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FINAL DRAFT

GURC REPORT NO. 165

NATURALLY OCCURING CARBON DIOXIDE SOURCES IN THE UNITED STATES -- A GEOLOGIC APPRAISAL AND ECONOMIC SENSITIVITY STUDY OF DRILLING AND PRODUCING CARBON DIOXIDE FOR USE IN ENHANCED OIL RECOVERY

by

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Prepared for:

United States Department of Energy
Division of Oil, Gas and Shale Technology
Washington, D.C. 20545

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FOREWORD

This report was prepared under US-DOE Contract No. EX-76-C-01-2025.

It fulfills the scope and objectives of work defined in Task XXI, Subtask (C), "Assist Pullman-Kellogg on its carbon dioxide availability and cost study by providing geologic, engineering and field application assistance."

Responsibility for the interpretations and opinions expressed herein rest with the Gulf Universities Research Consortium as contractor to the US-DOE for an independent study and appraisal of the subject resource.

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We wish to acknowledge the invaluable assistance provided by personnel in both the public and private sectors in the compilation of this report. Special thanks go to D. Rogers and the Colorado State Oil and Gas Conservation Commission, J. Ramey and the New Mexico Oil Conservation Commission, Ed Looper and the Mississippi State Geological Survey, and the Mississippi State Oil and Gas Board.

We would like to express our appreciation to the many industrial experts who not only furnished data, but provided invaluable advice, suggestions and review in support of this project.

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EXECUTIVE SUMMARY

This report was prepared for the Department of Energy in support of Pullman Kellogg's efforts to evaluate the overall potential supply and cost of obtaining carbon dioxide for enhanced oil recovery. This report specifically examines naturally occurring subsurface carbon dioxide.

The purpose of this report is two-fold:

1. to estimate the size of natural subsurface CO_2 reserves, and
2. to investigate the effect of price variation on the profitability of producing naturally occurring CO_2.

Several of the areas containing significant natural CO_2 deposits are still undergoing evaluation following initial exploration programs. Thus, the suites of geological and reservoir data required for determining gas volumes and production rates, such as permeability, porosity, net pay, areal extent and pressure were sometimes incomplete or derived from sparse well control. Readers are cautioned that much of the material presented herein will require sustained production history and increased well control for confirmation.

The following economic projections, while utilizing the best available data, are sensitivity studies designed to bracket a possible range of produced CO_2 costs. Economic projections are complicated by the legal implications surrounding financing, royalties, appropriate rates of return and environmental difficulties, as well as by geologic and engineering uncertainties.

Projections of the potential natural supply, costs of drilling and producing, and potential demand for naturally occurring carbon dioxide are presented herein for several areas of the United States.

1.0 INTRODUCTION

For several years miscible flooding has been investigated as a possible means of recovering additional oil from watered out reservoirs. Data from laboratory tests and field pilots appear to confirm the applicability of carbon dioxide as a material capable of recovering additional quantities of oil from such reservoirs. Preliminary estimates* cite 5-10 billion barrels of possible enhanced oil recovery by CO_2 flooding, which may require on the order of 40-50 Tcf of CO_2.

Current research and field tests should help resolve some of the uncertainties concerning the process so that the economics of CO_2 miscible flooding can be appraised more reliably. Two critical questions, however, remain to be resolved:

.. will the large volumes of CO_2 required be available?

.. at what price will they be available?

Pullman Kellogg**, under contract to the Department of Energy, with assistance from GURC, has investigated possible sources of CO_2 for enhanced oil recovery application. Two types of sources were evaluated: naturally occurring and

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*Enhanced Oil Recovery Potential in the United States, Office of Technology Assessment, Congress of the United States, January 1978.

**Sources and Delivery of Carbon Dioxide for Enhanced Oil Recovery, 1978, Contract No. EX-76-C-01-2515.

plant. An attempt was made to determine the quantities of CO_2 available, purity, and costs of obtaining and transporting the gas.

This project may be viewed as having three elements: (1) gathering of CO_2 at the "source", (2) purification and transportation of the CO_2, and (3) injection by field operator(s) in candidate reservoir(s).

For naturally occurring CO_2 it was agreed that GURC would assist Pullman-Kellogg by locating and characterizing the major source areas and estimate costs to drill and produce the CO_2 into a trunkline. Kellogg provided investment and operating cost estimates for compression, treatment, and transportation.

GURC's overall responsibility included three tasks:

.. Evaluation of reservoir rock properties and gas composition for each potential CO_2 source,

.. Estimate of costs for drilling and producing naturally occurring CO_2 reservoirs,

.. Field utilization of CO_2 in EOR projects.

2.0 DATA BASE SUPPORT

A Carbon Dioxide Data Base was constructed early in the project to facilitate data acquisition, storage, and analysis. The Bureau of Mines Helium Division has collected over 11,500 analyses of gas samples from oil and gas wells since 1917 and reported them in its publication, "Analysis of Natural Gases, 1917-74". GURC obtained a magnetic tape of this data and the 1975 and 1976 updates. All sample data with carbon dioxide content greater than 5 mole percent were stripped from this tape. The data were edited for errors, and numerous records were amended and supplemented with additional data to compile the final version of the CO_2 Data Base*.

*This Data Base is available from the Office of Information Systems at the University of Oklahoma.

3.0 ORIGINS OF CARBON DIOXIDE

Large concentrations of high purity, naturally occurring subsurface carbon dioxide are located in at least four geographic provinces of the United States. Central Mississippi, West Virginia, the Delaware-Val Verde Basin of West Texas and several locations in the Rocky Mountains contain gas deposits with high concentration of carbon dioxide.

Previous studies by numerous researchers, including Lang (1959), Picard (1962), and Hitchon (1963), have investigated subsurface carbon dioxide. Several theories explaining the origin and emplacement of carbon dioxide in these deposits have been suggested:

1. By-product following metamorphism of host carbonates by igneous intrusives.
2. Biogenic alteration of organic matter.
3. Juvenile origin from basement rocks.
4. Direct contribution by gases associated with igneous intrusives.

Lang concluded, after studying C^{13}/C^{12} isotope ratios from subsurface carbon dioxide samples, that the primary mechanism for the generation of carbon dioxide is the breakdown of marine carbonates, especially dolomites, after contact by igneous intrusives.

Picard's work in the Four Corners area also favored carbon dioxide generation by alteration of marine carbonates.

Although Picard suggested the bulk of the carbon dioxide in the Four Corners Area was generated by metamorphism of country rock, a smaller portion of the carbon dioxide was ascribed to "environmental" processes, involving the decay of organic matter.

Hitchon (1963) reported carbon dioxide, when present with over 40 percent natural gas, is probably biogenic in origin, while deposits with extremely high concentrations of carbon dioxide are probably derived from metamorphism of carbonates.

In West Virginia, the mixture of hydrocarbons, nitrogen, and carbon dioxide tends to support the theory of biogenic origin for that area's subsurface carbon dioxide.

Work by Lang, Hitchon, and Picard supports the theory of emplacement of carbon dioxide in Rocky Mountain deposits by igneous intrusive alteration of marine carbonates. Although other modes of generation may contribute, this appears to be the principal means of generation. Both prerequisites for carbon dioxide generation by metamorphic contact, marine carbonates and evidence of substantial igneous activity, are usually present in the areas containing high purity carbon dioxide deposits.

A similar mode of occurrence may be postulated for carbon dioxide deposits in the Jackson Dome area. Thick sections of Jurassic marine carbonates are present in conjunction with previous local tectonic activity around the Jackson Uplift.

Deposits of carbon dioxide in the Ordovician reservoirs of West Texas range from 40 to 98 percent carbon dioxide. A combination of biogenic alteration and generation by igneous intrusion into marine carbonates may help explain the range in carbon dioxide content in these reservoirs.

3.1 Statistical Analysis

To facilitate an understanding of the relationships between subsurface carbon dioxide, associated gases, and the geologic environment, a comprehensive statistical analysis was performed. Data recorded in the Bureau of Mines Analyses of Natural Gases, 1917-1974, and the 1975 and 1976 updates were analyzed by computer under subcontract by Daniel Analytical Services.

The result of this effort, entitled "Natural Occurrences of Carbon Dioxide - Comprehensive Analysis" and identified as Appendix A in this report, presents several correlations which may provide further insight into the origins of subsurface carbon dioxide.

Figure 1.3.2 of Appendix A shows carbon dioxide percentage versus frequency and cumulative frequency distributions. Evidence of a bi-modal distribution of samples in the curves suggests two possible populations of carbon dioxide occurrences. As illustrated in Figure 1.3.2 the majority of analyzed samples contain less than 5 percent carbon dioxide, with another small but significant cluster of samples containing from 80 to 100 percent carbon dioxide.

Small quantities of less than 5 percent carbon dioxide are often associated with methane in natural gas deposits, as indicated in Figure 1.5.5. Numerous researchers including Farmer (1966) and Salisbury (1965) have linked small percentages of carbon dioxide to biogenic alteration of organic matter and hydrocarbons. Hitchon (1963) suggested carbon dioxide, when associated with a methane fraction greater than 40 percent, was derived biogenically.

The discussion in Section 1.5.13 of Appendix A examines the tendency of samples with high percentages of carbon dioxide to be associated with nitrogen, argon and helium. Gas seeps analyzed from areas with recent volcanic activity are known to contain high concentrations of carbon dioxide and nitrogen, with minor quantities of argon and helium.

These plots lend support to the theories advanced in Section 3.0, whereby small percentages of CO_2 associated with methane are generated as a result of biogenic degradation of hydrocarbons or organic matter. Deposits with higher purity CO_2, greater than 80 percent, are probably derived from igneous intrusives, either from thermal degradation (Lang, et al) with host carbonates or as direct eminations from an igneous body. CO_2 present in gases with large methane and CO_2 fractions, as in West Virginia and West Texas, may be the result of both organic and inorganic processes.

4.0 SOURCE DELINEATION

Initial delineation of areas containing potential reserves of CO_2 was conducted using the gas quality and reservoir characteristics data in the CO_2 Data Base.

The regions considered include West Virginia, the Jackson Dome area in Mississippi, the Delaware-Val Verde Basins in West Texas, and 9 sub-areas of the Rocky Mountains, as follows:

- Southwest Colorado, McElmo Dome area
- South Central Colorado, Sheep Mountain area
- North Central Colorado, North Park Basin
- Northeast New Mexico, Sierra Grande Arch area
- Northwest New Mexico, San Juan Basin
- Central Utah, Farnham Dome area
- Central Utah, Gordon Creek area
- Southeast Utah, Paradox Basin
- Wyoming, Sweetwater and Uinta Counties area

Gas compositions in the above areas are varied.

Table 1 briefly characterizes the gas compositions, estimated productivity, and pressures of the more significant CO_2 source areas.

The Rocky Mountain sub-areas generally contain CO_2 of 85 mole percent or greater, with a few mole percent methane and/or nitrogen as contaminants.

Gas sampled from the Smackover and Norphlet trends in the Jackson Dome area contain CO_2 concentrations from 70-99 percent and is associated with considerable percentages of H_2S in some localities. Commercial hydrocarbon production occurs in the downdip Smackover and Norphlet with lower concentrations of CO_2 reported.

Gas containing CO_2 in West Virginia ranges from 10 to 83 percent CO_2 and is associated with a methane fraction from 40 to 80 percent. Small percentages of nitrogen are usually present.

TABLE 1

AREAS REPORTED TO HAVE SIGNIFICANT CO_2 DEPOSITS

State	Field/ Location	Gas Composition Mole Percent	Productive Stratigraphic Units	Expected* Sustained Deliverability MMcfd	Expected Range of Shut In Wellhead Pressures PSIG	Expected Range of Initial Flowing Wellhead Pressures PSIG	Expected Well Depths Feet
COLORADO (Southwest)	McElmo Dome Area, Dove Creek; Montezuma and Dolores Co's.	>96% CO_2 Balance N_2	Leadville, Elbert	3-12	2200-2800	600-850	6000-8000
COLORADO (South Central)	Sheep Mountain Area; Huerfano Co.	96-99% CO_2 Balance N_2, CH_4	Dakota, Entrada	3-12	700-1100	200-700	3400-7000
MISSISSIPPI (Central)	Jackson Dome Area Rankin & Madison Cos.	70-99% CO_2 Many Wells >98% CO_2 May Contain From Trace to 10% H_2S	Smackover, Norphlet	4-16	4000-6500	2000-4000	12000-17000
NEW MEXICO (Northeast)	Harding, Union, Mora, Colfax Cos.	92-99.7% CO_2 Balance N_2	Triassic-Santa Rosa Permian-Glorieta, Tubb	.1-2	250-700	50-500	1500-2800
UTAH (Central)	Gordon Creek Area; Carbon Co.	91-99% CO_2 Balance N_2, CH_4	Sinbad, Coconino	NA	3900-4200	NA	11000-12000
UTAH (Southwest)	Farnham Dome Area; Carbon Co.	98% CO_2	Navajo, Sinbad, Kaibab	NA	1000-1500	NA	2800-5000
WEST VIRGINIA (South Central)	Fayette & Kanawha Cos.	20-80% CO_2 Balance N_2, CH_4	Tuscarora	.1-2	1800-2900	NA	6000-9000
WYOMING (Southwest)	Church Buttes Area; Uinta & Sweetwater Cos.	83-86% CO_2 2% H_2S Balance N_2, CH_4	Madison	2-6	NA	Low	18000-19000

*Highly speculative; requires sustained production history for confirmation.

5.0 SELECTION CRITERIA FOR DETAILED STUDY

Three criteria were established to determine which of these source areas warranted detailed reservoir and economic evaluation:

(1) reserves apparently sufficient for pipeline consideration,

(2) proximity to miscible flood candidate reservoirs, and

(3) evidence of strong industry interest.

On this basis four areas were chosen for further geologic, reservoir, and economic analysis:

.. McElmo Dome area, southwest Colorado,

.. Sheep Mountain area, south central Colorado,

.. Northeast New Mexico, and

.. Jackson Dome area, Mississippi.

These areas, each representing a unique geologic environment and posing varying drilling and production conditions, are reasonably representative of the range of expected naturally-occurring CO_2 sources.

6.0 RESERVOIR CHARACTERIZATION METHODOLOGY

Reservoir rock properties such as permeability, porosity, effective net pay, bottom hole pressure, and temperature are critical parameters for estimating original gas in place (OGIP) and sustained gas deliverability. Detailed site specific reservoir description and well test data for naturally-occurring carbon dioxide are not readily available in the public domain. Thus, visits were made to state geological and regulatory offices to obtain well data from records available for public inspection.

In cases where local reservoir data were unavailable, reservoir properties were estimated from regional data. Bottom hole temperatures were computed from the AAPG Geothermal Gradient Map of North America*. Initial reservoir pressures were estimated from pressure versus depth plots using regional data available in the CO_2 Data Base. To assess the influence on OGIP of variations in porosity, net pay and gas saturation, several sensitivity studies were conducted.

6.1 Reservoir Analysis Methodology

For each area studied, the OGIP (pure CO_2) for one acre-foot of pore space was calculated as a function of

*AAPG Geothermal Gradient Map of North America, AAPG and USGS, prepared by the Geothermal Survey of North America Subcommittee of the AAPG Research Committee.

initial BHP, temperature and Z factor using the relation:

$$G = T_{sc}P_i/P_{sc}Z_iT_i \times 43{,}560^*$$

OGIP per acre-foot of pore space was plotted versus depth, as illustrated in Figure 1. As shown, the OGIP/acre-foot exhibits a rapid increase with depth down to approximately 6,000 feet. Below 6,000 feet OGIP/acre-foot increases minimally.

Each of the geologic areas of interest was characterized by the depths at which CO_2 occurs and the anticipated range of net pay thickness.

Effective net pay was estimated after analysis of the perforated interval, core analyses, and subsurface log interpretation. In each area, distribution of net pay in wells drilled to date approximates log normal. The 10th, 50th, and 90th percentile were assumed representative of distribution of pay in the "worst likely", "modal", and best likely" wells, respectively, when each reservoir or producing area is fully developed.

Porosities were estimated from core data and compensated neutron, sonic and density logs.

In a given reservoir the OGIP per 640 acre-spaced well is a function of the gas saturation-porosity product (SgØ) and net pay. As shown by Figure 2, in a typical 8,000 foot

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*See Definition of Symbols.

FIGURE 1
OGIP vs. DEPTH

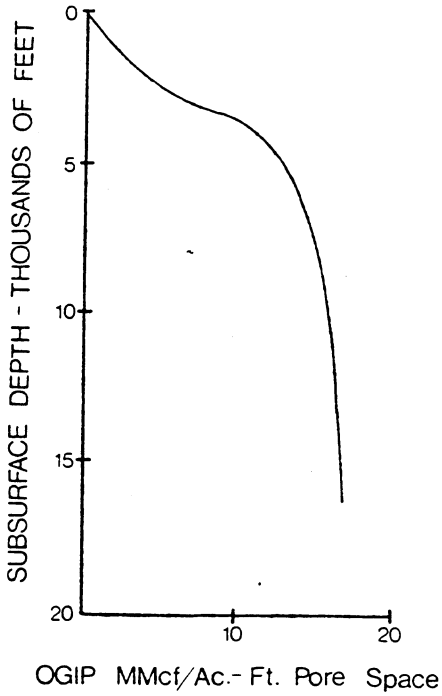


FIGURE 3
Recovery Efficiency vs. Depth
for a Wellhead Abandonment
Pressure of. 400 psi

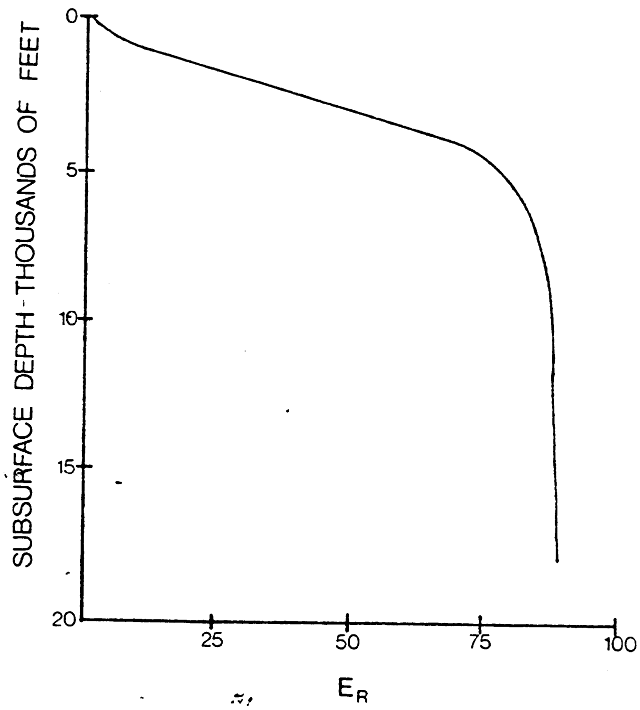
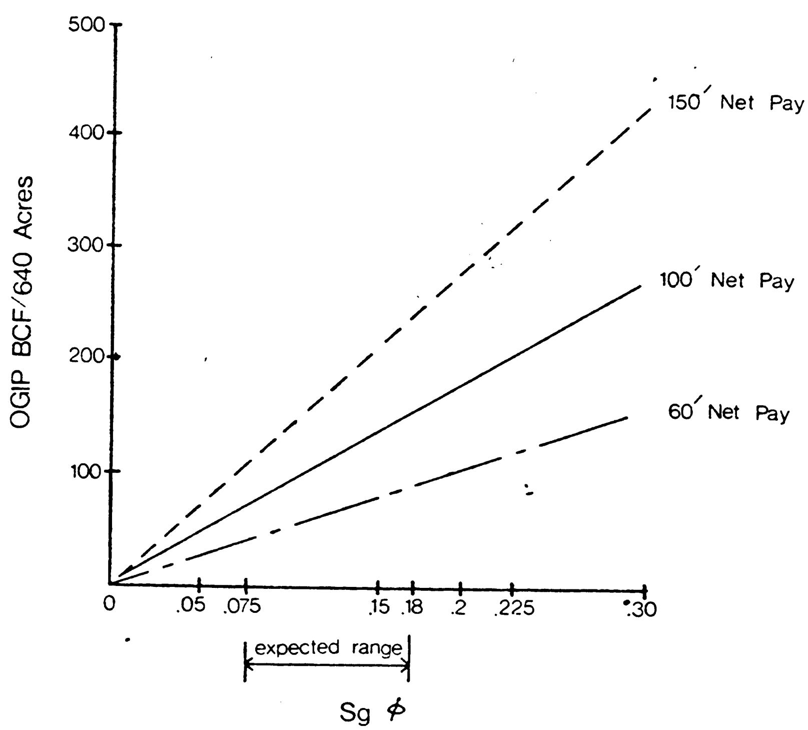


FIGURE 2
OGIP vs. Gas Saturation X Porosity
for Varying Thicknesses for
a Reservoir at a Depth of 8,000 feet



deep reservoir, the OGIP per 640 acre-spaced well could vary from about 25 to 230 Bcf, for net pay thicknesses of 60 to 150 feet and reasonable values of Sgø for commercial wells.

It is evident that, in each area, there will be variation in reservoir rock quality and, thus, in OGIP and deliverability. We have elected to represent the anticipated variation of each area as the performance of a set of wells of varying quality. Thus, in each area, OGIP has been estimated for a "best likely well", a "modal well", and a "worst likely well", considering observed variations in net pay, porosity-gas saturation product, and bottom hole pressure.

Field test data, including flow rates, flowing tubing pressures and drawdowns were then analyzed. For each area a range of average sustained deliverabilities and flowing tubing pressures was estimated. Production was assumed to be by depletion drive for all areas investigated.

Estimated recovery efficiencies for each area were calculated from abandonment pressures determined after discussions with industry personnel. In a depletion drive reservoir, recovery efficiencies are a function of initial BHP and abandonment pressures as indicated by the following equation:

$$E_R = 1 - \frac{P_a}{Z_a} \Big/ \frac{P_i}{Z_i}$$

As shown in Figure 3, recovery efficiency, calculated for a wellhead abandonment pressure (P_a) of 400 psi, increases rapidly with depth to about 88 percent at 4,000 feet, then stabilizes. Wellhead abandonment pressures for each area were converted to bottom hole abandonment pressures to account for regional variations in depth. Actual abandonment pressures in any area will be a function of compression intake pressure and drawdown.

For each area, a set of well "models" spanning the probable variation in rock quality; OGIP, and sustained productivity was created. Flowing bottom hole pressure decline curves were constructed as a function of cumulative gas produced, allowing easy correlation with varying flow rates and recovery efficiencies. Individual well economics on these representative well models were then calculated.

7.0 ECONOMIC ANALYSIS METHODOLOGY

A simple economic "model" was constructed using estimated investment and operating costs and reservoir sensitivity studies as input. The objective was to develop a range of per-Mcf costs for CO_2, dehydrated and delivered to an interstate pipeline at specified pressures for each of the analyzed areas.

In an effort to estimate the probable costs of drilling CO_2 wells, cost data were collected on typical natural gas wells through communication with the AAPG, AGA, API, and numerous industry personnel. Communication with industry personnel indicated natural gas well cost data were insufficient for accurate estimation of CO_2 well costs. Reported drilling costs for CO_2 wells in the areas of interest were found to be substantially higher than originally anticipated. These higher drilling and completion costs are explained in part by the following:

- Road and site costs, rugged topography,
- Remote locations; distances from traditional oil field service and supply centers,
- Problems with hole collapse in shale formations, requiring high cost drilling fluids (oil base muds),
- Drilling with air to limit formation damage in low permeability zones,
- Encountering thick sections of hard igneous rock,

.. Large casing and tubing sizes,

.. Highly corrosive nature of CO_2 requiring special coatings and stainless steel wellheads,

.. Presence of archeological sites and required studies,

.. High cost directional drilling to deviate holes for topographic and environmental reasons,

.. Requirement for buried gathering lines.

Drilling costs, thus, are highly site specific and regionally variant due to topographic and geologic variations. Completed well costs herein were based on those reported by operators in each area. A dry hole "cost" was estimated in each area, based on historical dry hole ratios and estimated intangible well costs, for both exploration and development drilling phases.

Lease bonus fees and estimated probable operating costs for CO_2 wells were obtained from industry personnel. Investment and operating costs for surface processing equipment were supplied by Pullman Kellogg. For all areas other than New Mexico, surface equipment design was based on 50 MMcfd capacity "modules" composed of a dehydration, compression, hydrate inhibiting, and gathering system. For the New Mexico area economic analysis, compression system investment and operating costs were omitted, since compression was assumed to be undertaken by the pipeline.

Each well was assigned a pro rata expenditure for surface processing equipment based on its production contribution to the 50 MMcfd module. The compression system, based on pipeline delivery pressure of about 2000 psi, required one stage of compression for flowing wellhead pressures between 565-2000 psi, two stages for flowing pressures of 185-565 and three stages for flowing pressures of 50-185. Actual surface processing costs may vary considerably if two-phase flow is encountered at the surface.

Discounted cash flow economic evaluations considering lease bonus, exploration cost, drilling and development expenses, gathering, treating, and compression costs, and probable time delays (as discussed below) were calculated using a commercial computer package*.

Earning power was calculated on an after Federal income tax basis, with a tax rate of 48 percent and no depletion allowance for all cases. A 12.5 percent royalty was assumed.

Economics were calculated in constant value 1978 dollars and assume that inflation in investment and operating expenses will not exceed inflation in gas price.

In the McElmo Dome and Sheep Mountain areas a time span of five years was selected as probably representative of the length of time between initial lease expenditures and first production and delivery of the CO_2 to the consuming EOR operator. The time period from initial lease bonus expenditure until CO_2 enters the pipeline in year 6 is shown in

*POGO (Profitability of Oil and Gas Opportunities, PSI Energy Software).

Figure 4. It provides for exploration and proving of reserves in years 2-4, building of the pipeline in years 3 through 4, and development drilling and installation of surface processing equipment in year 5. Production of CO_2 was assumed to commence in year 6 and was sustained until the calculated reserves were produced.

For the Jackson Dome and northeast New Mexico areas an additional year was added for the development phase. This allowed major capital expenditures for development drilling and surface processing equipment to be budgeted over years 5 and 6. Initial CO_2 production begins in year 7.

This time lag between initial expenditures and initial CO_2 production, as would be expected, had a negative impact on present value economics.

At variable times, dependent on each well's pressure decline behavior, additional compression stages may be introduced, and are represented by X. Economics were considerably affected by the time table for compression stages in all areas.

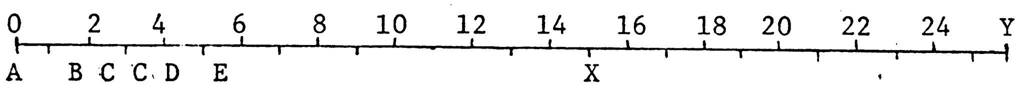
All economics were calculated based on well spacing of 640 acres per well. Ultimate well spacing may be greater or smaller depending on actual well and reservoir performance and cost experience.

Results presented in the following sections must be considered speculative and depend on sustained production history for confirmation.

Figure 4

TYPICAL TIME FRAME FOR USE IN PRESENT VALUE ECONOMIC

EVALUATION OF CO_2 EXPLORATION-PRODUCTION PROGRAM



EVENT	YEARS	COMMENTS
A	1	Lease bonus expenditures and geologic-geophysical evaluation begins.
B	2-4	Exploration commences and reservoirs defined
C	3	Pipeline construction - initiated
C	4	Pipeline building continues
D	5	Development drilling; surface processing equipment and gathering system installed
E	6	First CO_2 produced into pipeline and injected by EOR operator
	6-Y	Variable years of production until reserve is produced
X	Variable	Years in which additional compression stages may be required

8.0 IN DEPTH ANALYSIS OF PRIMARY CO_2 SOURCE AREAS

The locations of major CO_2 productive areas, including the four areas examined in depth in this report, are identified in Figure 5. Brief summaries of the potential reserve, gas purity, average deliverability per well and expected field capacity are included for each of the areas.

Additionally, areas containing significant oil reservoirs amenable to CO_2 flooding are identified on Figure 5. Estimates of potential oil recoverable by CO_2 flooding, CO_2 requirement in Mcf per barrel recovered, and potential "net new" CO_2 requirements are included for three areas containing significant candidate reservoirs.

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8.1 Southwestern Colorado - McElmo Dome Area

8.1.1 Geologic Introduction

Exploration for CO_2 reservoirs in southwestern Colorado has focused on the McElmo Dome area in Montezuma County and the Doe Canyon-Dove Creek area of Dolores County. The two CO_2 productive zones in this portion of the Paradox Basin are the Leadville (Mississippian) and the Ouray (Devonian), found at depths of 6500-9000 feet subsurface. Both formations are composed of limestones and dolomites, with the Leadville indicating greater productivity.

Analysis of produced gas from both formations indicates a composition of 96-99 percent CO_2 with 1-4 percent nitrogen.

Exploratory wells, identified on Figure 6* appear to have delineated a productive area in the southern portion of the structure. Wells identified as 18, 22, 25, C, D, E, and F reportedly were completed as potential producers. Data is unavailable regarding CO_2 productivity in well numbers 16 and 27. Wells 17, 23, 24, 26 and 29 were reportedly plugged as dry holes. Productive area at the southern end of the structure is estimated to be roughly 100 sections, or 64,000 acres.

