Assistant Secretary for Energy Technology
Office of Fossil Energy Programs
Division of Program Control and Support

AD. 2376

Enhanced Recovery of Unconventional Gas

The Methodology- Volume III (of 3 Volumes)

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Available from:

National Technical Information Service (NTIS)
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161

Price: Printed copy: \$13.25
 Microfiche: \$3.00

Assistant Secretary for Energy Technology
Office of Fossil Energy Programs
Division of Program Control and Support
Washington, D.C. 20545

Enhanced Recovery of Unconventional Gas

The Methodology- Volume III (of 3 Volumes)

Prepared by:

Mr. Vello A. Kuuskraa, Lewin and Associates, Inc.

Dr. J. P. Brashear, Lewin and Associates, Inc.

Dr. Todd M. Doscher, University of
Southern California

Mr. Lloyd E. Elkins, Independent Consultant

Under Contract to:

Lewin and Associates, Inc.

Washington, D.C. 20024

Contract No. EF-77-C-01-2705

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, mark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

ENHANCED RECOVERY OF
UNCONVENTIONAL GAS

THE METHODOLOGY -
VOLUME III (of 3 Volumes)

Prepared by
Mr. Vello A. Kuuskraa, Lewin and Associates, Inc.
Dr. J. P. Brashear, Lewin and Associates, Inc.
Dr. Todd M. Doscher, University of
Southern California
Mr. Lloyd E. Elkins, Independent Consultant

Under Contract to
Lewin and Associates, Inc.
Washington, D. C. 20024

Contract No. EF-77-C-01-2705

MARGIN INDEX

Chapter One: INTRODUCTION AND OVERVIEW OF THE ANALYTIC APPROACH

Chapter Two: ESTIMATED PRODUCTION FROM CONVENTIONAL SOURCES OF NATURAL GAS

Chapter Three: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM TIGHT GAS SANDS

- I. The Resource Base
- II. Production and Recovery Models
- III. The Economic Model

Chapter Four: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM DEVONIAN SHALE

- I. The Resource Base
- II. Production and Recovery Models
- III. The Economic Model

Chapter Five: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM COAL SEAMS

- I. The Resource Base
- II. Production and Recovery Models
- III. The Economic Model

Chapter Six: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM GEOPRESSURED AQUIFERS

- I. The Resource Base
- II. Production and Recovery Models
- III. The Economic Model

TABLE OF CONTENTS

	<u>Page</u>
<u>CHAPTER ONE: INTRODUCTION AND OVERVIEW OF THE ANALYTIC APPROACH</u>	
I. INTRODUCTION	1-1
II. ACKNOWLEDGEMENTS	1-1
III. OVERALL APPROACH TO DEVELOPMENT OF THE EGR STRATEGIC PLAN	1-1
A. Phases in the Overall Approach	1-2
B. Overview of the Design Phase	1-4
D. Discussion of the Analysis Phase	1-5
IV. OVERVIEW OF VOLUME III	1-11
List of Contributors	1-13
 <u>CHAPTER TWO: ESTIMATED PRODUCTION FROM CONVENTIONAL SOURCES OF NATURAL GAS</u>	
I. INTRODUCTION	2-1
II. PRODUCTION FORECAST - CONVENTIONAL SOURCES	2-2
III. ESTIMATES OF PRODUCTION FROM PROVED RESERVES TO THE YEAR 2000	2-6
IV. ESTIMATES OF PRODUCTION FROM INFERRED RESERVES TO THE YEAR 2000	2-9
A. Background	2-9
B. Definitions	2-10
C. Approach to the Analysis	2-11
D. Previous Approaches for Estimating Inferred Reserves	2-12
E. Analysis of the Ultimate Fraction Model	2-14
F. Development of the Incremental Model	2-17

Table of Contents
Page Two

	<u>Page</u>
Chapter Two (Continued)	
G. Analysis of the Incremental Model	2-22
H. Comparison of Ultimate Predictions	2-22
I. Production of Inferred Reserves from 1976 to 2000	2-23
J. Confidence Limits	2-24
K. Conclusions for Study of Inferred Reserves	2-25
V. ESTIMATES OF PRODUCTION FROM NEW DISCOVERIES	2-27
VI. SUMMARY OF PRODUCTION FROM CONVENTIONAL SOURCES	2-30
 <u>CHAPTER THREE: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM TIGHT GAS SANDS</u>	
INTRODUCTION AND SUMMARY	3-1
I. THE RESOURCE BASE	
A. Scope of the Study	3-3
B. Data Collection Methods	3-9
C. Interpretation of the Data	3-14
D. Preparing the Data for Analysis	3-26
II. PRODUCTION AND RECOVERY MODELS	
A. Overview	3-35
B. The Reservoir Simulator	3-36
C. General Validation of the Reservoir Simulator	3-46
D. Validation for Continuous Tight Gas Sand Reservoirs	3-60
E. Validation and Adaptation for Lenticular Gas Reservoirs	3-64
F. Key Technical Assumptions	3-73
III. THE ECONOMIC MODEL	
A. Overview	3-103
B. General Structure	3-104
C. Investment Costs	3-105

Table of Contents

Page Three

	<u>Page</u>
Chapter Three (Continued)	
D. Operating and Maintenance Costs	3-117
E. Royalties, Taxes, and Financial Assumptions	3-120
F. Procedure for Multiple Simulations	3-125
G. Indices Used to Update Costs	3-126
H. Aggregation and Timing	3-133
 <u>CHAPTER FOUR: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM DEVONIAN SHALE</u>	
INTRODUCTION AND SUMMARY	4-1
I. THE RESOURCE BASE	
A. Scope of the Analysis	4-5
B. Definition of Analytic Areas	4-8
C. Development of Decline Curves	4-15
D. Adjustments to the Empirical Production Curves	4-20
E. Final Devonian Shale Production Curves	4-33
II. PRODUCTION AND RECOVERY MODELS	
A. Use of History Matching	4-35
B. The Results of History Matching	4-37
C. Results of the Initial Analysis	4-40
D. Additional Analysis	4-42
E. Prospects for Improving Recovery Efficiency	4-47
F. Validating Empirical Estimates of Reservoir Production Through Engineering Analysis	4-51
III. THE ECONOMIC MODEL	
A. Introduction	4-69
B. Major Elements in the Model	4-70
 <u>CHAPTER FIVE: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM COAL SEAMS</u>	
INTRODUCTION AND SUMMARY	5-1
I. THE RESOURCE BASE	
A. General Information	5-3
B. Deep, Unminable Coal Seams	5-4
C. Thin Coal Seams	5-7

