	$300/0.15 = 2000$
Development Success Ratio	0.70
Dry Development Wells	$2000/.7 - 2000 = 857$
Dry Development Well Cost	\$85,000
Successful Development Well Cost	\$104,000
Total Drilling Cost	$(85000)(857) + (104,000)(2000)$ $= \$280,850,000$
Marginal Cost	$\$280,850,000/300,000,000 \text{ MCF}$ $= \$0.94/\text{MCF}$

Source: Prepared by the Author

**Table 3.14 Marginal Cost for Probable Resources in the
5,000-10,000 ft. Depth Increment**

Resource	4200 BCF
Ultimate Recovery per Well	1 BCF
Exploratory Wells	None
Successful Development Wells	$4200/1 = 4200$
Development Success Ratio	0.70
Dry Development Wells	$4200/.70 - 4200 = 1800$
Dry Development Well Cost	\$261,000
Successful Development Well Cost	\$420,000
Total Drilling Cost	$(261,000)(1800) + (420,000)(4200)$ $= \$2,233,800,000$
Marginal Cost	$\$2,233,800,000/4,200,000,000$ MCF $= \$0.53/\text{MCF}$

Source: Prepared by the Author

**Table 3.15 Marginal Cost for Probable Resources in the
10,000-15,000 ft. Depth Increment**

Resource	2512 BCF
Ultimate Recovery per Well	2 BCF
Exploratory Wells	none
Successful Development Wells	$2512/2 = 1256$
Development Success Ratio	0.70
Dry Development Wells	$1256/0.70 - 1256 = 538$
Dry Development Well Cost	\$1,057,000
Successful Development Well Cost	\$1,305,000
Total Drilling Cost	$(1,057,000)(538) + (1,305,000)(1256)$ $= \$2,207,700,000$
Marginal Cost	$\$2,207,700,000/2,512,000,000 \text{ MCF}$ $= \$0.88/\text{MCF}$

Source: Prepared by the Author

**Table 3.16 Marginal Cost for Probable Resources in the
15,000-20,000 ft. Depth Increment**

Resource	7000 BCF
Ultimate Recovery per Well	5 BCF
Exploratory Wells	None
Successful Development Wells	$7000/5 = 1400$
Development Success Ratio	0.70
Dry Development Wells	$1400/0.70 - 1400 = 600$
Dry Development Well Cost	\$2,494,000
Successful Development Well Cost	\$3,127,000
Total Drilling Cost	$(2,494,000)(600) + (3,127,000)(1400)$ = \$5,874,200,000
Marginal Cost	$\$5,874,200,000/7,000,000,000$ MCF = \$0.84/MCF

Source: Prepared by the Author

**Table 3.17 Marginal Cost for Probable Resources in the
20,000-25,000 ft. Depth Increment**

Resource	1002 BCF
Ultimate Recovery per Well	10 BCF
Exploratory Wells	none
Successful Development Wells	$1002/10 = 100$
Development Success Ratio	0.70
Dry Development Wells	$100/.70 \quad 100 = 43$
Dry Development Well Cost	\$4,571,000
Successful Development Well Cost	\$5,771,000
Total Drilling Cost	$(4,571,000)(43) + (5,771,000)(100)$ $= \$773,650,000$
Marginal Cost	$\$773,650,000/1,002,000,000 \text{ MCF}$ $= \$0.77/\text{MCF}$

Source: Prepared by the Author

according to the methodology presented in the first section of this chapter. The results are presented in Table 3.18. Finally, a plot of the marginal and average costs is constructed. The plot is shown in Figure 3.4. This plot will be used for comparison with results obtained in Chapter 4.

3.2.4 Analysis for Possible and Speculative Resources

In analyzing possible and speculative resources, the first step is to develop a field size distribution for each depth increment in the possible and speculative categories. This is done by following the methodology presented in the first part of this chapter. Tables 3.19-3.26 summarize the calculations for finding field size distributions for the resources.

Once a field size distribution is found, the marginal costs can be calculated as shown in Tables 3.27-3.34. As an example, a typical line from Tables 3.27-3.34 is examined. The size, number of fields, and the resource are obtained from Table 3.19. The number of successful exploratory wells is equal to the number of fields because one successful exploratory well is needed to find each field. The number of dry exploratory wells is calculated by using the exploratory success ratio. The exploratory cost is equal to the

Table 3.18 Marginal and Average Costs for Probable Resources

<u>Added Resources (BCF)</u>	<u>Cumulative Added Resource (BCF)</u>	<u>Marginal Cost (\$/MCF)</u>	<u>Average Cost (\$/MCF)</u>
4200	4200	0.53	0.53
1002	5202	0.77	0.58*
7000	12202	0.84	0.73*
2512	14714	0.88	0.75
300	15014	0.94	0.76

*These numbers are averages of the marginal cost weighted the associated resources. For example,
 $0.58 = [0.53(4200) + 0.77(1002)] / (4200 + 1002)$
and $0.73 = [0.53(4200) + 0.77(1002) + 0.84(7000)] / (4200 + 1002 + 7000)$

Source: Prepared by the Author

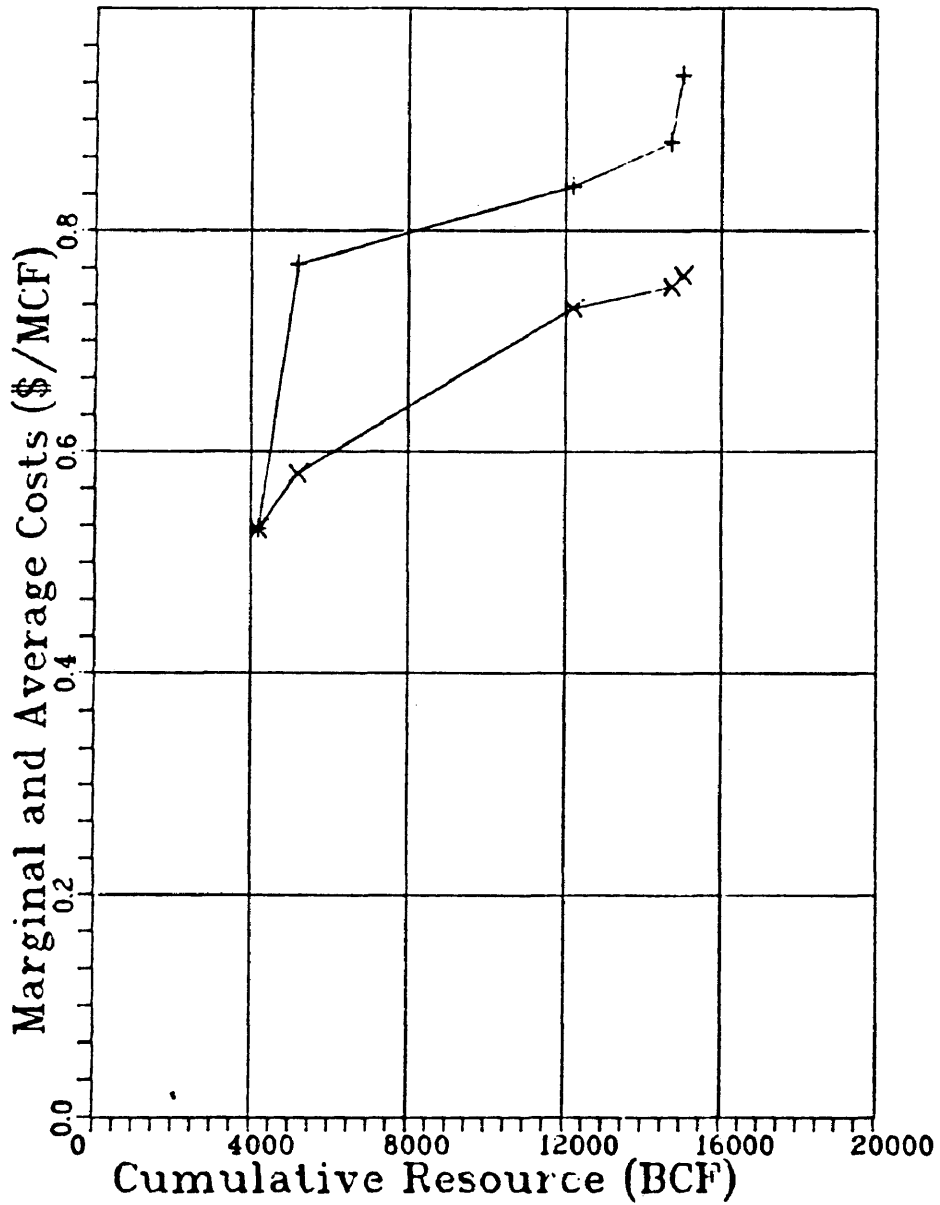


Figure 3.4 Marginal (+) and Average (x) Costs for Probable Resources

Table 3.19 Field Size Distribution Calculations for Possible Natural Gas, 0-5,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	P _B - P _A
0.15 - 0.25	-1.89 - -1.39	-3.43	-2.35	.0003	.0093	.009
0.25 - 0.5	-1.39 - -0.69	-2.35	-0.85	.0093	.1977	.1884
0.50 - 1.0	-0.69 - 0	-0.85	0.63	.1977	.7356	.5379
1.00 - 2.0	0 - 0.69	0.63	2.12	.7356	.9830	.2474
2.00 - 3.0	0.69 - 1.099	2.12	3.00	.983	.9986	.0156

Z_A and $Z_B = [\ln(\text{Field Size Ranges}) - \mu] / \sigma$
 P_A and P_B are from normal probability tables using Z_A and Z_B .

$\ln(0.6) = \mu - \sigma^2 \quad \mu = -0.295$
 $\ln(3) = \mu + 3\sigma \quad \sigma = 0.465$
 $Z = (\ln(x) - \mu) / \sigma$

$$N \sum_{i=1}^I F_i P_i = T$$

$[.009(.15) + .1884(.375) + .5379(.6) + .2474(1.5) + .0156(3)] \times N = 1700$

$N = 2092$

Field Size (BCF)	P_i	Number of Fields = 2092 x P_i	Resource for i th Range = Field Size x Number of Fields
0.15	.009	19	2.85
0.375	.1884	394	147.75
0.6	.5379	1,125	675
1.5	.2474	518	777
3.0	.0156	33	99
TOTALS	.9983	2,089	1,701.6

Source: Prepared by the Author

Table 3.20 Field Size Distribution Calculations for Possible Natural Gas 5,000-10,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	$\frac{P_B - P_A}{B - A}$
1.0 - 2.0	0 - 0.69	-3.91	-2.43	.00005	.00755	.0075
2.0 - 4.0	0.69 - 1.39	-2.43	-0.92	.00755	.17879	.17124
4.0 - 8.0	1.39 - 2.08	-0.92	0.56	.17879	.71226	.53347
8.0 - 16.0	2.08 - 2.77	0.56	2.04	.71226	.97932	.26706
16.0 - 25.0	2.77 - 3.22	2.04	3.01	.97932	.99869	.01937

Z_A and $Z_B = [\ln(\text{Field Size Ranges}) - \mu] / \sigma$
 P_A and P_B are from normal probability tables using Z_A and Z_B .

$\ln(5) = \mu - \sigma^2$ $\mu = 1.82$
 $\ln(25) = \mu + 3\sigma$ $\sigma = 0.465$

$Z = (\ln(x) - \mu) / \sigma$

$$N \sum_{i=1}^I F_i P_i = T$$

$[.0075(1.0) + .17124(3.0) + .53347(5.0) + .26706(12.0) + .01937(25.0)] \times N = 9,000$

$N = 1,309$

Field Size (BCF)	P_i	Number of Fields = 2092 x P_i	Resource for ith Range = Field Size x Number of Fields
1.0	.0075	10	10
3.0	.17124	224	672
5.0	.53347	698	3,490
12.0	.26706	350	4,200
25.0	.01937	25	625
TOTALS	.99863	1,307	8,997

Source: Prepared by the Author

Table 3.21 Field Size Distribution Calculations for Possible Natural Gas, 10,000-15,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	P _B - P _A
2.0 - 4.0	0.69 - 1.39	-3.95	-2.15	.00004	.01578	.01574
4.0 - 8.0	1.39 - 2.08	-2.15	-.385	.01578	.35012	.33434
8.0 - 16.0	2.08 - 2.77	-.385	1.38	.35012	.91621	.56609
16.0 - 30.0	2.77 - 3.40	1.38	3.00	.91621	.99865	.08244

Z_A and Z_B = [ln (Field Size Ranges) - μ] / σ
 P_A and P_B are from normal probability tables using Z_A and Z_B.