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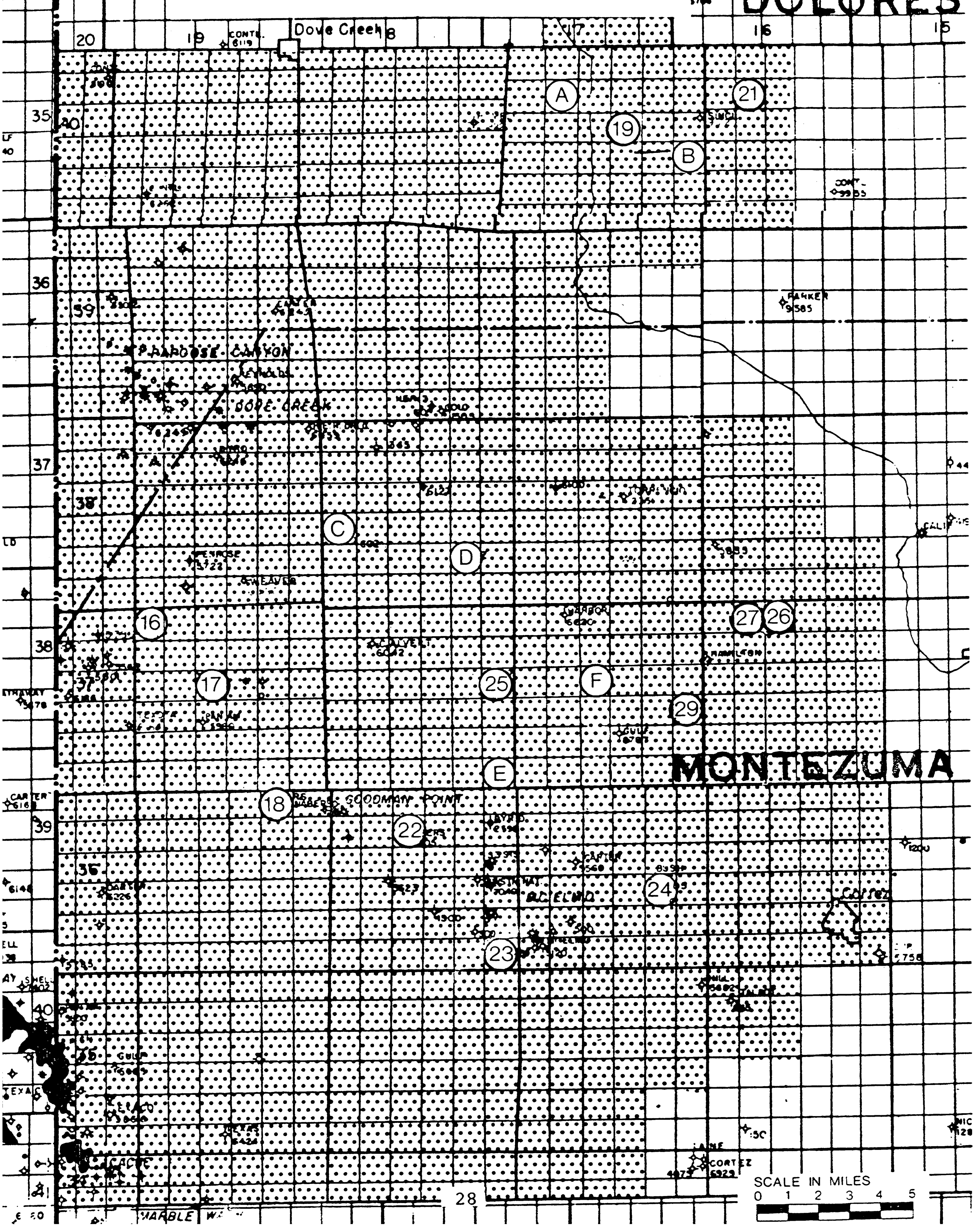
*Location maps referred to in this and subsequent sections were adopted from maps provided by McNeill in his report, "A Study of the Natural Carbon Dioxide Occurrences in a Four-Region Area of the United States". Stippled areas on these maps are referred to by McNeill as follows, "... Areas of interest were outlined on the basis of lease ownership, unit outlines or anticipated reservoir configuration ...".

Figure 6
WELL IDENTIFICATION - McELMO DOME AREA



Although at least one productive well, identified as well A on Figure 6, has been completed in the northern Dove Creek portion of the structure, control is insufficient for accurate reservoir delineation in the northern area. Of the remaining wells, well 19 is apparently dry, while well B reportedly encountered a faulted section in the Mississippian and is being sidetracked for recompletion. No data is available on well 21.

8.1.2 Reservoir Analysis

Data on exploratory CO_2 wells in the McElmo area were acquired from public records in the office of the Colorado Oil and Gas Commission, Denver, Colorado. Data obtained include well completion reports, back pressure tests, core analyses, and electric logs. Communication with various industry personnel provided insight into geologic controls determining productivity during evaluation of the area.

Net pay thicknesses were determined by interpretation of core analysis reports, compensated neutron logs, formation density logs, and perforation records in completion reports.

Porosity and permeability values were estimated from logs and core analysis reports. Gas saturation was estimated to be 80 percent.

Reservoir temperatures and initial bottom hole pressures were derived from regional data available in the CO_2 Data Base.

It is anticipated that with one stage of compression bottom hole abandonment pressures of around 1200 psi can be achieved. This would result in recovery efficiencies on the order of 65-70 percent OGIP.

Assuming the reservoir has an areal extent of 100 productive sections, and from 75 to 100 feet net pay thickness with approximately 7 percent porosity, OGIP is estimated to be from 3.8 to 4.9 Tcf. Ultimate recovery (65-70% RE) might range from 2.6 to 3.4 Tcf.

8.1.3 Well Analysis

Calculated absolute open flows (CAOF) for individual wells exhibit wide variation, reportedly ranging from 17 to 115 MMcfd. Sustained deliverability is expected to be significantly less than CAOF. Estimate of probable sustained deliverability was complicated by complex reservoir geology and evidence of substantial rock heterogeneity. Core analyses indicate two possible controls on reservoir porosity and permeability. Both fracture and matrix porosity and permeability have been reported. Fracture controlled permeability, frequently found in carbonate rocks, often results in a rapid initial decline of wellbore pressures and flow rates. Following the initial decline, pressures and flow rates tend to stabilize at low levels for long periods. Matrix controlled permeability, on the other hand, allows a more "typical" wellbore pressure decline and, for the same initial CAOF, would tend to sustain higher flowing rates and pressures than fracture controlled permeability.

Sustained well deliverabilities are anticipated in the 3 - 12 MMcfd range, with flowing wellhead pressures from 600-850 psi. If flowing wellhead pressures in this range can be achieved, then only one stage of compression should be required for delivery into a pipeline at around 2000 psi.

8.1.4 Economic Analysis

Sensitivity of earning power to variation in sustained flow rate and reserve per well was evaluated considering three rate cases and three reserve cases. Thus, the following "model" wells were created; a "worst likely well" producing 3 MMcfd, a "modal well" producing 6 MMcfd, and a "best likely well" producing 12 MMcfd. Economics of each of the model wells was examined for per well reserves of 15 Bcf, 30 Bcf, and 60 Bcf.

Capital expenditures for each well "model" are summarized in Table 2. The completed well cost, pro rata dry hole cost, lease bonus fees, and gathering system cost were considered independent of the production rate and were held constant for all three well "models".

TABLE 2

INVESTMENT - McELMO DOME, COLORADO

FLOW RATE	COMPRESSION B.H.P. REQUIRED	COMPRESSION* INVESTMENT IN $	DEHYDRATION COST IN $	WELL COST IN $	DRY** HOLE COST (PRO RATA)	GATHER-*** ING SYSTEM COST IN $	TOTAL[I] $
3 MMcfd	387	209,290	24,000	750,000	112,500	250,000	1,345,790
6 MMcfd	774	418,580	48,000	750,000	112,500	250,000	1,579,080
12 MMcfd	1,548	837,150	96,000	750,000	112,500	250,000	2,045,650

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*Based on $540.8/BHP.

**Pro rata dry hole cost assigned on intangible investment for 25 dry wells per 75 producing wells.

***Gathering system based on 1 mile of 4" S.S. quality pipe. Also includes $65,000/well for hydrate control.

[I]Total excludes $25,600/640 acres lease fee.

Each producing well was burdened with a pro rata share of the total intangible cost of dry holes and lease bonus. Based on observed experience in the area, a dry hole ratio of 1 in 3 during exploration drilling was utilized. The ratio was assumed to be 1 in 4 during development drilling.

Cost estimates for surface processing equipment were based on 50 MMcfd modules, and investment for compression and dehydration equipment for each well was prorated based on each well's share of the entire module. As noted previously, one stage of compression was estimated to be adequate to achieve recovery efficiencies in the range of 65-70 percent.

Total investment (1978 dollars) for a 3 MMcfd well was estimated at \$1.4 million, for a 6 MMcfd well at \$1.6 million, while a 12 MMcfd well's estimated cost was \$2.1 million. The substantial increase in investment as production capacity increases is proportional to increased compression horsepower required. Operating costs utilized are indicated in Table 3.

The investment schedule assumes expenditures will occur over a 5-year period prior to actual CO_2 production. Discounted cash flow rates of return (DCF-ROR) calculated assuming gas prices of \$.25/Mcf and \$.50/Mcf are presented in Figures 7 and 8.

TABLE 3

OPERATING COSTS - McELMO DOME, COLORADO

\$/well/month = 300

¢/Mcf for compression from 565 psi - 2000 psi = 7.7

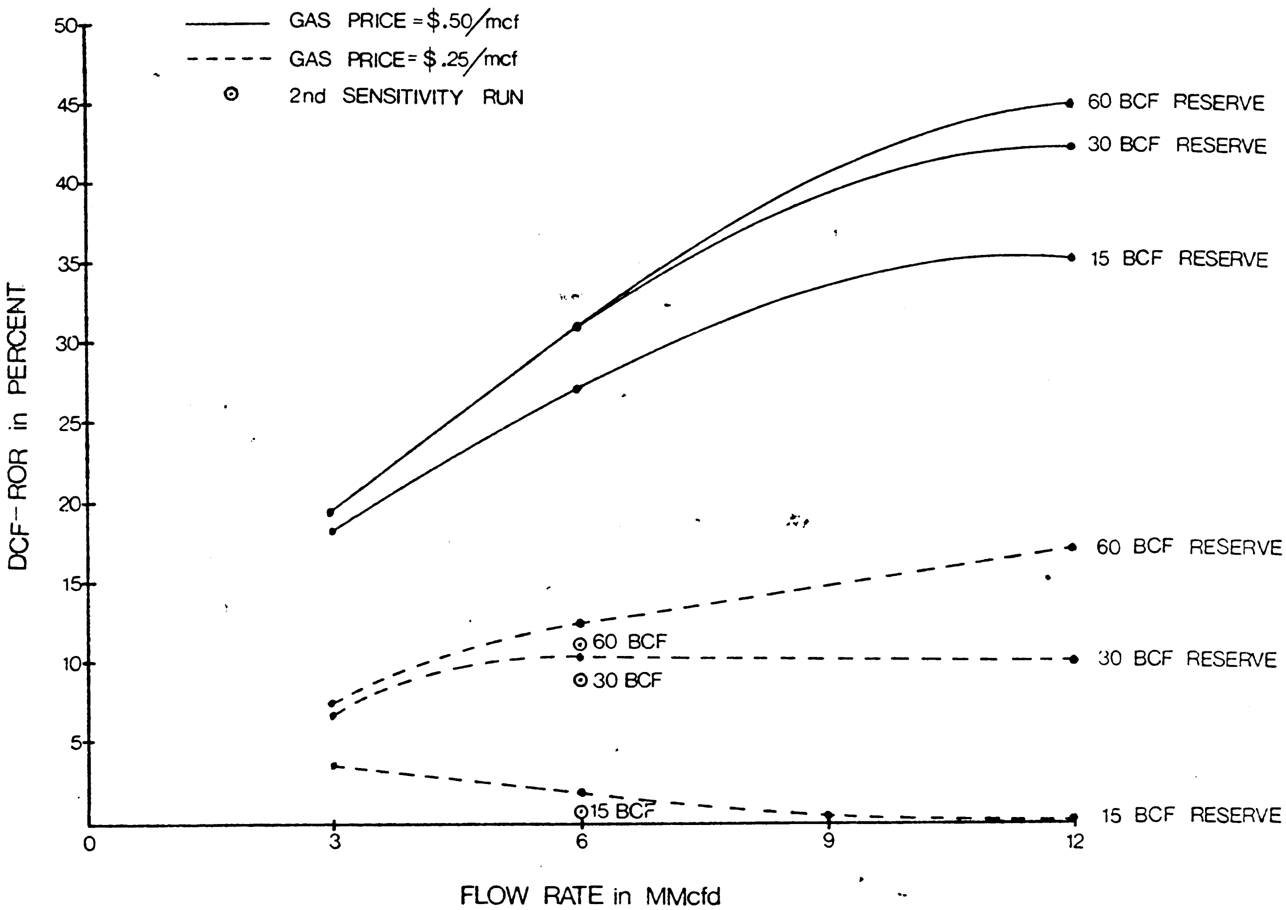
¢/Mcf for dehydration = .53

¢/Mcf for hydrate control = .4

TOTAL COST \$/UNIT = .0863/Mcf

Figure 7

AFIT DCF-ROR vs. FLOW RATE VARYING PER WELL RESERVE AND GAS PRICE
McELMO DOME, COLORADO



In Figure 7, AFIT DCF-ROR is plotted versus flow rate for various gas reserves and prices. At $.25/Mcf, earning power for a well with less than 30 Bcf will be lower at a production rate of 12 MMcfd than at a rate of 6 MMcfd. This phenomenon is attributed to the substantially larger front-end investment required for compression and dehydrating equipment for the higher production rate. The extra investment will pay out only with higher reserves or wellhead prices. Similarly, if a well has a reserve of 15 Bcf or less, a production rate of 3 MMcfd would yield a higher earning power than one of 6 MMcfd.

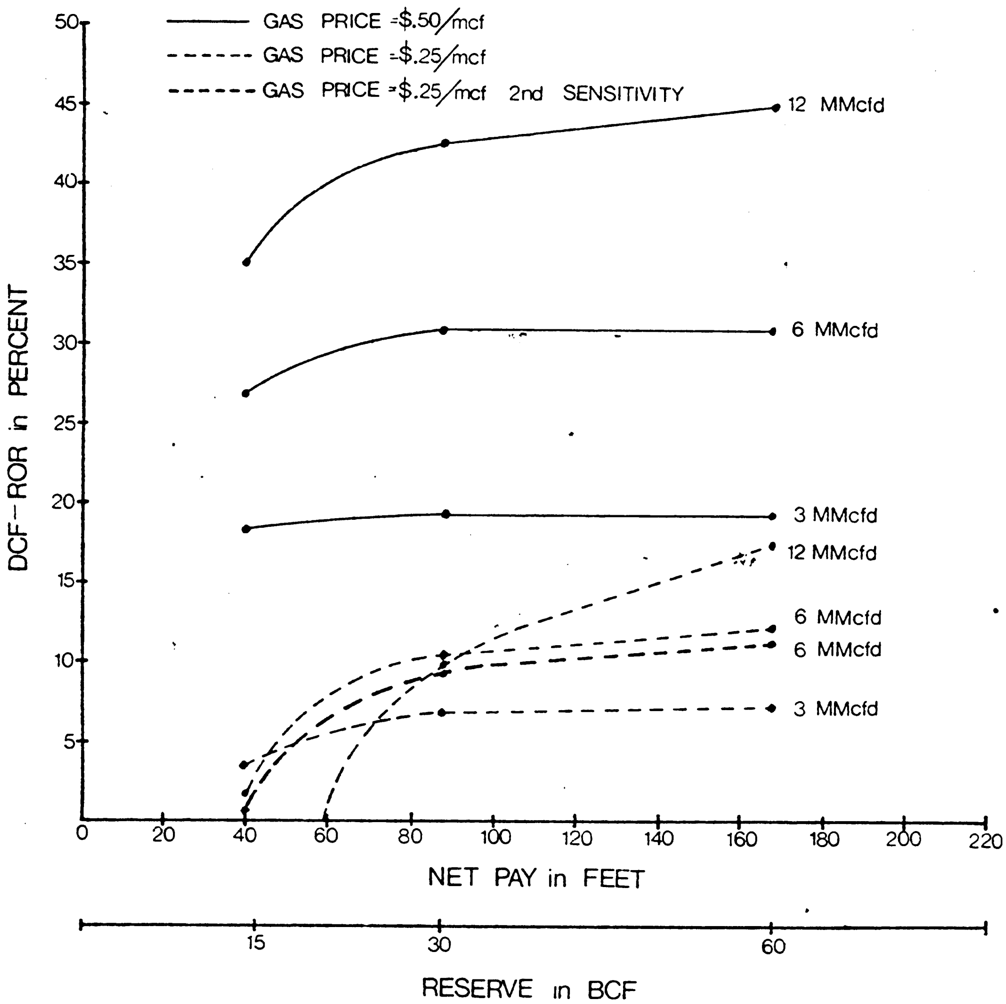
Figure 8 presents the same data as Figure 7, but plots DCF-ROR versus reserve for various flow rates and prices. For a well with 60 Bcf as a reserve, DCF-ROR increases as production rate increases, up to the maximum rate evaluated of 12 MMcfd. However, at $.25/Mcf, as the per well reserve drops to 30 Bcf the DCF-ROR is relatively insensitive to rate above 6 MMcfd.

As per well reserves fall to 15 Bcf the "optimum" rate appears to be less than 3 MMcfd, with additional compression to produce at higher rates apparently being unwarranted.

At a gas price of $.50/Mcf, the additional revenue gained tends to overcome the additional front-end investment, and higher production rates show a positive correlation with increased DCF-ROR at all reserve per well figures.

Figure 8

AFIT DCF-ROR vs. PER WELL RESERVE FOR VARYING FLOW RATES AND GAS PRICE
McELMO DOME, COLORADO



These calculations indicate that because of high front-end expenditures required for compression and surface processing equipment, sustained rate and ultimate gas reserve become critical parameters in determining production economics.

8.1.5 Additional Time Delay-Cost Sensitivity Calculation

The McElmo Dome area development is occurring in an area described as rich in Indian artifacts. Expensive archeological studies reportedly have been performed. Gathering system flow lines may have to be buried throughout the area. Some wells reportedly have been deviated for archeological or environmental reasons. These difficulties are time and capital consumptive for the operator.

A second set of economic analyses was conducted to study earning power sensitivity to variation in capital investment and additional time delay. To account for additional delays incurred in development of the area due to the above factors, the time required for development was increased by one year. To assess the influence of increased overhead, an additional operating cost estimated at 20 percent of the well cost was budgeted over the final two years of development. Capital expenditures for development were allocated over years 5 and 6.

This sensitivity analysis examined a flow rate of 6 MMcfd for the same three per well reserve cases analyzed previously, 15 Bcf, 30 Bcf and 60 Bcf. Results presented in

Figure 7 indicate the additional expenditures and time delays will have only a slight negative effect on earning power.

All McElmo Dome area analyses assumed 640 acre drainage. If the actual drainage area is substantially less, the per well reserves will be proportionately smaller. The above calculations indicate little economic inducement for infill drilling if drainage is less than 640 acres/well. Figure 7 indicates that, depending on wellhead price, the earning power will be particularly affected as per well reserves drop below about 30 Bcf, due to the large capital expenditures required for wells and surface processing equipment.

Recent literature suggests industry is considering a pipeline with a capacity of 300 MMcfd from the McElmo area to West Texas.

For the "modal" reserve case of 30 Bcf per well, a well draining 640 acres with an average sustained deliverability of 6 MMcfd would produce its reserve in 13 years. If 100 sections were productive, then a pipeline demand of 300 MMcfd could probably be met for 25 years.

8.2 South Central Colorado - Sheep Mountain Area

8.2.1 Geologic Introduction

The Sheep Mountain area, located in Huerfano Co., Colorado, is CO_2 productive from two stratigraphic units. The Dakota (Cretaceous), and a smaller reservoir, the Entrada (Jurassic), produce gas composed of 97 to 99.6 percent CO_2 with minor amounts of N_2 and methane present.

The Dakota and Entrada are porous sand bodies forming narrow elongate reservoirs. Core analyses and log data indicate rapid lateral shaling out of both reservoirs. Additionally, in Huerfano County the sands appear to be located on two large structural highs, thus forming combined stratigraphic and structural traps.

Drilling in the area has been considerably more difficult than anticipated. Surface topography is generally rough, creating siting and operational difficulties. Many wells have had to be deviated. Sections of up to 1000 feet of igneous rock have been encountered. Hole collapse problems in the Pierre Shale have necessitated the use of an oil base mud for portions of the drilling.

Dakota and Entrada beds exhibit dips of up to 20 degrees in the area. Evidence of substantial vertical fault displacement has been observed in several wells.

The top of the Dakota is encountered from 3,000 to 8,000 feet subsurface. Gross thickness of the Dakota formation in the Sheep Mountain area ranges from 150-350 feet.

The top of the Entrada is usually found about 300 feet stratigraphically below the Dakota. The Entrada formation exhibits a similar range of gross thickness. The Entrada apparently is a smaller reservoir areally than the Dakota. The Entrada was not analyzed in as great a detail as the Dakota, since initial indications are that Entrada production will not be comingled with Dakota production.

Well numbers 30, 31, 34, 36, 42, 44, 46, 47, 49 and L, identified on Figure 9*, are potential Dakota producers. Well numbers 33, 35, 39, J and M have been reported as dry holes. Data is lacking for wells 32, 41, 45, 48, I and K.

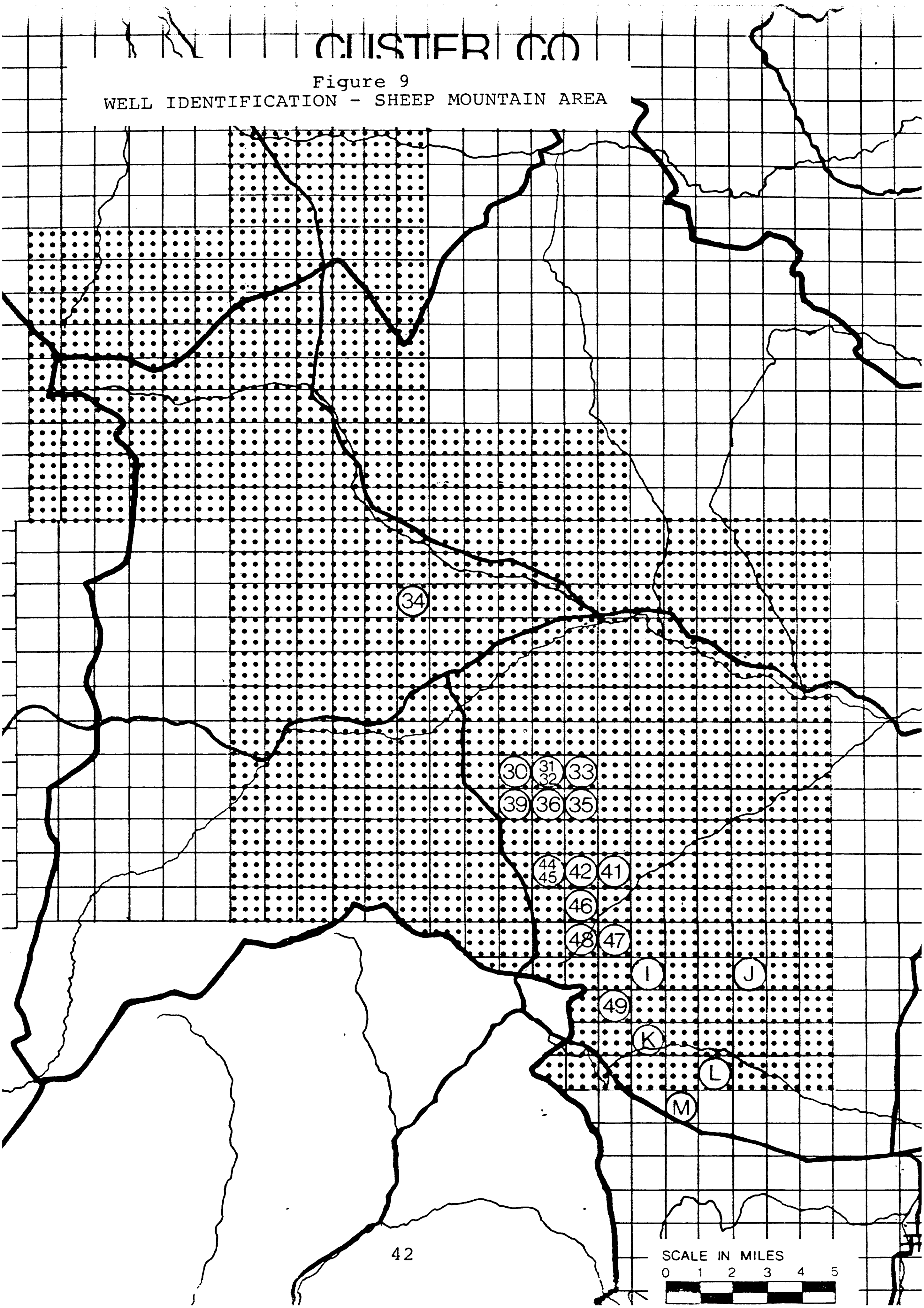
The productive Dakota area on the southern half of the structure appears to have been effectively delineated by exploratory wells. A potentially productive area in the northern portion has not yet been fully evaluated. One well drilled in the northern portion of the structure, number 34 on Figure 9, exhibits good porosity and permeability in the Dakota and appears promising as a CO_2 producer. Available geologic control suggests the Dakota reservoir contains a probable minimum of 25 productive sections, or 16,000 acres and a possible upper limit estimated at around 30 sections or 19,000 acres.

8.2.2 Reservoir Analysis

Reservoir analysis was based on data obtained from public files of the Colorado Oil and Gas Commission offices in Denver, Colorado. Well completion

*Modified after McNeill.

Figure 9
WELL IDENTIFICATION - SHEEP MOUNTAIN AREA



reports, core analyses, and daily drilling summaries provided considerable data and insight into the results obtained in the exploration program. Additional data was obtained from industry personnel.

Variation in net productive pay thickness of the Dakota was determined by analysis of core data, perforation records, and log interpretation.

Porosity and permeability data from available core reports were statistically analyzed to determine distribution and appropriate means. Individual mean porosity values for analyzed wells ranged from 13.3 to 19.6 percent. Permeability means ranged from .35 md. to 497 md.

Bottom hole pressures and temperatures were obtained from completion reports and daily drilling reports. Gas saturation was estimated to be 80 percent.

If productive area of the Dakota reservoir ranges from 25 to 30 sections, with 75 to 125 feet of net pay and an average porosity of 17 percent, OGIP in the Dakota is estimated to be 1.9 Tcf to 3.8 Tcf. Ultimate recovery (65% RE) might range from 1.3 Tcf to 2.5 Tcf.

8.2.3 Well Analysis

Wells reportedly tested at flow rates from 1 MMcfd to 27 MMcfd. Flowing tubing pressures varied from 80 psi to 880 psi. Wells yielding the lower flow rates and tubing pressures reportedly have had wellbore damage, so test results may not reflect their true potential.

Per well average sustained deliverability is estimated to range from 3 to 12 MMcfd. The wells are expected to be produced at sufficient flowing pressures to enable delivery to a pipeline (1500-2000 psi), with only one stage of compression.

Average pressure drawdown between shut in pressure and flowing pressure was estimated from flow test data. Recovery efficiencies were estimated from shut in and flowing bottom hole pressure decline curves as a function of cumulative gas produced. Abandonment was presumed to occur when wellhead flowing pressures required more than one stage of compression for pipeline delivery. Calculations indicate recovery efficiencies on the order of 65 percent of OGIP probably can be achieved with one stage of compression.

8.2.4 Economic Analysis

Average sustained production rates of 3 MMcfd, 6 MMcfd and 12 MMcfd were assumed representative of field wells when development is completed. Earning power sensitivity to these "model" wells was analyzed for per well reserves of 36 Bcf, 70 Bcf, and 137 Bcf. Drilling was assumed to occur on 640 acre spacing.

Capital expenditures for each completed well model are presented in Table 4. The completed well cost, pro rata dry

TABLE 4

INVESTMENT - SHEEP MOUNTAIN, COLORADO

FLOW RATE	COMPRESSION B.H.P. REQUIRED	COMPRESSION* INVESTMENT IN $	DEHYDRATION COST IN $	WELL COST IN $	DRY** HOLE COST (PRO-RATA) IN $	GATHER-*** ING SYSTEM COST IN $	TOTAL[I] $
3 MMcfd	387	209,290	24,000	650,000	128,700	250,000	1,261,990
6 MMcfd	774	418,580	48,000	650,000	128,700	250,000	1,495,280
12 MMcfd	1,548	837,150	96,000	650,000	128,700	250,000	1,961,850

* Based on $540.8/BHP.

** Prorata dry hole cost assigned on intangible investment for 15 dry wells per 30 producing wells.

*** Gathering system based on 1 mile of 4" S.S. quality pipe. Also includes $65,000/well for hydrate control.

[I] Total excludes 75,000/640 acres lease bonus.

hole cost, lease bonus fees, and gathering system cost were considered fixed fees independent of production rate.

Producing wells were assigned, on a pro rata basis, the total intangible cost of dry holes. Exploratory drilling in Sheep Mountain thus far has yielded a dry hole ratio of 1 in 3. A similar ratio was predicted for development drilling.

Surface processing equipment costs were developed on the basis of 50 MMcfd modules, with compression and dehydration equipment investment for each well proportional to the well's contribution to the module. It was assumed that with one stage of compression recovery efficiencies on the order of 65 percent could be achieved.

Total investment for a 3 MMcfd well "model" was placed at $1.4 million, for a 6 MMcfd well "model" at $1.7 million, and for a 12 MMcfd well "model" at $2.1 million. The variation in investment as production rate increases is related to the increased capital expenditures required for compression and dehydration equipment capacity.

Operating costs for the well and surface processing are summarized in Table 5.

Capital expenditures for Sheep Mountain were scheduled over five years, as indicated in Figure 4, with initial CO_2 production occurring in year 6.

Results of after Federal income tax discounted cash flow rate of return (AFIT DCF-ROR) calculations using the

TABLE 5

OPERATING COSTS - SHEEP MOUNTAIN, COLORADO

$/well/month = 300

¢/Mcf for compression = 7.7

¢/Mcf for dehydration = .53

¢/Mcf for hydrate control = .4

TOTAL COST $/UNIT = .0863/Mcf

above input and gas prices of \$.25/Mcf and \$.50/Mcf, are presented in Figures 10 and 11.

Figure 10 shows AFIT DCF-ROR versus flow rate for various gas reserve and prices. When gas is priced at \$.25/Mcf, for the lowest flow rate examined, 3 MMcfd, DCF-ROR increase is minimal as per well reserve increases from 36 Bcf to 70 Bcf. DCF-ROR then increases only slightly as reserve increases from 70 Bcf to 137 Bcf. For a rate of 6 MMcfd, DCF-ROR shows a mild upturn as reserve increases from 36 Bcf to 70 Bcf. The 12 MMcfd rate case yields an increase in DCF-ROR each time reserve is increased. Figure 10 indicates for areas with thicker pay, i.e., if per well reserve on 640 acre spacing is in excess of 70 Bcf, that infill drilling, possibly on 320 acres per well, may be feasible. Infill drilling could yield greater field production capacity with little loss of earning power per well for all flow rates examined.