Table of Contents
Page Four

	<u>Page</u>
Chapter Five (Continued)	
D. Shallow, Minable Coal Seams	5-8
E. Methane Emissions in Association with Mining	5-9
F. Summary	5-15
II. PRODUCTION AND RECOVERY MODELS	
A. Production Mechanisms	5-17
B. Diffusion Controlled Release of Gas	5-17
C. Permeability Controlled Release of Gas	5-23
D. Comparative Analysis of Production Mechanisms	5-33
III. ECONOMIC MODELS	
A. Introduction	5-39
B. Deep, Unminable Coal Seams	5-39
C. Shallow Coal Seams	5-44
<u>CHAPTER SIX: METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM GEOPRESSURED AQUIFERS</u>	
INTRODUCTION AND SUMMARY	6-1
I. THE RESOURCE BASE	
A. Areal Extent of Geopressured Aquifers	6-3
B. Other Key Reservoir Parameters	6-9
C. Geopressured Aquifers of the Texas Gulf Coast	6-10
D. Geopressured Aquifers of the Louisiana Gulf Coast	6-12
II. PRODUCTION AND RECOVERY MODELS	
A. Calculation of Production Rates by Fluid Expansion	6-15
B. Additional Considerations	6-17
C. Analysis of Production Rate	6-18
D. Reinjection of Water into the Producing Aquifer	6-22
E. Disposal of Produced Water	6-25
F. Producing Well Problems	6-28
G. The Potential for Producing Geopressured Aquifers at Gas/Water Ratios in Excess of Solution Values	6-32

Chapter Six (Continued)

III. THE ECONOMIC MODEL

A. Basis for the Derivation	6-35
B. Minimum Required Methane Content to Cover Operating Costs	6-41
C. Minimum Required Production Rate and Methane Content to Cover Investment Costs	6-42
D. Minimum Required Production Rate/Methane Content Combination to Cover Operating and Investment Costs	6-43

LIST OF EXHIBITS

	<u>Page</u>
<u>CHAPTER ONE</u>	
1-1 Phases in the Strategic Planning Process	1-3
1-2 Simplified Flow Diagram of the EGR Analysis Phase	1-6
<u>CHAPTER TWO</u>	
2-1 Projected Production from Conventional Gas Reserves	2-5
2-2 Rate of Production of Natural Gas as a Percentage of Proved Reserves	2-7
2-3 New Discoveries of Conventional Source Natural Gas in the Lower 48 States	2-28
<u>CHAPTER THREE</u>	
3-1 Location of Major Tight Gas Basins	3-4
3-2 Target Formations in the Tight Gas Basins	3-7
3-3 Anticipated Areal Extent of Tight Gas Basins	3-10
3-4 Well Record Worksheet	3-13
3-5 Non-Associated Gas "Reservoirs" -- Field/Sub-Basin Data Form	3-15
3-6 Effect of Confining Pressure on the Permeability of Fort Union Formation Sandstone Samples	3-18
3-7 Adjustment Factors for Reducing Bench-Measured Permeability to In Situ Conditions	3-19

List of Exhibits
Page Two

		<u>Page</u>
3-8	Assumed Relationship Between Reported Permeability and In Situ Gas Permeability	3-20
3-9	Example of Projection Factor from the Wattenberg Field	3-22
3-10	Projected Cumulative Percent Area Versus Cumulative Percent Recovery for Wattenberg Field	3-23
3-11	Reservoir Characteristics of Tight Gas Formations	3-32
3-12	Production Model Input Data Sheet	3-33
3-13	Schematic Representation of Plan View Simulation	3-38
3-14	Typical Pressure and Production Profiles	3-41
3-15	Type Curve Match Using Gas Properties	3-48
3-16	Input Variables	3-51
3-17	Typical Relative Permeability	3-53
3-18	Typical Capillary Pressure Curve	3-54
3-19	Results for Analysis I	3-55
3-20	Input Data for Analysis II	3-57
3-21	Results for Case II Analyses	3-58
3-22	Comparison of Simulation Results with Field Data - Case 3	3-63
3-23	Comparison of Simulation Results with Field Data - Cases 1, 2, 3	3-63
3-24	Input Data - Well No. 212	3-67
3-25	History Match Analysis of Cumulative Production for Well No. 212	3-69
3-26	History Match Analysis of Daily Production for Well No. 212	3-70
3-27	History Match Analysis of Fracture Length for Well No. 212	3-71

List of Exhibits
Page Three

	<u>Page</u>
3-28 Analysis of Effective Fracture Half-Length for a 1000-Foot Fracture	3-74
3-29 Lens Correction Function	3-76
3-30 Deviation in Cumulative Production From Infinite Reservoir Case; Finite Linear System	3-96
3-31 Well Contact Function: Fractured Well Curve	3-98
3-32 Well Contact Function: Unfractured Well Curve	3-99
3-33 Sand Contact Function: Fractured Well Curve	3-100
3-34 Sand Contact Function: Unfractured Well Curve	3-101
3-35 Drilling and Completion Costs for Two Sample Areas	3-107
3-36 Drilling and Completion Cost Equation Coefficients	3-108
3-37 Estimated Fracture Cost for Tight Gas Formations	3-111
3-38 Example Costs for Advanced 300,000 Gal. Fracture Treatment of Tight Gas Sands	3-112
3-39 Coefficients of the Fracture Cost Equations for Tight Gas Sands	3-113
3-40 Lease and Well Equipment Costs by Region	3-115
3-41 Typical Operating Costs for Gas Wells (Colorado)	3-118
3-42 Coefficients for Calculating Operating and Maintenance Costs	3-119
3-43 State Severance Tax Rates	3-121
3-44 State Income Tax Rates	3-124
3-45 Inflation Indices	3-127
3-46 Part A: Index Allocation for Drilling and Completion Costs	3-130
Part B: Index Allocation for Lease and Well Equipment Costs	3-131
3-47 Construction of Composite Multipliers	3-132
3-48 Development Schedule	3-135