Ln(8) = μ - σ² μ = 2.23
 Ln(30) = μ + 3σ σ = 0.39

Z = (Ln(x) - μ) / σ

$$N \sum_{i=1}^I F_i P_i = T$$

[.01574(2) + .33434(6) + .56609(8) + .08244(30)] x N = 8320

N = 920

Field Size (BCF)	P _i	Number of Fields = 2092 x P _i	Resource for ith Range = Field Size x Number of Fields
2.0	.01574	14	28
6.0	.33434	308	1,848
8.0	.56609	521	4,168
30.0	.08244	76	2,280
TOTALS	.99861	919	8,324

Source: Prepared by the Author

Table 3.22 Field Size Distribution Calculations for Possible Natural Gas, 15,000-20,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	P _B - P _A
5.0 - 8.0	1.61 - 2.08	-2.82	-1.81	.0024	.03515	.03275
8.0 - 16.0	2.08 - 2.77	-1.81	-.323	.03515	.37335	.3382
16.0 - 32.0	2.77 - 3.47	-.323	1.18	.37335	.881	.50765
32.0 - 64.0	3.47 - 4.16	1.18	2.67	.881	.99621	.11521
64.0 - 75.0	4.16 - 4.32	2.67	3.01	.99621	.99869	.00248

Z_A and Z_B = [ln (Field Size Ranges) - μ] / σ
 P_A and P_B are from normal probability tables using Z_A and Z_B.

$$\begin{aligned} \ln(15) &= \mu - \sigma^2 & \mu &= 2.92 \\ \ln(75) &= \mu + 3\sigma & \sigma &= .465 \end{aligned}$$

$$Z = (\ln(x) - \mu) / \sigma$$

$$N \sum_{i=1}^I F_i P_i = T$$

$$[.03275(5) + .3382(15) + .50765(24) + .11521(48) + .00248(75)] \times N = 7000$$

$$N = 302$$

Field Size (BCF)	P _i	Number of Fields = 2092 x P _i	Resource for ith Range = Field Size x Number of Fields
5.0	.03275	10	50
15.0	.3382	102	1,530
24.0	.50765	153	3,672
48.0	.11521	35	1,680
75.0	.00248	1	75
TOTALS	.99629	300	7,007

Source: Prepared by the Author

Table 3.23 Field Size Distribution Calculations for Possible Natural Gas 20,000 - 25,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	P _B - P _A
10 - 16	2.30 - 2.77	-2.84	-1.83	.00226	.03363	.03137
16 - 32	2.77 - 3.47	-1.83	-.323	.03363	.37335	.33972
32 - 64	3.47 - 4.16	-.323	1.16	.37335	.87697	.50362
64 - 128	4.16 - 4.85	1.16	2.64	.87697	.99585	.11888
128 - 150	4.85 - 5.01	2.64	2.99	.99585	.99861	.00276

Z_A and $Z_B = \{ \ln (\text{Field Size Ranges}) - \mu \} / \sigma$
 P_A and P_B are from normal probability tables using Z_A and Z_B .

$\ln(15) = \mu - \sigma^2$ $\mu = 3.62$
 $\ln(75) = \mu + 3\sigma$ $\sigma = .465$

$Z = (\ln(x) - \mu) / \sigma$

$$\sum_{i=1}^I F_i P_i = T$$

$[.03137(10) + .33972(30) + .50862(48) + .11888(96)] \times N = 6,000 - 150^*$

$N = 127$

Field Size (BCF)	P _i	Number of Fields = 2092 x P _i	Resource for ith Range = Field Size x Number of Fields
10	.03137	4	40
30	.33972	43	1,290
48	.50362	64	3,072
96	.11888	15	1,440
150	.00276	1	150
Totals	.99635	127	5,992

*Since the PGC has specified that there will be 1 field of 150 BCF, the field size distribution contains 1 field of 150 BCF even though the statistics don't show it.

Source: Prepared by the Author

Table 3.24 Field Size Distribution Calculations for Possible Natural Gas, 25,000-30,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z		P		P _B - P _A	
		A	B	A	B	B	A
10 - 16	2.30 - 2.77	-2.84	-1.83	.00226	.03363	.03137	
16 - 32	2.77 - 3.47	-1.83	-.323	.03363	.37335	.33972	
32 - 64	3.47 - 4.16	-.323	1.16	.37335	.87697	.50362	
64 - 128	4.16 - 4.85	1.16	2.64	.87697	.99585	.11888	
128 - 150	4.85 - 5.01	2.64	2.99	.99585	.99861	.00276	

Z_A and $Z_B = [\ln(\text{Field Size Ranges}) - \mu] / \sigma$
 P_A and P_B are from normal probability tables using Z_A and Z_B .

$\ln(30) = \mu - \sigma^2$ $\mu = 3.62$
 $\ln(150) = \mu + 3\sigma$ $\sigma = .465$

$Z = (\ln(x) - \mu) / \sigma$

$$\sum_{i=1}^I F_i P_i = T$$

$[(.03137(10) + .33972(30) + .50862(48) + .11888(96)] \times N$
 $= 1000 - 150^*$

$N = 18$

Field Size (BCF)	P_i	Number of Fields = 2092 x P_i	Resource for ith Range = Field Size x Number of Fields
10	.03137	1	10
30	.33972	6	180
48	.50362	9	432
96	.11888	2	192
150	.00276	1	150
Totals	.99635	19	964

*Since the PGC has specified that there will be 1 field of 150 BCF, the field size distribution contains 1 field of 150 BCF even though the statistics don't show it.

Source: Prepared by the Author

Table 3.25 Field Size Distribution Calculations for Speculative Natural Gas, 5,000-10,000 Feet

Field Size Range (BCF)	Ln (Field Size Range)	Z _A	Z _B	P _A	P _B	P _B - P _A
1.0 - 2.0	0 - 0.69	-3.91	-2.43	.00005	.00755	.0075
2.0 - 4.0	0.69 - 1.39	-2.43	-0.92	.00755	.17879	.17124
4.0 - 8.0	1.39 - 2.08	-0.92	0.56	.17879	.71226	.53347
8.0 - 16.0	2.08 - 2.77	0.56	2.04	.71226	.97932	.26706
16.0 - 25.0	2.77 - 3.22	2.04	3.01	.97932	.99869	.01937

Z_A and $Z_B = [\ln(\text{Field Size Ranges}) - \mu] / \sigma$
 P_A and P_B are from normal probability tables using Z_A and Z_B .

$\ln(5) = \mu - \sigma^2 \quad \mu = 1.82$
 $\ln(25) = \mu + 3\sigma \quad \sigma = 0.465$

$Z = (\ln(x) - \mu) / \sigma$

$$N \sum_{i=1}^I F_i P_i = T$$

$[.0075(1) + .17124(3) + .53347(5) + .26706(12) + .01937(25)] \times N = 207$

$N = 30$

Field Size (BCF)	P _i	Number of Fields = 2092 x P _i	Resource for ith Range = Field Size x Number of Fields
1.0	.0075	1	1
3.0	.17124	5	15
5.0	.53347	16	80
12.0	.26706	8	96
25.0	.01937	11	25
Totals	.99864	31	217

Source: Prepared by the Author

Table 3.26 Field Size Distribution Calculations for Speculative Natural Gas, 10,000-15,000 Feet

<u>Field Size Range (BCF)</u>	<u>Ln (Field Size Range)</u>	<u>Z_A</u>	<u>Z_B</u>	<u>P_A</u>	<u>P_B</u>	<u>P_B - P_A</u>
2.0 - 4.0	0.69 - 1.39	-3.93	-1.85	.00004	.03216	.03212
4.0 - 8.0	1.39 - 2.08	-1.85	-.95	.03216	.17106	.1389
8.0 - 16.0	2.08 - 2.77	-.95	.54	.17106	.70540	.53434
16.0 - 32.0	2.77 - 3.40	.54	2.04	.70540	.97932	.27392
32.0 - 50.00	3.47 - 3.91	2.04	2.99	.97932	.99861	.01929

Z_A and Z_B = [ln (Field Size Ranges) - μ]/σ
 P_A and P_B are from normal probability tables using Z_A and Z_B.

Ln(10) = μ - σ² μ = 2.52
 Ln(50) = μ + 3σ σ = .465

Z = (Ln(x) - μ) / σ

$$N \sum_{i=1}^I F_i P_i = T$$

[.03212(2) + .1389(6) + .53434(10) + .27392(24) + .01929(50)] x N = 800

N = 58

<u>Field Size (BCF)</u>	<u>P_i</u>	<u>Number of Fields = 2092 x P_i</u>	<u>Resource for ith Range = Field Size x Number of Fields</u>
2.0	.03212	2	4
6.0	.1389	8	48
10.0	.53434	31	310
24.0	.27392	16	384
50.0	.01929	1	50
TOTALS	.99857	58	796

Source: Prepared by the Author

Table 3.27 Marginal Costs for Possible Resources, 0-5,000 feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MM\$)	Successful Development Wells	Dry Development Wells	Development Costs (MM\$)	Total Cost (MM\$)	Marginal Cost (\$/MCF)
0.15	19	2.85	19	76	9.291	0	0	0	9.291	3.26
0.375	394	147.75	394	1,576	192.666	591	253	82.969	275.629	1.87
0.6	1,125	675	1,125	4,500	550.125	3375	1446	473.91	1024.035	1.52
1.5	518	777	518	2,072	253.302	4662	1998	654.678	907.98	1.17
3.0	33	99	33	132	16.137	627	269	88.073	104.21	1.05

Source: Prepared by the Author

Table 3.28 Marginal Costs for Possible Resources, 5,000-10,000 Feet

Size of Fields (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MMS)	Successful Development Wells	Dry Development Wells	Development Costs (MMS)	Total Cost (MMS)	Marginal Cost (\$/BCF)
1.0	10	10	10	40	14.78	0	0	0	14.78	1.48
3.0	224	672	224	896	331.072	448	192	238.272	569.344	0.85
5.0	698	3490	698	2792	1,031.644	2792	1197	1485.057	2516.701	0.72
12.0	350	4200	350	1400	517.3	3850	1650	2047.65	2564.95	0.61
25.0	25	625	25	100	36.95	600	257	319.077	356.027	0.60

Source: Prepared by the Author

Table 3.29 Marginal Costs for Possible Resources, 10,000-15,000 Feet

Size (BCT)	Number of Fields	Resource (BCT)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (M\$)	Successful Development Wells	Dry Development Wells	Development Costs (M\$)	Total Cost (M\$)	Marginal Cost (\$/MCF)
2	14	20	14	56	83.44	0	0	0	83.44	2.98
6	308	1848	308	1232	1835.68	616	264	1082.928	2918.608	1.58
8	521	4168	521	2084	3105.16	1563	670	2747.905	5853.065	1.40
30	76	2280	76	304	452.96	1064	456	1870.512	2323.472	1.02

Source: Prepared by the Author

Table 3.30 Marginal Costs for Possible Resources, 15,000-20,000 Feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MM\$)	Successful Development Wells	Dry Development Wells	Development Costs (MM\$)	Total Cost (MM\$)	Marginal Cost (\$/MCF)
5	10	50	10	40	145.27	0	0	0	145.27	2.91
15	102	1530	102	408	1481.754	204	87	854.886	2336.64	1.53
24	153	3672	153	612	2222.631	581	249	2437.793	4660.424	1.27
48	35	1680	35	140	508.445	301	129	1262.953	1771.398	1.05
75	1	75	1	4	14.527	14	6	58.742	73.269	0.98

Source: Prepared by the Author

Table 3.31 Marginal Costs for Possible Resources, 20,000-25,000 Feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MM\$)	Successful Development Wells	Dry Development Wells	Development Costs (MM\$)	Total Cost (MM\$)	Marginal Cost (\$/MCF)
10	4	40	4	16	109.072	0	0	0	109.072	2.73
30	43	1290	43	172	1172.524	86	37	665.433	1837.957	1.42
48	64	3072	64	256	1745.152	243	104	1877.737	3622.889	1.18
96	15	1440	15	60	409.02	129	55	995.864	1404.884	0.98
150	1	150	1	4	27.268	14	6	108.22	135.488	0.90

Source: Prepared by the Author

Table 3.32 Marginal Costs for Possible Resources, 25,000-30,000 Feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MMS)	Successful Development Wells	Dry Development Wells	Development Costs (MMS)	Total Cost (MMS)	Marginal Cost (\$/MCF)
10	1	10	1	4	43.522	0	0	0	43.522	4.35
30	6	180	6	24	261.132	12	5	134.948	396.08	2.20
48	9	432	9	36	391.698	34	15	388.426	780.124	1.81
96	2	192	2	8	87.044	17	7	190.569	277.613	1.45
150	1	150	1	4	43.522	14	6	158.654	202.176	1.35

Source: Prepared by the Author

Table 3.33 Marginal Costs for Speculative Resources, 5,000-10,000 Feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MMS)	Successful Development Wells	Dry Development Wells	Development Costs (MMS)	Total Cost (MMS)	Marginal Cost (\$/MCF)
1	1	1	1	9	2,728	0	0	0	2,728	2.73
3	5	15	5	45	13.64	10	4	5.244	18.884	1.26
5	16	80	16	144	43.648	64	27	33.927	77.575	0.97
12	8	96	8	72	21.824	88	38	46.878	68.702	0.72
25	1	25	1	9	2,728	24	10	12.69	15,418	0.61

Source: Prepared by the Author

Table 3.34 Marginal Costs for Speculative Resources, 10,000-15,000 Feet

Size (BCF)	Number of Fields	Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (MM\$)	Successful Development Wells	Dry Development Wells	Development Costs (MM\$)	Total Cost (MM\$)	Marginal Cost (\$/MCF)
2	2	4	2	18	23.36	0	0	0	23.36	5.84
6	8	48	8	72	93.44	16	7	28.279	121.719	2.54
10	31	310	31	279	362.08	124	53	217.841	579.921	1.87
24	16	384	16	144	186.88	176	75	308.955	495.835	1.29
50	1	50	1	9	11.68	24	10	41.89	53.57	1.07

Source: Prepared by the Author

number of successful exploratory wells, multiplied by the successful exploratory cost per well, added to the number of dry exploratory wells and multiplied by the dry exploratory cost per well. The successful development wells are found by dividing the resource by the ultimate recovery per well and subtracting the successful exploratory wells as explained in Section 3.1. The dry development wells are found by using the development success ratio. The development costs are equal to the number of successful development wells, multiplied by the successful development cost per well, added to the number of dry development wells, and multiplied by the dry development cost per well. The total cost is equal to the exploratory cost added to the development cost. The marginal cost is equal to the total cost divided by the resource.