Figure 11 is derived from the same data as Figure 10, but shows AFIT DCF-ROR versus per well reserve for various flow rates and prices.

Figure 11, for a gas price of \$.25/Mcf, shows a flow rate of 3 MMcfd yields an insignificant change in earning power as per well reserves increase from 36 Bcf to 70 Bcf and then from 70 Bcf to 137 Bcf. Earning power shows a modest gain when reserve increases from 36 Bcf to 70 Bcf

Figure 10

AFIT DCF-ROR vs. FLOW RATE FOR VARYING PER WELL RESERVE AND GAS PRICE
SHEEP MT., COLORADO

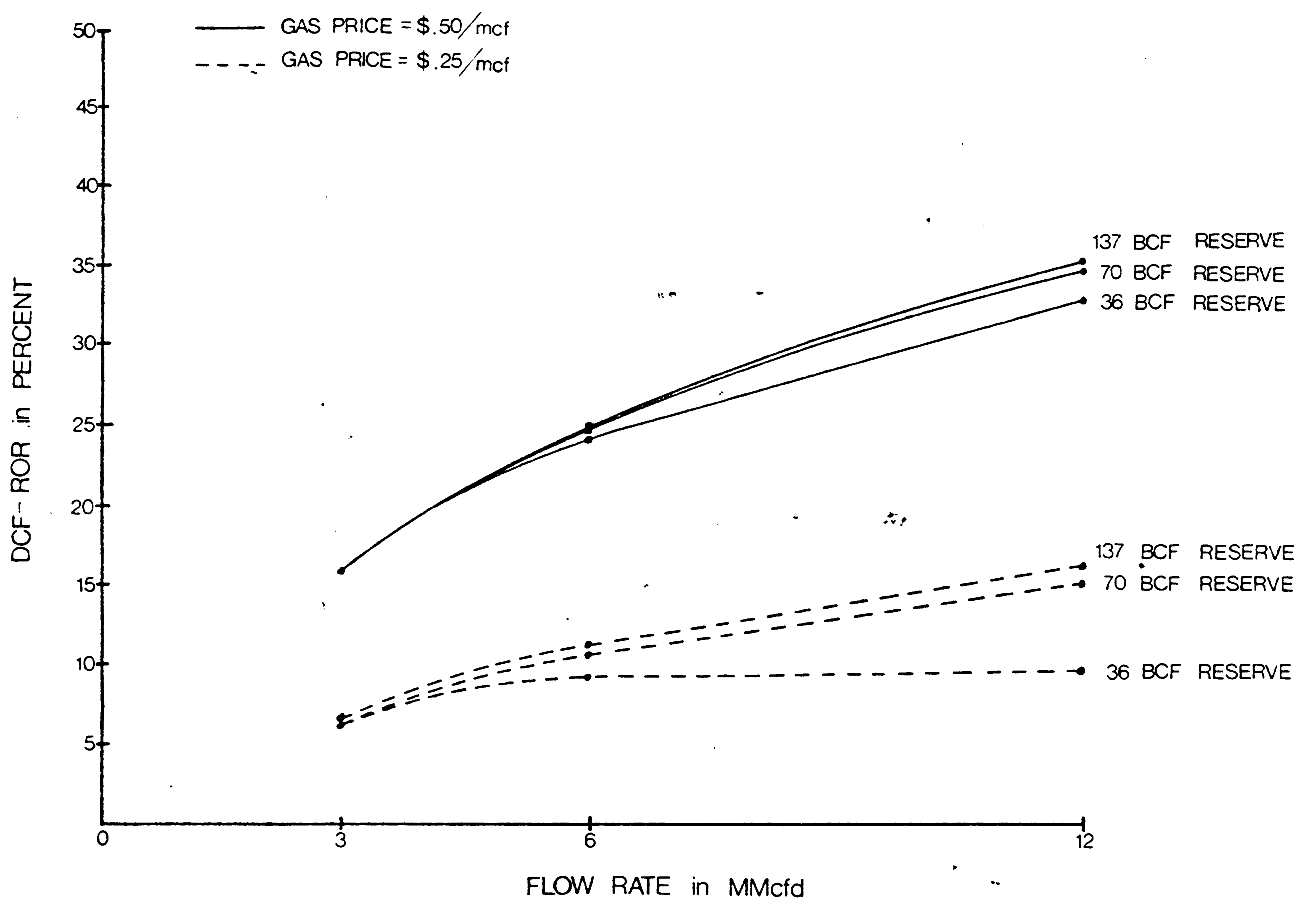
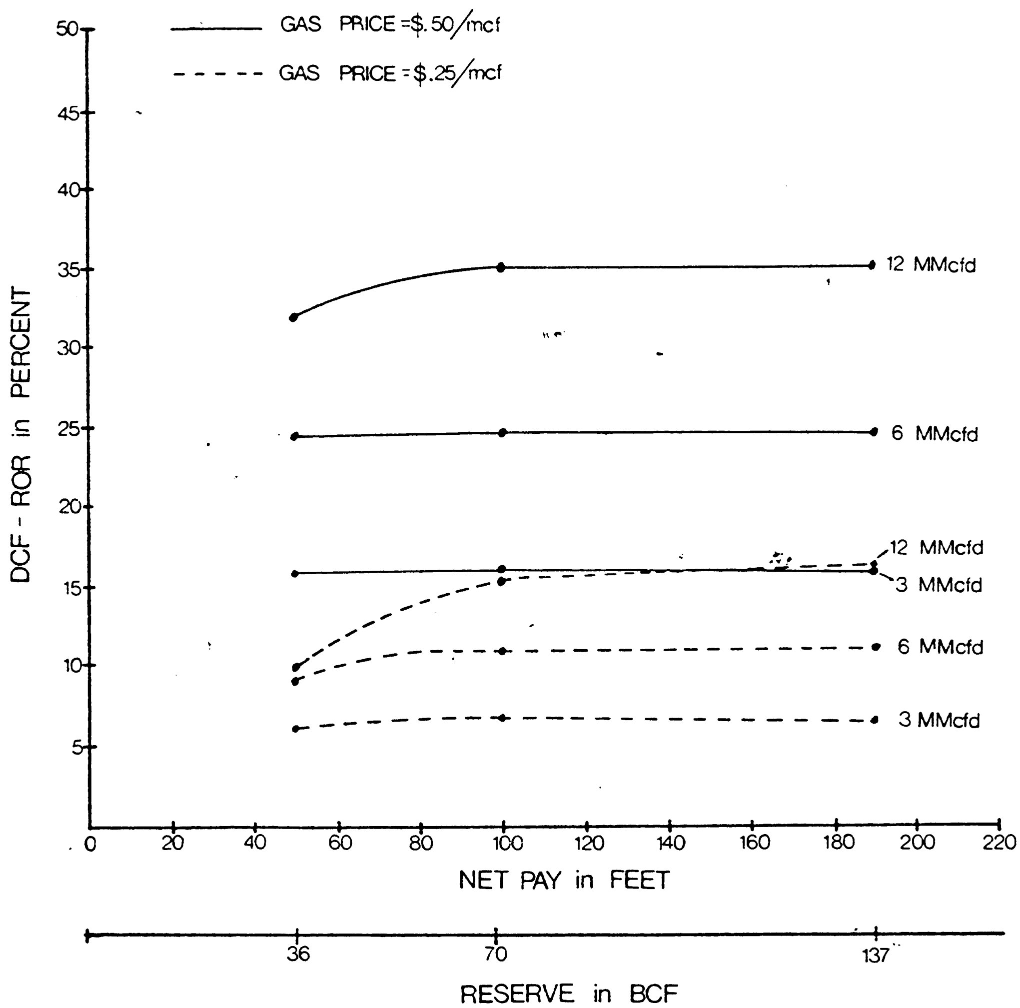


Figure 11

AFIT DCF-ROR vs. WELL RESERVE FOR VARYING FLOW RATES AND GAS PRICE
SHEEP MT, COLORADO



for the median rate of 6 MMcfd. Little enhancement of earning power is seen with a reserve greater than 70 Bcf for a rate of 6 MMcfd. A rate of 12 MMcfd shows a significant increase in earning power when reserves are increased from 36 Bcf to 70 Bcf, but very little gain when per well reserve increases from 70 Bcf to 137 Bcf.

When gas price is increased to $.50/Mcf, the front end investment is recovered rapidly causing flow rate to become the predominant influence on DCF-ROR. As indicated in Figures 10 and 11 little change in DCF-ROR is seen in any of the three rate cases as per well reserve increases. For the higher price case examined, $.50/Mcf, Figure 11 clearly shows gain in DCF-ROR is a function of an increase in flow rate rather than an increase in reserve per well.

Thus, Figures 10 and 11 indicate that for areas exhibiting thicker net pay, a drilling program on a well spacing of 320 acres per well would cause little reduction in earning power, while significantly increasing overall field production capacity. Additionally, although test data indicate permeability is well above average in most wells, if drainage areas were found to be significantly less than 640 acres per well, a 65 percent recovery efficiency could be overly optimistic. A lower RE per 640 acres could necessitate infill drilling.

8.3 Northeast New Mexico Area

8.3.1 Geologic Introduction

Several areas in northeastern and north central New Mexico, including locations near Bueyeros, Wagon Mound and Turkey Mound, have been recent exploration targets for commercial CO_2 reserves.

The most rewarding drilling activity to date has occurred on a large structural nose on the eastern flank of the Sierra Grande Uplift. Covering portions of Union, Harding, and Quay Counties, the structure encompasses the Bueyeros CO_2 field, which has produced CO_2 since the early 1930's for the manufacture of dry ice.

Recent exploratory drilling in the area indicates high grade CO_2 of 99.1 to 100 percent purity, with a maximum of .3 percent N_2 and .2 percent hydrocarbons as contaminants.

Several stratigraphic units in the area have exhibited shows of CO_2. The Glorieta (Permian), Tubb (Permian), and a granite wash member appear to be CO_2 productive.

The top of the Tubb, the primary producer, is clearly identified directly below the Cimarron Anhydrite on electric logs and is found at depths from 1900 feet to 2700 feet subsurface.

Tubb deposition apparently did not occur to the northwest of the structure, resulting in a depositional pinch-out on the Sierra Grande Uplift. Tubb thickness increases rapidly downdip, to a maximum of 500 feet in the southeastern portion of the structure.

The Tubb pinch-out limits productivity in the northwestern portion of the structure. An apparent gas water contact limits productivity downdip in the southeastern and southwestern portions of the structure.

Preliminary application has been made to the State of New Mexico, by a major operator in the area, for a unit containing nearly 1.2 million acres, to be called the Bravo Dome Carbon Dioxide Unit. The proposed unit boundaries are outlined in white on Figure 12*.

Twenty-four exploratory wells, as identified in Figure 12 apparently have delineated a large CO_2 productive area. Wells 55, 58, 59, 61-65, 67-69, and 71-80 were reportedly productive. Numbers 53, 57, 60, and 66 were reported as dry holes. Well number 81 was reported as a mechanical failure. No data are available on wells 56 and 70. Although well control for such a large area is poor, averaging one well per 40,000 acres, there appears to be a potentially productive area of approximately 880,000 acres or roughly 38 townships. Productive area is defined as that acreage containing a minimum of 20 net feet of pay.

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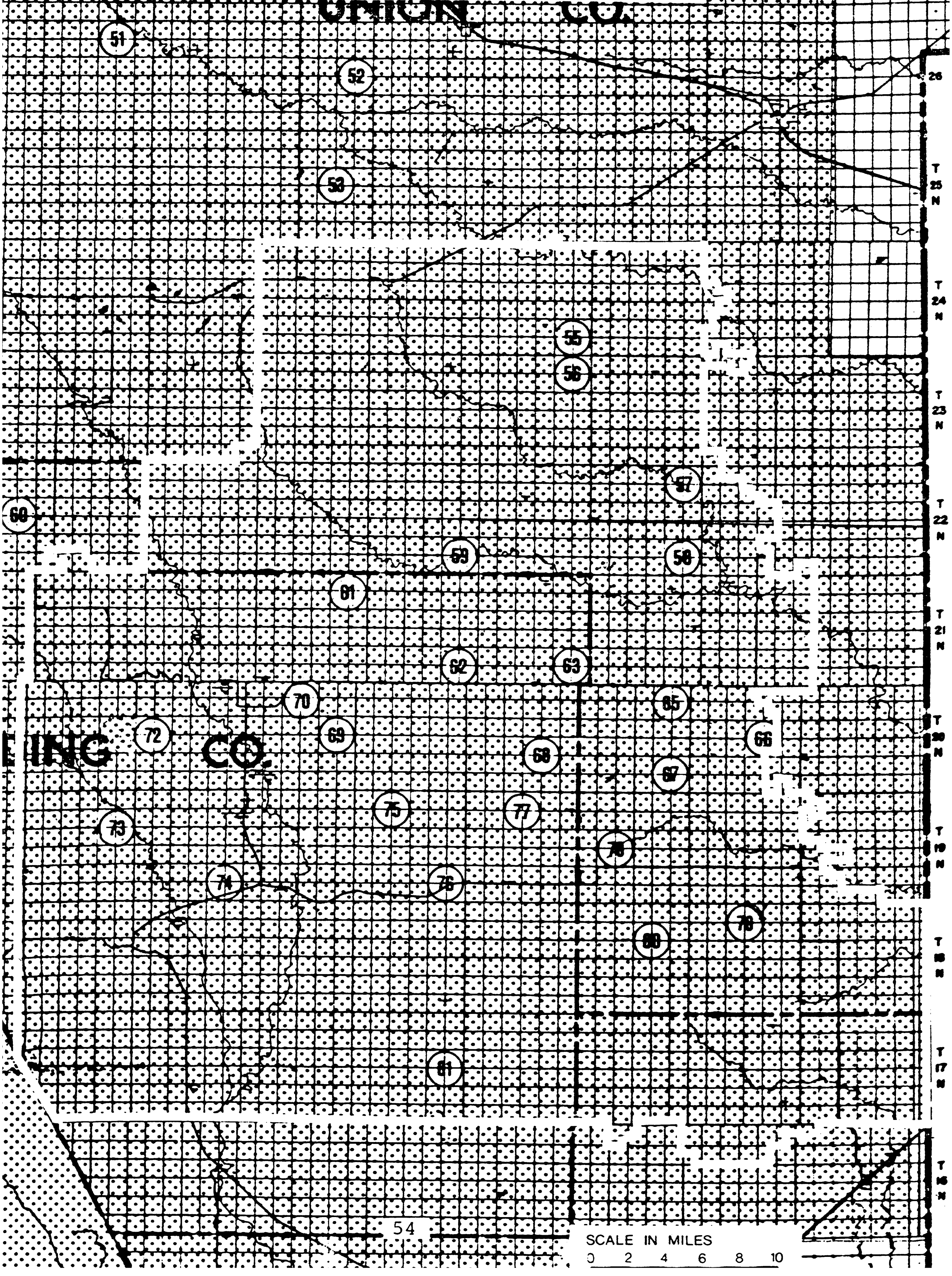
*Adopted from McNeill.

Figure 12
WELL IDENTIFICATION - N.E. NEW MEXICO AREA



8.3.2 Reservoir Analysis

Data utilized in the analyses herein were obtained from public files of the New Mexico Oil Conservation Commission in Santa Fe, New Mexico. Data were obtained from completion reports, scout cards, production records and subsurface logs. The absence of meaningful CO_2 production records for the Bueyeros field and poor well control for such a large area compounded difficulties in interpreting complex reservoir characteristics.

Distribution of net pay thickness was estimated from perforation records in completion reports and available logs of the section. Other investigators have reported considerable difficulty in correlation of specific porosity zones or net pay in geologic cross sections.

Initial bottom hole pressures and porosity values were determined from working maps of the area obtained in State offices.

Reservoir temperatures were estimated from regional data available in the CO_2 Data Base. Gas saturation was estimated to be 80 percent.

Porosity values averaged 20 percent over the area. Porosity values are lower in the updip section, and generally increase in the thicker downdip section. Permeability, while following the same general trend of porosity, is generally low, contributing to low deliverability and flowing tubing pressures.

High purity CO_2 gas, containing 98-99.9 percent CO_2, has been produced from Bueyeros field since the early 1930's for the manufacture of dry ice. Flow rates from several of these earlier wells have reportedly exceeded 1 MMcfd, at flowing tubing pressures of 300-330 psi.

Although production records are inadequate, some sources familiar with the area have observed that little or no reservoir pressure decline has occurred in the wells produced in the Bueyeros area in over 20 years.

Bottom hole pressures in the Bravo Dome area do not exhibit normal correlation with subsea depth. Bottom hole pressures observed in recent exploratory wells ranged from 314 psi, at 2821 feet subsea, in well 72 on Figure 12, to 990 psi, at 2606 feet subsea, in well 61 on Figure 12. Corresponding subsea gradients range from .137 psi/ft. to .396 psi/ft. Thus, both bottom hole pressures and subsea gradients are generally higher in the southwest portion of the area and decrease in a northeasterly direction.

Several theories have been advanced for the indicated bottom hole pressure variations, including:

1. Possibility of a CO_2 source on the southwestern side of reservoir actively charging the reservoir.
2. Possible leaks into Palo Duro or Dalhart basin on the northeastern side of the structure.

The variation in observed bottom hole pressure complicated analysis of probable well and reservoir behavior.

Calculated recovery efficiencies in the area should be considered uncertain at this time. Based on bottom hole abandonment pressures of 225 psi, recovery efficiencies on the order of 65 percent can be calculated. Such bottom hole abandonment pressures would require two stages of compression. If economic justification could be found for three stages of compression, then recovery efficiencies might reach 85 percent.

Assuming the productive area covers 880,000 acres, or roughly 38 townships, with an average of 40 to 60 feet net pay, and approximately 20 percent porosity, OGIP is estimated to range from 10.9 Tcf to 16.3 Tcf. The ultimate recovery (65% RE) would then range from 7.0 Tcf to 10.6 Tcf.

8.3.3 Well Analysis

Exploratory wells identified as potential producing wells in Figure 12, tested flow rates from .25 MMcfd to 1.9 MMcfd. Flowing tubing pressures were generally low, ranging from 30 psi to 250 psi. Most wells exhibiting initial flow rates less than .5 MMcfd were reportedly acidized to improve performance.

Anticipated sustained per well deliverabilities range from .3 MMcfd to 1.2 MMcfd, with flowing tubing pressures of at least 140 psi. With sustained flowing tubing pressures in excess of 140 psi, two stages of compression should be sufficient for delivery to the pipeline.

8.3.4 Economic Analysis

Economics were calculated for three sets of model wells and assumed producing rates of .3 MMcfd, .6 MMcfd, and 1.2 MMcfd. Economics for each set of model wells were examined for reserves of 3.0 Bcf, 6.5 Bcf, and 14.3 Bcf. The range of per well reserve estimates is based on a recovery efficiency of 65 percent from a 640 acre drainage area.

Estimated capital expenditures, representing lease bonus costs, completed well cost, pro rata dry hole cost, gathering system and dehydrator investment, are presented in Table 6.

A dry hole ratio of 1 in 4 during exploratory drilling was based on historical data derived from the exploratory program, while a dry hole ratio of 1 in 5 was assumed for development drilling. Each producing well was burdened with a pro rata share of the total intangible cost of dry holes and lease bonus fees.

As it is expected the pipeline will be responsible for compression of the gas, economic analyses were based only on the production, drying, and gathering of CO_2 and did not include compression expenses. (It is uncertain at this time whether well performance will warrant the installation of

TABLE 6

INVESTMENT - NORTHEAST NEW MEXICO

FLOW RATE	DEHYDRATION COST IN $	WELL COST IN $	DRY HOLE* COST IN $ (PRORATA)	GATHERING** SYSTEM COST IN $	TOTAL[I]
.3 MMcfd	2,400	150,000	18,000	190,000	360,400
.6 MMcfd	4,800	150,000	18,000	190,000	362,800
1.2 MMcfd	9,600	150,000	18,000	190,000	367,600

*Prorata dry hole cost assigned on intangible investment for 25 dry wells per 100 producing.

**Gathering system based on 1 mile of 2" SS quality pipe. Also includes $32,500/well for hydrate control.

[I] Total excludes $22,000/640 acres lease fee.

three stages of compression. Optimization of compression sizing and scheduling this low pressure gas resource is beyond the scope of this report.)

Table 7 summarizes well operating costs, gas processing costs, and hydrate inhibiting costs.

Investment was assumed to occur over a six year period prior to actual CO_2 production. Development capital expenditures were scheduled over the two years prior to CO_2 production. Figures 13 and 14 present results of economic analyses for gas prices of \$.25/Mcf and \$.50/Mcf.

Shown on Figure 13 is AFIT DCF-ROR versus flow rate for various per-well gas reserve and prices. For a flow rate of .3 MMcfd, with a gas price of \$.25/Mcf and the lowest per well reserve analyzed, 3.0 Bcf, the earning power is one percent. Flow rates of .6 or 1.2 MMcfd will both have earning powers of less than five percent for a reserve of 3.0 Bcf. As reserve increases to 6.5 Bcf per well, earning power increases rapidly for all three flow rates. When reserve per well rises to 14.3 Bcf, earning power, for a flow rate of .3 MMcfd, shows no increase over the 6.5 Bcf reserve case. However, earning power for the higher production rates of .6 MMcfd and 1.2 MMcfd continues to show moderate increases as per well reserves increase from 6.5 Bcf to 14.3 Bcf.

TABLE 7

OPERATING COSTS - NORTHEAST NEW MEXICO

$/well/month = 300

¢/Mcf for dehydration = .53

¢/Mcf for hydrate control = .4

TOTAL COST $/UNIT = .0093/Mcf

Figure 13

AFIT DCF-ROR vs. FLOW RATE FOR VARYING PER WELL RESERVE AND GAS PRICE

N.E. NEW MEXICO

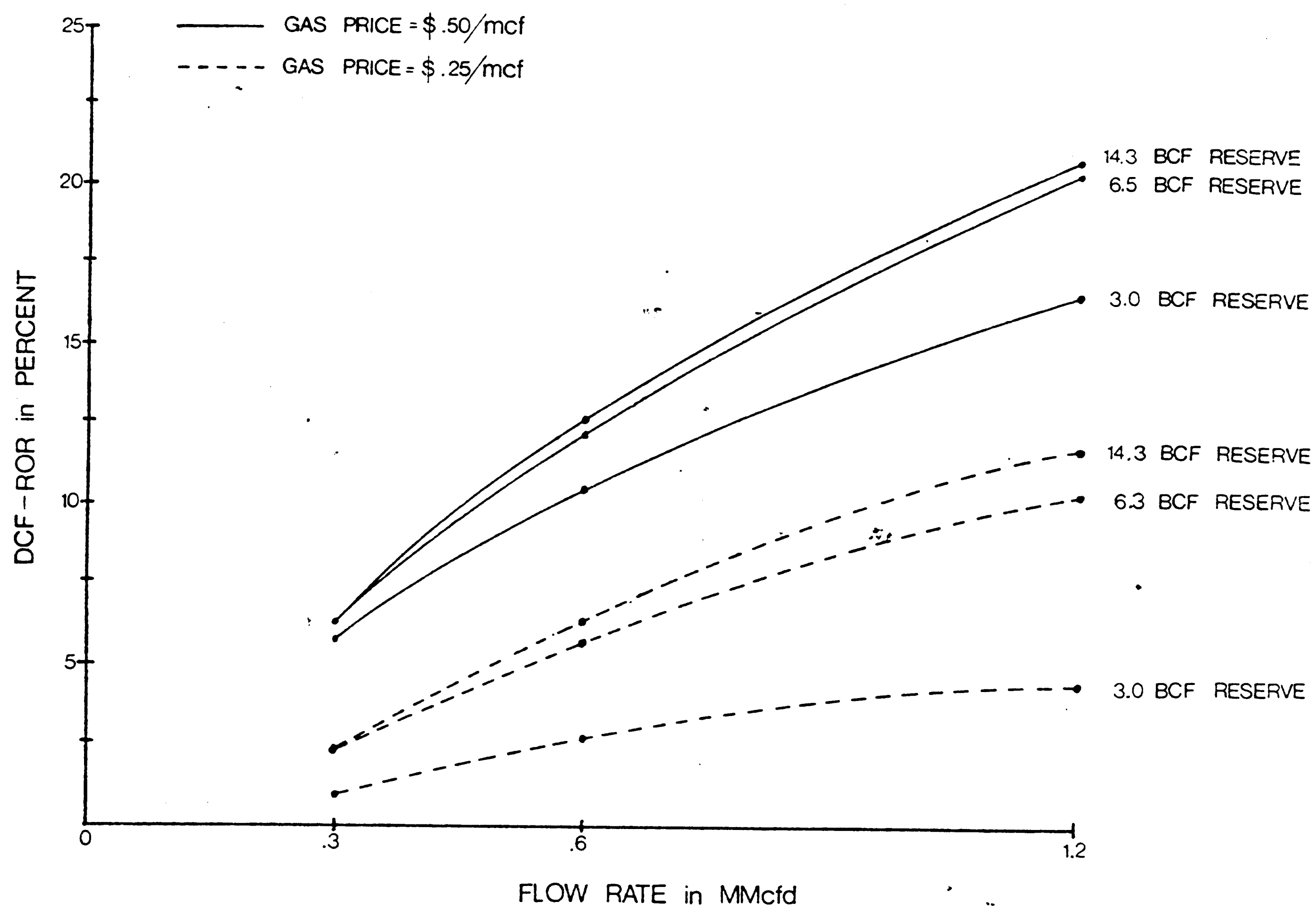
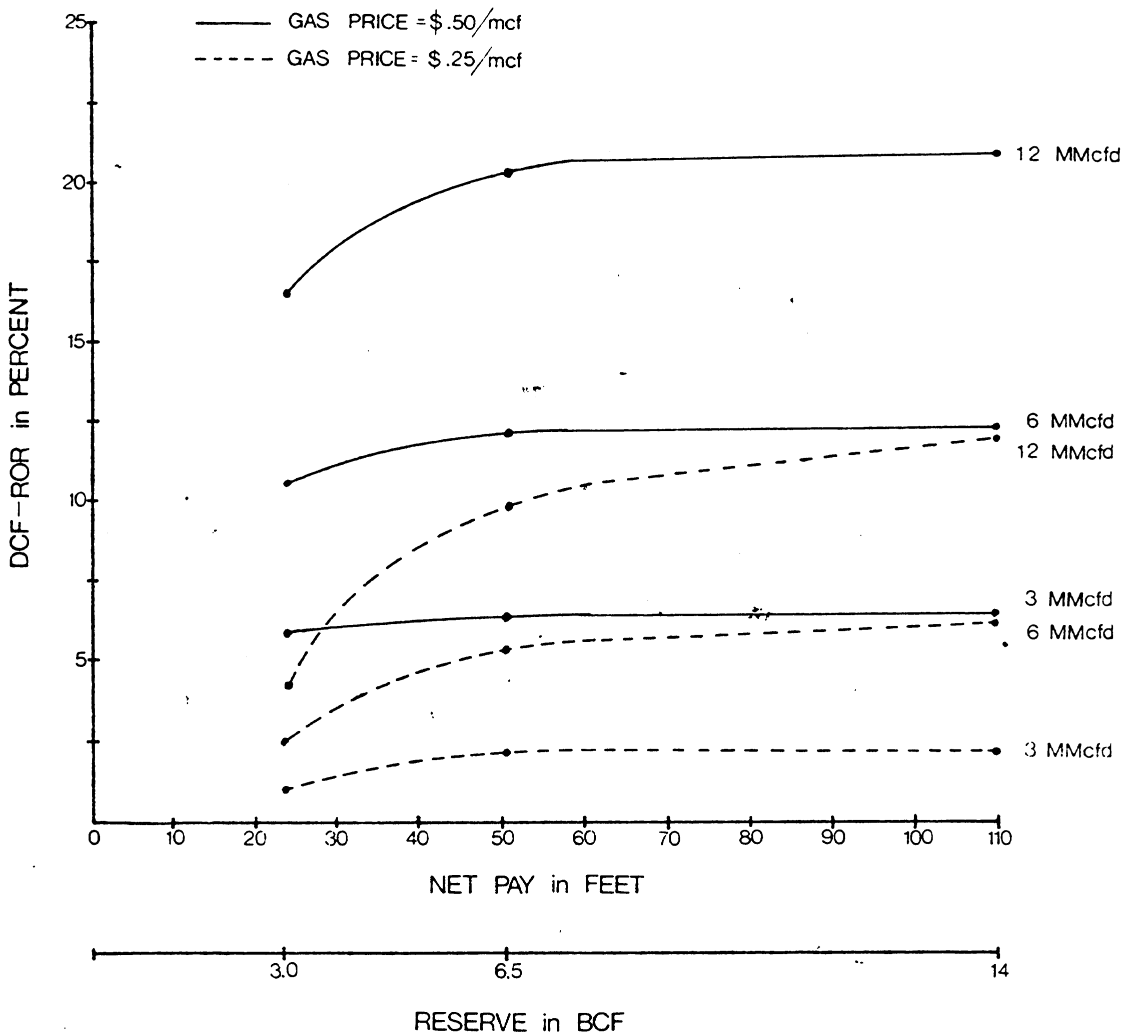


Figure 14

AFIT DCF-- ROR vs. PER WELL RESERVE FOR VARYING FLOW RATES AND GAS PRICE
N.E. NEW MEXICO



Plotted on Figure 14 is AFIT DCF-ROR versus per well reserve for various flow rates and prices. Figure 14 indicates earning power is more sensitive to flow rate than reserve when reserve is greater than 6.5 Bcf. For a gas price of $.25/Mcf, as the flow rate increases from .3 MMcfd to 1.2 MMcfd, the earning power increases from 1 to almost 5 percent for a reserve of 3.0 Bcf per well. For reserve cases of 6.5 Bcf and 14.3 Bcf, earning power shows substantial increase as flow rate increases from .3 to .6 MMcfd. As flow rate increases from .6 MMcfd to 1.2 MMcfd, earning power shows comparable increases.