List of Exhibits
Page Four

	<u>Page</u>
<u>CHAPTER FOUR</u>	
4-1 Geological Distribution of the Devonian Shales of the Appalachian Basin	4-6
4-2 Areal Extent of Study	4-10
4-3 Areal Extent of Analytic Units	4-14
4-4 Devonian Shale Wells as of December, 1974	4-19
4-5 Mud Creek Area - Floyd County, Kentucky High, Medium and Low Producing Areas	4-23
4-6 Isocontours of Total Accumulated Production	4-24
4-7 Production Contours for Area I	4-27
4-8 Comparison of Five-Year Cumulative Production of Wells Stimulated by Fracturing and Shooting	4-31
4-9 Basis of Devonian Production and Recovery Estimates	4-34
4-10 History Match of Simulation and Field Data	4-39
4-11 Reservoir and Production Data	4-43
4-12 History Match of Area V	4-44
4-13 History Match of Area VII	4-45
4-14 History Match of Area VIII	4-46
4-15 Relationship of Recovery Efficiency Versus Time	4-54
4-16 Log-Log Plot of Recovery Versus Time When Diffusion is the Controlling Production Mechanism	4-56
4-17 Log-Log Plot of Recovery Versus Time for Typical Shot Devonian Wells	4-57
4-18 Kanawha County - Shale Production	4-58
4-19 Pressure Distribution in Reservoir Producing at Constant Terminal Pressure	4-60
4-20 Dimensionless Water Influx, Constant Terminal Pressure Case, Radial Flow	4-62

		<u>Page</u>
<u>CHAPTER FIVE</u>		
5-1	Estimated Distribution of Total Bituminous Coal Resources by Coalbed Thickness for Colorado and Three Western States	5-6
5-2	Methane Emissions from U.S. Bituminous Coal Mines	5-11
5-3	Methane Emissions from U.S. Coal Mines	5-12
5-4	Location Map of Counties With Bituminous Coal Mines	5-13
5-5	Relationship of Recovery Efficiency Versus Time	5-21
5-6	Methane Recovery from Diffusion	5-22
5-7	Relationship Between Qtd and Dimensionless Time	5-25
5-8	Ten-Year Recovery of Methane from Pittsburgh Coal Using Vertical Wells	5-31
5-9	Ten-Year Recovery of Methane from Pocahontas Coal Using Vertical Wells	5-32
5-10	Ten-Year Recovery of Methane from Pittsburgh Coal	5-36
5-11	Ten-Year Recovery of Methane from Pocahontas Coal	5-37
<u>CHAPTER SIX</u>		
6-1	Distribution of Fault Block Sizes, Gulf of Mexico	6-4
6-2	Estimated Maximum Size of Individual Sand Bodies in Selected Deltaic Facies	6-7
6-3	Reservoir Properties of Prospective Fairways in Texas	6-11
6-4	Effect of Compression Drive Coefficient Upon Production History	6-21
6-5	Ten Year Average Production Rate As A Function of Net Pay, Permeability, and Area	6-23

List of Exhibits
Page Six

		<u>Page</u>
6-6	Ten Year Average Production Rate As A Function of Net Pay, Permeability, and Area	6-24
6-7	Typical Injectivity Curves	6-26
6-8	Amount of Water to be Disposed of to Allow Formation of a Steady State Pressure Profile	6-27
6-9	Effect of Permeability Production Near the Well On Sustained Producing Rate	6-31
6-10	Minimum Required Production Rate and Methane Content From Geopressured Aquifers (Under Five-Year Payback)	6-45
6-11	Minimum Required Production Rate and Methane Content From Geopressured Aquifers (Under Ten-Year Payback)	6-46

CHAPTER ONE

INTRODUCTION AND OVERVIEW OF THE ANALYTIC APPROACH

I. INTRODUCTION

The study of Enhanced Recovery of Unconventional Gas consists of three volumes, of which this is the third. Volume I, the Executive Summary, provides an overview of the potential of unconventional gas and discusses the trade-offs between R&D and increased economic incentives for ensuring its timely recovery. Volume II presents the analyses of each of the four resource areas and sets forth the programs that could make these resources commercial. Volume III describes the analytic approach and methodology used in the study.

Within Volume III, Chapter One provides an overview of the methodology. It is followed by five other chapters, each describing the specific methodology used in the examination of specific resources -- proved and inferred reserves of conventional gas, tight gas sands, Devonian shale, gas occluded in coal seams, and solution gas in geopressured aquifers.

II. ACKNOWLEDGEMENTS

The study drew on numerous organizations and individuals which we wish to thank for their contributions. It included the Enhanced Gas Recovery (EGR) Working Group, DOE executives, independent, expert consultants, and outside contractors. The specific individuals and organizations are listed at the end of this chapter.

III. OVERALL APPROACH TO DEVELOPMENT OF THE EGR STRATEGIC PLAN

The EGR research strategies and estimates of their potential that result from this study are designed to overcome the problems that have constrained the development of the unconventional sources of natural gas. The R&D strategies call for vigorous Federal-industry collaboration and commercialization. The substantial additions to the nation's gas supply that would result from unconventional sources are dependent on a timely and well managed implementation of the recommendations in the EGR Strategic Plan.

A. Phases in the Overall Approach

1. The Purpose of the Study

The Enhanced Gas Recovery Strategic Plan* supports Federal policy-makers and the EGR Working Group in selecting a portfolio of projects (strategies) that addresses the technical and geological problems that have deterred industry from developing these resources to date. As such, it provides the analytic foundation for selecting a rational, cost-effective R&D program for unconventional natural gas.

2. Steps in the Planning Process

The planning process for the Strategic Plan consists of three broad phases (Exhibit 1-1):

- The Design Phase defines the geological and technological problems encountered in economically producing gas from unconventional sources. Those problems that are being or will be addressed in the next five years by industry are included in the Base Case; those that remain are candidates for Federal R&D strategies. The solutions to these problems form the basis for specifying the Advanced Case and the DOE R&D plans to bring that Case about.
- The Analysis Phase provides estimates of gas production from unconventional sources. The definitions of Base and Advanced Cases developed in the Design Phase are translated

* This three-part report, Enhanced Recovery of Unconventional Gas, provided the basic resource data, defined the technical challenges, and the cost-effectiveness measures that served as inputs to the EGR Working Group and their preparation of the Enhanced Gas Recovery Strategic Plan.