These marginal costs are then sorted from lowest to highest as was done for the probable resources. Then the average cost is calculated using the methodology presented in Section 3.1. Table 3.35 presents these results. Figure 3.5 is a plot of the results. This plot will be used for comparison with the results obtained in Chapter 4.

Table 3.35 Possible and Speculative Natural Gas (All Depths)

<u>Added Reserves</u>	<u>Cumulative Added Reserves (BCF)</u>	<u>Marginal Cost (\$/MCF)</u>	<u>Average Cost (\$/MCF)</u>
625	625	0.60	0.60
4,200	4,825	0.61	0.61
25	4,850	0.61	0.61
3,490	8,340	0.72	0.66
96	8,436	0.72	0.66
672	9,108	0.85	0.67
150	9,258	0.90	0.67
80	9,338	0.97	0.68
1,440	10,778	0.98	0.72
75	10,853	0.98	0.72
2,280	13,133	1.02	0.77
99	13,232	1.05	0.77
1,680	14,912	1.05	0.80
50	14,962	1.07	0.80
777	15,739	1.17	0.82
3,072	18,811	1.18	0.88
15	18,826	1.26	0.88
3,672	22,498	1.27	0.94
384	22,882	1.29	0.95
150	23,032	1.35	0.95
4,168	27,200	1.40	1.02
1,290	28,490	1.42	1.04
192	28,682	1.45	1.04
10	28,692	1.48	1.04
675	29,367	1.52	1.05
1,530	30,997	1.53	1.07
1,848	32,745	1.58	1.11
432	33,177	1.81	1.11
310	33,487	1.87	1.12
147.75	33,634.75	1.87	1.12
180	33,814.75	2.20	1.13
48	33,862.75	2.54	1.13
40	33,902.75	2.73	1.13
1	33,903.75	2.73	1.13
50	33,953.75	2.91	1.14
28	33,981.75	2.98	1.14
2.85	33,984.6	3.26	1.14
10	33,994.6	4.35	1.14
4	33,998.6	5.84	1.14

Source: Prepared by the Author

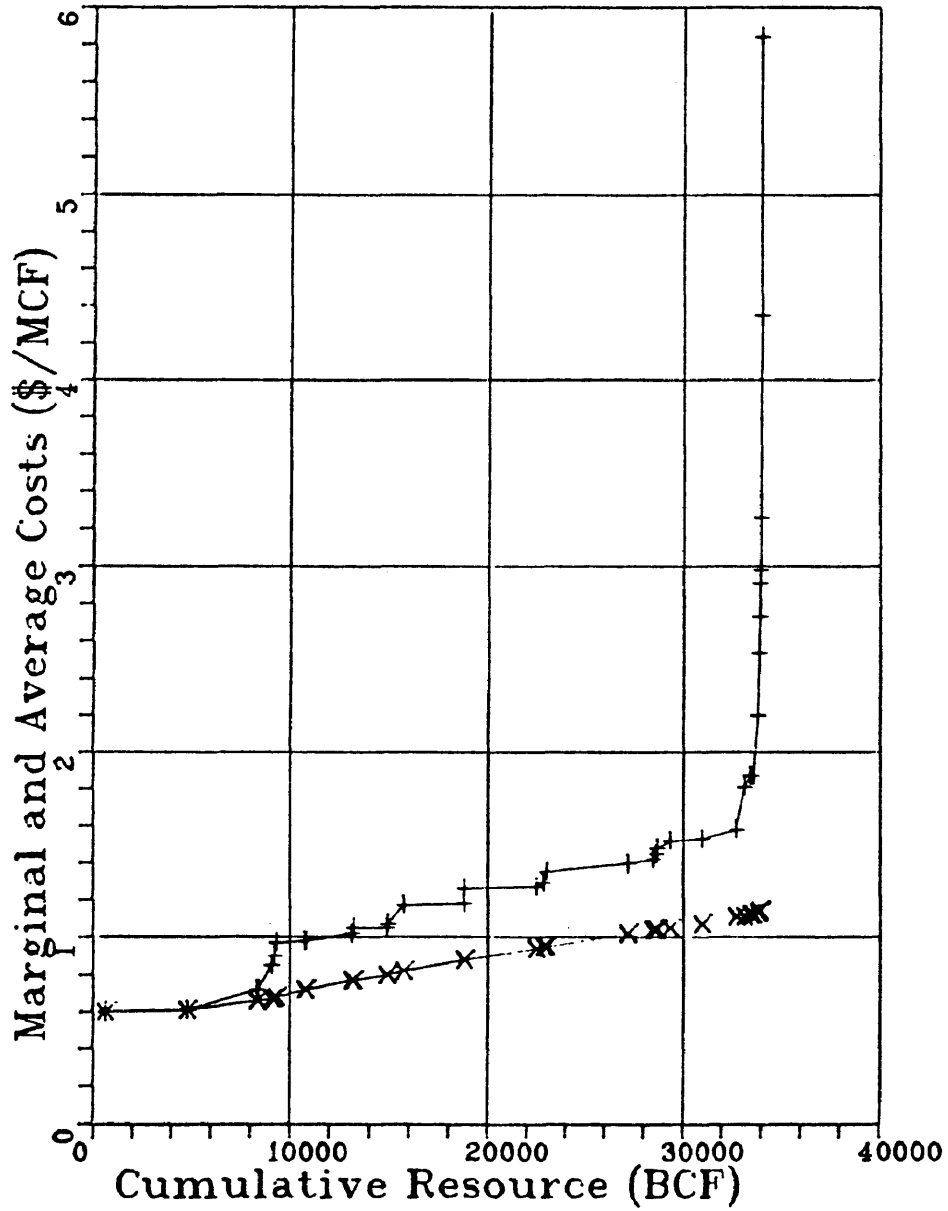


Figure 3.5 Marginal (+) and Average (x) Costs for Possible and Speculative Resources

Chapter 4

UNIT COSTS USING HISTORICAL DATA

In Section 1 of this chapter a method for determining drilling costs per unit of resource is presented. Then in section 2 the method is applied to historical data from the Permian Basin.

4.1 The Method

The method to be used relies extensively on historical data incorporating PGC estimates, analysis of historical data, cumulative exploratory resources, discovery model, and marginal and average costs.

4.1.1 PGC Estimates

This method for calculating drilling costs per unit of resource uses only two PGC estimates: (1) the total gas resource in the probable subdivision, and (2) the total gas resource in the possible and speculative subdivisions. This total resource is defined to be all of the gas resource at all depths within the separate subdivisions. It is necessary to use the total resource at all depths because historical data by depth increments is not generally available.

This method, unlike the method presented in Chapter 3, relies much less on PGC estimates. The only estimates used in this method are the total resources. These estimates are not critical to the results of this study because only the shape and orientation of the marginal and average cost curves (discussed in Chapter 5) are important, not the length of these curves.

4.1.2 Analysis of Historical Data

This method uses graphs of cumulative wells drilled versus cumulative resources. Four different types of graphs must be plotted: (1) cumulative successful exploratory wells versus cumulative exploratory resources, (2) cumulative total exploratory wells versus cumulative total exploratory resources, (3) cumulative successful development wells versus cumulative development resources, and (4) cumulative total development wells versus cumulative development resources. Examples of these curves are presented in Figures 4.1 through 4.4. These curves are nonlinear and convex because it is assumed that this is a mature basin and that as undiscovered natural gas becomes scarcer, drilling effort becomes less efficient, *ceteris paribus*.

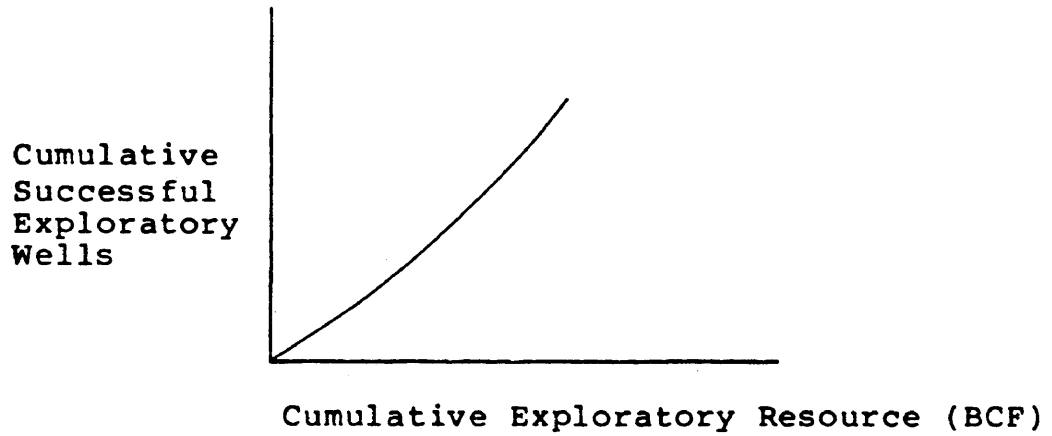


Figure 4.1 Cumulative Plot for Successful Exploratory Wells and Exploratory Resource

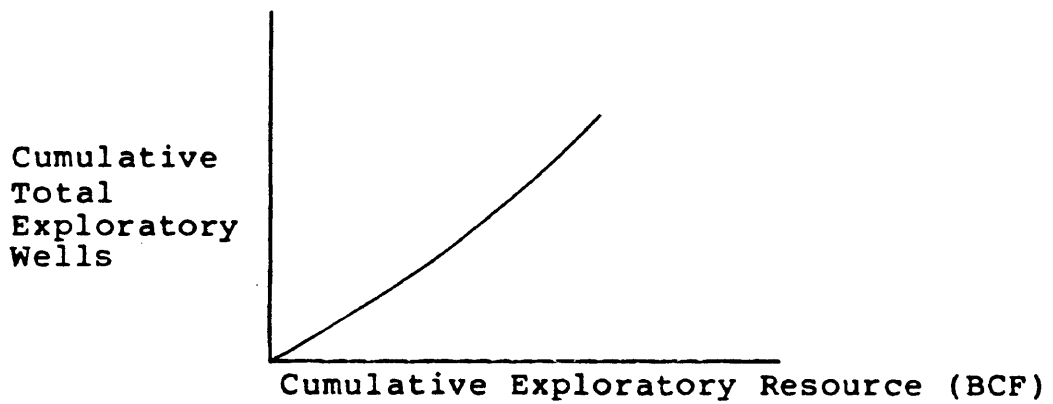


Figure 4.2 Cumulative Plot for Total Exploratory Wells and Exploratory Resource

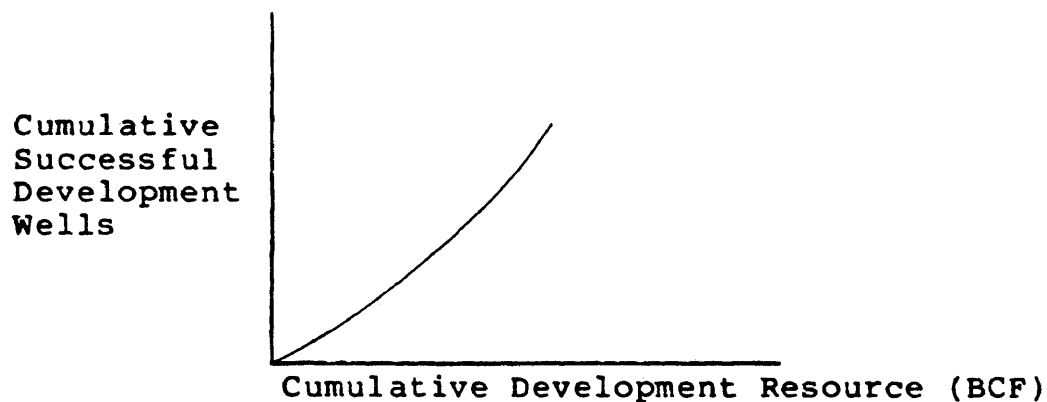


Figure 4.3 Cumulative Plot for Successful Development Wells and Development Resource