For gas prices of $.50/Mcf the earning power increases for each case examined. For flow rates of .3 MMcfd and .6 MMcfd with gas priced at $.50/Mcf, Figures 13 and 14 show insignificant gain in earning power as per well reserve increases from 3.0 Bcf to 14 Bcf. For a higher flow rate of 1.2 MMcfd, earning power increases up to a reserve of 6.5 Bcf, then stabilizes with increasing reserve.

Figures 13 and 14 should be utilized cautiously. Considering the variability of initial bottom hole pressures and the uncertainty in reservoir characteristics and reservoir continuity, economic interpretation prior to sustained production performance must be considered rather speculative. Cost of CO_2 delivered to the user must reflect a wellhead price that will earn an acceptable profit to the lease operator and must also reflect compression and transportation costs.

The economics reflected by Figures 13 and 14 assume 640 acre spacing and drainage areas. Depending on well performance, pricing, and CO_2 demand, closer or wider well spacing might be warranted. At this stage of development, however, further calculations are not justified.

Peak production rates discussed thus far from this accumulation have been in the 600 MMcfd range. If the average per well sustained delivery were .6 MMcfd, this would require a minimum of 1000 wells and would result in the production of 5 Tcf of CO_2 over a period of 25 years. When this total production is compared to the possible 7.0 to 10.6 Tcf original reserve, it seems apparent there is adequate gas in place to sustain this demand.

Well control in northeastern New Mexico is sparse. Effective drainage radii are not known. Pressure data obtained from the exploratory drilling program does not appear to conform to geologic and engineering norms. Interpretation of future productivity, reservoir behavior, and economics, thus, is highly speculative. Improved reservoir and economic evaluations can only be made with increased well density or control and sustained production data.

8.4 Central Mississippi - Jackson Dome Area

8.4.1 Geologic Introduction

Jurassic sediments in portions of Rankin, Madison, and Scott Counties, Mississippi, have tested sour gas over the past 20 years of exploration. A corridor of CO_2 and H_2S rich gas is located on the east-northeast flank of the Jackson Uplift and extends in an arc from north central Madison County through central Rankin County.

Two stratigraphic units, the Smackover (Jurassic) and the Norphlet (Jurassic) have indicated strong CO_2 potentials during exploratory drilling and testing.

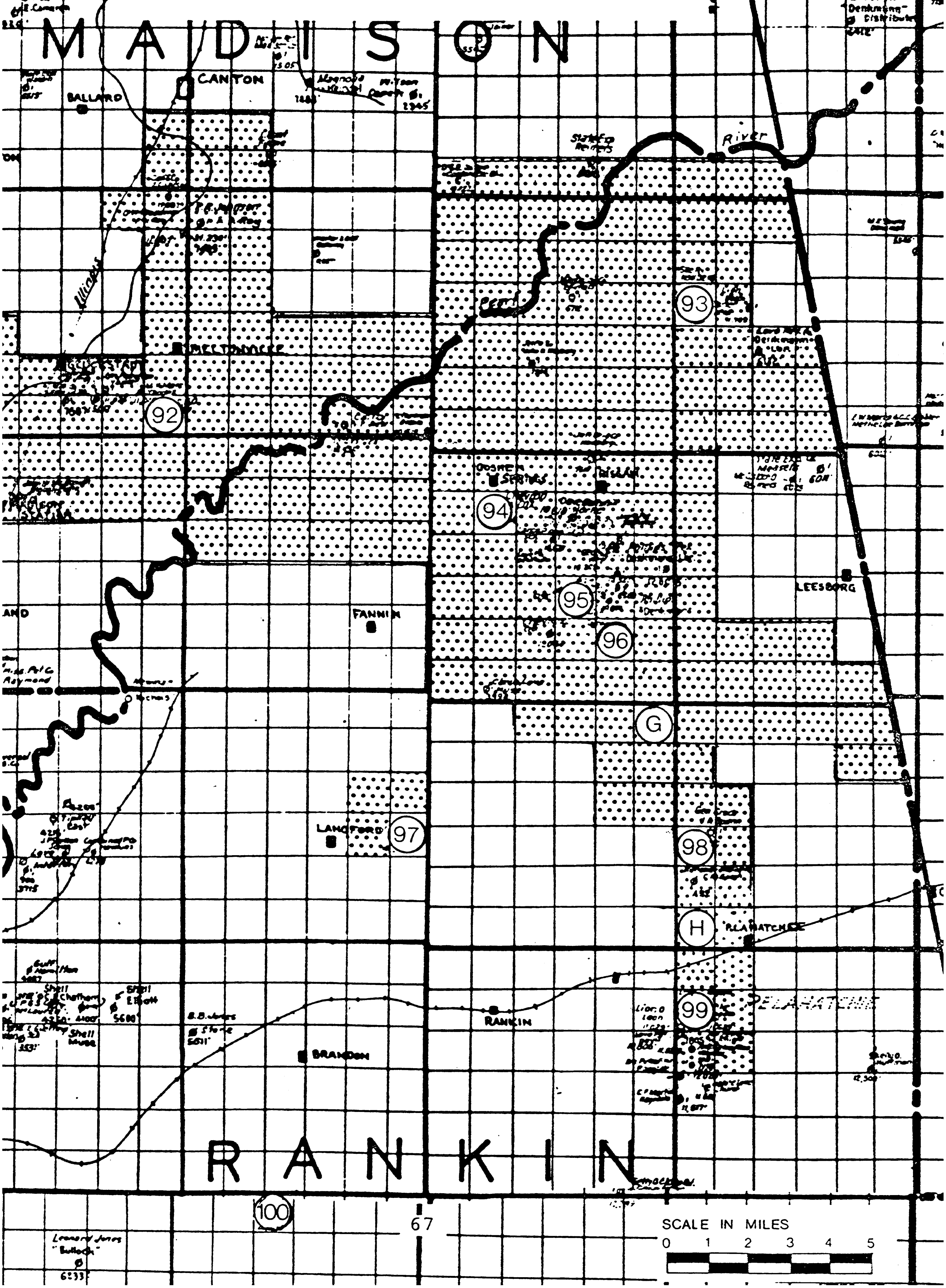
The sour gas productive trend also encompasses several hydrocarbon productive fields including Loring, Pelahatchie, Piney Woods and Thomasville.

Wells in the area have tested carbon dioxide concentrations ranging from 65 to 99.6 percent from the Jurassic section. The gas is associated with up to 10 percent H_2S and varied quantities of methane.

The carbon dioxide resource area of prime interest in this investigation is limited to areas penetrated by wells 92, 93, 94, 95, 96, G, 98, and H on Figure 15*. These wells appear to be located on four separate closures, some of which may have common accumulations. Tests in these wells indicate gas with a minimum of 98 percent CO_2 and a maximum of 1.5 percent H_2S. Several tests have indicated H_2S

*Adopted from McNeill.

Figure 15
WELL IDENTIFICATION -- JACKSON DOME AREA



concentrations less than one grain per 100 cubic feet. Available data indicate CO_2 concentrations in Jurassic gas tested by wells 97 and 99 is considerably less than 98 percent. While an additional CO_2 resource of considerable magnitude may exist with higher H_2S concentrations, it will not be examined in this report.

Estimate of gross thickness in the Smackover and Norphlet is complicated by differences of opinion among various investigators regarding Jurassic stratigraphic interpretation. Differentiation of the basal Smackover sands and the upper Norphlet sand is reportedly difficult.

The top of the Smackover in the Jackson Dome area is found between 14,000 to 16,000 feet subsurface. The Norphlet is located directly below the lower Smackover. The Smackover in this area is primarily carbonate, composed of brown to grey limestones and dolomites with interbedded dolomitic sands. A porous dolomitic basal sand member is usually present.

Gross thickness of the Smackover in the study area is estimated to be from 1,000 to 2,000 feet. Mellen (1967) has described Smackover porosity and permeability as highly varied in the carbonate section, ranging from porous oolitic, to intergranular, to vuggy and fractured.

The Norphlet is described as a sequence of primarily fine grained sands. Gross thickness for the Norphlet is a minimum of 300 feet.

8.4.2 Reservoir Analysis

Data for reservoir analyses were obtained from public records on file in the Mississippi Oil and Gas Board Office in Jackson, Mississippi, and through a GURC consultant. All available well completion reports, core analyses, logs and scout cards were utilized to interpret reservoir characteristics.

Net pay thickness was estimated by analysis of perforated intervals reported in well completion reports and scout cards, and by correlation with subsurface logs.

Porosities and permeabilities were estimated from available core analysis data and from literature on the Jurassic section in the area. Gas saturation was estimated to be 80 percent.

Reservoir temperatures and initial bottom hole flowing and shut in pressures were determined from well completion reports and scout cards. Pressure gradients exceed hydrostatic in portions of the reservoir. Pressure gradients ranged from .485 psi/ft. at 12,130 feet subsurface to .713 psi/ft. at 16,801 feet subsurface. Maximum shut in bottom hole pressures have reached 11,975 psi at 16,801 feet subsurface, yielding the maximum recorded subsurface pressure gradient of .713 psi/ft.

Seven of the wells identified on Figure 15, wells 92, 93, 94, 95, 96, 98, and H, reportedly tested gas with CO_2 in excess of 98 percent. These wells provide a bare minimum of well control. All seven of the indicated wells, drilled between 1951 and 1978, were drilled on structural highs, probably related to deep-seated salt features. Of these seven wells, all but number 96 were drilled for hydrocarbon exploration.

Wells 94, 95, and 96 appear to be located on a single, fairly large, elongate structural feature. The objective of well number 96, drilled and completed as a potential CO_2 producer by a major operator, was reportedly to test the Jurassic CO_2 potential on the southern flank of the feature. Well number G is being drilled as a confirmation CO_2 well to number 96 and, when completed, will provide additional data as to the productivity of this structure to the south.

Well 92 appears to be located on an uplift of limited areal extent. The operator of well 92 has applied to the Oil and Gas Board of the State of Mississippi for creation of a 1,760 acre gas unit. Well spacing of 880 acres per well was requested in the application.

Similarly, well 93 is located on a small structure in which the extent of CO_2 productivity is unknown.

Well 98 was apparently completed on the crest of another separate structure. Well H is reportedly on the southern edge of this structure and was CO_2 productive in several intervals of the Jurassic section.

Data indicate CO_2 concentrations in Jurassic gas tested by wells 97 and 99 is well below 98 percent.

Estimate of productive area is hampered by insufficient well control on the structural features of interest. Most control wells were drilled as hydrocarbon exploratory wells on seismic and gravity data. Lateral extent of productivity on the four structures discussed above is unknown at this time.

Preliminary estimates, based on limited well control, suggest the four features contain a minimum combined productive area of 27 sections, or 17,280 acres. Better estimates of productive area will require additional subsurface data.

Assuming combined productive area of these four structural features is a minimum of 27 sections, and total net pay of the Jurassic section is 120 feet to 250 feet with 13 percent average porosity, minimum original gas in place might range from 3.4 Tcf to 7.0 Tcf. Minimum ultimate recovery (60% RE) would then range from 2.0 Tcf to 4.2 Tcf.

8.4.3 Well Analysis

Wells designated as control wells on Figure 15 in Section 8.4.2 reportedly tested varying ranges of flow rates and tubing pressures from the Smackover and Norphlet as exhibited below.

	Flow Rate	Flowing Tubing Pressure
Smackover	2 MMcfd	3,375 psi
	12 MMcfd	3,450 psi
Norphlet	10.7 MMcfd	3,950 psi
	20.5 MMcfd	3,565 psi

Several wells exhibited productivity in both the Norphlet and Smackover.

Sustained per well deliverabilities from both the Smackover and Norphlet, individually, are expected to range from 4 MMcfd to 16 MMcfd. Initial flowing tubing pressures are expected to range from 2,000 psi to 4,500 psi. It seems unlikely that dual completions will be made in these two formations.

As flowing tubing pressures decline below 2,000 psi, a single stage of compression probably will be required to meet pipeline delivery pressures and to achieve recovery efficiencies on the order of 60 percent.

Abandonment pressures were calculated from shut in and flowing bottom hole pressure decline curves as a function of cumulative gas produced. Abandonment was assumed to occur when surface flowing pressures declined below 560 psi and more than one stage of compression was required to meet pipeline delivery pressures. Estimates indicate bottom hole abandonment pressures of around 2,300 psi should yield recovery efficiencies on the order of 60 percent of gas in place.

8.4.4 Economic Analysis

Economics were calculated for three sets of model wells, which assumed average sustained producing rates of 4 MMcfd, 8 MMcfd, and 16 MMcfd. Economics for each set of the model wells were evaluated for per well reserves of 17 Bcf, 51 Bcf, and 152 Bcf. This range of per well reserve estimates is based on recovery efficiencies of 60 percent from a 640 acre drainage area and net pays of 25, 75, and 225 feet, respectively.

Capital expenditures for each well model are summarized in Table 8. The completed well cost, pro rata dry hole cost, lease bonus fees, and gathering system cost were considered fixed costs, independent of the production rate.

Based on experience to date in the area, a dry hole ratio of one in five was assumed for both exploration and development drilling.

Cost estimates for surface processing equipment were based on 50 MMcfd modules. Investment for compression and dehydration facilities was prorated on the basis of each well's contribution to the entire module. Flowing tubing pressures will, initially, enable production without compression. At some point as flowing tubing pressures decline, depending on the production rate and reserve, one stage of compression will be required to meet a pipeline delivery pressure of 2,000 psi.

TABLE 8

INVESTMENT - JACKSON DOME AREA, MISSISSIPPI

FLOW RATE	COMPRESSION B.H.P. REQUIRED	COMPRESSION INVESTMENT IN $ *	DEHYDRATION COST IN $	WELL COST IN $	DRY HOLE COST (PRO-RATA) **	GATHERING SYSTEM COST IN $ ***	TOTAL $ I
4 MMcfd	516	279,050	32,000	2,500,000	360,000	250,000	3,171,050
8 MMcfd	1,032	558,090	64,000	2,500,000	360,000	250,000	3,482,090
16 MMcfd	2,064	1,116,170	128,000	2,500,000	360,000	250,000	4,104,170

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*Based on $540.8/BHP.

**Pro-rata dry hole cost assigned on intangible investment for 20 dry wells per 80 producing wells.

***Gathering system based on 1 mile of 4" S.S. quality pipe. Also includes $65,000/well for hydrate control.

I Total excludes $64,000/640 acres lease fee.

Well operating costs and surface processing operating costs, including hydrate inhibition, drying and compressing the gas, are listed in Table 9. It is assumed that costs of purifying the CO_2, i.e., removal of H_2S, will be borne by the pipeline.

The investment schedule assumed capital expenditures will occur over a six-year period prior to actual CO_2 production. Investment for development drilling and surface processing equipment was scheduled over the final two years (years 5 and 6) prior to CO_2 production.

Results of discounted cash flow rate of return calculations using the above reservoir input and gas prices of $.25/Mcf and $.50/Mcf are presented in Figures 16 and 17.

Figure 16 shows AFIT DCF-ROR versus flow rate for various per well reserves and gas prices. When gas is priced at $.25/Mcf, flow rates of 4 MMcfd, 8 MMcfd, or 16 MMcfd, yield a zero rate of return for a reserve of 17 Bcf. As per well reserve increases to 51 Bcf, each of the flow rate cases yields a moderate rate of return. An increase in reserve to 152 Bcf yields substantial improvement in the rate of return, generating a DCF-ROR of 6.6 percent for a flow rate of 4 MMcfd and 20 percent for a flow rate of 16 MMcfd.

TABLE 9

OPERATING COSTS - JACKSON DOME AREA, MISSISSIPPI

$/well/month = 300

¢/Mcf for compression from 565 psi - 2000 psi when required = 7.7

¢/Mcf for dehydration = .53

¢/Mcf for hydrate control = .4

TOTAL COST $/UNIT = .0863/Mcf

Figure 16

AFIT DCF-ROR vs. FLOW RATE FOR VARYING PER WELL RESERVES AND GAS PRICE
JACKSON DOME AREA, MISSISSIPPI

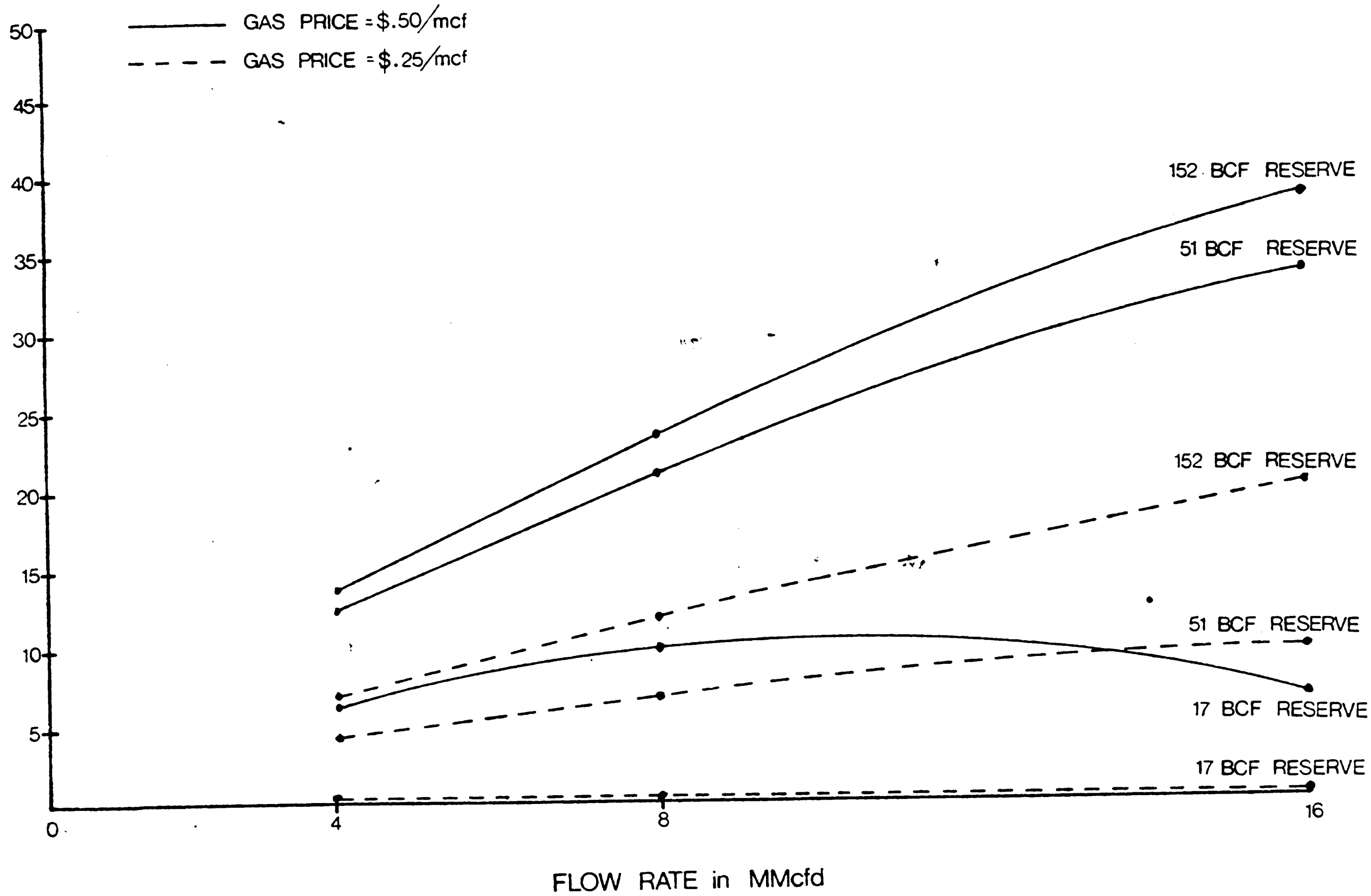


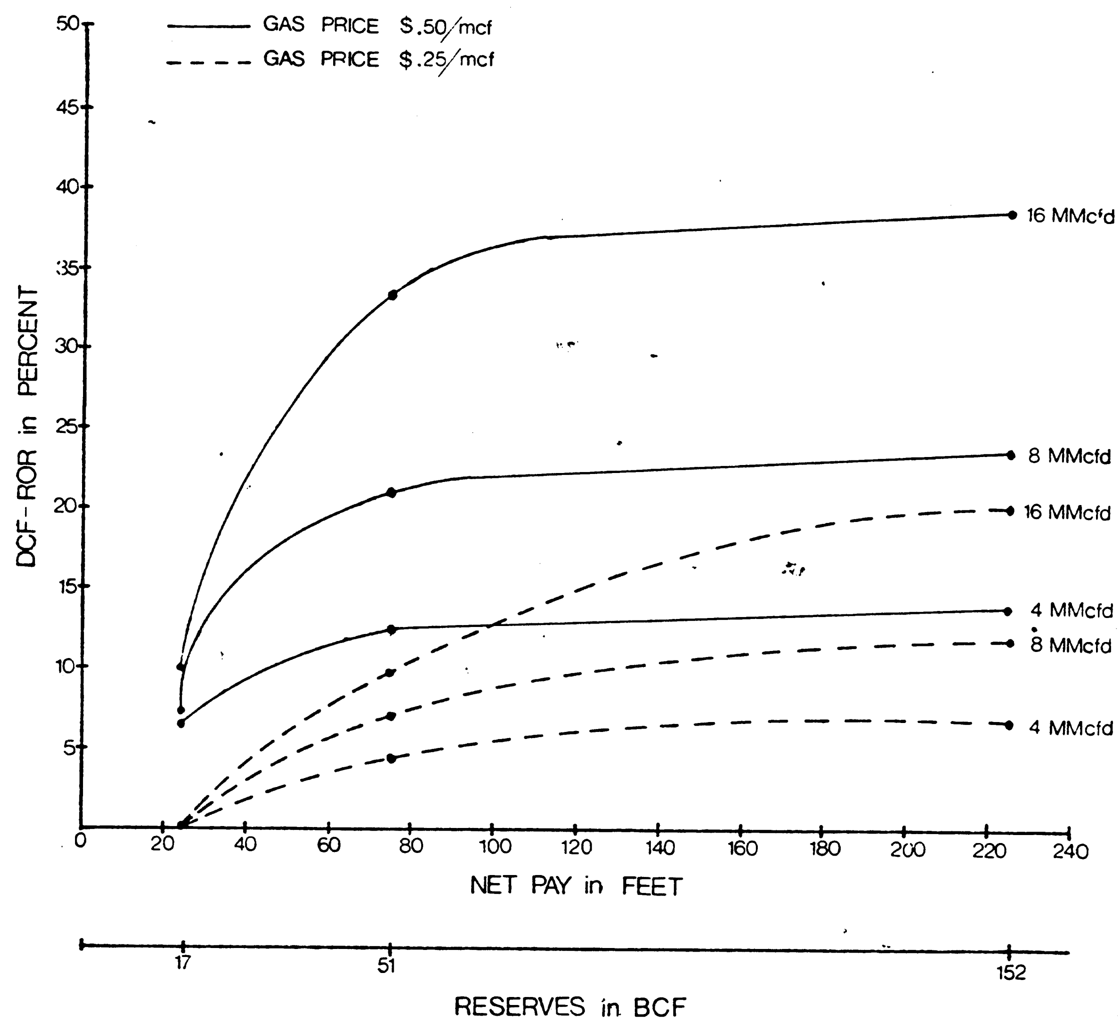
Figure 17 plots AFIT DCF-ROR versus per well gas reserve for varying flow rates and gas prices. As previously indicated, for a gas price of $.25/Mcf, the rate of return for evaluated flow rates is zero when per well gas reserve is 17 Bcf. An increase in reserve per well to 57 Bcf generates small rates of return at all three flow rates.

When a per well reserve of 152 Bcf was evaluated for a gas price of $.25/Mcf, flow rates of 8 MMcfd and 16 MMcfd yielded rates of return of 12 percent and 20 percent respectively. A flow rate of 4 MMcfd yielded only 6.5 percent, even with the large reserve.

Referring again to Figure 16, when gas price is increased to $.50/Mcf, the lowest reserve case analyzed, 17 Bcf, will yield an increasing DCF-ROR as rate increases from 4 MMcfd to 8 MMcfd. However, as flow rate increases beyond 8 MMcfd, DCF-ROR begins to decline, indicating an "optimum" producing rate around 8 MMcfd. This "optimum" is due to the increased surface processing equipment investment required with increased production rates. Thus, at $.50/Mcf a reserve of 17 Bcf is not sufficient to payout the large incremental capital expenditures required for increased surface processing capacity over a short productive period. When per well reserve is increased to 51 Bcf, a positive correlation between increased flow rate and increases in DCF-ROR is seen in all cases. This trend continues as reserve increases to 152 Bcf per well.

Figure 17

AFIT DCF-ROR vs. PER WELL RESERVE FOR VARYING FLOW RATES AND GAS PRICE
JACKSON DOME AREA, MISSISSIPPI



When gas is priced at $.50/Mcf, Figure 17 depicts, for a per well reserve of 51 Bcf, a sharp increase in DCF-ROR for all flow rates examined. When per well reserve increases from 51 Bcf to 152 Bcf, the curve flattens with increased reserve, and increases in flow rate become the predominant factor in generating increased DCF-ROR.

To date, exploration for CO_2 in Mississippi has been limited. Data utilized herein was generated by wells intended for hydrocarbon exploration rather than for CO_2 exploration. Increased well density and resulting subsurface data following further CO_2 exploration will be necessary to make reasonable forecasts and to evaluate production methodologies and economics.

These economics could be affected adversely if removal of the small amounts of H_2S requires significant reduction in wellhead flowing pressures, necessitating multi-stage compression for pipeline delivery. Such an investigation is beyond the scope of our study.

9.0 POTENTIAL OIL RECOVERY AND CO_2 REQUIREMENTS FOR CO_2 MISCIBLE FLOOD CANDIDATE RESERVOIRS

In conjunction with the naturally occurring CO_2 study, GURC examined candidate reservoirs that might contain significant quantities of waterflood residual oil in Mississippi, Southern Louisiana and West Texas. Brief summaries of these analyses are presented in Figure 5 and below.

Estimate of the quantity of residual oil recoverable by CO_2 flooding, the CO_2 requirement in Mcf per barrel of oil recovered, and the potential total "net new"* CO_2 demand were calculated for each area as follows.

9.1 Potential Oil Recovery and CO_2 Requirements for CO_2 Floods in Mississippi

Data on Mississippi reservoirs were obtained from the Mississippi State Oil and Gas Board Bulletin of 1976. Fields in Southern Mississippi meeting selected screening criteria of light oils with adequate depth for obtaining miscibility contain at least 600 million barrels of original oil in place (OOIP). Approximately 40 percent, or 240 million barrels, of the 600 million barrels of OOIP will be recovered by primary and secondary means, leaving 360 million barrels of residual oil in place (ROIP). GURC estimates about 30 percent, or roughly 100 million barrels, of the residual oil might be recovered through CO_2 floods. A "net new" CO_2 requirement of 10 Mcf per barrel of oil recovered was estimated, based on reported experience at Little Creek

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*"Net new" CO_2 = Total CO_2 injected - produced CO_2 recycled in reservoir.

field. This could result in a potential "net new" CO_2 requirement on the order of 1 Tcf for Southern Mississippi.

9.2 Potential Oil Recovery and CO_2 Requirements for CO_2 Floods in Louisiana

In Southern Louisiana high relief salt dome reservoirs were evaluated as the primary candidates amenable to CO_2 flooding. Lower and upper case scenarios were constructed to determine quantities of oil recoverable by CO_2 flooding and "net new" CO_2 requirements. Reservoir and production data were obtained from the Louisiana Department of Natural Resources publication, Secondary Recovery and Pressure Maintenance Operations in Louisiana (1977).

The probable lower case was derived by calculating OOIP of steeply dipping, water flooded salt dome <u>reservoirs</u>, containing greater than 5 million barrels OOIP per reservoir. Total OOIP in these reservoirs was estimated to be 500 million barrels. If 10 percent of the OOIP is recoverable by CO_2 flooding, then incremental recovery of 50 million barrels of oil may be possible. With an estimated "net new" CO_2 requirement of 6 Mcf per barrel calculated for the minimum case, total "net new" CO_2 requirement would approach 300 Bcf.

The probable upper case was derived by calculating the OOIP in 16 water flooded, steeply dipping, salt dome <u>fields</u>, containing more than 1 million barrels per field. OOIP in this case was estimated to be roughly 3.4 billion barrels.

If an incremental recovery efficiency of 10 percent of OOIP could be attained in these fields, 300 million barrels of incremental oil might be recoverable through CO_2 flooding. A "net new" CO_2 requirement of 6 Mcf per barrel could result in a demand of 1.8 Tcf of "net new" CO_2.

9.3 Potential Oil Recovery and CO_2 Requirements for CO_2 Floods in the Permian Basin

Estimate of quantities of oil recoverable by CO_2 flooding in West Texas were developed using data in the Petroleum Data Systems (PDS) files of Information Systems Programs in Norman, Oklahoma. Permian Basin reservoirs amenable to CO_2 flooding were accessed through the OILY and TEXS data bases on the basis of the following screening criteria:

1. Cumulative production by 1976 was greater than 5,000,000 barrels.
2. Depth to the top of the formation greater than 2,499, if API gravity greater than 30°.
3. Depth to the top of the formation greater than 5,999 feet, if API gravity was 27° through 30°.
4. Porosity "type" could not be fractured.

OOIP in the CO_2 miscible flood candidate reservoirs of the Permian Basin was calculated to be 42 billion barrels. Ultimate production by primary and secondary means was estimated at 13 billion barrels. Thus, residual oil in Permian

Basin reservoirs after waterflood will be on the order of 29 billion barrels. Projections of the percentage of incremental oil potentially recoverable by CO_2 flood were derived from analysis of field test results to date. GURC estimates 5 to 20 percent of OOIP will be potentially recoverable by CO_2 flooding in Permian Basin reservoirs. This incremental production would range from 2 to 8 billion barrels. Although field tests in West Texas have yielded a wide range of "net new" Mcf per barrel CO_2 requirements, 4 and 12 Mcf per barrel seems most applicable. If 2 to 8 billion barrels of incremental oil are ultimately recovered by CO_2 flooding, requiring 4 - 12 Mcf per barrel, total "net new" CO_2 demand in the Permian Basin will range from 8 to 96 Tcf.