EXHIBIT 1-1

PHASES IN THE STRATEGIC PLANNING PROCESS

into detailed, engineering specifications of the physical performance of the technology as it can be delivered reliably in the field. These detailed specifications are combined with the reservoir data through reservoir simulation and production history-matching to project gas recoveries. Finally, the costs of the technologies are combined with these production estimates and gas prices to evaluate economic viability. This procedure is applied under Base Case technology and Advanced Case technology. The incremental production of the Advanced Case over the Base Case is defined as the production benefits of a strategy -- a successful implementation of a technology development program.

- The Selection Phase consists of Federal officials' review of the candidate strategies from the Design Phase, a weighing of the costs and benefits, establishing priorities, and selecting the most cost-effective portfolio of strategies given budget constraints and other considerations.

This three-volume report represents the contribution of Lewin and Associates, Inc. to the Design and Analysis Phases. It is submitted for the review and revision of the Enhanced Gas Recovery Working Group, responsible for making final recommendations of the scope and funding for the respective strategies.

B. Overview of the Design Phase

The methodology in the Design Phase consisted of in-depth consultations with the geological, R&D, and production engineering staffs of the leading production and well-service firms to define the problems on a more operational, quantitative level -- as input to the Analysis Phase. An independent

survey* of over 90 firms in the industry served to validate the broad understanding of the resource problems, R&D plans, and the economic criteria used by industry. The results of the Design Phase are detailed in Volume II of this three-part report.

C. Discussion of the Analysis Phase

The Analysis Phase approximates, on a more general scale, the procedures followed by gas producers in evaluating prospective drilling opportunities. Exhibit 1-2 shows a simplified flow diagram of the EGR Analysis Phase. The analysis begins with the evaluation of geologic data and well records, continues with estimating production and evaluating economic feasibility, and concludes with a field development schedule -- in brief, it follows a geology-engineering-economic approach. The principal features of this approach are described briefly below and in greater detail in subsequent chapters.

1. Geology and Well Data

More than fifty geologists and engineers from industry, consulting firms, and government agencies participated in the data collection on the unconventional gas resources. These data included geologic studies, drilling, completion, and recovery performance of individual wells, test results, well locations, and exploration data. These data were synthesized into detailed geologic/reservoir descriptions for each of the resource targets and basins.

2. Reservoir Characteristics

Based on the geologic and well data, the total area of each relevant basin was divided into four segments:

* Booz, Allen and Hamilton, Inc., Empirical Study of the Natural Gas Industry, August, 1977.

EXHIBIT 1-2

SIMPLIFIED FLOW DIAGRAM OF THE EGR ANALYSIS PHASE**Geology and Well Data****Reservoir Characteristics
Technology Specification**

- Base Case
- Advanced Case

**Cost Data
Gas Price****Areal and Success
Rate Data****Production
Simulation****Production profile per formation:**

- Base Case
- Advanced Case

**Project Economics
Model****Economic production per well:**

- All prices
- Base Case
- Advanced Case

**Extrapolation and
Timing Model****Expected ultimate production and
production rates, all prices:**

- Base Case projection
- Advanced Case projection
- Increment of Advanced over
Base — Program Benefits
- Requirements for production

- Proved -- already proved by drilling and under development.
- Probable -- areas adjacent to proved areas where extension development is likely.
- Possible -- outlying areas in which there has been sufficient historical drilling to establish gas "shows", although perhaps not economic wells.
- Speculative -- areas in the basins which are either undrilled or in which drilling has not revealed gas deposits.

Proved areas were excluded from the study because this resource is already included in proved natural gas reserves. Speculative areas and basins for which data were lacking were also excluded* because the information available was insufficient to support the detailed engineering-economics approach to the analysis. Thus, only probable and possible areas -- areas undeveloped but having enough data to support detailed analysis -- were included in the study.

The reservoir properties of the target formations in these areas were analyzed in detail. The areas were further divided (areally) into sub-basins to insure relative homogeneity of the respective analytic units. These interpretations were reviewed by geologists and engineers experienced in the respective basins. The resulting analytic units used by the study were as follows:

* A separate effort was conducted by the Working Group to approximate the total gas-in-place in the speculative areas. These resources were subject to separate programs aimed at defining the reservoir parameters in these areas.

<u>Resource</u>	<u>Analytic Units</u>
Tight Gas Basins	622 reservoirs
Devonian Shale	33 areal units
Methane from Coal Seams	
-- with mining	Appalachian Region
-- unminable	All unminable coalbeds
Methane from Geopressured Aquifers	23 fairways and horizons

3. Technology Specification

The Base Case definition was derived from actual field experience of industry, as reported in the technical literature, from the opinions of experts, and from the R&D efforts planned by industry for the next five years, as ascertained through intensive consultation with leading producers and service companies. For each resource, the level of technology was specified in terms of the level of physical performance (e.g., fracture length and conductivity) that can currently or within the next five years be reliably achieved in replicable field applications.

The Advanced Case was defined as achieving an improved level of technical performance (as defined in the Design Phase). As in the Base Case, this case was specified in terms of the level of physical performance of the technology (e.g., longer fractures, increased conductivity).

4. Production Simulation

The detailed reservoir and geologic data of the analytic units were combined with the explicit specification of technology advances to produce production estimates.

- For the Tight Gas Sands, a state-of-the-art reservoir simulator was used to model the gas production from each reservoir unit, under Base and Advanced technologies.

The simulator, developed by Drs. S. A. Holditch and R. Morse of Texas A&M University, is a single-phase, two-dimensional finite difference model that simulates the flow of gas in a porous medium.

- Production estimates for the Devonian shale were principally based on area-specific, historic production data, adjusted to reflect both advances in technology and the thickness and intensity of natural fractures of the shales. Analytic solutions for unsteady state flow of gas and the A&M reservoir simulator were used to provide supportive and validating analyses of the reservoir properties of the shales.
- Production from minable coal seams was based on the rates of mining and methane emission. For unminable coal seams, recovery estimates were made by an analytic model that incorporated diffusion of gas through the matrix and unsteady state flow through a network of permeable natural fractures.
- Estimates of production from geopressured aquifers were based on a standard reservoir engineering flow model. Methane content of the brines was estimated from temperature, pressure, and salinity; the flow rate was calculated as a function of reservoir rock compressibility, relative permeability, thickness, and area.