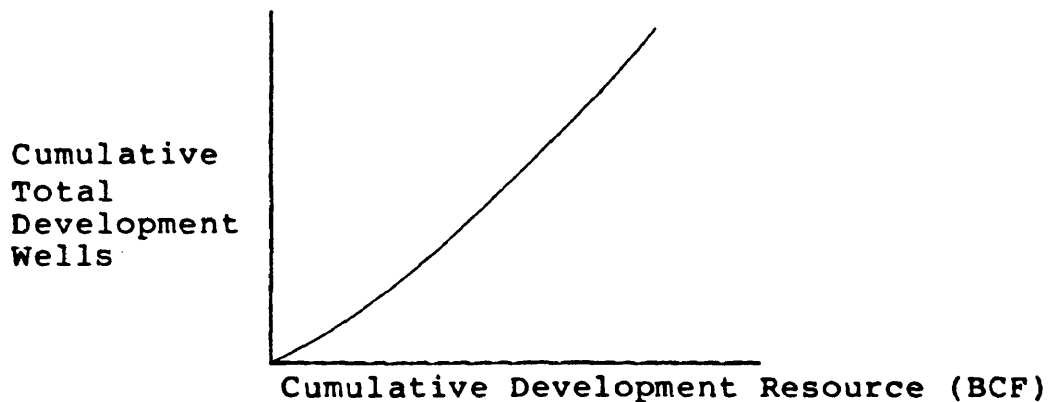


Figure 4.4 Cumulative Plot for Total Development Wells and Development Resource

In order to construct these curves, cumulative resource data is obtained from Reserves of Crude Oil and Gas Liquids, and Natural Gas in the United States (American Gas Association et al., 1967-1979). Cumulative well drilling data is obtained from the American Petroleum Institute Quarterly Review of Drilling Statistics (American Petroleum Institute, 1967-1979).

4.1.3 Cumulative Exploratory Resources

Exploratory resources are difficult to report because as time goes on more resource is added to the initial discovery. In actual practice, exploratory resources are never known until the field is abandoned. For this reason the cumulative exploratory resource must be adjusted to incorporate the fact that the reported resources will grow from year to year. The procedure used in the methodology of this chapter to adjust these resources is by John Haun (1981).

Haun uses what he calls a "reserve revision ratio." The ratio is a number that when multiplied by the reported resource gives the ultimate resource that will be produced from these discoveries. Since 13 years of data are used in this study there will be 13 ratios: a first-year ratio, a

second-year ratio, etc. According to Haun's method, the last year's ratio is equal to one. This is a fairly good assumption because most fields are developed sufficiently after 13 years to make an accurate ultimate recovery estimation.

The first-year ratio shows how the reported resources for a specific year change from the first year they are reported to the second year they are reported. For example, the first year ratio would show how the resource discovered in 1976 changes when it is reported in 1976 to when it is reported in 1977. The second-year ratio shows how reported resources change from the second year to the third year, etc. In order to clarify this procedure, the data in Table 4.1 will be used. The data in Table 4.1 are for only four

Table 4.1 Resources for Reserve Revision Ratio Example

<u>Year of Discovery</u>	<u>1974 Resource</u>	<u>Year of Report</u>		<u>1977 Resource</u>
		<u>1975 Resource</u>	<u>1976 Resource</u>	
1974	100	120	125	126
1975	-	50	60	65
1976	-	-	200	250
1977	-	-	-	10

Source: Prepared by the Author

years; for the Permian Basin, 13 years of data will be used.

The first year reserve revision ratio is

$$\frac{120 + 60 + 250}{100 + 50 + 200} = 1.228.$$

The second year reserve revision ratio is

$$\frac{125 + 65}{120 + 60} = 1.056.$$

The third year reserve revision ratio is

$$\frac{126}{125} = 1.008.$$

The fourth year reserve revision ratio is by definition equal to one.

As can be seen, the ratio becomes smaller with each succeeding year; i.e., the third-year ratio is less than the second-year ratio. This is because the reported resource becomes closer to the ultimate resource as the resource is developed.

Using the example numbers, the 10 BCF discovered in 1977 will increase by a factor equal to the product of all three ratios. Therefore, the ultimate recovery for the 10 BCF is

$$10 \times 1.229 \times 1.056 \times 1.008 = 13.082 \text{ BCF.}$$

The 200 BCF discovered in 1976 would use only the second and third year ratios because the report is already published

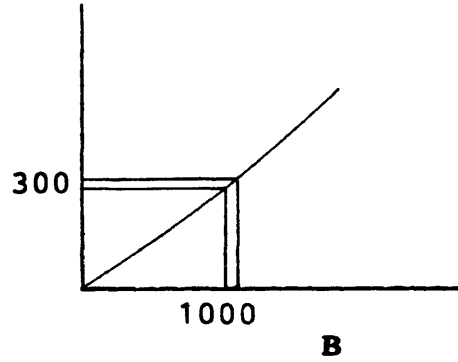
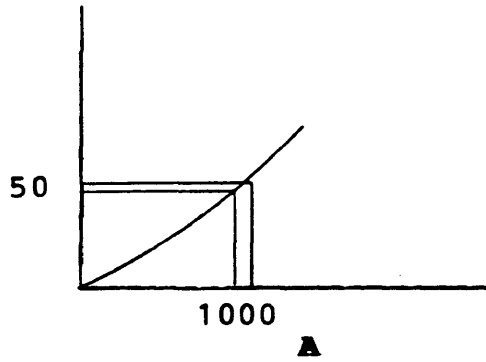
for 1977, and thus it is known how much the resource has grown in the first year after its discovery, 250 BCF. The ultimate recovery for the 200 BCF is

$$250 \times 1.056 \times 1.008 = 266.112 \text{ BCF.}$$

4.1.4 Discovery Model

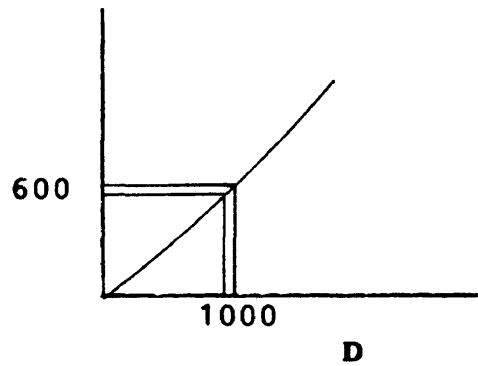
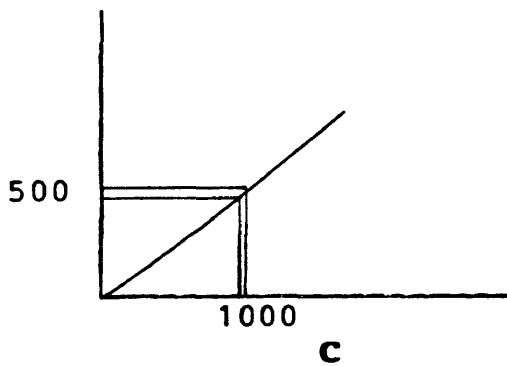
The curves discussed in subsection 4.1.2 can be constructed once the cumulative exploratory resource has been adjusted. In Figure 4.5, cumulative successful exploratory wells versus cumulative exploratory resource is curve A; cumulative total exploratory wells versus cumulative exploratory resource is curve B; cumulative successful development wells versus cumulative development resource is curve C, and cumulative total development wells versus cumulative development resource is curve D. For the Permian Basin data a regression analysis will be performed for each set of data so that future trends may be forecasted. The solid portions of the curves are calculated using the actual data, while the dashed portions of the curves are extrapolated from the regression equations.

These curves provide the number of each type of well for the possible and speculative resources: successful exploratory, dry exploratory, successful development, and



Cumulative Successful Exploratory Wells Versus Cumulative Exploratory Resources

Cumulative Total Exploratory Wells Versus Cumulative Exploratory Resources



Cumulative Successful Development Wells Versus Cumulative Development Resources

Cumulative Total Development Wells Versus Cumulative Development Resources

Figure 4.5 Cumulative Resources Versus Cumulative Wells (For use in discovery model calculations)

dry development. For the probable resource, only the number of successful and dry development wells are needed. In order to find the number of each type of well, a number of successful exploratory wells is assumed equal to approximately one year of successful exploratory drilling effort based on the past history of the basin. This number is not critical to the analysis because it will not change the shape or orientation of the marginal and average cost curves (discussed in subsection 4.1.5) but will only determine how many points will be plotted on the marginal and average cost curves.

From curve A the amount of added exploratory resource is determined. Using this resource, the total number of exploratory wells are found from curve B. The number of dry exploratory wells are found by subtracting successful exploratory wells from the total exploratory wells. The number of successful development wells are found from curve C using the same resource found in curve A. These successful development wells are needed to develop the exploratory resource found by the successful exploratory wells. The number of total development wells are found from curve D, and the number of dry development wells are found by subtracting the number of successful development wells from

the number of total development wells.

For example, if 50 successful exploratory wells are assumed, curve A shows that 1,000 BCF of natural gas will be discovered (see Figure 4.5). Curve B shows that 300 total exploratory wells will be drilled. Therefore, 250 dry exploratory wells will be drilled. Curve C shows that 500 successful development wells are needed to develop the 1,000 BCF. Curve D shows that 600 total development wells will be drilled. Therefore, 100 dry development wells will be drilled. From the number of each of the four types of wells and the cost for each type of well, marginal costs can be calculated.

For probable gas resources, the procedure above is followed, except that only curves C and D are used. A number of successful development wells is assumed (about one year's successful development drilling effort), and, from curve C, the amount of development resource found by these wells is determined. Then curve D is used to determine the total number of development wells needed to find this resource. The number of dry development wells are calculated by subtracting successful development wells from the total development wells.

4.1.5 Marginal and Average Costs

Once all the wells and their individual costs (see section 3.2 or 4.2) are known, the procedure for finding marginal costs is much the same as in Chapter 3. The marginal cost calculated is for the amount of reserves-possible and speculative, or probable-which was found by the one year of drilling effort.

For the first year's drilling effort, marginal and average costs are equal. For the second year the same number of successful wells is used in the procedure outlined in subsection 4.1.4. A marginal cost for the second year is generated. The average cost for the two years can be calculated as was done in Chapter 3 and is the average of the marginal costs weighted by the resources found in that year. This procedure continues until the resource predicted by the PGC are found. The actual resource may or may not be equal to the PGC estimates, but since only shapes and positions of the marginal and average cost curves developed from this chapter and Chapter 3 are to be compared, the difference between actual and estimated resources is not a major issue. Marginal and average cost curves are then plotted, as in Figure 4.6, for comparison with results produced in Chapter 3.

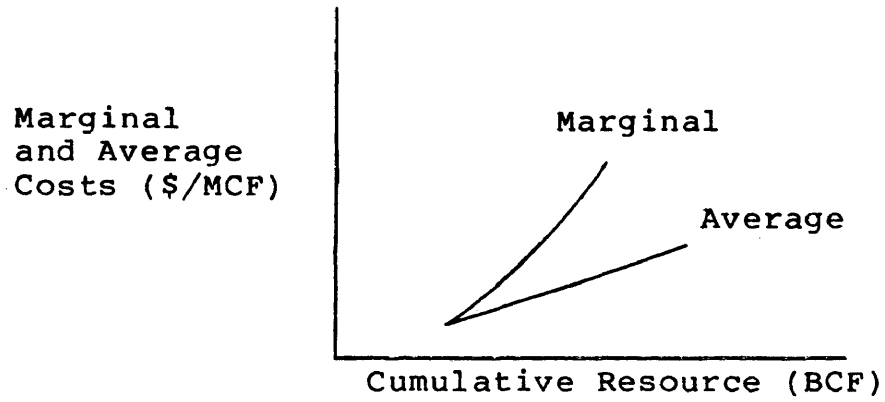


Figure 4.6 **Marginal and Average Cost Curves for Natural Gas**

4.2 Permian Basin Results

This section presents the data and results for the drilling cost analysis of the Permian Basin resources using historical data.