9.4 Potential Oil Recovery and CO_2 Requirements for CO_2 Floods in Other Areas

Operators are presently investigating the possibility of CO_2 floods in at least two major Rocky Mountain fields. If the economics of CO_2 miscible flooding appears favorable in field tests in these two reservoirs, one a carbonate and the other a sandstone, incremental oil production by CO_2 flooding and demand for CO_2 in the Rockies probably will both expand.

Some activity has taken place in West Virginia. Results to date, however, are inconclusive, and future recovery rates and injection requirements are conjectural. CO_2

reserves and incremental oil production resulting from CO_2 floods in West Virginia are not expected to be significant in comparison with the total United States.

10.0 SUMMARY ON NATURALLY OCCURRING CO_2 ACCUMULATIONS

The three areas surveyed in the Rocky Mountain province, the McElmo Dome area, Sheep Mountain area, and Bravo Dome area, potentially represent an aggregate CO_2 OGIP of 16.6 Tcf to 25 Tcf. Indicated CO_2 reserve from these areas is estimated to range from 10.9 Tcf to 16.5 Tcf. Peak pipeline delivery to West Texas oil fields will probably be 1.15 Bcfd.

Other CO_2 accumulations in Utah and Wyoming may eventually be developed, if demand is strong enough, and may significantly add to the indicated reserves in the Rockies.

OGIP (CO_2) in the Jackson Dome area of Mississippi is estimated to be 3.4 Tcf to 7.0 Tcf. Ultimate recovery will probably range from 2.0 Tcf to 4.2 Tcf. Maximum transport of gas available for oil fields in Southern Mississippi and Louisiana is expected to be on the order of 150 - 200 MMcfd.

DEFINITION OF SYMBOLS

AFIT	= after Federal income tax
Bcf	= billion cubic feet
CAOF	= calculated absolute open flow
DCF-ROR	= discounted cash flow rate of return
E_R	= recovery efficiency (fraction of OGIP)
G	= gas in place/acre-foot
Mcf	= thousand cubic feet
MMcf	= million cubic feet
OGIP	= original gas in place
P_a	= reservoir abandonment pressure
P_i	= initial reservoir pressure
P_{sc}	= pressure, standard conditions
S_g	= gas saturation
Tcf	= trillion cubic feet
T_i	= reservoir temperature
T_{sc}	= temperature, standard conditions
Z_a	= gas compressibility factor (abandonment)
Z_i	= gas compressibility factor (initial)
ϕ	= porosity

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APPENDIX A

NATURAL OCCURRENCES OF CARBON DIOXIDE
COMPREHENSIVE ANALYSIS
REPORT NO. 101-B

FINAL REPORT

NATURAL OCCURRENCES OF CARBON DIOXIDE
COMPREHENSIVE ANALYSIS
REPORT NO. 101-B

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MARCH 22, 1978

PREPARED FOR:

GULF UNIVERSITIES RESEARCH CONSORTIUM

IN SUPPORT OF:

GURC/ERDA EX-76-C-01-2025

NATURAL OCCURRENCES OF CARBON DIOXIDE
COMPREHENSIVE ANALYSIS

ABSTRACT

The exercise presented herein is the result of the continuing GURC/DANALYT effort to understand and describe the natural occurrences of carbon dioxide. The relationship of carbon dioxide to other measured physical parameters and to associated gases is explored. The correlations discovered provide broad guidelines and information to support theories of carbon dioxide formation in the subsurface.

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1.0 CARBON DIOXIDE COMPREHENSIVE ANALYSIS

1.1 DATA SOURCE AND DESCRIPTION

In support of the GURC carbon dioxide study and under GURC direction, DANALYT has built and initiated analysis of a data-base from natural gas analyses data generated by the U.S. Bureau of Mines, Branch of Helium Resources. Samples were first collected in 1917 by the Bureau of Mines and have been collected up to the present time as a continuing survey of natural helium occurrences. To date 11,526 gas samples have been obtained, of which 542 were added in 1976. Most of the gas samples are from domestic sources; however, 214 were collected from foreign gas fields (obtained after 1965).

Analytical work on samples collected early in the survey was conducted on the Orsat apparatus, with the one-cut apparatus and four-cut fractional distillation equipment added later. In 1949 a mass spectrometer was acquired and utilized for analyses after that time. Helium content analyses throughout the 1917-1976 period were made on special helium analytical equipment designed and built by the Bureau of Mines Helium Laboratory.

The Bureau of Mines has expended their greatest effort in the past to obtain/analyze gas samples from areas that showed promise of helium bearing natural gas. Because of this, emphasis has been placed on collecting Mid-continent area samples first, Rocky Mountain area samples second, and other areas third. After 1970, the attempt has been made to broaden the coverage into areas with less indication of helium content natural gas, e.g. Gulf Coast, and also to sample newly discovered fields. Most samples are collected/solicited by the Bureau of Mines, but submitted gas samples are analyzed as long as previous work is not duplicated.

1.2 DATA BASE FORMATION AND DATA VALIDATION

The data base was built from all gas samples that contained any amount of carbon dioxide; therefore, gas samples with carbon dioxide mole percent 0.0 or unknown were excluded. 10,553 samples satisfied these criteria. The coverage includes 36 states and 22 foreign countries, and over 4,000 fields in 710 counties producing from approximately 1,300 different formations.

The study was initiated by making investigative queries to obtain an understanding of the data and to look for inconsistencies and errors. At this point some heating (BTU) and zone thickness values were corrected with consultation from the U.S. Bureau of Mines Helium Resources Branch. Satisfied with the data quality, a data subset to be used to generate the plots was extracted from the 10,553 sample data base by applying validation restrictions to exclude non-applicable and undesirable data. All of the pipeline samples (998 analyses), gas seep samples (11 analyses), and water well samples (6 analyses) were excluded as well as air contaminated samples (111 analyses with oxygen present in greater than 5.0 mole percent amounts). An attempt was also made to eliminate over-representation of a particular reservoir if the carbon dioxide sample contents were significant. Two fields were considered over-represented and consequently limited to a normal sample of each for the study. The two fields so limited are: 1) Lisbon field, Utah; with 33 samples from the Mississippian series and 2) Seminole field, Texas; with 20 samples from the Permian Series San Andres Formation. 9,375 samples remained after the applied restrictions and comprise our subset.

Several plots were made that do not directly relate to the geologic occurrences of carbon dioxide, but because of their usefulness in describing the data they have been included in Appendix A. These include plots of carbon dioxide mole percent vs. year well completed, depth, thickness, and the greater molecular weight hydrocarbons.

The coverage appears broad enough to provide a statistically valid data set from which trends or associations may be discovered. Data of questionable quality have been eliminated and problems of over-representation dealt with. Sampling biases, although regrettably present, have been identified but are minor in scope and do not invalidate the study. We are fortunate that such a large quantity of data is available and immediately applicable to the problem of carbon dioxide occurrence, and a look at the physical measurements of natural gas samples containing carbon dioxide can aid in a better understanding of the relationship of carbon dioxide to other parameters.

1.3 FREQUENCY DISTRIBUTIONS

Simple frequency distribution diagrams were produced for carbon dioxide, methane, and nitrogen. These gases were selected because they contribute most to the content of the samples, and certain relationships exist among the three as discussed later in this chapter. Each data set was divided into twenty classes of 5.0 mole percent increments (except for Figure 1.3.2.1 which was divided into fifty classes of .1 mole percent), with the relative frequency of each class indicated by a diamond plot symbol and connected with a line.

The mean and standard deviation were also computed for each distribution and displayed as symbols along the bottom of the plot area. The standard deviation is represented by the smaller symbols. Superimposed on the frequency diagrams are the cumulative distributions with the line-connected plot symbol X.

The cumulative distribution of the reservoirs in regard to sample gas contents was determined and displayed on the respective plots by a dashed line and a circular plot symbol for carbon dioxide and methane. This was done to check the validity of our sample statistical analysis in relation to the reservoirs involved and to assure that the statistical analysis is indeed valid. An example of the problem would be that the sample frequency distributions do not differentiate between one reservoir that was sampled fifty times from fifty reservoirs that were each sampled once. The reservoir cumulative distributions allow us to check for reservoir-sample correspondence. The situation is complicated however, in that reservoirs produce samples with a range of the various gas contents. The ideal would have been to take the mean sample for each reservoir in regard to a particular gas, but because of time constraints, the reservoirs were counted in the cumulative distribution classes for the leanest occurring sample of the respective gas found in each reservoir. For example, a reservoir with two samples, one containing 5.0 and the other containing 15.0 mole percent carbon dioxide would be counted in the 5.0-10.0 class. This predictably favors classes of the lower gas percentages at the expense of the higher, but in a consistent manner. The important matter is that the sample and reservoir cumulative distributions correspond (considering the above discussed bias) very closely. In conclusion the sample statistical analysis can be applied to reservoir determinations safely, as a relatively few samples were taken from a relatively large number of reservoirs.

FIGURE 1.3.1 METHANE FREQUENCY DISTRIBUTION

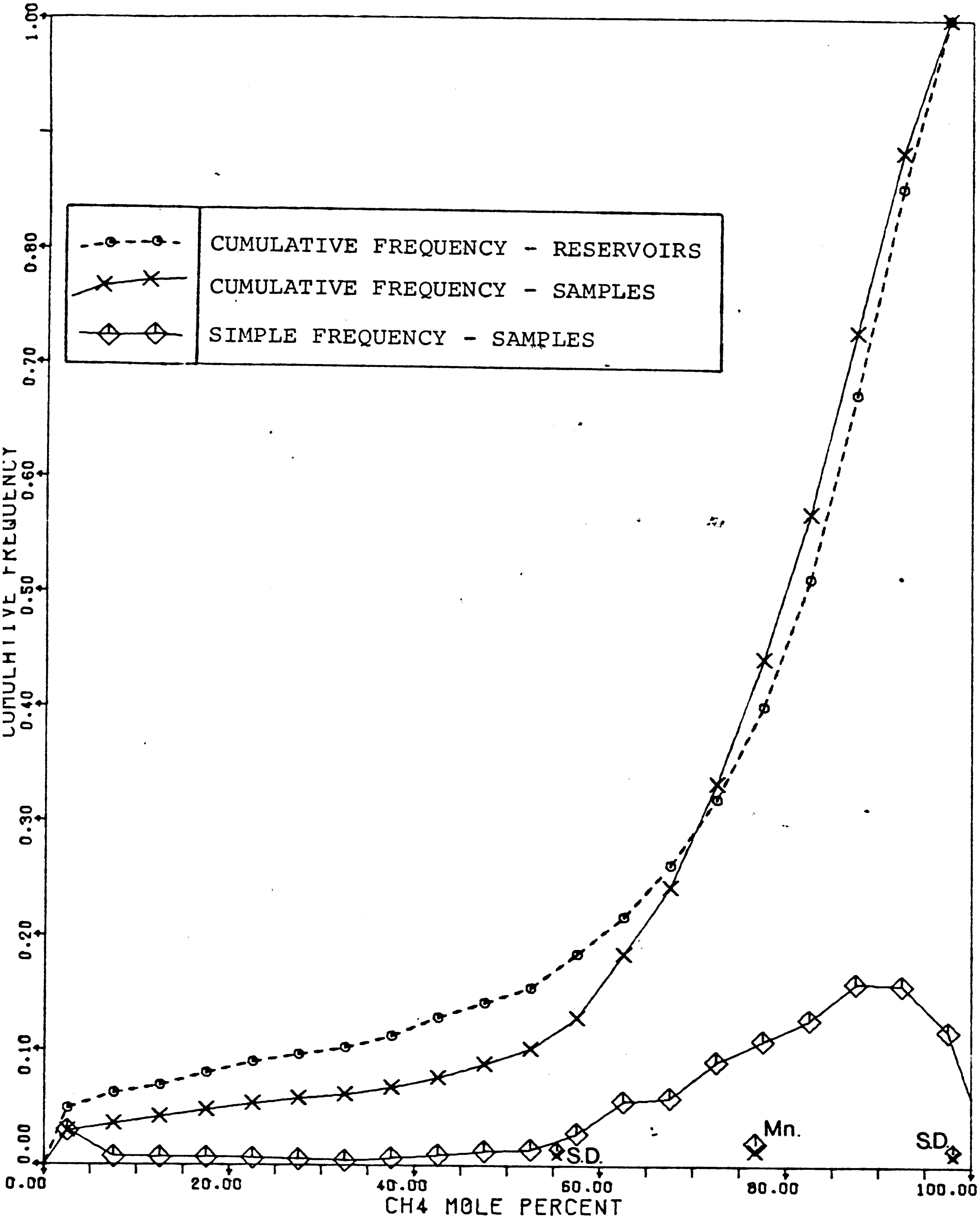
The simple distribution of the methane mole percentages is displayed for 9,356 samples, as well as the cumulative distribution for 1,354 reservoirs (dashed line). The major peak indicates that a third of the samples contained 85.0 to 95.0 mole percent methane, and 90 percent of the samples contained greater than 55.0 mole percent methane. The minor simple distribution peak at 0.0 to 5.0 mole percent contains three percent of the samples.

A bi-modal distribution of samples immediately raises the question of <u>why the different populations</u>. Possibly these two populations represent natural gas that has a different origin or mode of occurrence. We do know that the minor peak is the result of samples that are carbon dioxide rich (Figure 1.3.2), or nitrogen rich (Figure 1.3.3), or carbon dioxide and nitrogen rich as indicated in Figure 1.5.4.

Of the 1,354 reservoirs producing methane, 66 had samples containing less than 5.0 mole percent methane, 354 reservoirs had samples less than 70.0 mole percent methane, and the remaining 1,000 reservoirs did not contain samples with less than 70.0 mole percent.

METHANE FREQUENCY DISTRIBUTION

.EGEND
UMULATIVE FREQUENCY OF: CH4 MOLE PERCENT: X 9356 POINTS.
: ◇ 9356 POINTS.



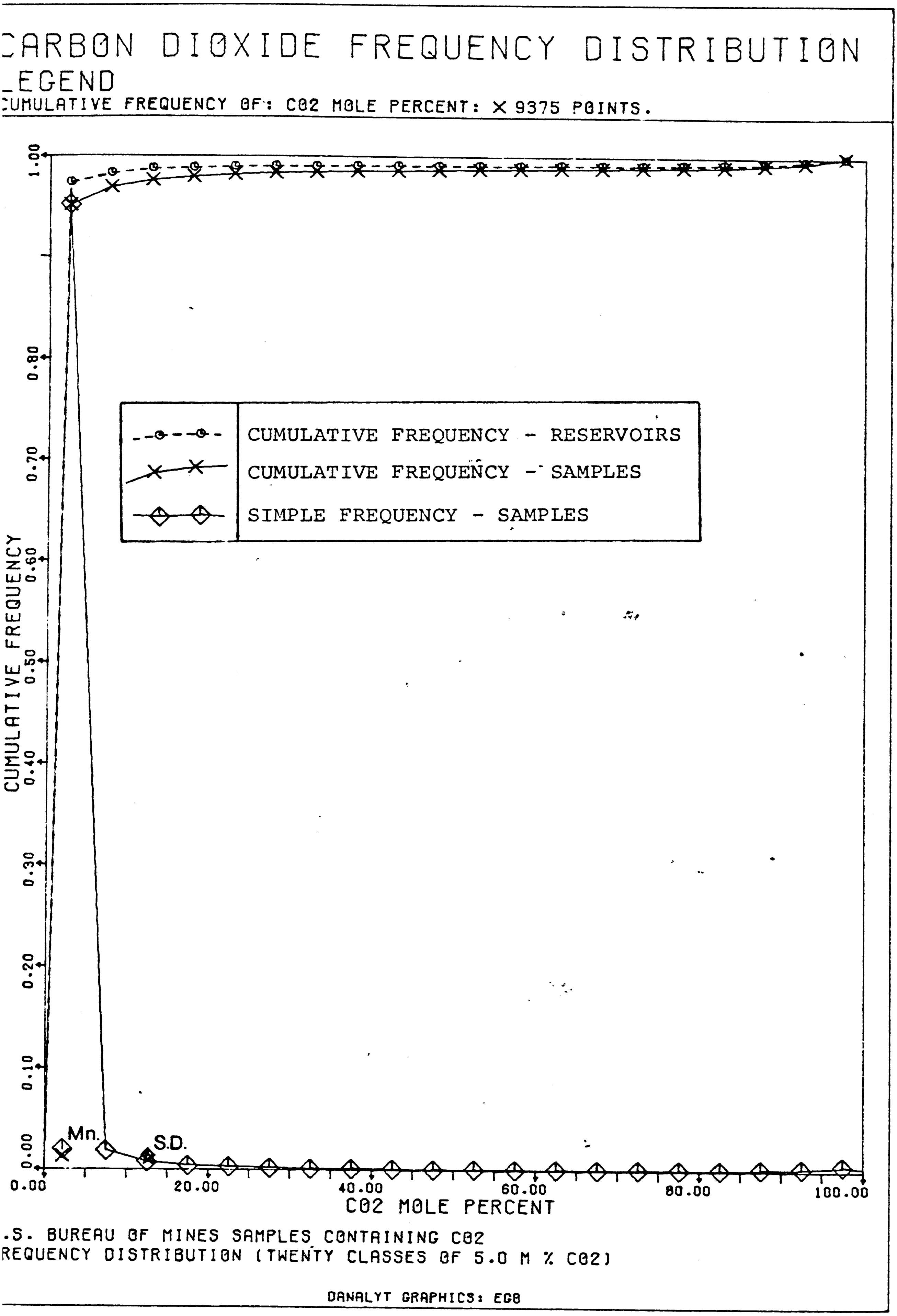
.S. BUREAU OF MINES SAMPLES CONTAINING CO2
:EQUENCY DISTRIBUTION (TWENTY CLASSES OF 5.0 M % CH4)

DANALYT GRAPHICS: EG8

FIGURE 1.3.2 CARBON DIOXIDE FREQUENCY DISTRIBUTION

The simple distribution of the carbon dioxide mole percentages are displayed for 9,375 samples and the cumulative distribution for 1,354 reservoirs. Ninety-five percent of the samples contained less than 5.0 mole percent carbon dioxide, and this class will be scrutinized more closely in Figure 1.3.2.1. The difference in number of samples with carbon dioxide mole percent less than and those greater than 5.0 percent is striking. One percent of the samples did contain carbon dioxide mole percentages greater than 80.0 percent, and there is an extreme sparsity of samples falling in the distribution mid-range. Only .44 percent of the samples had carbon dioxide contents from 40.0 to 80.0 mole percent. We again see our bi-modal distribution as noted in Figure 1.3.1.

Of the 1,354 reservoirs yielding carbon dioxide, 1,330 produced samples with carbon dioxide less than 10.0 mole percent. Only 10 reservoirs did not produce any samples with carbon dioxide less than 80.0 mole percent.



CARBON DIOXIDE FREQUENCY DISTRIBUTION
LEGEND
CUMULATIVE FREQUENCY OF: C02 MOLE PERCENT: X 9375 POINTS.
CUMULATIVE FREQUENCY - RESERVOIRS
CUMULATIVE FREQUENCY - SAMPLES
SIMPLE FREQUENCY - SAMPLES
CUMULATIVE FREQUENCY
1.00
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
Mn.
S.D.
0.00
20.00
40.00
60.00
80.00
100.00
C02 MOLE PERCENT
.S. BUREAU OF MINES SAMPLES CONTAINING C02
REQUENCY DISTRIBUTION (TWENTY CLASSES OF 5.0 M % C02)
DANALYT GRAPHICS: EG8

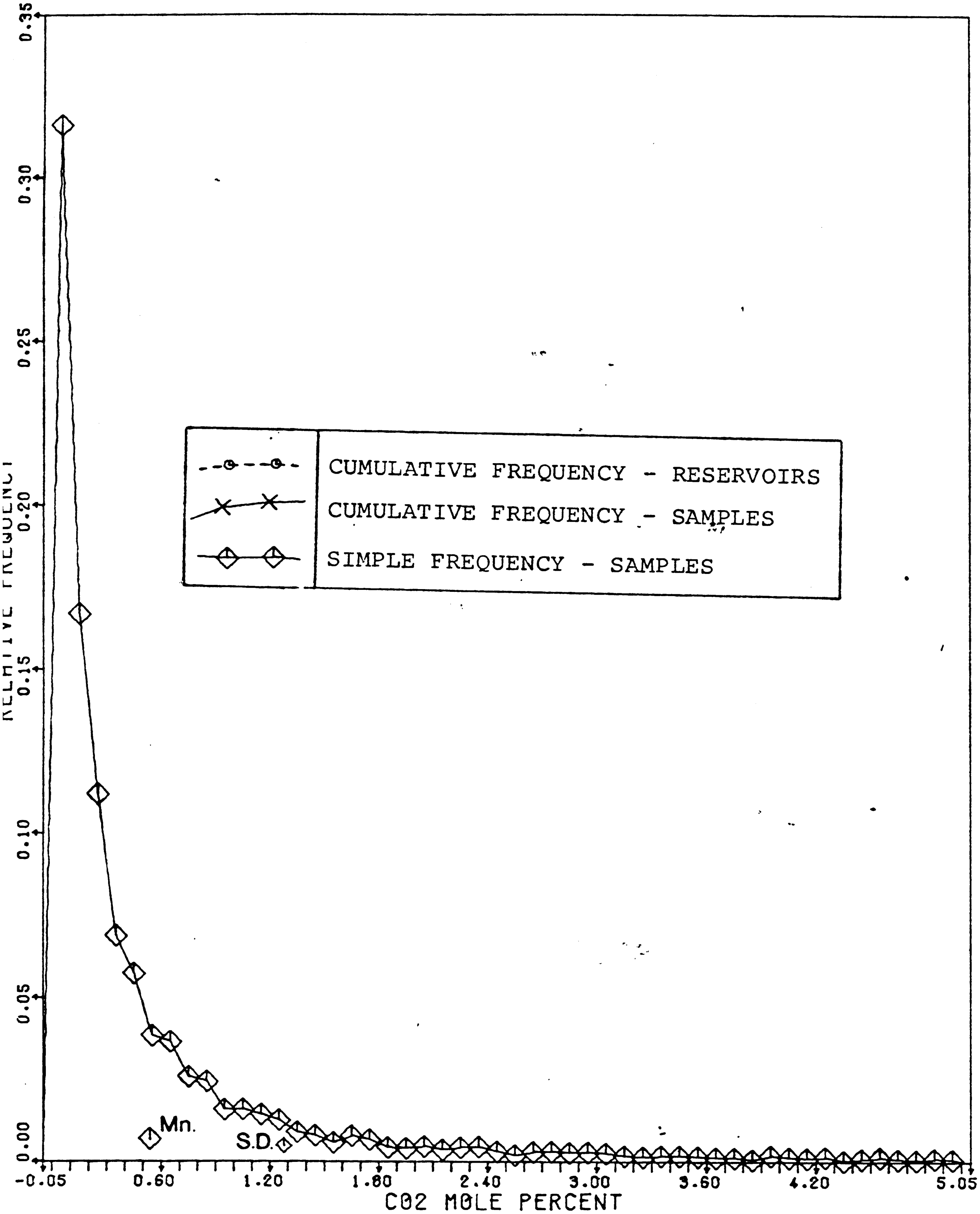
FIGURE 1.3.2.1 CARBON DIOXIDE FREQUENCY DISTRIBUTION (0-5 M% CO2)

The samples containing less than or equal to 5.0 mole percent carbon dioxide were plotted to take a closer look at the distribution of the 0.0-5.0 carbon dioxide mole percent containing samples. When the data base was built, all samples with unknown or no carbon dioxide content were excluded. Samples with gas traces (less than .1 content) were converted to .0 mole percent as the content was simply noted as trace by the Bureau of Mines. Consequently, for carbon dioxide, a value of 0.0 mole percent indicates a trace of carbon dioxide was present. Of the 8,915 samples with carbon dioxide mole percentages less than or equal to 5.0 mole percent, 2,852 samples contained either a trace or .1 mole percent carbon dioxide. 8,404 samples contained less than 2.0 mole percent carbon dioxide.

ARBON DIOXIDE FREQUENCY DISTRIBUTION

EGEND

:LATIVE FREQUENCY OF: CO2 MOLE PERCENT: ◈ 8915 POINTS.



S. BUREAU OF MINES SAMPLES CONTAINING CO2

:EQUENCY DISTRIBUTION (FIFTY CLASSES OF .1 M % CO2)

DANALYT GRAPHICS: EG8

FIGURE 1.3.3 NITROGEN FREQUENCY DISTRIBUTION

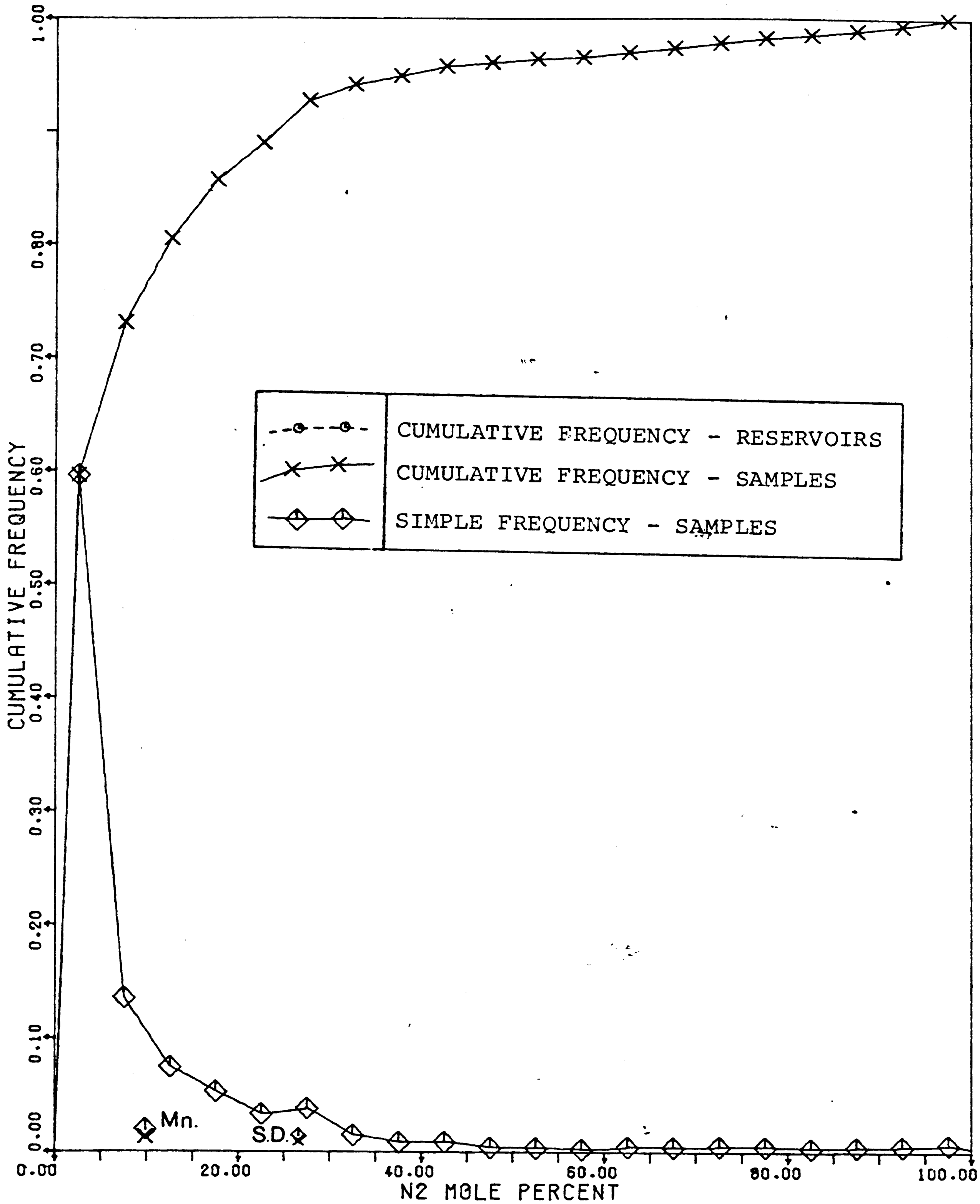
The simple and cumulative distributions are displayed for 9,365 nitrogen containing samples. The 0.-5.0 mole percent class contains 60 percent of the samples, and ninety percent of the samples yielded less than 30.0 mole percent nitrogen. With nitrogen content greater than 50.0 mole percent the classes are approximately equal.

NITROGEN FREQUENCY DISTRIBUTION

LEGEND

CUMULATIVE FREQUENCY OF: N2 MOLE PERCENT: X 9365 POINTS.

: ◇ 9365 POINTS.