5. Project Economics Model

The next step was the analysis of economic feasibility. A discounted net present value (NPV) cash flow model was used for the Tight Gas Sands and Devonian shale. To reflect the larger uncertainty in resource characterization,

a payback model was used for methane from coal seams and geopressured aquifers. In all cases, the revenue stream was estimated by multiplying the net gas price (after royalty and production taxes) by the previously estimated production rate. Gas prices of \$1.75, \$3.00, and \$4.50 per Mcf (in mid-1977 dollars) were analyzed.

Cost estimates were based on actual field experience, updated to mid-1977 levels. Major cost items included drilling and completion costs, incremental well stimulation costs, surface equipment, operating and maintenance expenses, general and administrative costs, exploration and dry hole costs, and income taxes. Standard gas accounting conventions were used for defining tangible costs and depreciation. The costs were varied by location, depth, and technology. In all cases revenues were compared with costs using explicit financial criteria (NPV greater than zero at specified discounted rates or payback less than a specified number of years). When these criteria were met, the project was deemed economic.

6. Extrapolation and Timing Model

For each basin, a success factor was defined for probable and possible areas, respectively. These factors were based on recent exploratory and development success in the basins as reported by the American Petroleum Institute and the American Association of Petroleum Geologists. The success factors were multiplied by the areas of the probable and possible portions of each basin to yield the expected success in areas. Each area was divided by the drainage area per well (which varies with technology and reservoir properties) to define the expected number of wells in each sub-basin. The drilling and completion of these wells was then phased so that the rate of expansion represented an orderly progression of development across the basins. Probable areas were assumed to be drilled prior to possible areas.

The results of the individual analytic units, sub-basins, and basins were aggregated to provide estimates of:

- Ultimate recovery, annual production rates, and cumulative recovery for both Base Case and Advanced Case technologies.
- The incremental benefits of the respective strategies (Advanced Case production minus Base Case production).
- Supportive requirements associated with EGR production, e.g., number of wells, stimulations, and water requirements.

In summary, the Analysis Phase was designed to approximate industry processes for evaluating the economic feasibility and likely development of the unconventional resources.

IV. OVERVIEW OF VOLUME III

The five remaining chapters of Volume III describe the method used in conducting the Analysis Phase.

- Chapter Two presents the basis for estimating production from conventional sources of natural gas, including proved resources, inferred resources, and new discoveries. This estimate provides a baseline for determining the need for gas from unconventional sources.
- Chapter Three describes the methods used in analyzing Tight Gas sands, including collection of the resource data, the simulation of production, and the economics and timing models.

- Chapter Four consists of the methods used to evaluate the potential of the Devonian shale of Appalachia, with emphasis on the empirical production curves and their validation.
- Chapter Five discusses the approach and assumptions used in analyzing the potential of gas recovery in conjunction with mining and the gas potential of unminable coal seams.
- Chapter Six provides a description of the data base, assumptions, recovery model, and economics of producing gas in solution in geopressured aquifers.

LIST OF CONTRIBUTORS

The following individuals and organizations provided their talents to this study:

- Overall Support - Lewin and Associates, Inc.
 Dr. Frank Morra, Economic Modeling
 Ms. Sandra Chalton, Devonian Shale Analysis
 Mr. Edgar Hammershaimb, Devonian Shale Analysis
 Mr. Roy Beatty, Statistical Analysis
 Mr. Jay Brash, Statistical Analysis
 Ms. Sharon Anderson, Graphics
 Mrs. Suzanne Crane, Editorial/Typing
- Geological Data
 Mr. Charles Atkinson - DOE, Nevada Operations
 Mr. Carroll Knudsen - C&K Geonuclear, Inc.
 Mr. Conrad Appledorn - CER, Inc.
 Mr. Nick Newman - CER, Inc.
 Dr. George Griswold - Sandia Laboratories
 Mr. Norm Warpinski - Sandia Laboratories
 Mr. Gene Foss - Independent Geologist
 Mr. Tom Beard - Independent Geologist
 Mr. Alan Hansen - Independent Geologist
 Mr. Alan Lohse - Gruy Federal, Inc.
 Mr. Dwayne Godsey - Resource Sciences Corp.
 Mr. Ray Williams - DOE, Bartlesville
- Production Technology
 Dr. S. A. Holditch - Texas A&M
 Mr. Dwayne Chestnut - Energy Consulting Associates
 Mr. Maurice Deul - BOM/Pittsburgh

Beyond these individuals, the study staff acknowledges the valuable contribution of the USGS staff in Denver and the technical staff of numerous gas production, coal mining, and service companies.

CHAPTER TWO

ESTIMATED PRODUCTION FROM
CONVENTIONAL SOURCES OF NATURAL GAS

I. INTRODUCTION

One of the basic questions in any analysis of unconventional natural gas supply is:

What will be the likely level of conventional natural gas production in the near-term and through the rest of this century?

Because considerable lead times are involved in development of energy resources, public and private policy makers must have an adequate answer to this question in order to plan future actions, given the considerable risks associated with supply falling short of demand.

Currently, there are several estimates of the potential gas supply to the year 2000. The differences can be explained by differences in the basic assumptions imbedded in each study:

- **Proved Reserves:** Production from proved reserves is the largest component of near-term conventional natural gas and can be predicted with a high degree of accuracy; thus, all projections should be essentially the same.
- **Developmental Drilling:** Reserves are added by developmental drilling in existing fields and is called "inferred reserves". It is the second largest component of near-term gas supply. Many current supply projections have used incomplete data or relied on methodologies that do not match with recent results. As technical refinements are applied, smaller differences should be expected in this area.

- New Discoveries: Production from new discoveries and their growth is the major unknown. The major concern is that much of the undiscovered gas is judged to exist in frontier (off-shore, deep, and hostile) areas, and these areas may not contribute significantly to domestic gas supply in the near-term.

Thus, under current conditions domestically produced natural gas supply can be projected with high confidence through the early to mid-1980s. After that period, one must directly assess the nature and location of the underlying domestic resource base and assess the production cost data before making estimates of longer-term natural gas supply.