4.2.1 PGC Data

As stated in Section 4.1, this method relies primarily on historical data. However, two PGC estimates must be used to find marginal and average costs per MCF. The first PGC estimate is the total resource in the probable category for all depths. The second PGC estimate is the total resource in the possible and speculative categories combined for all depths. The PGC estimate is 15014 BCF in the probable category and 34027 BCF in the possible and speculative categories.

4.2.2 Historical Data

This subsection presents historical data obtained from two publications. Reserves of Crude Oil and Natural Gas Liquids, and Natural Gas in the United States (American Gas Association and American Petroleum Institute 1967-1979) is used for historical data pertaining to exploratory resources and development resources discovered during 1967-1979.

Quarterly Review of Drilling Statistics for the United States (American Petroleum Institute, 1967-1979) is used for historical data pertaining to dry and successful exploratory and development wells drilled during 1967-1979.

Table 4.2 presents historical data for exploratory resources for the Permian Basin. Table 4.3 presents historical data for exploratory resources. The resources listed in the last column will be used in conjunction with the rest of the resources reported to construct plots of cumulative exploratory resources versus cumulative exploratory wells (see subsections 4.2.4 and 4.2.5).

Table 4.4 shows the historical data for successful development gas wells, and Table 4.5 gives the historical data for total (dry and successful) development gas wells. The American Petroleum Institute (API) provides data for total development wells, oil wells, gas wells, and dry wells. Since there is no way to tell which dry wells were targeted for oil and which were targeted for gas, the dry wells must be apportioned between oil and gas. The CSM research group's method is to use the ratio of successful gas wells to successful oil wells. For example, 70 successful oil wells, 30 successful gas wells, and 200 dry wells, 60 of the 200 dry wells would be considered to

Table 4.2 Development Resource History

<u>Year</u>	<u>Resource (BCF)</u>	<u>Cumulative Resource (BCF)</u>
1967	2,980.9	2,980.9
1968	682.4	3,663.3
1969	704.2	4,367.5
1970	1,435.2	5,802.7
1971	1,425.9	7,228.6
1972	1,451.2	8,679.8
1973	919.2	9,599.0
1974	675.9	10,274.8
1975	547.0	10,821.8
1976	438.4	11,260.2
1977	189.5	11,449.7
1978	255.3	11,705.0
1979	101.8	11,806.8

Source: American Gas Association and American Petroleum
Institute

Table 4.3 Exploratory Resource History

Year of Discovery	Year of Report												
	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
1967	263.2	307.7	428.6	437.8	474.3	553.9	600.1	699.7	678.0	794.4	797.2	766.8	772.0
1968		184.1	332.3	497.9	807.5	907.3	1638.8	1765.0	1779.3	1654.9	1548.5	1587.1	1675.9
1969			229.1	522.4	794.0	1324.9	1331.1	1469.1	1325.2	1346.7	1239.8	1255.9	1261.3
1970				204.3	305.5	320.9	261.9	414.8	503.7	503.0	501.7	501.9	557.1
1971					8.0	102.3	208.5	255.5	320.0	320.1	300.5	284.3	267.3
1972						84.4	181.3	191.6	170.5	254.2	228.8	215.9	231.0
1973							347.2	531.3	711.0	769.0	937.9	1012.6	1129.2
1974								156.6	278.1	278.1	277.3	278.0	254.6
1975									79.7	119.4	134.0	155.4	178.1
1976										54.0	82.6	96.9	110.9
1977											60.3	95.6	130.4
1978												53.3	115.4
1979													34.7

Source: American Gas Association and American Petroleum Institute

Table 4.4 Successful Development Gas Wells

<u>Year</u>	<u>Wells</u>	<u>Cumulative Wells</u>
1967	146	146
1968	136	282
1969	112	394
1970	140	534
1971	156	690
1972	175	865
1973	316	1181
1974	353	1534
1975	382	1916
1976	358	2274
1977	542	2816
1978	457	3273
1979	495	3768

Source: American Petroleum Institute

Table 4.5 Total Development Gas Wells

<u>Year</u>	<u>Wells</u>	<u>Cumulative Wells</u>
1967	168	168
1968	158	326
1969	129	455
1970	157	612
1971	175	787
1972	195	982
1973	354	1336
1974	389	1725
1975	416	2141
1976	408	2549
1977	600	3149
1978	514	3663
1979	533	4196

Source: American Petroleum Institute

have been targeted for gas, and 140 of the 200 dry wells would be considered to have been targeted for oil. Therefore, in Tables 4.4 and 4.5, 30 successful gas wells and 90 total gas wells would be reported.

Table 4.6 gives the historical data for successful exploratory gas wells and Table 4.7 gives the historical data for total exploratory gas wells. Once again the dry wells are apportioned to oil and gas wells as was done for dry development wells.

4.2.3 Drilling Costs Per Well

The same drilling costs per well are used here that were used in Section 3.2. Since the only estimate that is used by this method is the total resource, there is no depth differentiation. For this reason a composite drilling cost per well must be developed. A way to do this is to calculate an average drilling cost weighted by the percentage of wells drilled in the Permian Basin as reported by the Joint Association Survey on Drilling Costs in 1980 (API, Independent Petroleum Association of America, and Mid-Continent Oil and Gas Association, 1980). Tables 4.8 and 4.9 summarize these data and show the calculations used to find average drilling costs per well.

Table 4.6 Successful Exploratory Gas Wells

<u>Year</u>	<u>Wells</u>	<u>Cumulative Wells</u>
1967	24	24
1968	24	48
1969	24	72
1970	24	96
1971	21	117
1972	30	147
1973	71	218
1974	75	293
1975	87	380
1976	127	507
1977	109	616
1978	114	730
1979	69	799

Source: American Petroleum Institute

Table 4.7 Total Exploratory Gas Wells

<u>Year</u>	<u>Wells</u>	<u>Cumulative Wells</u>
1967	109	109
1968	104	213
1969	87	300
1970	112	412
1971	84	496
1972	138	634
1973	241	875
1974	250	1125
1975	314	1439
1976	364	1803
1977	331	2134
1978	358	2492
1979	295	2787

Source: American Petroleum Institute

Table 4.8 Successful Development and Exploratory Costs Per Well

Depth Increment (ft)	Gas Wells Drilled	% of Total Gas Wells	Development		% of Total Gas Wells x		Exploratory		% of Total Gas Wells x	
			Gas Well Cost(\$)	Development Gas Well Cost(\$)	Development Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)	
0 - 5,000	115	19.86	104,000	20,654	133,000	26,414	133,000	26,414	26,414	
5,000 - 10,000	409	70.64	420,000	296,688	478,000	337,660	478,000	337,660	337,660	
10,000 - 15,000	20	3.45	1,305,000	45,023	1,384,000	47,748	1,384,000	47,748	47,748	
15,000 - 20,000	20	3.45	3,127,000	107,882	3,243,000	111,884	3,243,000	111,884	111,884	
20,000 - 25,000	8	1.38	5,771,000	79,640	6,152,000	84,898	6,152,000	84,898	84,898	
25,000 - 30,000	7	1.21	8,209,000	99,329	9,446,000	114,297	9,446,000	114,297	114,297	
TOTALS:		579		649,216		722,901		722,901		

Source: Colorado School of Mines Research Group, American Petroleum Institute, Department of Energy, and the Author

Table 4.9 Dry Development and Exploratory Costs Per Well

Depth Increment (ft)	Gas Wells Drilled	% of Total Gas Wells	Development		% of Total Gas Wells x		Exploratory		% of Total Gas Wells x	
			Gas Well Cost(\$)	Gas Well Cost(\$)	Development Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)	Development Gas Well Cost(\$)	Exploratory Gas Well Cost(\$)		
0 - 5,000	392	39.08	85,000	33,218	89,000	34,781				
5,000 - 10,000	486	48.45	261,000	126,455	250,000	121,125				
10,000 - 15,000	116	11.56	1,057,000	122,189	1,144,000	132,246				
15,000 - 20,000	7	0.70	2,494,000	17,458	2,821,000	19,747				
20,000 - 25,000	1	0.10	4,571,000	4,571	5,279,000	5,279				
25,000 - 30,000	1	0.10	7,288,000	7,288	8,519,000	8,519				
TOTALS:	1003	99.99		311,119		321,697				

Source: Colorado School of Mines Research Group, American Petroleum Institute,
Department of Energy, and the Author

The first step is to calculate the percentage of the total wells reported by the Joint Association Survey that were drilled in each depth increment. This percentage is multiplied by the drilling cost per well for each depth increment as given by the CSM research group. These numbers are then added up to find the average drilling costs per well. This procedure is repeated for dry and successful, exploratory and development wells. The average costs per well are found in the Totals row in Tables 4.8 and 4.9.

4.2.4 Revision Ratios

The data in Table 4.3 is used to calculate revision ratios for the Permian Basin by using the methodology presented in Section 4.1. The revision ratios are used to revise the resources as reported in 1979 so that they will become ultimate resources instead of reported resources. The revision ratios are presented in Table 4.10. For instance, the year 12 revision ratio is $772.0/766.8 = 1.007$, (772.0 and 766.8 appear in Table 4.3). The year 11 revision ratio is $(766.8 + 1675.9)/(797.2 + 1587.1) = 1.024$.

The revision ratios must be accumulated in order to revise the exploratory resources. For example, the year 11

Table 4.10 Revision Ratios

<u>Year</u>	<u>Revision Ratio</u>	<u>Cumulative Revision Ratio</u>
1967	1.000	1.000
1968	1.007	1.007
1969	1.024	1.031
1970	1.013	1.045
1971	1.020	1.065
1972	0.941	1.003
1973	1.028	1.031
1974	1.020	1.051
1975	1.216	1.278
1976	1.143	1.461
1977	1.248	1.824
1978	1.364	2.487
1979	1.679	4.176

Source: Prepared by the Author

cumulative revision ratio equals the year 12 cumulative revision ratio multiplied by the year 11 revision ratio.

Table 4.11 shows the calculations for the revised exploratory resources. The resource as reported in 1979 (Table 4.3) is revised by multiplying the resource by the cumulative revision ratio. Then, the resources are accumulated by addition. These cumulative revised resources will be used to construct cumulative wells versus cumulative resources curves later in this section.

In Section 4.1 it was stated that revision ratios always decrease. This may not happen in actual practice. Table 4.9 shows that generally the revision ratios decreases but there are some anomalies. In Table 4.9, the year 1 revision ratio is associated with 1979, the year 2 revision ratio is associated with 1978, etc.

4.2.5 Marginal and Average Costs

The data in Tables 4.2, 4.4-4.7, and 4.10 are used to construct plots of cumulative wells versus cumulative resources as explained in Section 4.1. These plots are shown in Figures 4.7-4.10. Using this data, a least squares analysis is performed to determine the relationship between cumulative wells and cumulative resources. Polynomial

Table 4.11 Exploratory Resources Discovered

<u>Year</u>	<u>Resource (BCF)</u>	<u>Cumulative Revision Ratio</u>	<u>Revised Resource (BCF)</u>	<u>Cumulative Revised Resource (BCF)</u>
13	772.0	1.000	772.0	772.0
12	1675.9	1.007	1687.6	2459.6
11	1261.3	1.031	1300.4	3760.0
10	557.1	1.045	582.2	4342.2
9	267.3	1.065	284.7	4626.9
8	231.0	1.003	231.7	4858.6
7	1129.2	1.031	1164.2	6022.8
6	254.6	1.051	267.6	6290.4
5	178.1	1.278	227.6	6518
4	110.9	1.461	162.0	6680
3	130.4	1.824	237.8	6917.8
2	115.4	2.487	287.0	7204.8
1	34.7	4.176	144.9	7349.7