U.S. BUREAU OF MINES SAMPLES CONTAINING CO2

FREQUENCY DISTRIBUTION (TWENTY CLASSES OF 5.0 M % N2)

DANALYT GRAPHICS: EG8

1.4 PHYSICAL DESCRIPTION PLOTS

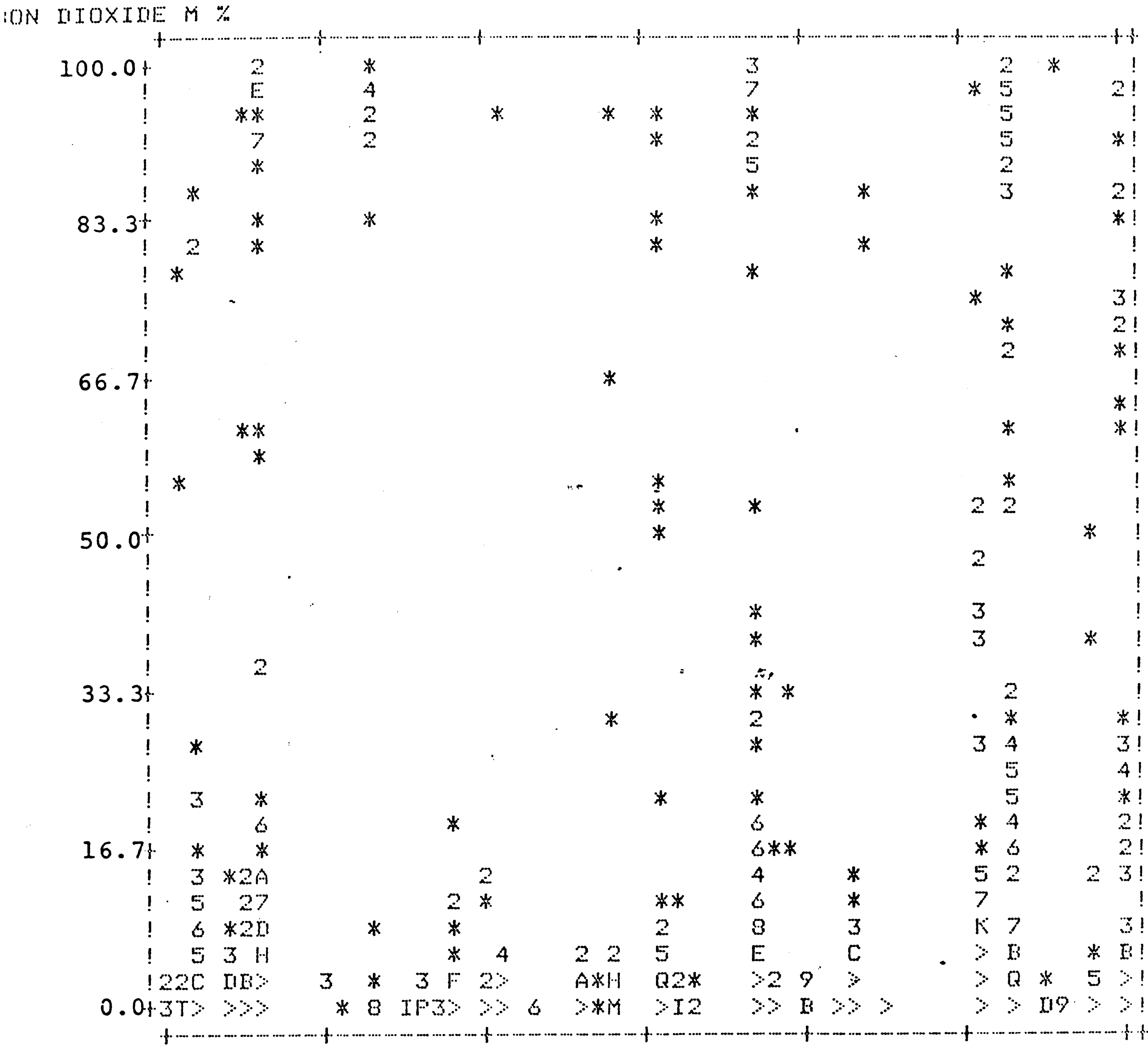
The occurrence or relationship of carbon dioxide containing samples with various physical descriptive parameters is displayed by utilizing the Danalyt Printer Plot module. As the Printer Plot module is a quick, line-printer plotting routine, the axis scaling and plot position may span a significant portion of a particular axis; however, the Printer Plot module indicates the number of points falling within one print location by symbols as defined in Table 1.4.1. The number of total points plotted is indicated at the margin of each plot, and these numbers will vary from plot to plot because of unknowns in the subset. Appropriate narrative accompanies each plot to quickly explain the significant occurrences or relationships of carbon dioxide.

TABLE 1.4.1 PRINTER PLOT MODULE SYMBOLS

NO. OF PLOTTED POINTS	PLOT SYMBOLS	NO. OF PLOTTED POINTS	PLOT SYMBOLS
None	Blank	19	J
1	*	20	K
2	2	21	L
3	3	22	M
4	4	23	N
5	5	24	O
6	6	25	P
7	7	26	Q
8	8	27	R
9	9	28	S
10	A	29	T
11	B	30	U
12	C	31	V
13	D	32	W
14	E	33	X
15	F	34	Y
16	G	35	Z
17	H	>35	>
18	I		

FIGURE 1.4.2 STATE VS. CARBON DIOXIDE MOLE PERCENT

9,228 points are plotted to locate the states that produced high carbon dioxide content samples. The major natural gas producing states generally contain at least some carbon dioxide saturated stratigraphic zones. States from which a notable number of high carbon dioxide gas samples (10 or more greater than 60.0 mole percent) were obtained are Colorado, Idaho, New Mexico, Utah, and Wyoming. The number of points plotted (applicable samples collected) for each state is noted along the abscissa.

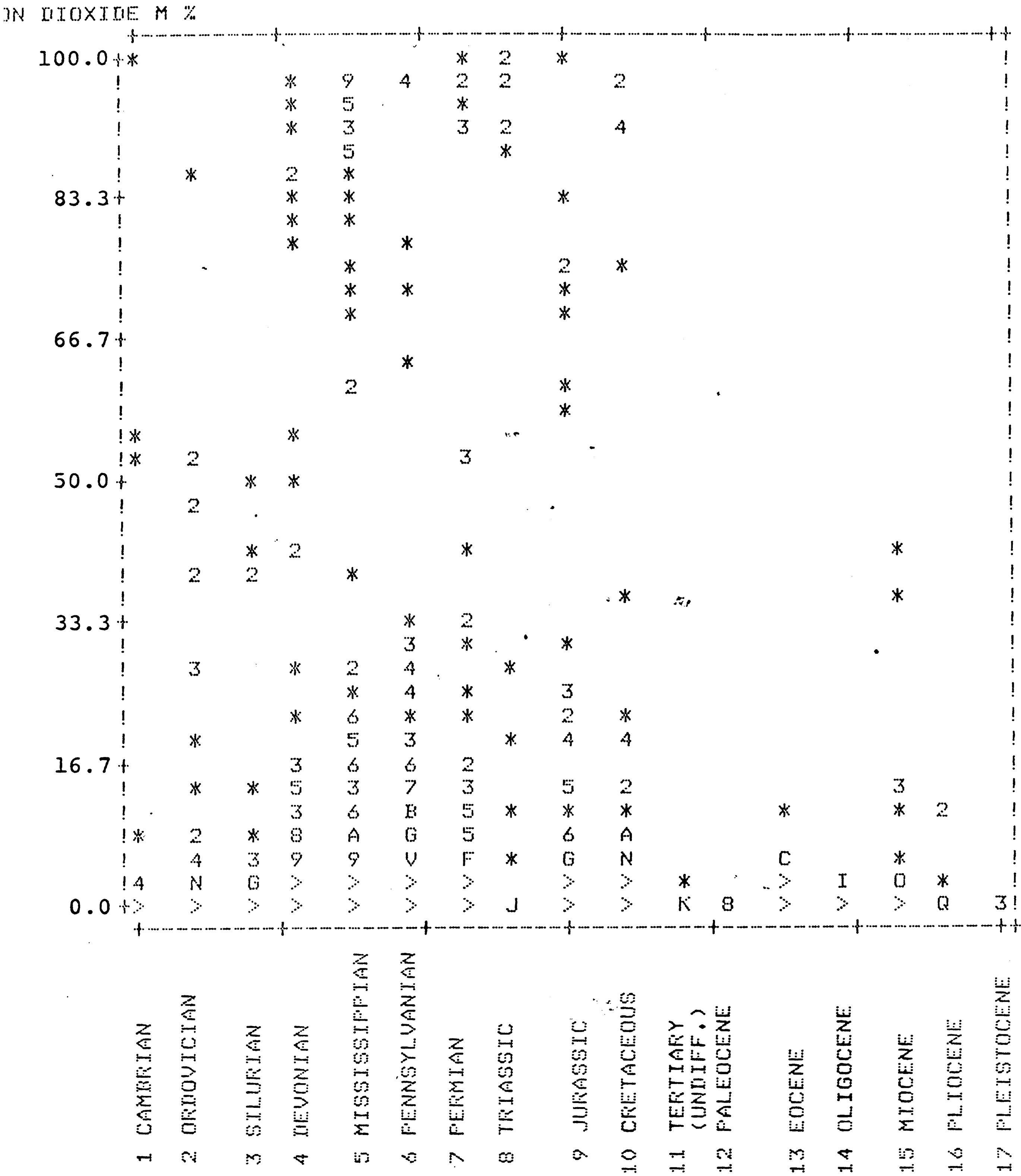


NO. OF SAMPLES FOR EACH STATE	
ALABAMA	5
ALASKA	33
ARIZONA	82
ARKANSAS	149
CALIFORNIA	132
COLORADO	416
CONNECTICUT	0
DELAWARE	0
FLORIDA	3
GEORGIA	1
HAWAII	0
IDAHO	20
ILLINOIS	18
INDIANA	28
IOWA	3
KANSAS	1091
KENTUCKY	77
LOUISIANA	304
MAINE	0
MARYLAND	6
MASSACHUSETTS	0
MICHIGAN	112
MINNESOTA	2
MISSISSIPPI	44
MISSOURI	0
MONTANA	172
NEBRASKA	21
NEVADA	3
NEW HAMPSHIRE	0
NEW JERSEY	0
NEW MEXICO	605
NEW YORK	45
NORTH CAROLINA	2
NORTH DAKOTA	20
OHIO	158
OKLAHOMA	1656
OREGON	2
PENNSYLVANIA	148
RHODE ISLAND	0
SOUTH CAROLINA	0
SOUTH DAKOTA	0
TENNESSEE	0
TEXAS	2825
UTAH	260
VERMONT	0
VIRGINIA	14
WASHINGTON	10
WEST VIRGINIA	337
WISCONSIN	0
WYOMING	424

POINTS= 9228 STATE

FIGURE 1.4.3 GEOLOGIC TIME UNIT VS CARBON DIOXIDE MOLE PERCENT

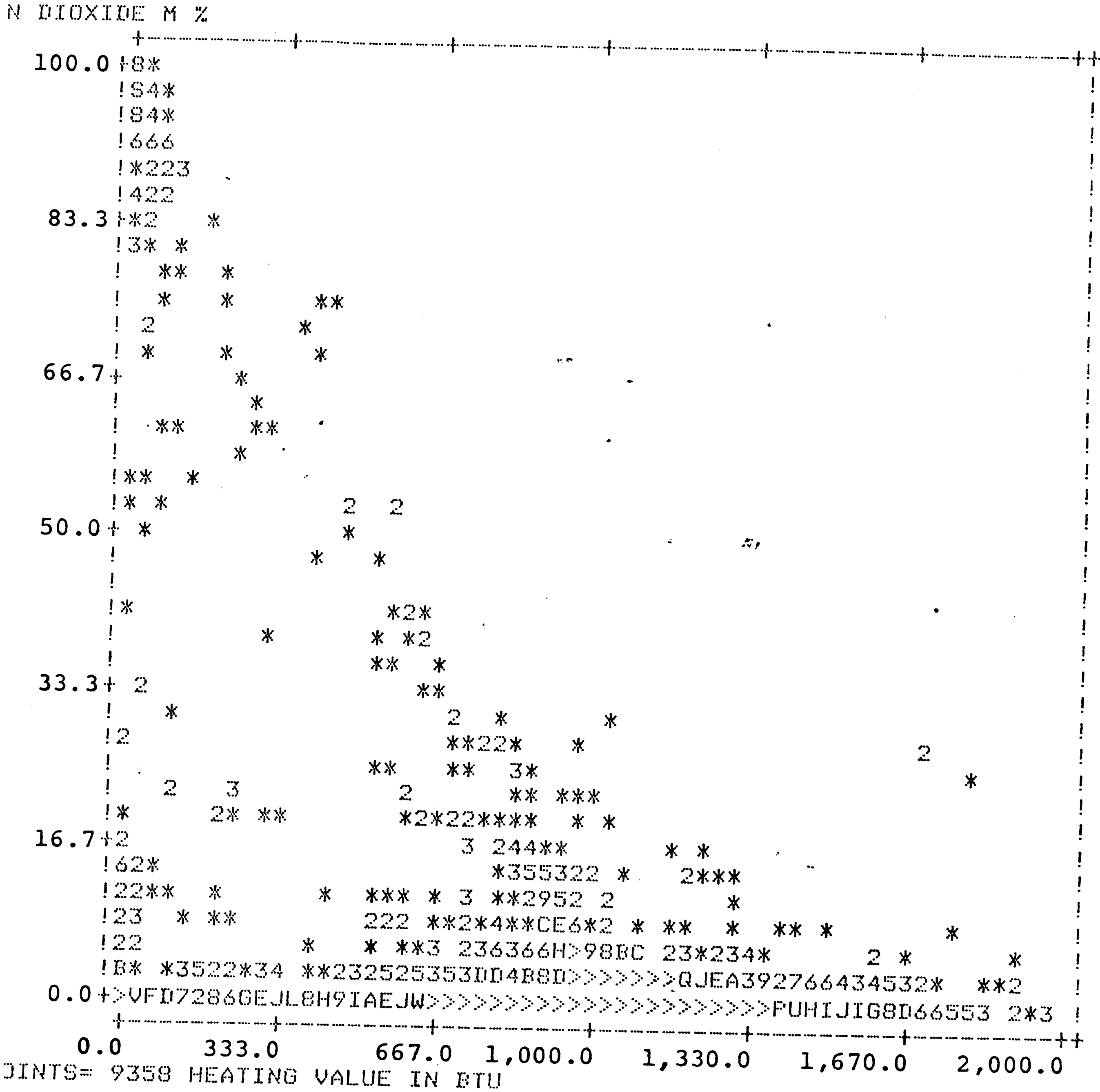
Gas samples containing high amounts of carbon dioxide were obtained from reservoirs in formations of Paleozoic and Mesozoic age. Few high carbon dioxide gas samples were collected from Tertiary age formations (either Tertiary System undifferentiated or known Series), and no high carbon dioxide gas samples were collected from Quaternary age formations. The number of samples for each geologic time unit are also included along the abscissa for easy reference.



SAMPLES CH GEO. UNIT	171	252	241	511	862	2650	1279	30	197	1089	21	8	433	414	245	29	3

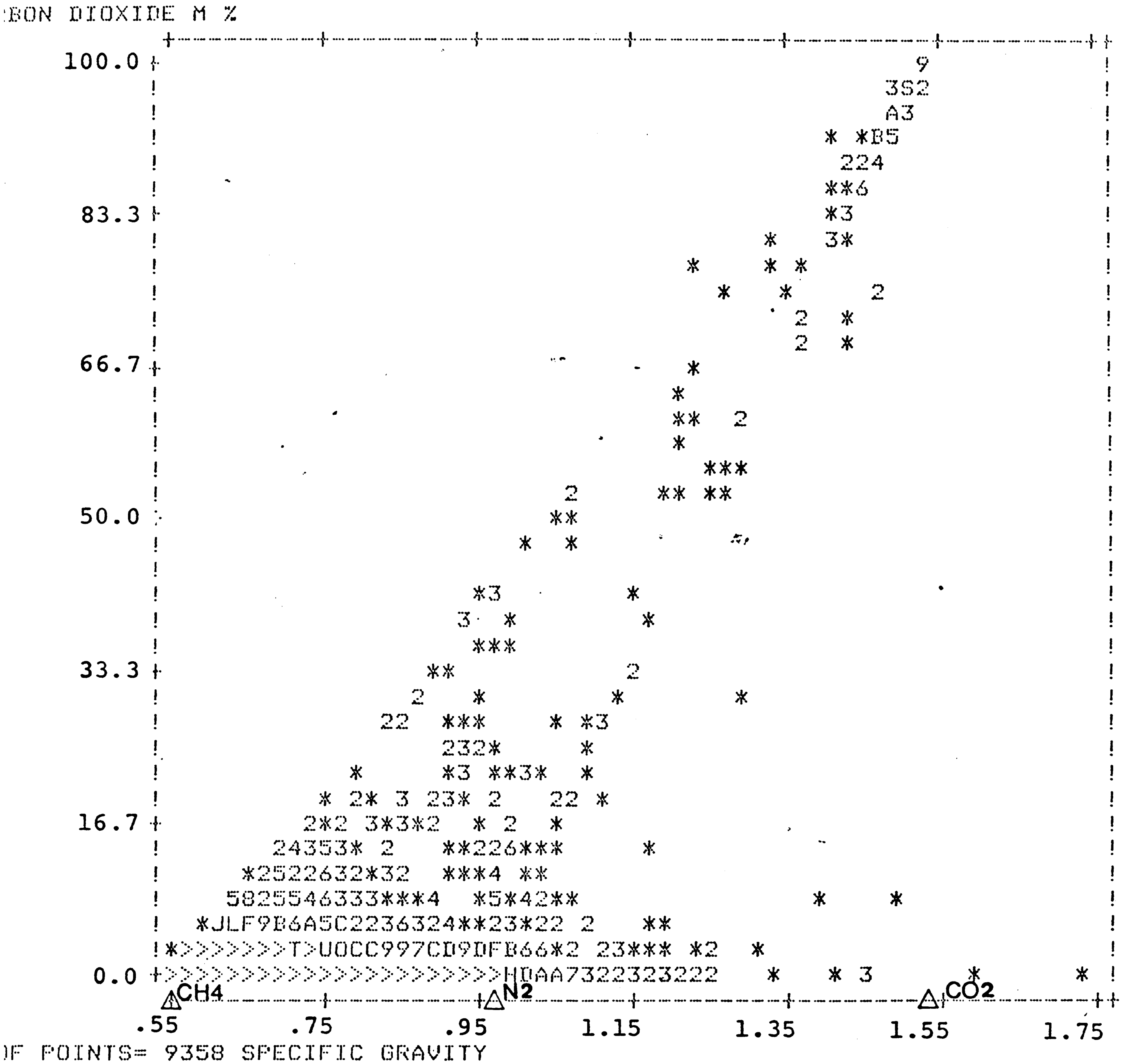
POINTS= 8435 GEOLOGIC TIME UNIT

FIGURE 1.4.4 HEATING VALUE VS. CARBON DIOXIDE MOLE PERCENT



The heating value measured was gross heat on a dry basis, calculated in B.T.U. per cubic foot. Most samples generated about 1,000 B.T.U of heat, which is essentially the heating value of methane (1013 B.T.U.). The inverse relationship of carbon dioxide content in the gas with the heating value is readily apparent.

FIGURE 1.4.5 SPECIFIC GRAVITY VS. CARBON DIOXIDE MOLE PERCENT



Carbon dioxide content has a marked effect on the specific gravity of a gas sample. The specific gravity of pure carbon dioxide is 1.529, and the positive correlation of carbon dioxide mole percent with the specific gravity of the sample is easily seen. Pointers at the base of the plot denote the specific gravities of pure methane (.5544), nitrogen (.9672) and carbon dioxide.

1.5 RELATIONAL PLOTS OF GAS COMPONENTS

The Bureau of Mines determined the mole percent contribution of various gases to each natural gas sample. The natural gas components analyzed were: methane, ethane, propane, n-butane, iso-butane, n-pentane, iso-pentane, cyclopentane, hydrocarbons of greater molecular weight than pentane (hexanes plus), nitrogen, oxygen, argon, hydrogen, hydrogen sulfide, carbon dioxide and helium. In order to simplify our analysis, the lighter plant liquids, ethane and propane, were added together, as well as the heavier plant liquids, butanes through hexanes plus for each gas sample. The components oxygen and hydrogen are undoubtedly gas contaminants and were scrutinized in the analysis solely as data quality checks. Of the 10,553 gas analyses in the data base, 10,349 contained oxygen less than 3 percent and 10,521 contained hydrogen less than 1 percent.

1.5.1 MULTI-VARIATE ANALYSIS

A multi-variate analysis is complicated by the interrelationships of the variables involved in a particular system. Here we are concerned with variables that contribute to a 100.0 percent total amount. In a simple two variable system, a scatter diagram would plot data points along line A-A' as in Figure 1.5.1 for variables X and Y. A third variable in the system would result in points being plotted within the triangle. The more variables in the system, the greater the "pull" of the point concentration toward the axes origin, in the direction of the arrow in Figure 1.5.1. This is simply because any two variables contribute less to the total when more variables are in the system, and we are assuming all of the variables are weighted equally, i.e. that the means of the variables are approximately equal. However, our gas components do not contribute equally to the total. The major contributors are methane, nitrogen, and carbon dioxide, whereas the hydrocarbons with a molecular weight greater than methane contribute to a lesser extent and helium, hydrogen sulfide or argon contribute least. So our multi-variate system is weighted in favor of certain gas constituents to varying degrees. Therefore, the great majority

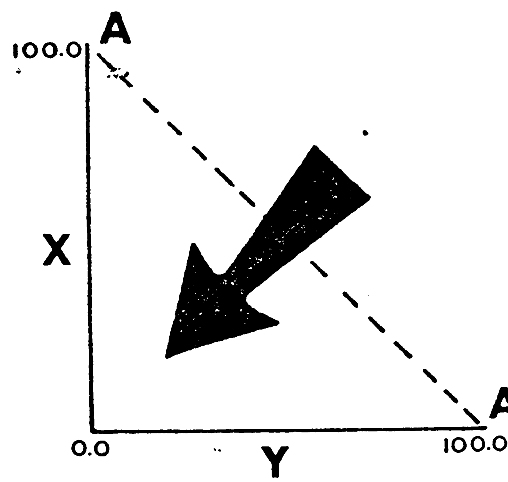


FIGURE 1.5.1
GENERAL RELATIONSHIP DIAGRAM

of the plotted points are essentially under the control of methane, nitrogen and carbon dioxide. The other gases exert much less control over the plot locations; however, note that the effect is cumulative in the direction of the arrow in Figure 1.5.1 for gases that are not axis-specified for a particular plot.

1.5.2 CORRELATIVE ANALYSIS

Correlative analysis of the various gas constituents and proper plot interpretation must also take into account the relative contribution of the various gases to the natural gas sample sum totals. The various gases can be generally divided into two groups, major contributors and minor contributors as suggested in the previous paragraph. Positive correlations of minor vs. minor, minor vs. major, or major vs. major gas contributors look very different when plotted.

1.5.2.1 MINOR VS. MINOR GAS POSITIVE CORRELATION

A positive correlation of a minor vs. minor gas would appear as shown in the generalized diagram of Figure 1.5.2.1, with the area of point concentration in the shaded area. As minor gases make up only a small percentage of the gas samples, they are not affected by the "hypotenuse limit" and exhibit a traditionally conceived linear positive correlation. A good example of a minor vs. minor gas positive correlation is shown by argon and helium, Figure 1.5.8.

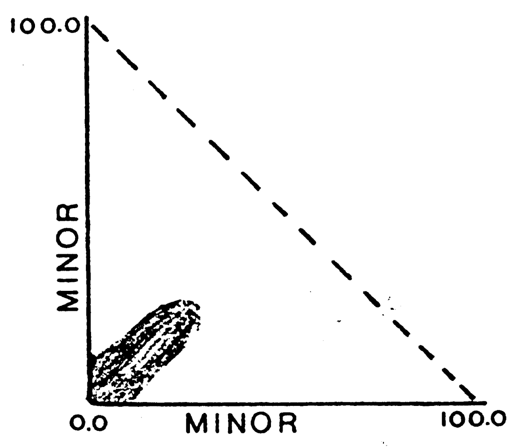


FIGURE 1.5.2.1 MINOR VS. MINOR GAS POSITIVE CORRELATION

1.5.2.2 MINOR VS. MAJOR GAS POSITIVE CORRELATION

Figure 1.5.2.2 indicates the general point concentration of a minor vs. major gas positive correlation. The major gas severely limits the sample space available to the associated minor gas. The highest concentrations of the minor gas are found with less than the highest concentrations of the major gas. Helium mole percent vs. nitrogen mole percent plot, Figure 1.5.9 is a good example of a minor vs. major gas positive correlation.

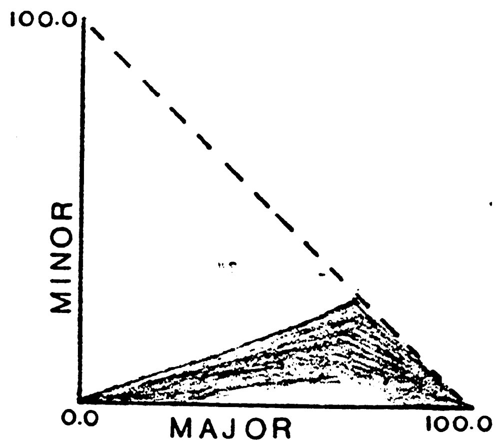


FIGURE 1.5.2.2 MINOR VS. MAJOR GAS POSITIVE CORRELATION

1.5.2.3 MAJOR VS. MAJOR GAS POSITIVE CORRELATION

A major vs. major gas positive correlation would result in the point concentration lying along the hypotenuse, as indicated in Figure 1.5.2.3. The two major gases tend to occur and to contribute together to make up the greater part of the gas samples. Nitrogen mole percent plotted against methane mole percent as in Figure 1.5.3 exhibits this type of positive correlation plot.

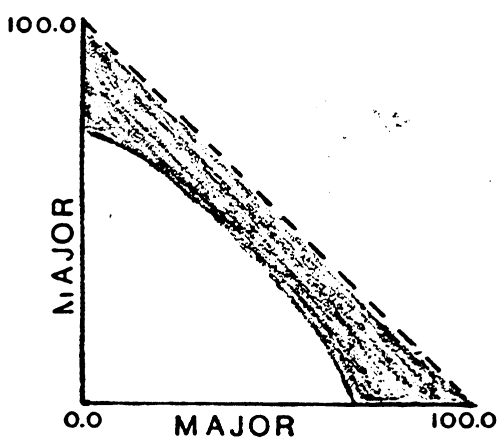
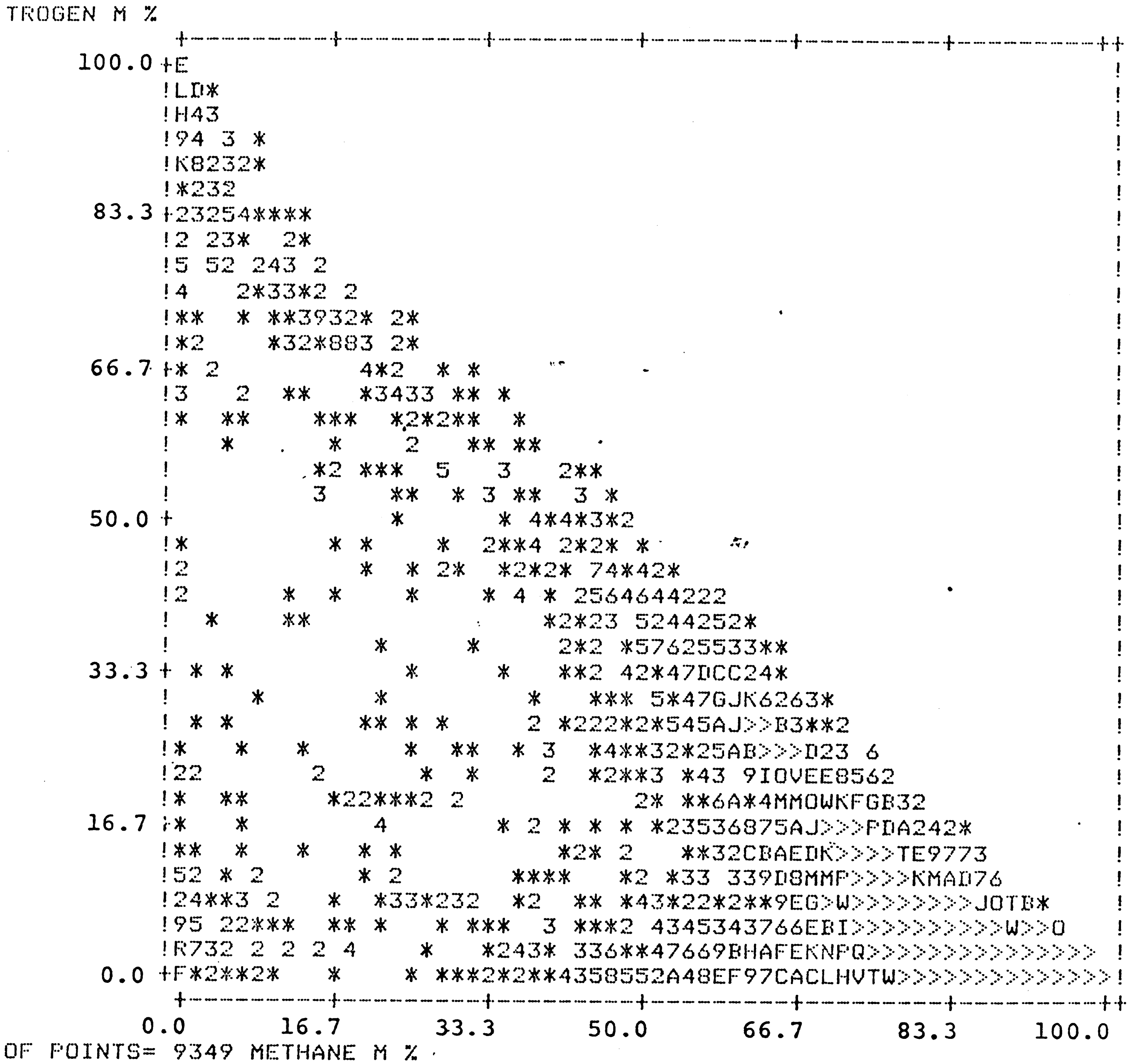