II. PRODUCTION FORECAST -- CONVENTIONAL SOURCES

This chapter presents the study's estimates of natural gas production from conventional sources. The discussion in this chapter addresses separately the three components of conventional natural gas:

- Production from proved reserves, excluding Alaska
- Production from inferred reserves
- Production from new discoveries from conventional sources.

Of these, the major analytic contribution of this study is in the analysis of production from "inferred reserves", the phrase used by USGS Circular 725 to describe the probable future additions to currently proved reserves. It is defined as the sum of future additions that will become

"proved" through extensions, revisions, and "small" new reservoirs in existing fields.*

The results indicate that conventional sources will be unable to meet current demand by 1980 and by the year 2000 will support less than one-half of the current level of gas consumption.

- New discoveries and extensions of known fields have replaced less than one-half of the natural gas** consumed over the last seven years.
- Total proved reserves as a result have declined by 26% since 1970, from 290 Tcf to 216 Tcf. Of the 216 Tcf, 32 Tcf are in Alaska, unavailable without a pipeline or other means of transportation -- leaving only 184 Tcf in readily accessible proved reserves, as of December 31, 1976.***
- With annual production running at 19.5 Tcf, the ratio of proved reserves to production is at an all time low, about 11 to 1; at current production rates and without new additions, the nation has about an eleven year gas supply in terms of recoverable reserves -- about nine and a half years when Alaska is excluded.

* "Large" new pools are carried in AGA records as new discoveries, whereas "small" new pools are allocated to the initial reserve estimates, just as are extensions and revisions.

** Throughout this paper, the term "natural gas" refers to both non-associated and associated/dissolved hydrocarbons in the gaseous state at standard temperature. The term excluded natural gas liquids.

*** API/AGA Reserves of Crude Oil, Natural Gas and Natural Gas Liquids: 1976. Table VII-2, p. 119.

Projected production from conventional sources of domestic natural gas under gas prices and production technology as of the end of 1976* shows a continuing downturn throughout the rest of this century.

PROJECTED SUPPLY OF CONVENTIONAL
SOURCE NATURAL GAS

<u>Year</u>	<u>Tcf/Year</u>
1978	19
1980	17
1985	13
1990	11
2000	8

As shown in Exhibit 2-1, currently proved reserves will be largely exhausted by the year 2000 and production from conventional sources will be largely dependent on new discoveries and "inferred reserves".

The analysis reflects the gas price as of the end of 1976, approximately \$1.50 per Mcf. Although a full analysis of price/supply elasticity of conventional gas sources was beyond the scope of this study, geologic data and the analysis of near-conventional gas sources show that important additions to supply could accrue only after prices reach threshold levels that open up major new, and heretofore uneconomic, frontiers.

The next three sections describe in detail the methodology which was employed to produce these estimates.

* API/AGA Reserves of Crude Oil, Natural Gas and Natural Gas Liquids: 1976. Table VII-2, p. 119.

EXHIBIT 2-1
PROJECTED PRODUCTION FROM CONVENTIONAL GAS RESERVES
 (at Gas Price as of End of 1976)

1/ RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN THE UNITED STATES AND CANADA AS OF DECEMBER 31, 1976, BY AGA/API/CPA.

2/ BASED ON A RECENT LEWIN AND ASSOCIATES, INC., STUDY, ANALYSIS OF THE TIMING AND TOTAL OF INFERRED RESERVES OF NATURAL GAS IN THE CONTIGUOUS UNITED STATES, BY J. BRASHEAR AND F. MORRA.

3/ BASED ON ONSHORE (LOWER 48) DISCOVERIES OF 1.0 TCF/YEAR AND OFFSHORE (LOWER 48) DISCOVERIES OF 0.5 TCF/YEAR, GROWING TO 3.9 AND 1.9 TCF RESPECTIVELY THROUGH DEVELOPMENTAL DRILLING.

III. ESTIMATES OF PRODUCTION FROM PROVED RESERVES TO THE YEAR 2000

At the end of 1976, proved reserves of natural gas were 216 Tcf. Of these, 32 Tcf are in Alaska, and are hence unavailable without a pipeline or other means of transportation. Thus, only 184 Tcf are readily accessible to meet near term needs. Moreover, Alaskan gas, delivered, would cost considerably more than the price levels assumed in the present estimates.

The 184 Tcf of proved reserves from the "lower 48" were produced at a production to reserves (P/R) ratio of 1 to 10. As shown in Exhibit 2-2, this appears to be the production rate which would be "likely" during the period 1978-2000 using an extrapolation of historical trends. (Should the P/R accelerate, the projections would be slightly higher initially, but would decrease dramatically thereafter.)

Setting the P/R ratio at 1 to 10, a percentage decline model was used to produce the proved reserves, as follows:

- Let $R(t)$ be the estimate of proved reserves at the beginning of year "t".
- Let $P(t)$ be the estimate of production from proved reserves during year "t".
- The decline model becomes:
 - $R(t+1) = (0.90)(R(t))$
 - $P(t) = (0.10) R(t)$

EXHIBIT 2-2

RATE OF PRODUCTION OF NATURAL GAS
AS A PERCENTAGE OF PROVED RESERVES

<u>Year</u>	<u>Production as % Reserves</u>
1947	3.48
1948	3.62
1949	3.59
1950	3.82
1951	4.29
1952	4.45
1953	4.63
1954	4.45
1955	4.78
1956	4.88
1957	4.84
1958	4.66
1959	4.90
1960	4.99
1961	5.10
1962	5.12
1963	5.34
1964	5.56
1965	5.67
1966	6.11
1967	6.35
1968	6.61
1969	7.21
1970	7.98
1971	8.33
1972	8.90
1973	9.42
1974	9.52
1975	9.53
1976	9.85

For the data reported in this section, R(1) was set at 184 Tcf based on the API/AGA estimate of proved reserves of natural gas in the 48 contiguous states (i.e., excluding Alaska) as of the end of 1976.