Source: Prepared by the Author

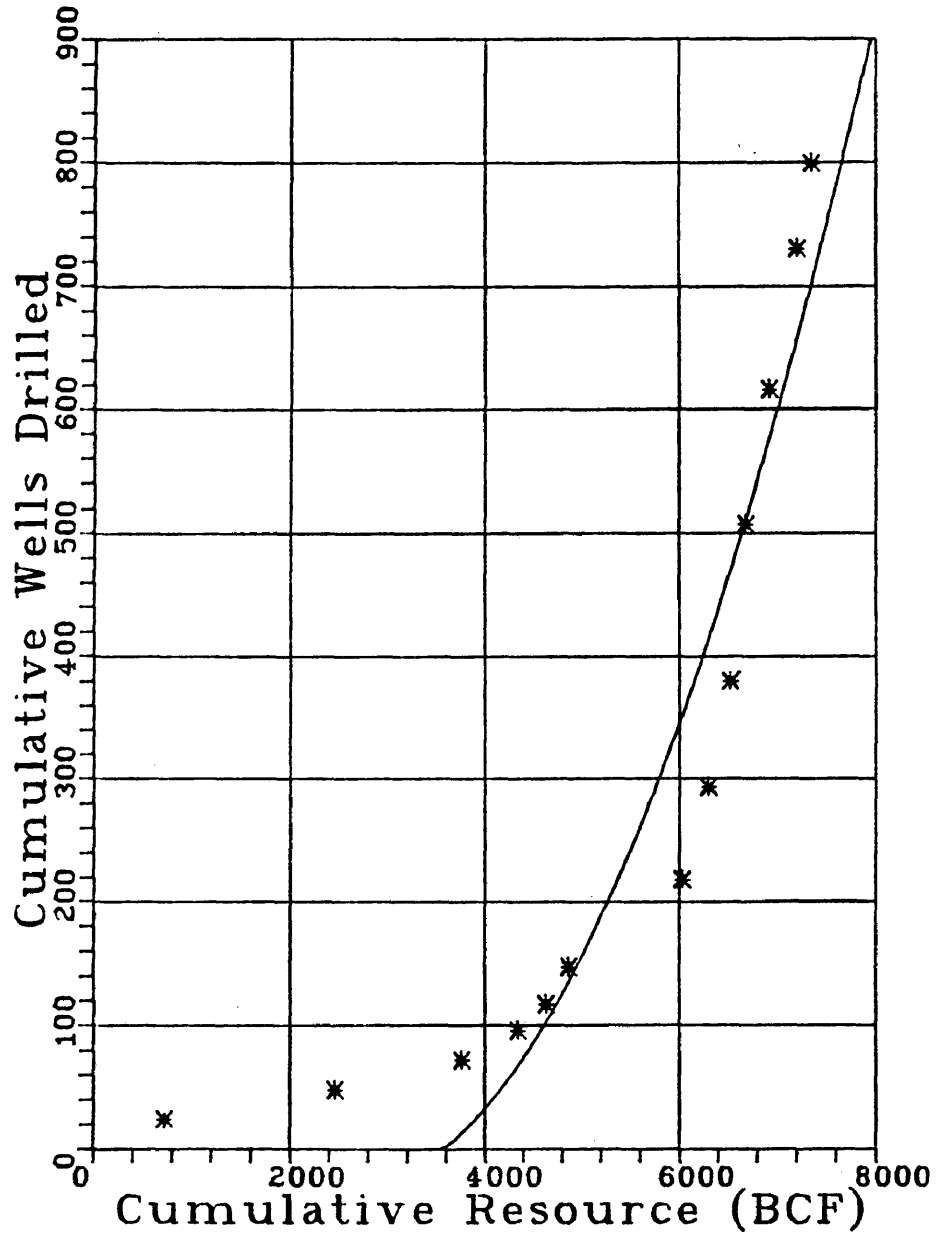


Figure 4.7 Cumulative Successful Exploratory Wells Drilled Versus Cumulative Exploratory Resources (including regression line)

Note: Regression line valid for cumulative resource greater than 4,000 BCF.

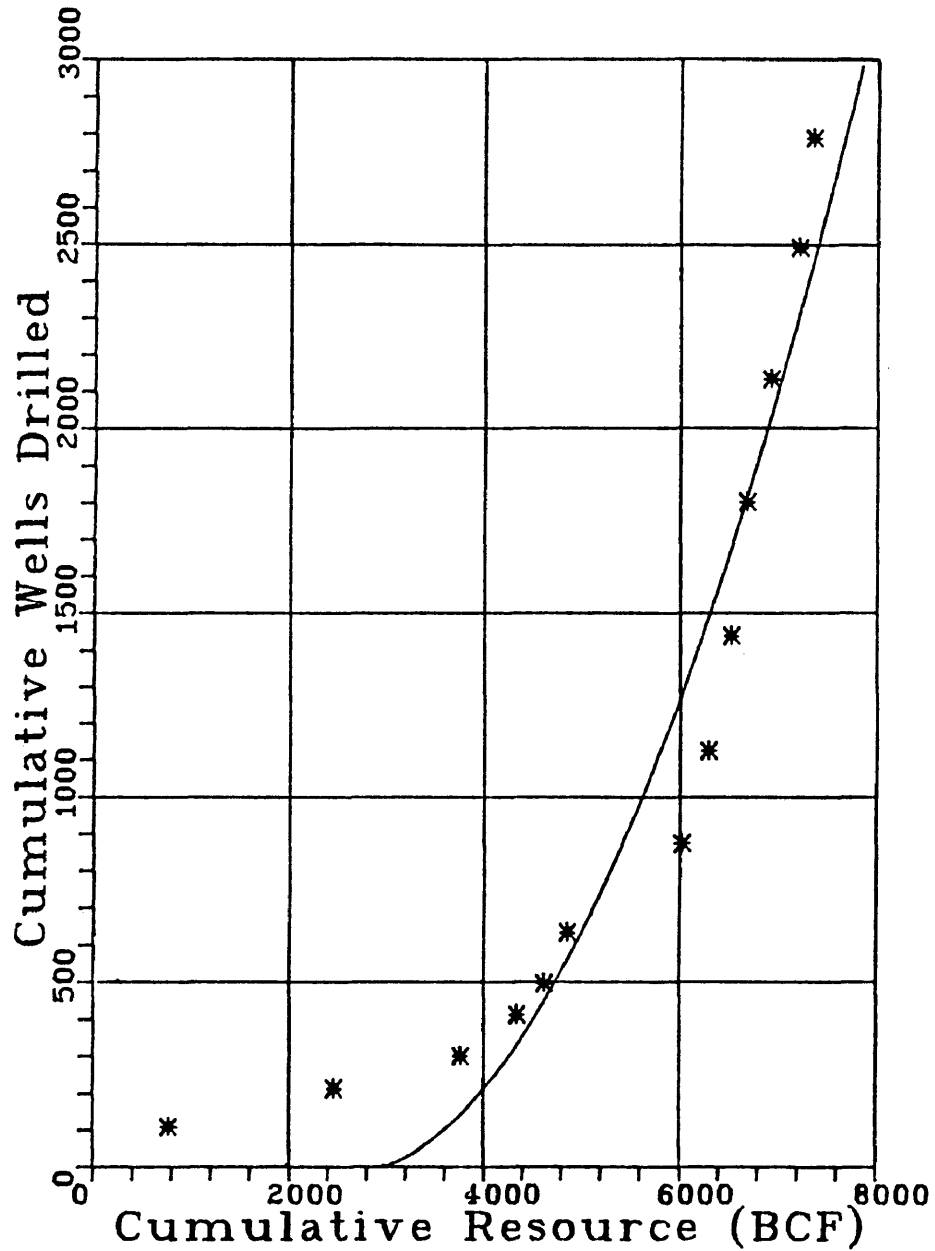


Figure 4.8 Cumulative Total Wells Drilled Versus Cumulative Exploratory Resources (including regression line)

Note: Regression line valid for cumulative resource greater than 4,000 BCF.

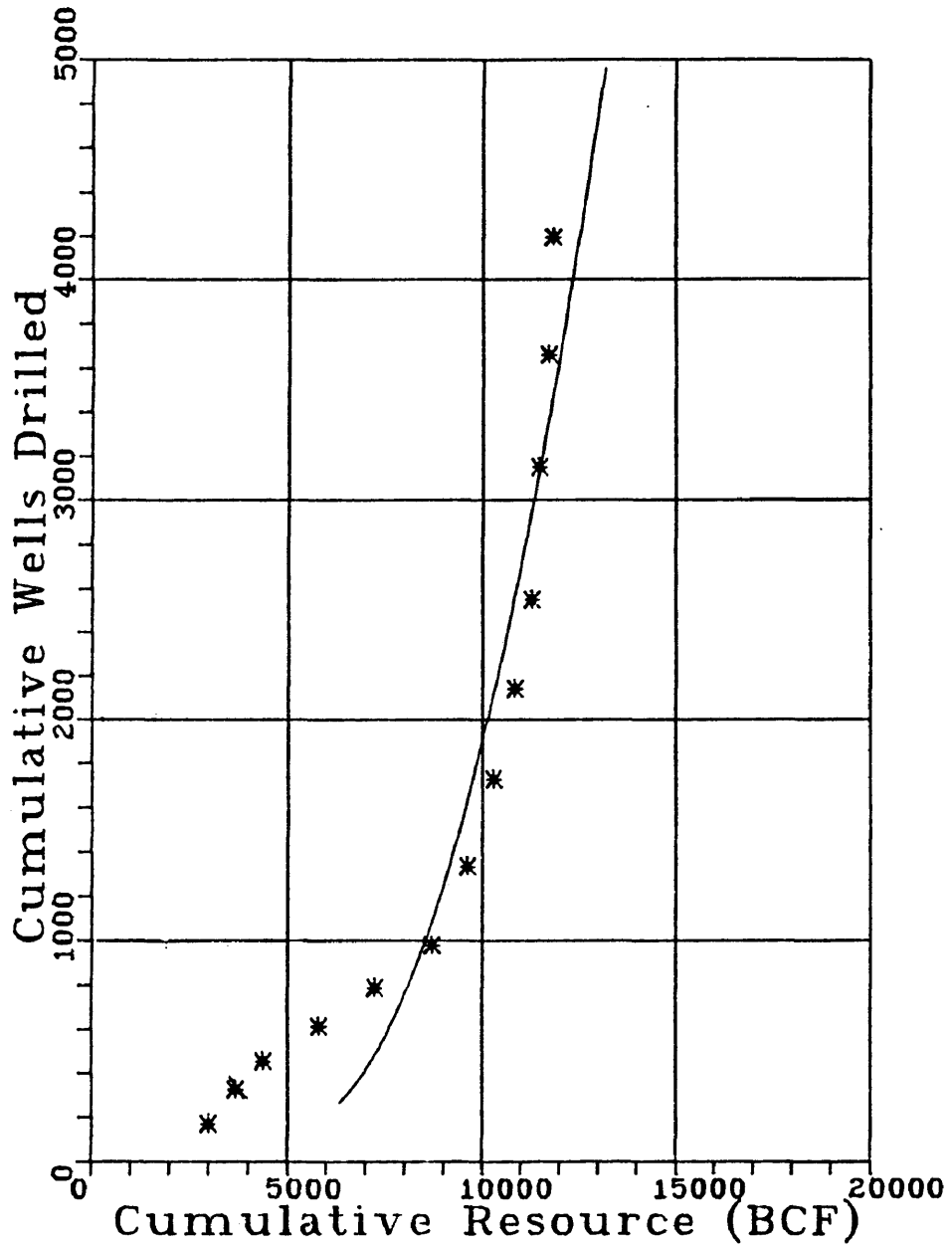


Figure 4.9 Cumulative Successful Development Wells Drilled Versus Cumulative Development Resources (including regression line)

Note: Regression line valid for cumulative resource greater than 6,000 BCF.