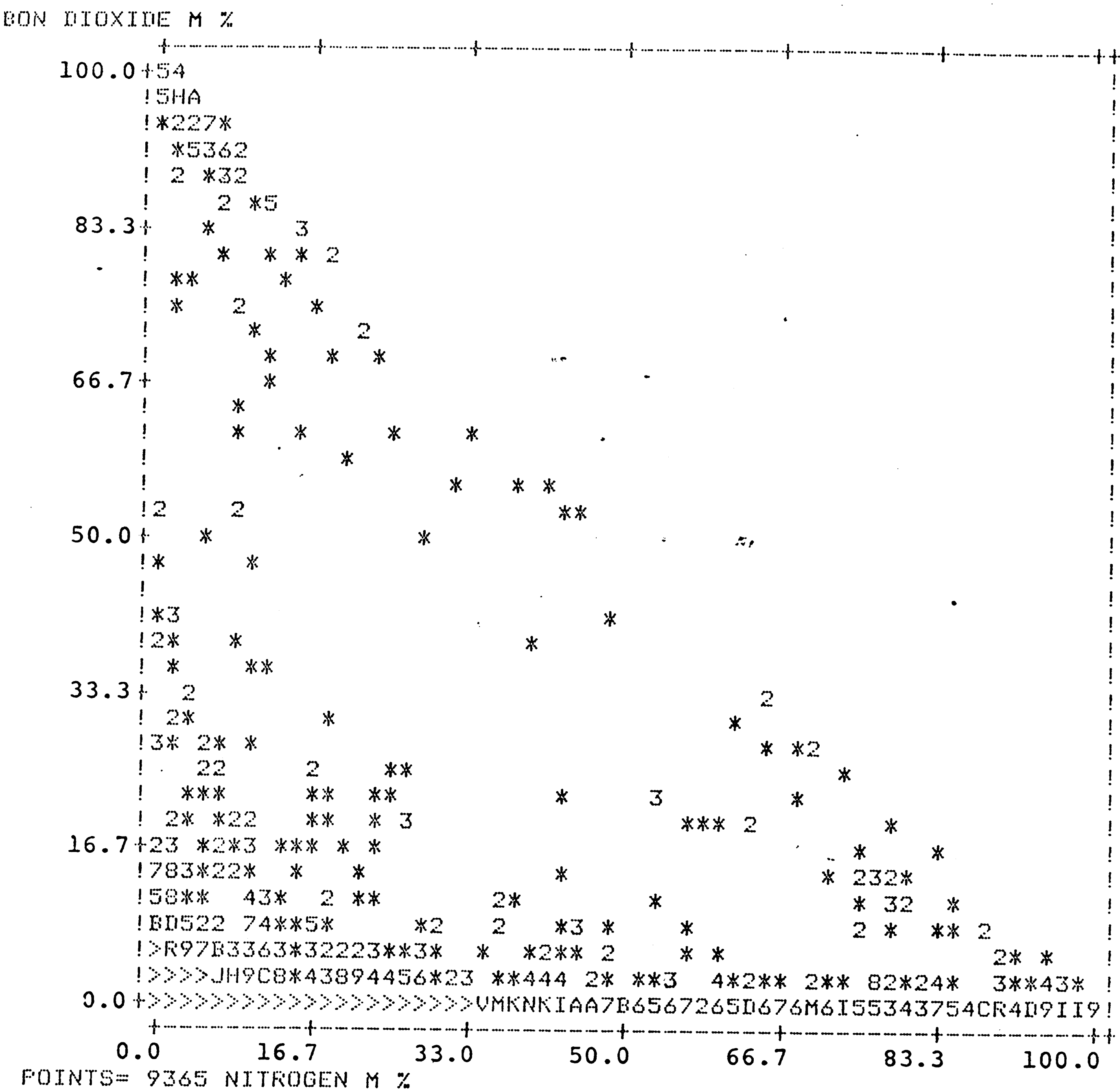
FIGURE 1.5.2.3 MAJOR VS. MAJOR GAS POSITIVE CORRELATION

FIGURE 1.5.3 METHANE MOLE PERCENT VS. NITROGEN MOLE PERCENT



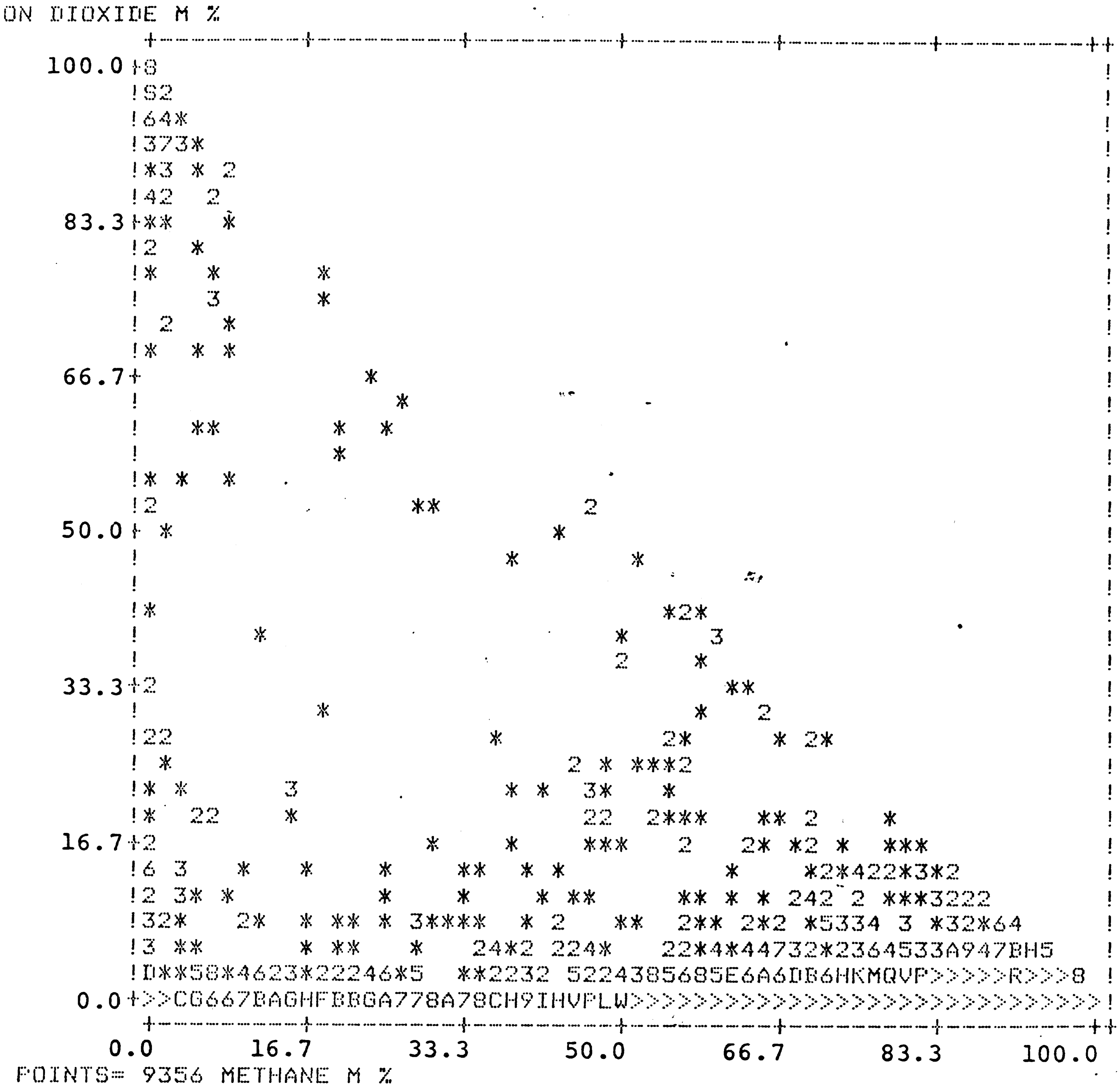
This plot reveals the strong positive correlation of nitrogen and methane in the gas samples. Nitrogen and methane are associated and usually contribute together to make up at least 70.0 percent of the natural gas contained in each sample. Samples with 30.0 to 60.0 mole percent methane appear to contain either small or large percentages of nitrogen, and the data cluster with methane and nitrogen sample content less than 10.0 percent is the result of gas samples with high carbon dioxide percentages, as revealed in Figure 1.5.4.

FIGURE 1.5.4 CARBON DIOXIDE MOLE PERCENT VS. NITROGEN MOLE PERCENT



The concentration of points with high carbon dioxide content natural gas is easily seen. Gas samples with a high carbon dioxide mole percentage tend to have the remaining portion of the sample made up of nitrogen. However, gas samples with carbon dioxide less than 60.0 mole percent either have nitrogen comprising most of the remaining sample space or not. The methane-rich samples plot near the origin, and the previously noted association of nitrogen and methane is indicated by the large number of points plotted along the nitrogen axis.

FIGURE 1.5.5 CARBON DIOXIDE MOLE PERCENT VS. METHANE MOLE PERCENT



Carbon dioxide mole percent plotted against methane mole percent provides another view of the previously discussed CO2-N2-CH4 relationships. The complete absence of samples containing comparable amounts of carbon dioxide, nitrogen and methane is striking.

An interesting observation is the close similarity of this plot with Figure 1.4.4 HEATING VALUE VS. CARBON DIOXIDE MOLE PERCENT. As nitrogen and carbon dioxide have no heating value and pure methane yields 1013 B.T.U., a point scatter has been produced similar to Figure 1.5.5.

1.5.6 CARBON DIOXIDE-NITROGEN-METHANE RELATIONSHIPS

The frequency diagrams of section 1.3 display the occurrence of carbon dioxide, nitrogen and methane in the natural gas samples. Methane is by far the dominant constituent as indicated by the Methane frequency diagram (Figure 1.3.1). Nitrogen containing samples contributed almost equally to the classes with nitrogen sample contents from 50.0 to 100.0 mole percent (Figure 1.3.3). Carbon dioxide occurred in either extremely low or extremely high amounts with virtually no representation in the midrange (Figure 1.3.2). The frequency diagrams give us a statistical explanation of the contribution of the gases to the samples, but an examination of the gas relational plots (Section 1.5) is necessary in order to discover associations and relationships among the various constituents.

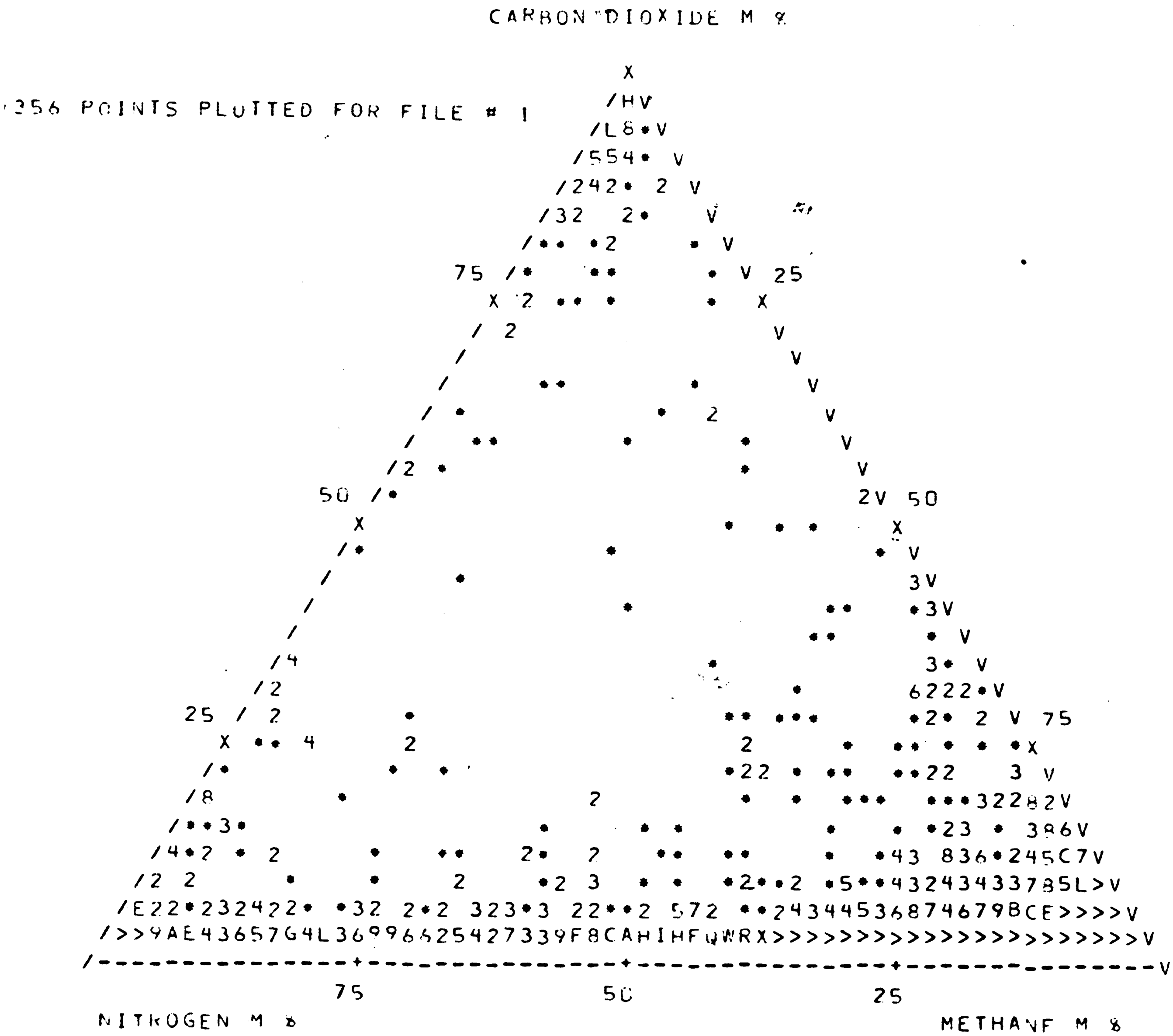
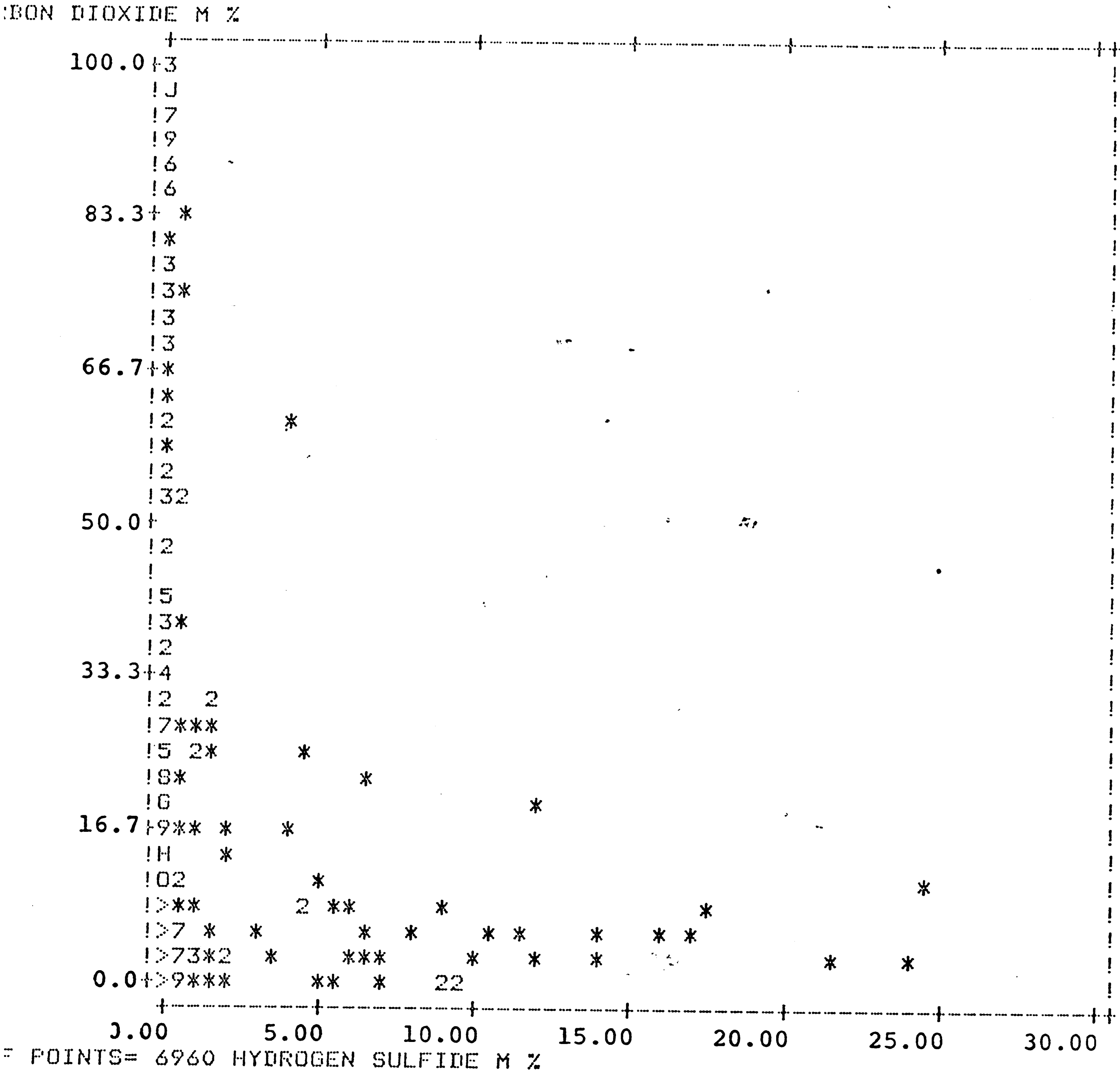


FIGURE 1.5.6 CO_2 - N_2 - CH_4 Relationships

A positive correlation exists for argon and helium (Figure 1.5.8), and for helium and nitrogen (Figure 1.5.9); however, this tells us relatively little about the inclinations of carbon dioxide. Of greater interest is the relationship of carbon dioxide with nitrogen with methane as explored in Figures 1.5.3, 1.5.4 and 1.5.5. Figure 1.5.9 is a ternary diagram summing up the indicated carbon dioxide, nitrogen and methane relationships.

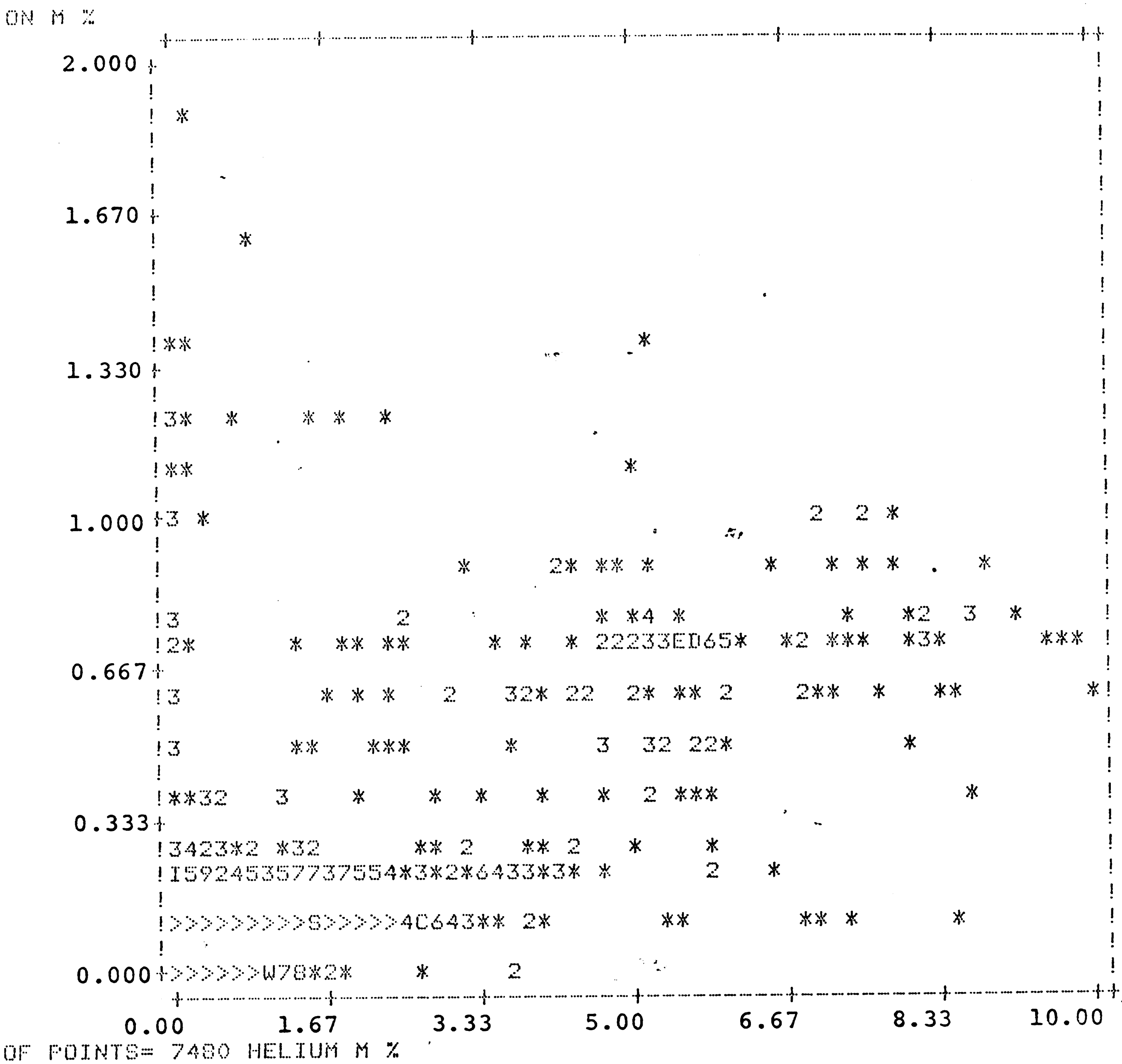
As expected, the greatest number of samples by far have a high methane content; however, a number of samples contain significant amounts of nitrogen or high carbon dioxide mole percentages. The strong nitrogen-methane correlation as discussed with Figure 1.5.3 is seen along the N_2-CH_4 axis. The tendency for high carbon dioxide containing samples to also contain nitrogen as noted in Figure 1.5.4 is shown, as well as the virtual absence of samples containing comparable amounts of carbon dioxide, nitrogen and methane. (Noted in Figure 1.5.5).

FIGURE 1.5.7 CARBON DIOXIDE MOLE PERCENT VS. HYDROGEN SULFIDE MOLE PERCENT



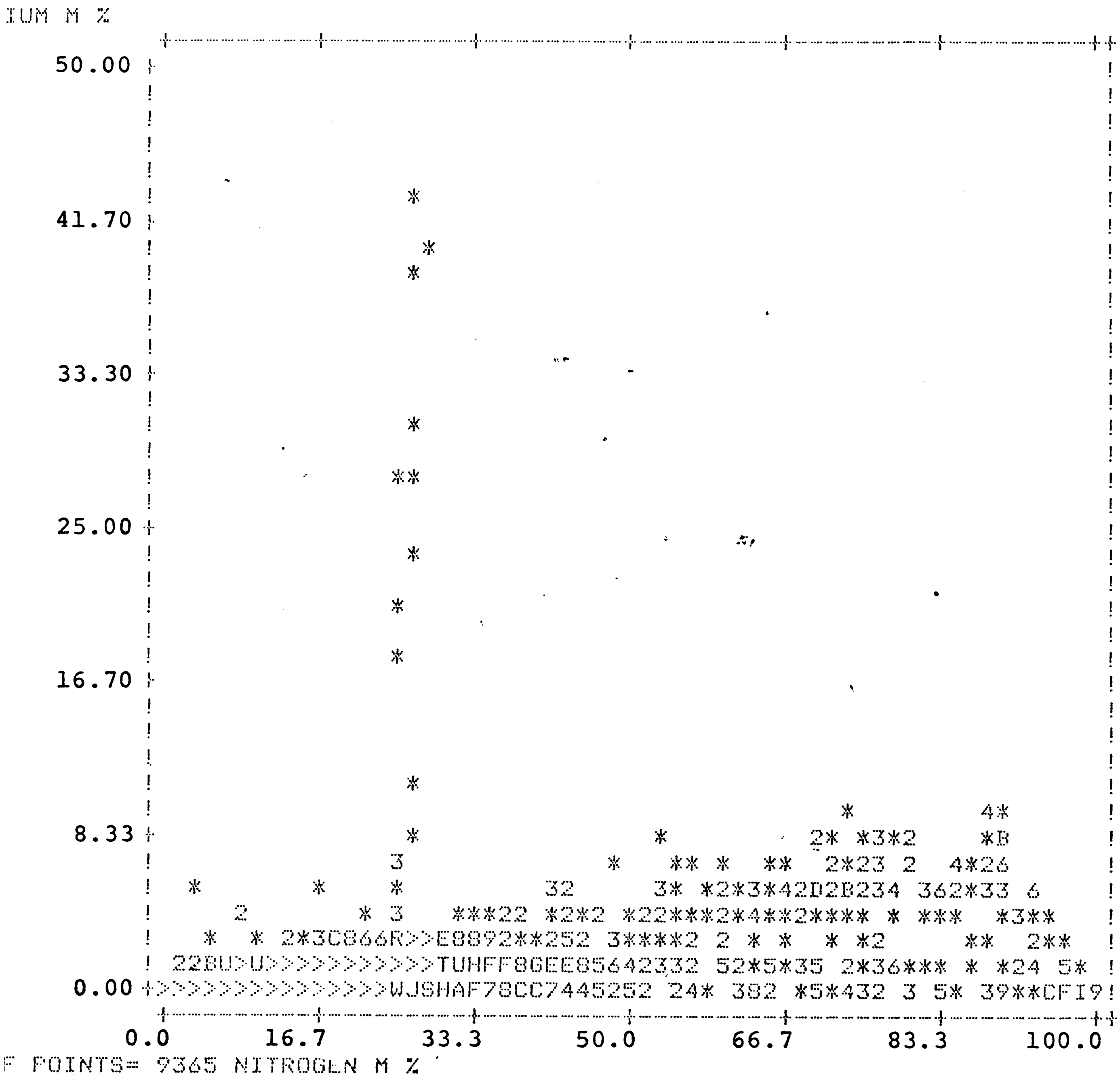
Only 15 gas samples of the 153 samples with carbon dioxide greater than 30.0 mole percent contained any hydrogen sulfide at all. However, only 74 out of the 6960 samples with a known hydrogen sulfide value exceeded .5 mole percent. The Bureau of Mines has indicated the hydrogen sulfide values may be unreliable due to absorption during sampling; this would result in hydrogen sulfide values being lower than the true natural gas content.

FIGURE 1.5.8 ARGON MOLE PERCENT VS. HELIUM MOLE PERCENT



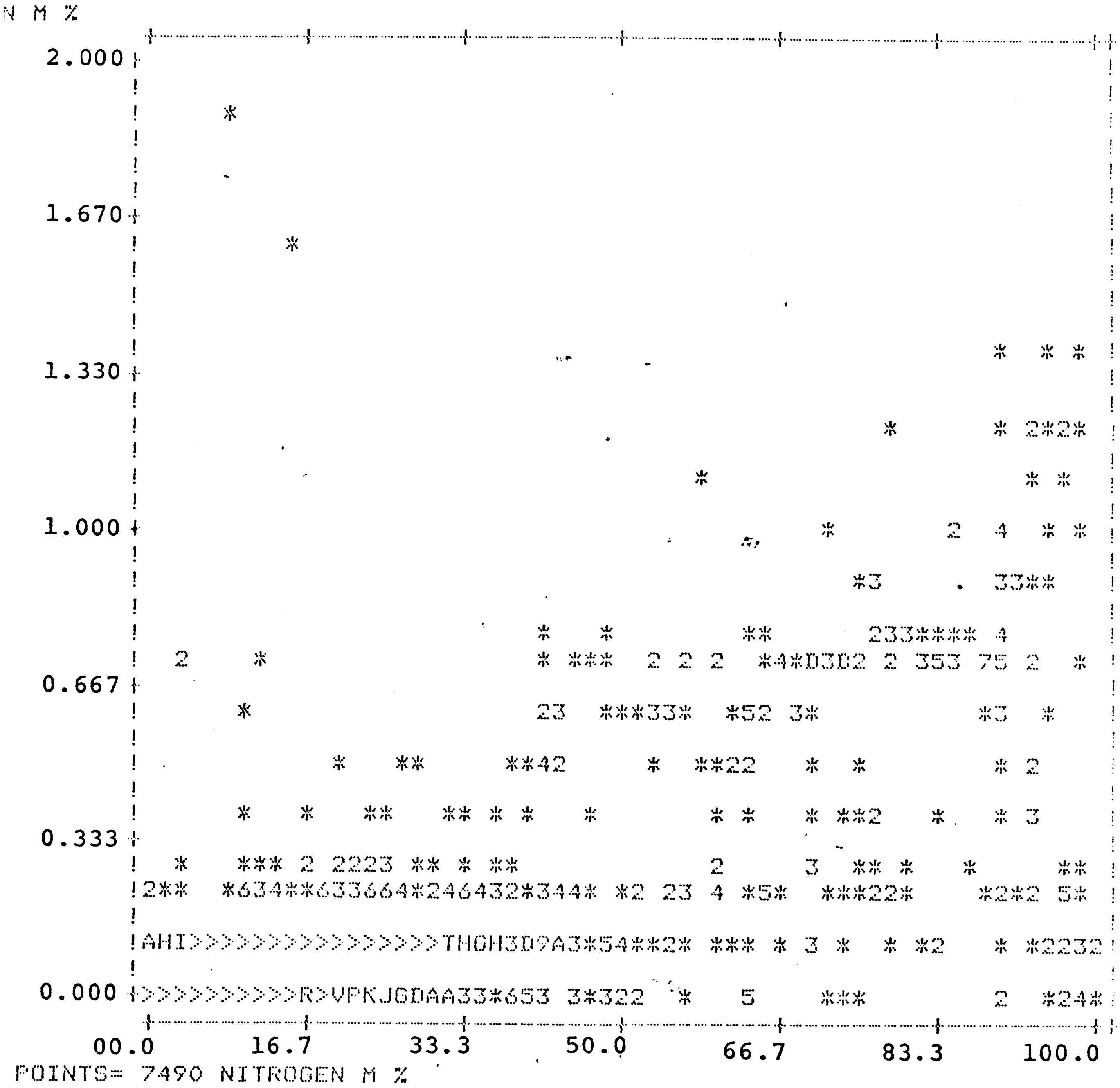
Argon and helium are minor constituents of natural gas and accordingly comprise only a small portion within the gas samples. The positive correlation of argon and helium is easily seen, with samples containing argon also containing helium in proportional amounts. The slope of the line of correlation is approximately .13, therefore a sample with 5.0 mole percent helium ideally should contain .65 mole percent argon.