This model yields the following yearly production figures for these five-year intervals:

<u>Year</u>	<u>Production from Reserves Listed as "Proved" in 1976</u>
1980	13.5 Tcf
1985	8.0 Tcf
1990	4.7 Tcf
1995	2.8 Tcf
2000	1.6 Tcf

This is a cumulative production of 169 Tcf by the year 2000 or approximately 92% of the currently proved reserves as of the end of 1976. By 2000, then, only 15 Tcf, or 8%, of current proved reserves would remain to be produced.

These results are relatively insensitive to alternative assumptions about the rate of decline. If production reserves (P/R) ratio became 1 to 9 (equivalent to an 11% decline rate), 171 Tcf would be produced by 2000. At a P/R ratio of 1 to 8 or a decline rate of 12%, a total of 174 Tcf of proved reserves would be produced by the year 2000.

Thus, the analysis shows that currently proved reserves of natural gas will be virtually exhausted by the year 2000.

IV. ESTIMATES OF PRODUCTION FROM INFERRED RESERVES TO THE YEAR 2000

A. Background

This section reports an investigation of inferred reserves of natural gas in the contiguous (i.e., lower 48) United States.

The amount of inferred reserves suggested by the analysis is considerably less than that predicted by previous studies (e.g., USGS Circular 726). Because these findings diverged so greatly from previous studies (by M. Hubbert and USGS), a detailed investigation of the previous methods of estimating inferred reserves was conducted. To provide a standard of reference for these studies, three standards were used:

- How well would the method estimate the amount of inferred reserves added from fields discovered prior to 1967 in the 10-year period from 1965 to 1975?
- How well would the method predict the amount of inferred reserves added during the period 1965 to 1975, including new discoveries in this period?
- How well would the method predict the amount of inferred reserves added during 1976 (and 1977)?

Using these standards, the study concluded that the previously established methods were inadequate for the year-to-year estimation of inferred reserves. A series of new models, based on year-to-year changes in estimates of ultimate recovery, were constructed and subjected to the tests of history. An empirical model using 50 years of reserves growth from time of discovery to final estimate was found to most closely fit the evaluation standards.

This new model predicts that the total of inferred reserves based on currently proved reserves (i.e., ignoring future discoveries) is approximately 97 Tcf, of which 87 Tcf will be added by the year 2000, and that every 1 Tcf discovered in a particular year will grow eventually to 3.92 Tcf through extension drilling.

A Monte Carlo simulation was used to assess the 95% confidence interval. The largest interval, around the estimate of total inferred reserves, was only $\pm 9\%$.

Based on the match with the historical criteria and the narrowness of the confidence interval, it was concluded that the model was acceptable for the present analysis.

B. Definitions

The following definitions are employed in the study of inferred reserves. The remainder of Section IV discusses the methodology used for calculating inferred reserves.

- Resource: The amount of natural gas in place.
- Proved Reserves: The portion of the resource in currently discovered fields that can be produced assuming current technology and economics.
- Inferred Reserves: Future additions to proved reserves in currently known fields that become "proved" due to extension drilling, revisions of estimates, and the discovery of pools too small to be considered significant new finds. Continuation of economic and technological trends is broadly assumed.

The development of a natural gas field inevitably leads to adjusting the original estimates of proved reserves: that is, extension drilling, changes in technology and economics, and unpredicted variations in the performance of the field lead to revisions and extensions of the initial proved reserves.

The United States Geological Survey (USGS) has coined the term "inferred reserves" to describe the estimate of these adjustments.

C. Approach to the Analysis

Using the historical data on proved reserves and ultimate recovery contained in the 1966-1975 series of API/AGA "Bluebooks",* this paper investigates the existing models used for estimating inferred reserves and proposes an improved method for more precisely determining the future contribution of inferred reserves to the nation's energy supply.

The work reported herein is concerned with three basic problems:

- To estimate the total of "inferred reserves".
- To estimate the amount of these inferred reserves which will become "proved" in each subsequent year between 1977 and 2000.
- To estimate the production of natural gas from these reserves on a yearly basis between 1977 and 2000.

* Each year, the totals of (1) proved reserves, (2) revisions and extensions, (3) cumulative production, and (4) ultimate recovery of natural gas are reported in the publication Reserves of Crude Oil, Natural Gas in the United States and Canada, published jointly since 1966 by the American Gas Association (AGA) and American Petroleum Institute (API). Because of the distinctive blue cover of these reports, we refer to these hereafter as the "API/AGA Bluebooks".

D. Previous Approaches for Estimating Inferred Reserves

Several previous researchers have addressed the problem of estimating the total of "inferred reserves". Among these are:

- M. King Hubbert, 1972
- USGS (Circular 725), 1975
- David H. Root, 1977

The 1975 USGS estimate is an application of the Hubbert (1972) approach using three additional years' data and performing the calculations on a state-by-state basis. The recent work by Root (1977), described below, represents a new approach.

The existing approaches use Table XVII* of the API/AGA "Bluebooks" to link ultimate recovery to the year of discovery of natural gas fields. These are classified as "ultimate fraction" models because they seek to find the value of a fraction $\alpha(t)$ which may be incorporated in the formula:

$$\alpha(t)g(y,t) = g(y, \infty)$$

Where:

$g(y,t)$ = Estimated ultimate recovery of natural gas for fields discovered in year y at "age" t . If x is the current year, $x = y + t$. The quantity $g(y,t)$ may be obtained from Table XVII of the API/AGA "Bluebook".

* For the years 1966-1969, the information is found in Table XIII.

$g(y, \infty)$ = Estimated ultimate recovery of natural gas for fields discovered in year y after the process of revisions and extensions is complete (i.e., at age "infinity").

$\alpha(t)$ = The correction factor required to estimate $g(y, \infty)$ from $g(y, t)$.

Hubbert estimated the values of the correction factor by smoothing a curve to the graph of time since discovery versus percentage change in reserves since discovery. In the course of his work, Hubbert concluded that the logistic function was the best form for $\alpha(t)$:

$$g(y, t) = g(y, \infty) \times (1 - e^{-B(t+c)})$$

Where $B = 0.063$ per year

and $c = 4.343$ years

Hubbert's major work was done in 1972 and therefore was able to use only six years of data on additions and extensions to reserves (such data having only been published by the API/AGA since 1966).