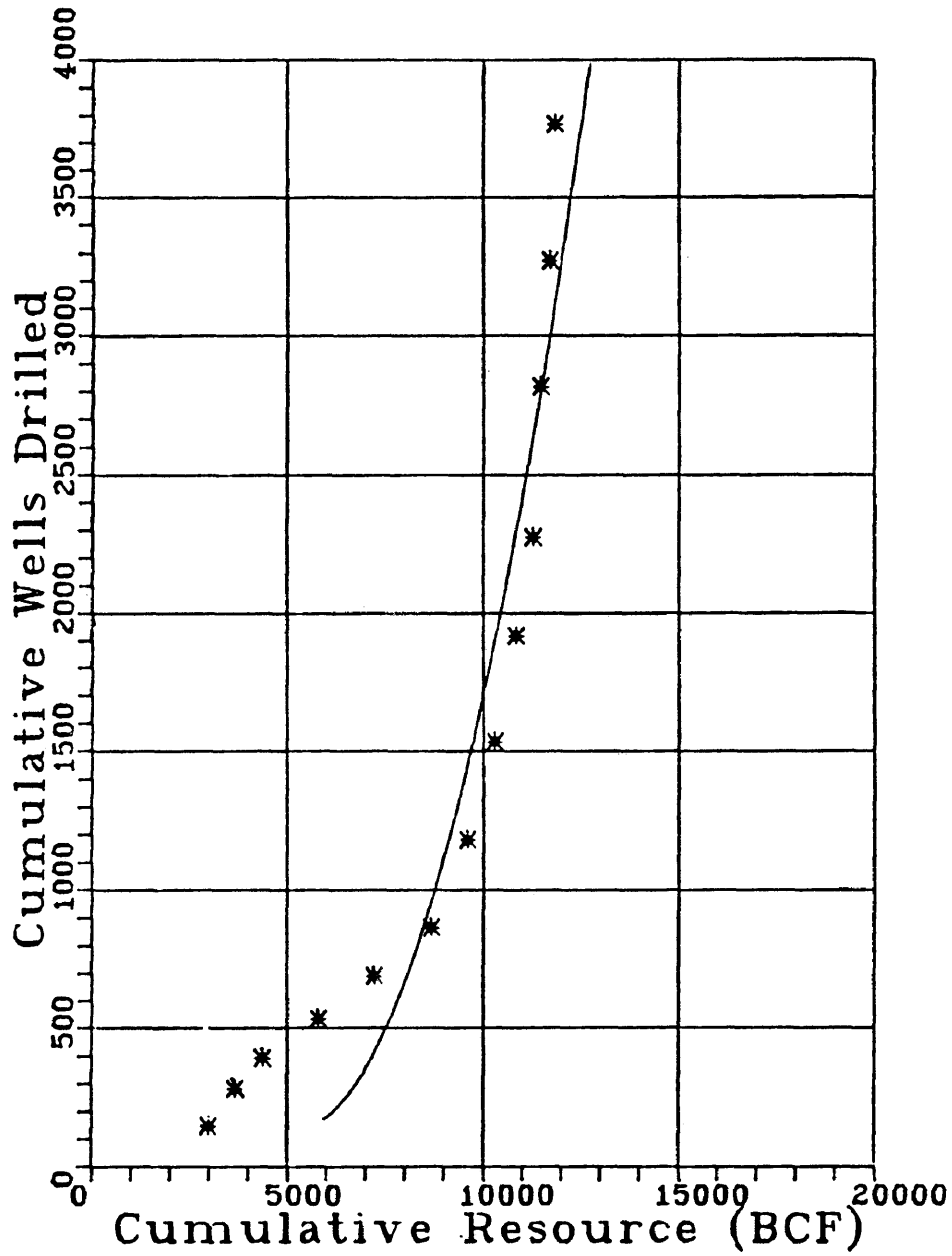


Figure 4.10 Cumulative Total Development Wells Drilled Versus Cumulative Development Resources (including regression line)

Note: Regression line valid for cumulative resource greater than 6,000 BCF.

relationships of order 2 were used. Logarithmic models were not investigated because extrapolations of these curves must be done and these models do not work particularly well with extrapolations. Higher order polynomial models were not used because there is no reason that the curves should have inflection points. The results of the regressions are presented in Table 4.12.

For the probable resource predicted by the PGC, 3000 successful development wells are assumed to be drilled in each calculation increment. This is assumed for ease of calculation and does not affect the final shape of the marginal and average cost curves, only the number of points plotted on the marginal and average cost curves.

From the regression equation for successful development wells, the amount of development resource discovered by the 3,000 successful wells is found. Then, the regression equation for total development wells is used with this amount of development resource to find the total development wells that are to be drilled. Dry development wells are calculated by subtracting the successful development wells from the total development wells. The dry and successful development wells are then multiplied by their respective costs (Tables 4.8 and 4.9) and added together to find the

Table 4.12 Regression Results

Plot	Regression Equation $y = f(x)$ Wells = f(Resource)	Standard Deviation	Adj. R ²	Degrees of Freedom
Cumulative Successful Development Wells vs. Cumulative Development Resources	$y = 1996.6 - 0.713x + 0.00006835x^2$ (2.54) (-3.01) (4.42)	366.8	0.907	10
Cumulative Total Development Wells vs. Cumulative Development Resources	$y = 2208 - 0.784x + 0.00007551x^2$ (2.53) (-2.98) (4.40)	407.4	0.908	10
Cumulative Successful Exploratory Wells vs. Cumulative Exploratory Resources	$y = 189.1 - 0.1689x + 0.00003248x^2$ (1.74) (-3.17) (5.40)	83.52	0.905	10
Cumulative Total Exploratory Wells vs. Cumulative Exploratory Resources	$y = 638.4 - 0.5294x + 0.00010567x^2$ (1.90) (-3.21) (5.72)	252.7	0.923	10

Note: Numbers in parenthesis are t-statistics for the co-efficients.

Source: Prepared by the Author

total development cost. The marginal cost is found by dividing the total cost by the resource found by the increment. The average cost is then calculated as was done in Section 3.2. Table 4.13 presents these calculations. Figure 4.11 is a plot of the marginal and average costs. This plot will be used for comparison with the results obtained in Section 3.2.

For the possible and speculative resources predicted by the PGC, 2,000 successful exploratory wells are assumed to be drilled in each calculation increment. Again, this number is assumed for ease of calculation.

From the regression equation for successful exploratory wells, the amount of exploratory resource discovered by the 2,000 successful wells is found. The regression equations for total exploratory, successful development, and total development wells are used with the resource to find the number of total exploratory, successful development, and total development wells are needed to find and develop the resource found by the 2,000 successful exploratory wells. The number of dry wells is calculated by subtracting the successful wells from the total wells. The four kinds of wells and their respective costs are added together to find the total cost. The marginal and average costs are then

Table 4.13 Marginal and Average Cost Calculations for Probable Resources

Resource (BCF)	Cumulative Resource (BCF)	Successful Development Wells	Dry Development Wells	Total Development Cost (MHS)	Marginal Cost (\$/MCF)	Average Cost (\$/MCF)
2561	2561	3000	318	2046.6	0.80	0.80
2021	4582	3000	319	2046.9	1.01	0.89
1724	6306	3000	319	2046.9	1.19	0.97
1528	7834	3000	319	2046.9	1.34	1.05
1388	9222	3000	318	2046.6	1.47	1.11
1280	10502	3000	316	2045.7	1.60	1.17
1194	11696	3000	315	2045.4	1.71	1.22
1122	12818	3000	321	2047.5	1.82	1.28
1063	13881	3000	316	2045.7	1.92	1.33
1133	15014	3366	355	2295.7	2.03	1.38

Source: Prepared by the Author

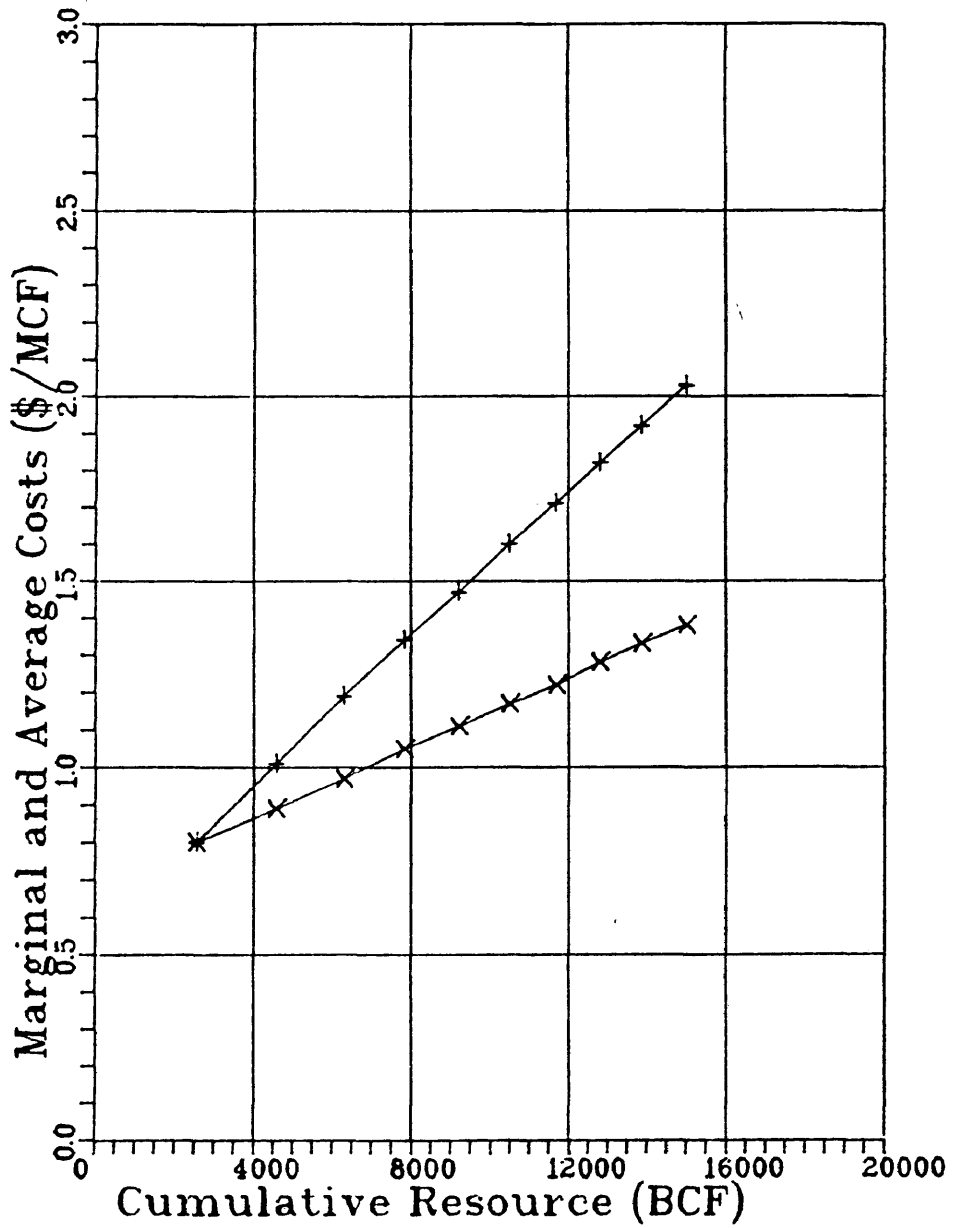


Figure 4.11 Marginal (+) and Average (x) Costs for Probable Resources

calculated by the methods explained in Chapter 3. Table 4.14 summarizes these calculations. Figure 4.12 is a plot of the results. These results will be used in the next chapter for comparison with the results obtained in Chapter 3.

Table 4.14 Marginal and Average Cost Calculations for Possible and Speculative Resources

Resource (BCF)	Cumulative Resource (BCF)	Successful Exploratory Wells	Dry Exploratory Wells	Exploratory Cost (M\$)	Successful Development Wells	Dry Development Wells	Development Cost (M\$)	Total Cost (M\$)	Marginal Cost (\$/MCF)	Average Cost (\$/MCF)
4278	4278	2000	4610	2929	14293	1507	9748	12677	2.96	2.96
2862	7140	2000	4560	2913	10959	1154	7474	10387	3.63	3.23
2310	9450	2000	4568	2915	9662	1016	6589	9504	4.11	3.44
1983	11433	2000	4537	2906	7765	934	6053	8959	4.52	3.63
1772	13205	2000	4545	2908	8387	882	5719	8627	4.87	3.80
1615	14820	2000	4506	2896	8017	843	5467	8363	5.18	3.95
1493	16313	2000	4577	2918	7729	815	5261	8189	5.49	4.09
1397	17710	2000	4565	2915	7503	798	5119	8034	5.75	4.22
1313	19023	2000	4528	2903	7303	765	4979	7882	6.00	4.34
1245	20268	2000	4526	2902	7142	745	4868	7770	6.24	4.46
1190	21458	2000	4544	2908	7024	733	4788	7696	6.47	4.57
1137	22595	2000	4533	2904	6894	718	4699	7603	6.69	4.68
1092	23687	2000	4531	2904	6787	713	4628	7532	6.90	4.78
1050	24737	2000	4517	2899	6674	702	4551	7450	7.10	4.88
1018	25755	2000	4541	2907	6621	693	4514	7421	7.29	4.97
983	26738	2000	4514	2898	6524	683	4448	7346	7.47	5.06
954	27692	2000	4499	2893	6462	671	4404	7297	7.65	5.15
927	28619	2000	4553	2911	6396	670	4361	7271	7.84	5.24
902	29521	2000	4528	2903	6330	669	4318	7221	8.01	5.32
879	30400	2000	4522	2901	6280	658	4281	7182	8.17	5.40
859	31259	2000	4535	2905	6239	654	4253	7158	8.33	5.48
838	32097	2000	4529	2904	6183	653	4217	7121	8.50	5.56
820	32917	2000	4526	2902	6147	638	4189	7091	8.65	5.64
801	33718	2000	4509	2897	6087	638	4150	7047	8.80	5.71
309	34027	779	1771	1133	2373	257	1621	2754	8.91	5.74