FIGURE 1.5.9 HELIUM MOLE PERCENT VS. NITROGEN MOLE PERCENT



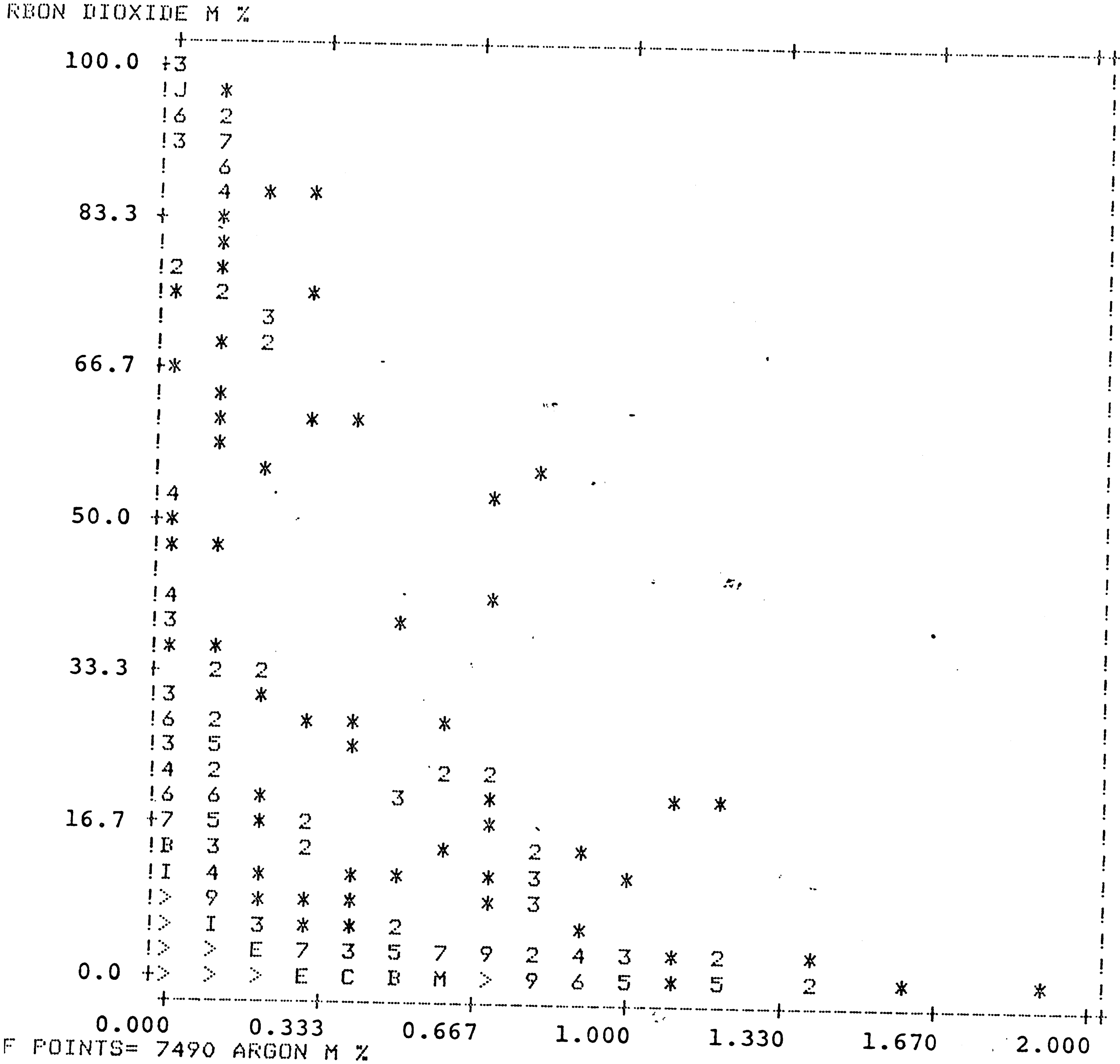
Helium is associated with nitrogen in occurrence, and samples composed largely of nitrogen contained substantial amounts of helium. The string of points at 25.0 mole percent nitrogen with helium contents greater than 5.0 mole percent are all samples from Cliffside Field, Texas. Ignoring these anomalous points, the samples with the highest helium content come from samples containing 70.0-90.0 mole percent nitrogen.

FIGURE 1.5.10 ARGON MOLE PERCENT VS. NITROGEN MOLE PERCENT



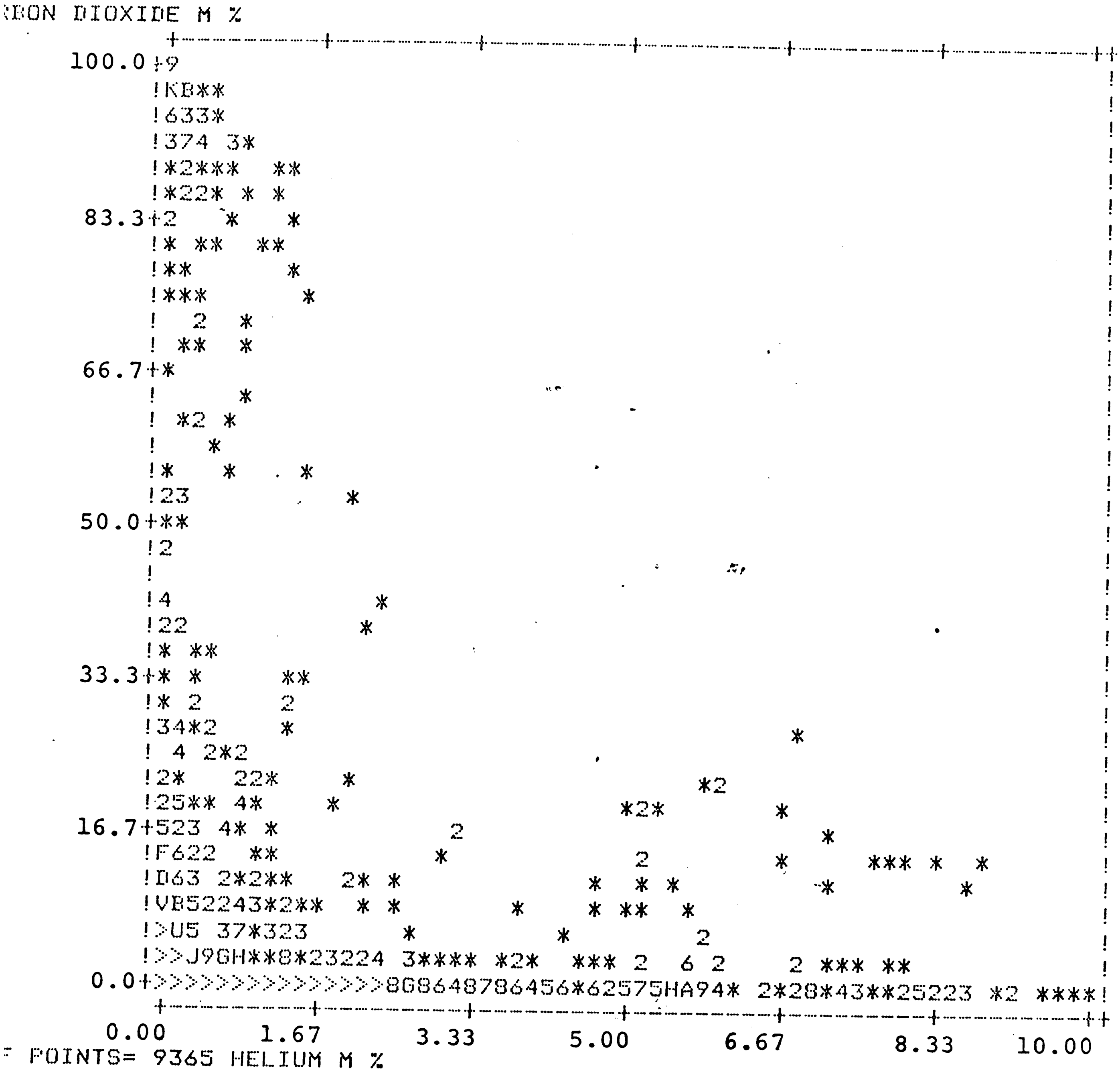
Nitrogen and argon are clearly associated in occurrence, with samples containing 70.0-98.0 percent nitrogen yielding over 1.0 mole percent argon. From Figures 1.5.8 and 1.5.9, and considering this plot, we see a close association of nitrogen, helium and argon.

FIGURE 1.5.11 CARBON DIOXIDE MOLE PERCENT VS. ARGON MOLE PERCENT



Samples containing large amounts of carbon dioxide (greater than 50.0 mole percent) often contain argon. This is not surprising since samples rich in carbon dioxide also contain substantial nitrogen (Figure 1.5.4), which is closely associated with argon (Figure 1.5.10).

FIGURE 1.5.12 CARBON DIOXIDE MOLE PERCENT VS. HELIUM MOLE PERCENT



Helium is often found in carbon dioxide rich gas samples. Nearly 2.0 mole percent helium has been found in samples containing 70.0 to 85.0 mole percent carbon dioxide. The large number of points plotted along the helium axis with 0.0 to 3.0 mole percent carbon dioxide are samples composed of nitrogen and methane (Figure 1.5.3) containing (nitrogen-associated) helium.

1.5.13 CARBON DIOXIDE-NITROGEN-HELIUM-ARGON RELATIONSHIPS

Figures 1.5.8,9,10,11 and 12 illustrate each facet of the inter-relationships of carbon dioxide, nitrogen, helium, and argon. Of these four gases, positive correlations are readily identified among nitrogen, helium and argon (Figures 1.5.8,9,10). The relationship of carbon dioxide to these three is not as readily apparent, but crucial to deciphering its origin and occurrence.

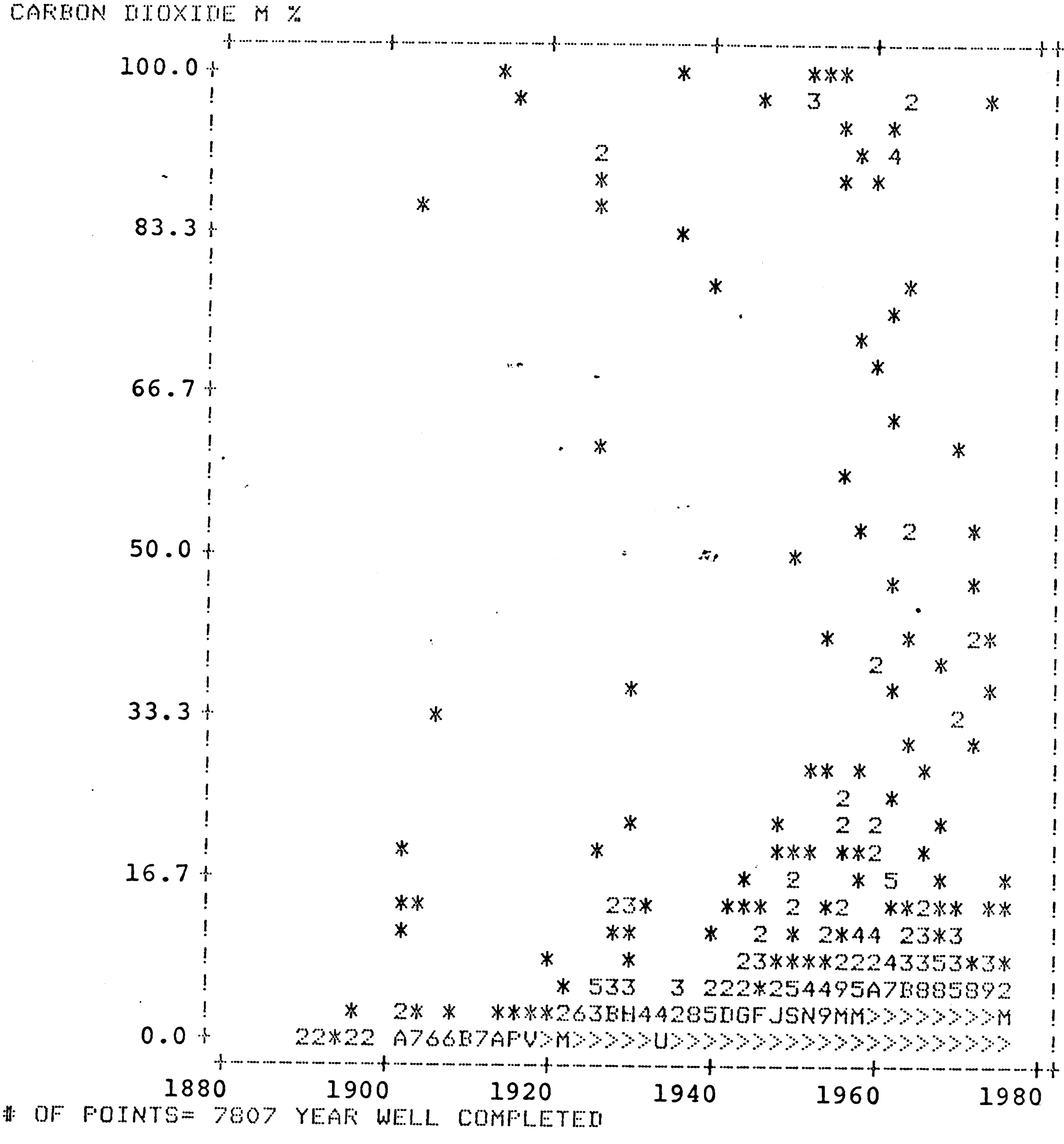
Samples rich (greater than 50.0 mole percent) in carbon dioxide tend to contain significant amounts of nitrogen (Figure 1.5.4), as well as appreciable amounts of argon (Figure 1.5.11) and helium (Figure 1.5.12). We have speculated as to the possibility of a different mode of occurrence or origin for reservoirs producing rich or lean carbon dioxide containing natural gas as suggested by our bi-modal distributions (Figures 1.3.1,2). This was further substantiated by the carbon dioxide-nitrogen-methane relationships (Section 1.5.9).

However, the association of helium and argon with nitrogen is strongest with nitrogen rich gas samples, apparently indifferent to whether carbon dioxide is present in appreciable quantities or not. So simply stated, it appears carbon dioxide rich samples contain nitrogen with helium and argon present because of their strong nitrogen associations.

APPENDIX A

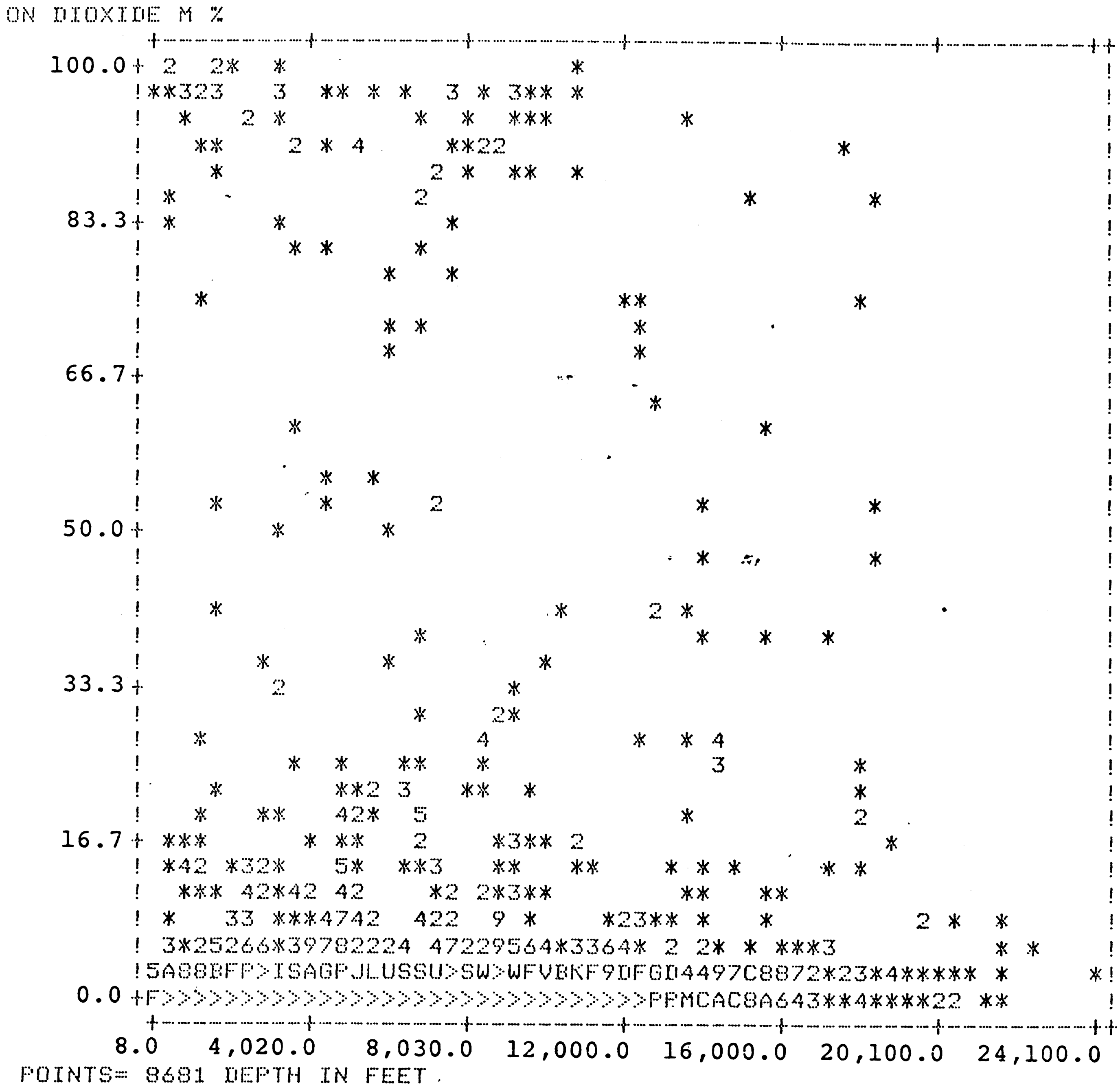
EXPLORATORY PLOTS

FIGURE A.1 CARBON DIOXIDE MOLE PERCENT VS. YEAR WELL COMPLETED



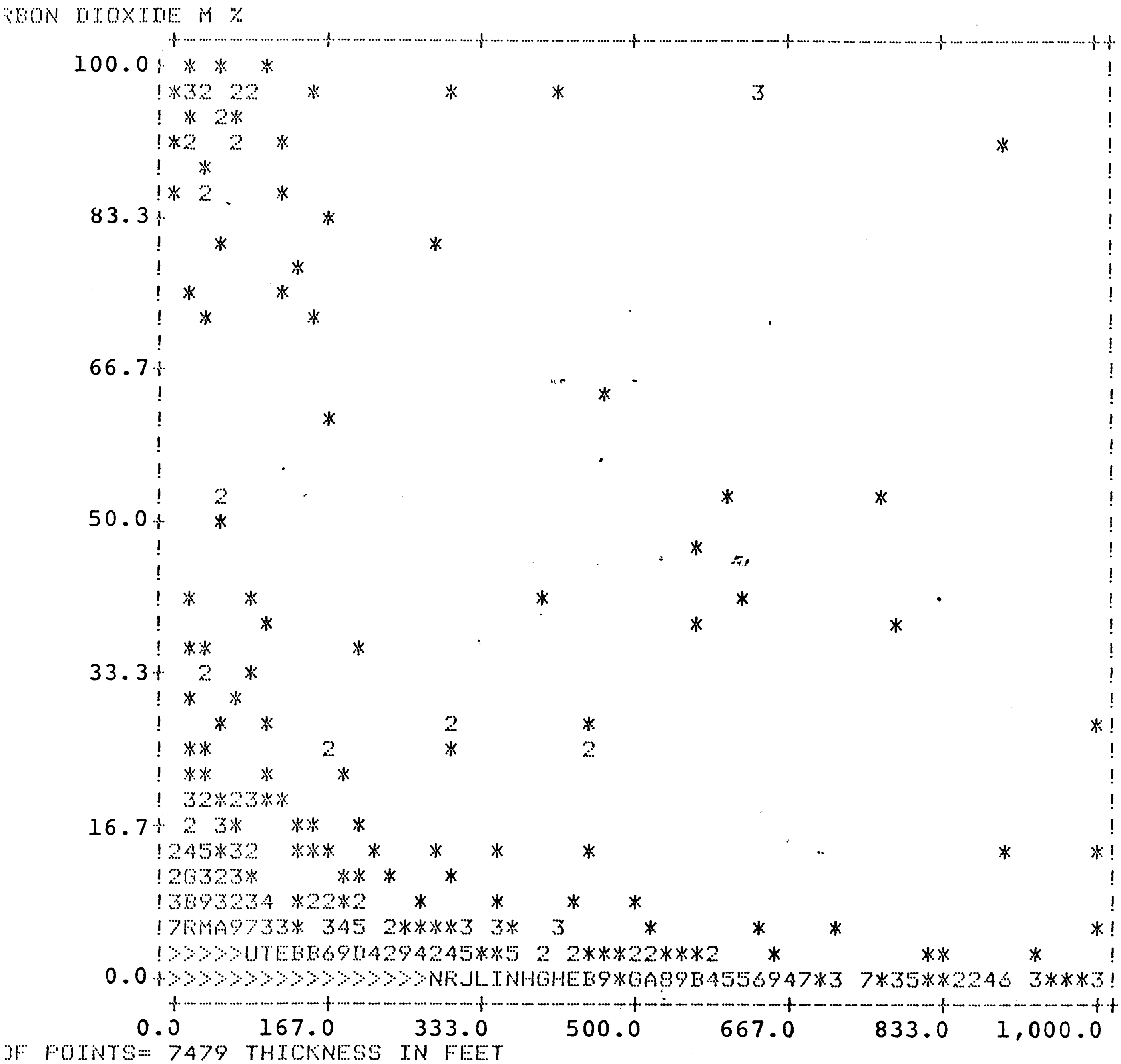
Natural gas samples containing at least a trace of carbon dioxide were collected from wells completed in 1890 to 1976. Of the 304 gas samples containing carbon dioxide greater than 5.0 mole percent and year well completed known, 219 were from wells completed in 1947 to 1974.

FIGURE A.2 CARBON DIOXIDE MOLE PERCENT VS. ZONE DEPTH



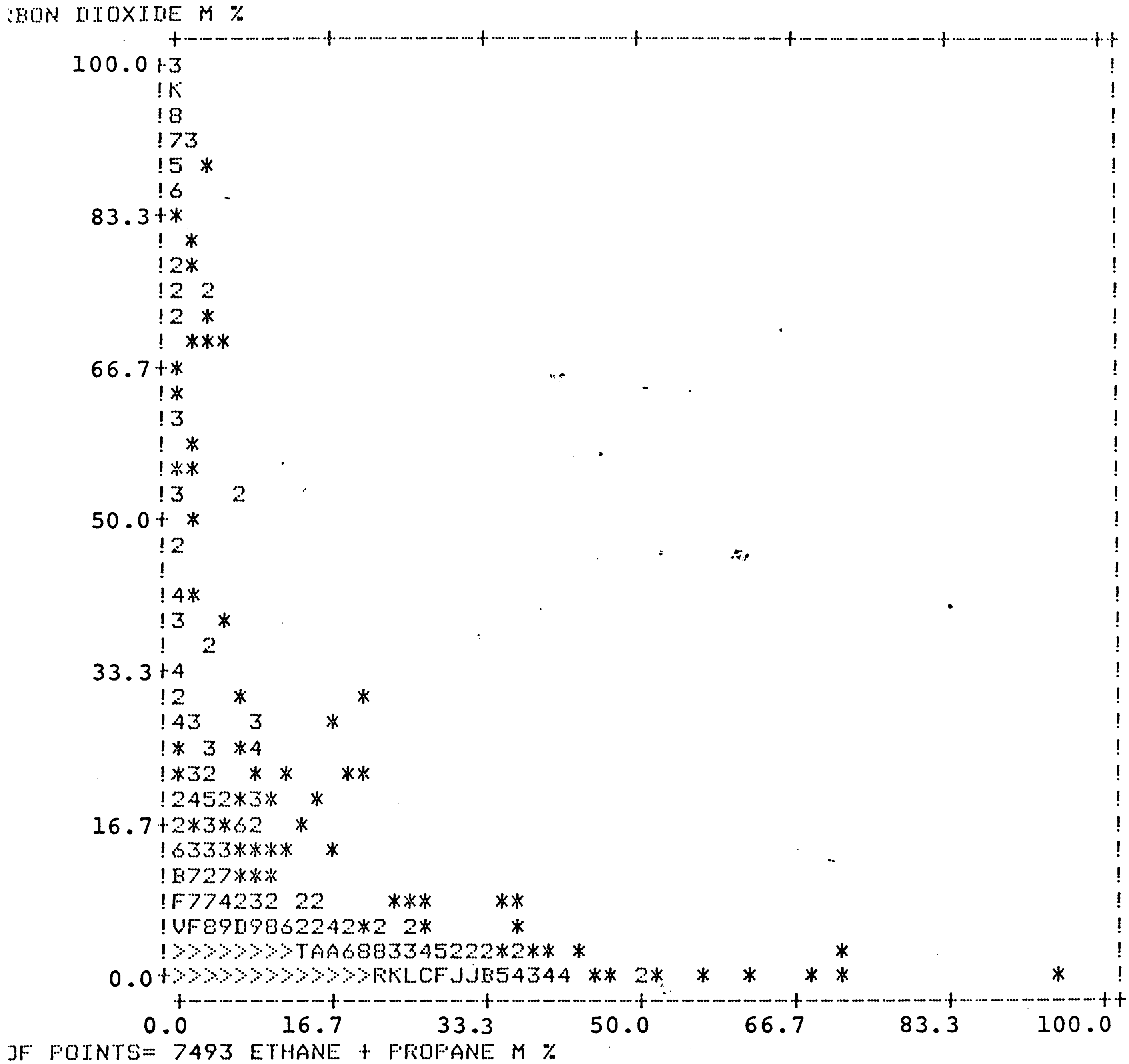
Reservoirs that yielded high mole percentages of carbon dioxide gas lay at depths ranging from near-surface to 19,000 feet. Of the 463 samples with carbon dioxide content greater than 5.0 percent and depth known, 372 were collected from reservoirs less than 10,000 feet deep. The deepest sample that contained contained carbon dioxide (2.0 mole percent) was collected from a reservoir at 24,065 feet. There does not appear to be any correlation of carbon dioxide occurrence with depth in general.

FIGURE A.3 CARBON DIOXIDE MOLE PERCENT VS. ZONE THICKNESS



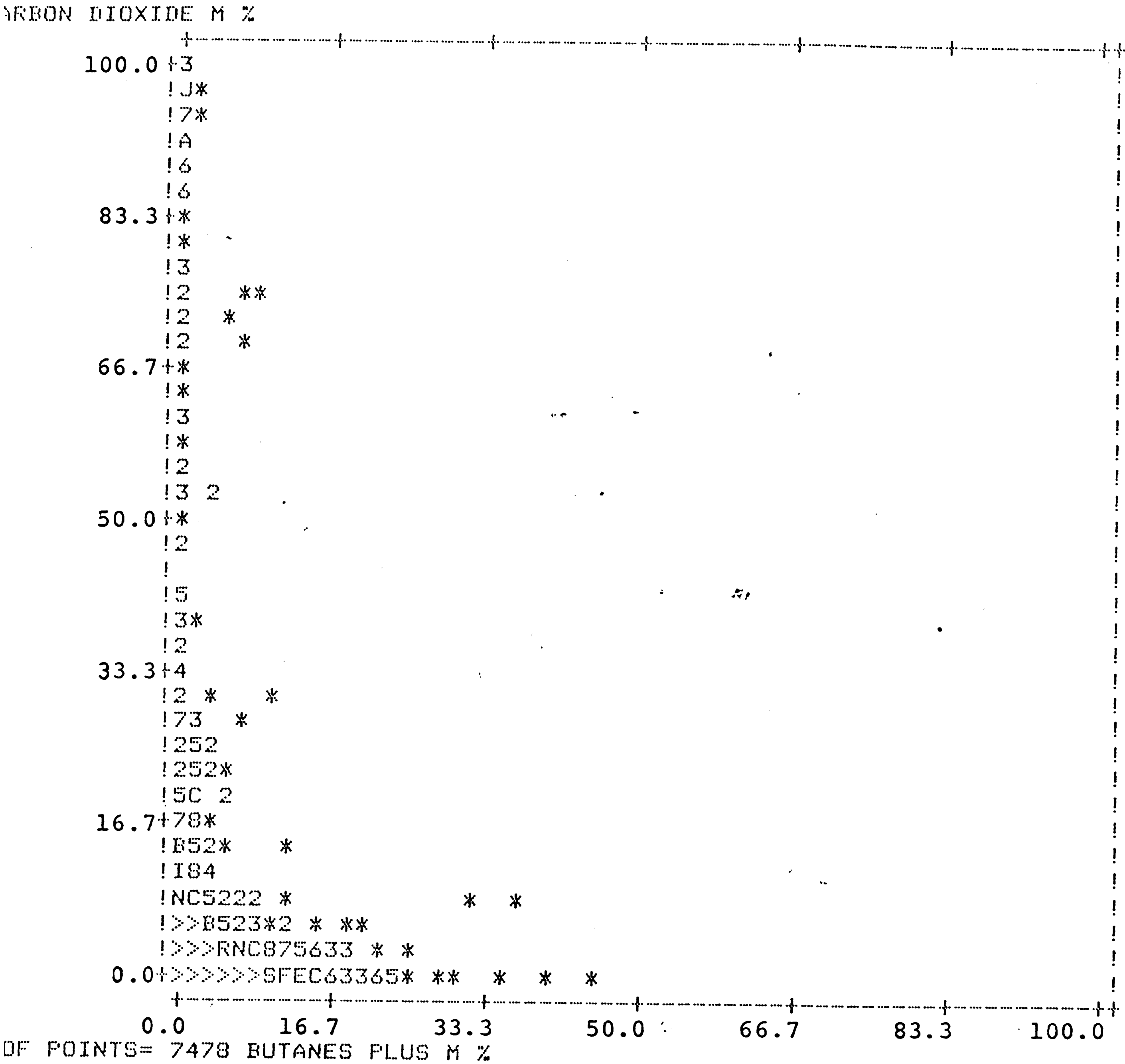
Of the 332 samples containing 5.0 mole percent carbon dioxide with zone thickness known, 241 were collected from gas zones less than 170 feet thick. Most natural gas is produced from zones less than 170 feet thick and carbon dioxide rich zones are no different.

FIGURE A.4 CARBON DIOXIDE MOLE PERCENT VS. ETHANE + PROPANE MOLE PERCENT



Ethane and propane mole percentages were added together and plotted against carbon dioxide mole percent. Carbon dioxide rich gas samples (greater than 30.0 mole percent) did not contain over 1.0 percent ethane and propane.

FIGURE A.5 CARBON DIOXIDE MOLE PERCENT VS. BUTANES (PLUS) MOLE PERCENT



The mole percentages of the butanes and the greater molecular weight hydrocarbons were added together and plotted against carbon dioxide mole percent. Of the 460 samples with carbon dioxide mole percentages greater than 5.0 percent, only 29 contained a butanes (plus) fraction greater than 5.0 mole percent.