Source: Prepared by the Author

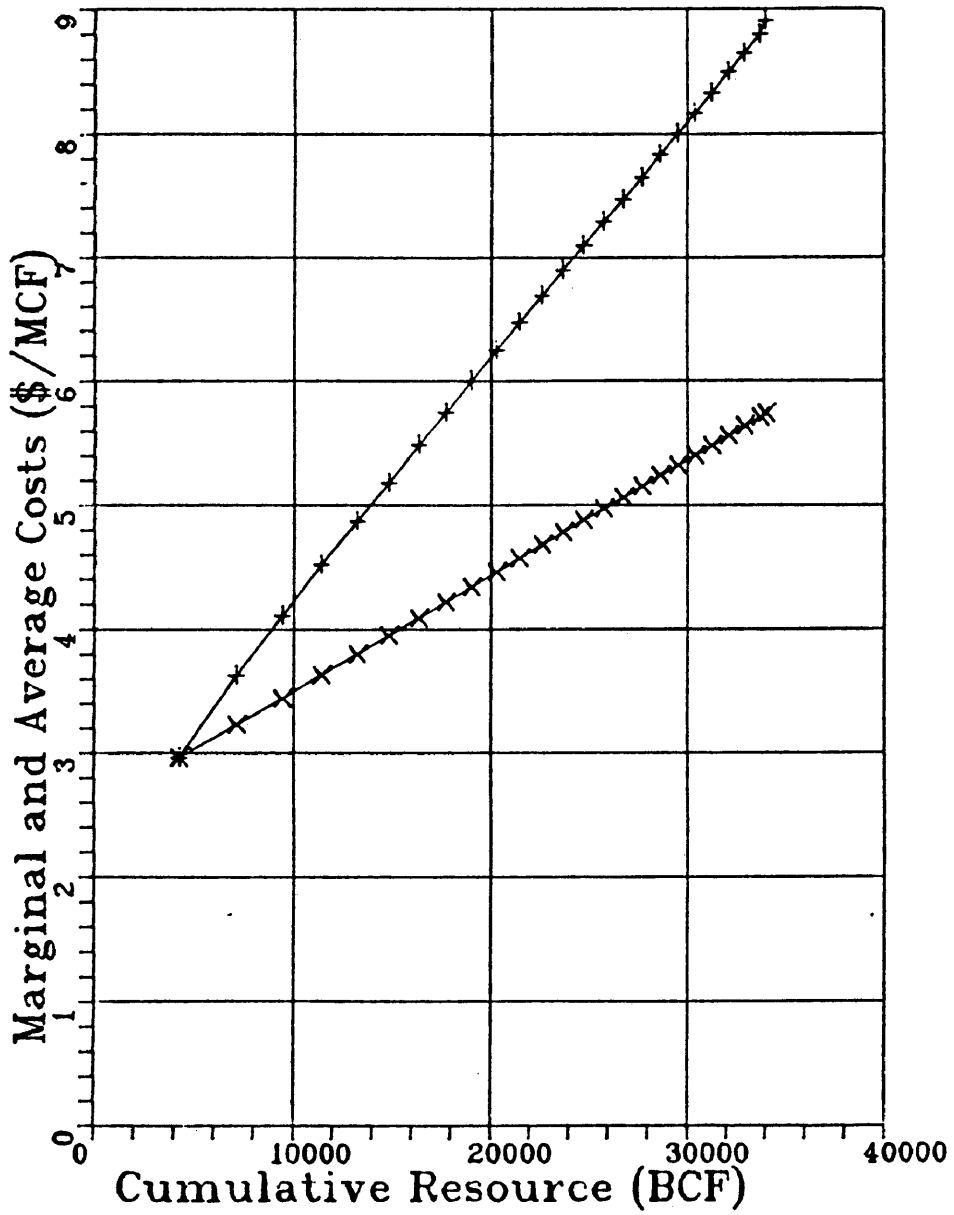


Figure 4.12 Marginal (+) and Average (x) Costs for Possible and Speculative Resources

Chapter 5

COMPARISON OF RESULTS

This chapter compares the results obtained in Chapters 3 and 4. The marginal and average cost curves will be compared by looking at starting points, ending points, the general shape of the curves, and the change in costs divided by the change in resources. In addition, success ratios, recoveries per well, and the number of fields discovered are compared for the two models presented in Chapters 3 and 4.

The comparison of the marginal cost curves for the probable resource is presented in Table 5.1. The marginal costs for the Historical Model are always greater than for the PGC Model at the same level of cumulative resource. By dividing the change in marginal costs by the change in resource it is seen that the marginal costs increase faster for the Historical Model than for the PGC Model.

The comparison of the average cost curves for the probable resources is presented in Table 5.2. Again the average costs for the Historical Model are always greater than the PGC Model at the same level of resources and the marginal costs for the Historical Model increase faster than the PGC Model.

Table 5.1 Comparison of Marginal Cost Curves for Probable Resources

	<u>Starting Points</u>		<u>Ending Points</u>		Shape of Curve	Change in Cost Change in Resource (\$/MCF/BCF)
	Marginal Cost (\$/MCF)	Resource (BCF)	Marginal Cost (\$/MCF)	Resource (BCF)		
Historical Model	0.80	2561	2.03	15014	straight line with positive slope	$\frac{2.03 - 0.80}{15014 - 2561} = 9.88 \times 10^{-5}$
PGC Model	0.53	4200	0.94	15014	scattered points with upward trend	$\frac{0.94 - 0.53}{15014 - 4200} = 3.79 \times 10^{-5}$

Source: Prepared by the Author

Table 5.2 Comparison of Average Cost Curves for Probable Resources

	<u>Starting Points</u>		<u>Ending Points</u>		Shape of Curve	Change in Cost Change in Resource (\$/MCF/BCF)
	Average Cost (\$/MCF)	Resource (BCF)	Average Cost (\$/MCF)	Resource (BCF)		
Historical Model	0.80	2561	1.38	15014	straight line with positive slope	$\frac{1.38 - 0.80}{15014 - 2561} = 4.66 \times 10^{-5}$
PGC Model	0.53	4200	0.76	15014	scattered points with upward trend	$\frac{0.76 - 0.53}{15014 - 4200} = 2.13 \times 10^{-5}$

Source: Prepared by the Author

The PGC estimates that the development success ratio for probable resources is 0.70. By dividing the number of successful development wells by the total number of development wells in Table 4.12, the development success ratio for the Historical Model can be calculated. It is equal to $30366 / (30336 + 3216) = 0.91$.

The PGC estimates recoveries per well for the probable resource. The recovery per well is different for each depth interval and ranges from 0.15 BCF/well to 10 BCF/well. From Table 4.12, recoveries per well can be found by dividing the resource in the first column by the successful development wells in the third column. The recoveries per well for the Historical Model range from 0.34 BCF/well to 0.85 BCF/well.

It is assumed for probable natural gas resources that no exploratory wells are drilled. Since it is also assumed that a field is discovered by one successful exploratory well, there is no way to determine how many fields for probable resources are discovered in either model.

The comparison of the marginal cost curves for the possible and speculative resources is presented in Table 5.3. Marginal costs when using the Historical Model are always higher than when using the PGC Model. Marginal costs increase faster in the Historical Model than they do in the PGC Model.

Table 5.3 Comparison of Marginal Cost Curves for Possible and Speculative Resources

	<u>Starting Points</u>		<u>Ending Points</u>		Shape of Curve	Change in Cost Change in Reserves (\$/MCP/BCP)
	Marginal Cost (\$/MCP)	Resource (BCP)	Marginal Cost (\$/MCP)	Resource (BCP)		
Historical Model	2.96	4278	8.91	34027	straight line with positive slope	$0.91 - 2.96 = 2.00 \times 10^{-4}$ $\frac{34027 - 4278}{34027 - 4278} = 2.00 \times 10^{-4}$
PGC Model	0.60	625	5.84	33998.6	scattered points with upward trend	$5.85 - 0.60 = 1.57 \times 10^{-4}$ $\frac{33998.6 - 625.0}{33998.6 - 625.0} = 1.57 \times 10^{-4}$

Source: Prepared by the Author

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The comparison of the average cost curves for the possible and speculative resources is presented in Table 5.4. In the Historical Model average costs are always greater than in the PGC Model and increase faster.

The PGC estimates that the development success ratio for the possible and speculative resources is 0.70. By dividing the successful development wells by the total development wells listed in Table 4.13, the development success ratio for the historical model can be calculated. The ratio is $182,892 / (182,892 + 19,209) = 0.90$.

The PGC also estimates that the exploratory success ratio for the possible resource is 0.20. For the speculative resource, it is estimated to be 0.10. Using data from Table 4.13, the historical model predicts that the exploratory success ratio will be $48,779 / (48,779 + 110,674) = 0.31$.

The PGC estimates recoveries per well for the possible and speculative resources. The estimates range from 0.15 BCF/well to 10 BCF/well. From Table 4.13 recoveries per well can be calculated by dividing the resource in the first column by the sum of the successful development wells and the successful exploratory wells. For the historical model,

Table 5.4 Comparison of Average Cost Curves for Possible and Speculative Resources

	<u>Starting Points</u>		<u>Ending Points</u>		Shape of Curve	Change in Cost Change in Reserves $\frac{(\$ / MCF / BCF)}{}$
	$\frac{(\$ / MCF)}{}$	Resource (BCF)	$\frac{(\$ / MCF)}{}$	Resource (BCF)		
Historical Model	2.96	4278	5.74	34027	straight line with positive slope	$\frac{5.74 - 2.96}{34027 - 4278} = 9.34 \times 10^{-5}$
PGC Model	0.60	625	1.14	33998.6	straight line with positive slope	$\frac{1.14 - 0.60}{33998.6 - 625.0} = 1.57 \times 10^{-5}$

Source: Prepared by the Author

recoveries per well range from 0.1 BCF/well to 0.26 BCF/well.

The PGC field size data along with the use of the lognormal distribution predicts that there will be 4,861 fields discovered for the possible and speculative resources. From Table 4.13 the amount of fields discovered can be found by adding up the successful exploratory wells. This may be done because it is assumed that it takes one successful exploratory well to find every field. From the historical model, it is predicted that 48,779 fields will be found.

From an overall view, the best way to compare the two models is to compare the average costs at the endpoints of the average cost curves. This is a useful cost because it reflects the average cost for the entire resource expected to be discovered. For the probable resource, the average cost at the endpoint is equal to \$1.38/MCF for the Historical Model and \$0.76/MCF for the PGC Model. So, overall, the Historical Model prediction of the probable resource development cost is twice that of the PGC Model. For the possible and speculative resources, the average cost at the endpoint is \$5.74/MCF for the Historical Model and \$1.14/MCF for the PGC model. The Historical Model predicts

a resource development cost five times higher than that predicted by the PGC Model.

Chapter 6

CONCLUSIONS AND SUGGESTIONS FOR FUTURE RESEARCH

6.1 Conclusions

Overall, the PGC Model estimates are more optimistic than the Historical Model. This may be because the PGC has been overly optimistic in its estimates or that the historical data is too pessimistic when extrapolated into the future.

The PGC, however, has been pessimistic when estimating success ratios. For the PGC Model the prediction of development and exploratory success ratios are lower than that of the Historical Model. On the other hand, the PGC predicts higher recoveries per well than does the historical data. The PGC also predicts fewer fields of larger size than does the historical data.

Since historical data cannot predict changes in technology the extrapolation of historical data into the future will be pessimistic. This is one reason why the Historical Model predicts higher costs than does the PGC model.

The historical data reflects mostly shallow natural gas resources since deeper resources have been only recently developed. For this reason the PGC Model probably gives

better results for the deeper resources in the Permian Basin. This is also reflected in the recoveries per well. The Historical Model's predictions of recoveries per well is less than those of the PGC. The PGC is expecting recoveries per well to be high in the deeper resources.

The Historical Model also predicts a greater number of wells needed to develop the resource than does the PGC Model. This is because the Historical Model predicts lower recoveries per successful well, and therefore more wells to develop the resource.

The actual costs of discovering and developing the resources discussed in this thesis will not be known until the actual drilling is done. The purpose of this study, therefore, is not to predict these costs accurately, but rather to present two models that may give some insight into the ranges of these costs.

6.2 Suggestions for Future Research

The model based on historical data uses data from the years 1967-1979. It would be useful to incorporate data from later years into the model and repeat the study. One could examine changes in the historical curves (Figures 4.7-4.10) as well as changes in the final marginal and

average cost curves (Figures 4.11 and 4.12). Another study could be done by adding a technology forecasting model in order to improve upon the Historical Model.

One way to improve the model based primarily on PGC estimates is to incorporate a Delphi approach into the gathering of the PGC estimates. This would result in better PGC estimates and therefore better results. Another improvement would be to ask for more estimates from the PGC. For instance, more information about field size distributions would eliminate the need for using the log-normal distribution to produce the field size distributions.

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