In 1976, Dr. David Root of the USGS approached the same problem by using a more sophisticated numerical technique. He was able to use the 1966-1975 API/AGA tables of ultimate recovery and discovery year to directly estimate the logarithm of the derivative of the function $\alpha(t)$. By numerical integration and exponentiation, he produced a table of values $\alpha(t)$, but did not attempt to fit a smooth curve to these values.

To solve for this final value, Root made the assumptions that: (1) the process of additions to reserves through revisions and extensions is completed within 44.5 years following discovery; and (2) that all changes in the estimates of ultimate recovery were positive (i.e., reserves were never revised downward).

E. Analysis of the Ultimate Fraction Model

An analysis of the data base revealed that considerable revisions and extensions take place in fields older than 44.5 years* and that negative revisions have been common in the past six years of history. Therefore, Root's methodology was replicated, except that a new set of values for the correction factor were created under the assumptions that the process of revisions and extensions would be completed in 55.5 years -- as far back as data are available -- and could include negative adjustments. To provide an additional comparison, Hubbert's 1972 equation was applied to the full set of data available at present.

A comparison of the performance of these three approaches of incremental modeling is shown below:

<u>Model</u>	<u>Estimate of Total "Inferred" Reserves</u>
• Hubbert's Approach (1972)	175.3**
• Root (1976)	137.9
• Lewin and Associates Adaptation of Root (1977)	126.8

* For example, from 1974 to 1975, fields discovered in 1922 -- at 53 years of age -- showed an increase of 3.9% due to revisions and extensions, while fields discovered in 1931 -- at 44 years of age -- showed a 10.3% increase. Decreases of similar magnitude are also observed.

** Note that the estimate for Hubbert's approach is somewhat different from that estimated by USGS (Circular 725) using 1975 data on a state-by-state basis, which estimated 164 Tcf at that time. The printed value is given as 201 Tcf, but communication with USGS indicates that a tabulation error resulted in the over-estimate. The revised estimate is 164 Tcf.

These three "ultimate fraction" models were developed solely for the purpose of predicting total additions to ultimate recovery. However, it is possible to adapt them for use in the determination of the addition to reserves on a year-to-year basis.

Specifically:

$$g(y,t) \times \alpha(t) = g(y,\infty)$$

$$\text{thus, } g(y,t) = g(y,\infty) \times (1/\alpha(t))$$

Similarly:

$$g(y,t+1) = g(y,\infty) \times (1/\alpha(t+1))$$

Thus, the additions in one year are estimated by:

$$g(y,t+1) - g(y,t)$$

which is equal to:

$$\begin{aligned} & [g(y,\infty) \times (1/\alpha(t+1))] - [g(y,\infty) \times (1/\alpha(t))] \\ & = [g(y,\infty) \times [(1/\alpha(t+1)) - (1/\alpha(t))]] \quad (\text{EQ.1}) \end{aligned}$$

It is possible to obtain the $g(y,\infty)$ from the entries in Table XVII of the API/AGA "Bluebook" as adjusted by the $\alpha(t)$ function for each model. Future additions may be estimated by Equation 1 (above) on a yearly basis.

Ultimately, any statistical prediction model must stand the test of time -- how well does it match with actual data. The performance of each model was evaluated against three such empirical standards (i.e., the Hubbert approach, Root, and the Lewin and Associates adaption of Root).

1. The amount of additions to ultimate recovery through revisions, extensions, and discovery of small deposits within existing fields during the period 1967-1975. This standard, therefore, includes new discoveries attributed to the years 1967-1975.
2. The amount of additions to ultimate recovery through revisions, extensions, and discovery of small deposits within existing fields contributed by fields discovered from 1920 through 1966 during the period 1967-1975. This standard omits new discoveries from 1967-1975.
3. Prediction of the amount to be added for the year 1976. Although a precise figure was not available at the time of the analysis, the standard presented represents the maximum and minimum values possible.

The comparison of the models with these standards is shown below:

<u>Model</u>	<u>Standard One (Tcf)</u>	<u>Standard Two (Tcf)</u>	<u>Standard Three (Tcf)</u>
Standards for Comparison:	76.0	43.8	4.2 to 6.2*
• Hubbert's Approach	118.4	106.2	10.7
• Root's Approach	82.0	75.1	9.4
• Lewin and Associates Adaptation of Root	76.9	70.3	8.6

Of the three models, the version developed by the study staff comes closest to the three standards, but even it is considerably at variance with the standards, particularly Standards Two and Three.

On the basis of this comparison, it was decided to abandon the "ultimate fraction" model approach and to seek a more direct solution to the problem of determining year-to-year additions. This work is described below.

F. Development of the Incremental Model

The "ultimate fraction" model has an inherent weakness in that it takes the numerical equivalent of the derivative of the ultimate recovery function and, by necessity, brings forward any assumptions and error associated with the original function. An empirically more accurate

* In the current absence of the API/AGA data for 1976, only a range is determinable, depending on the disposition of new pools in known fields -- some will be counted as new discoveries of 1976, while the balance will be allocated to the year of the field's discovery.

model would need to use direct estimates of the percentage change in proved reserves from year-to-year. This "incremental" model approach was tested by the Lewin study.

The API/AGA "Bluebooks" from 1966-1975 provide the basic data series (all available at the time of the analysis). In particular, the data in each edition may be employed to predict the percentage change in ultimate recovery estimates from year-to-year. The data yield nine estimates of this change for fields of ages between 1 and 47. In addition, since the data began with fields discovered in 1920, there are eight estimates for fields 48 years old, seven estimates of fields of age 49 years, and so on, to two estimates for fields that are 55 years of age.

The arithmetic mean of each group of estimates was chosen as the best approximation to $f(t)$, defined below:

$f(t)$: For fields of age " t " years, the percentage change in ultimate recovery (due to revisions, extensions, and discoveries of small pools within existing fields) that would be recorded as the field's age became " $t+1$ ".

Thus, it is possible to use the most recent version of Table XVII in the 1975 API/AGA "Bluebook" to project the additions as far forward as desired by employing the following approach:

Year of Discovery: Denoted y , ranges from 1920 through 1975. Fields discovered prior to 1920 were omitted from the analysis.

Age: For each year to be projected, denoted P, age is determined as $P - y = t$. For example, in referring to the percentage change from 1975 to 1976 attributable to fields discovered in 1945, one would use $f(30)$ (where $1975 - 1945 = 30$).

Additions: It is possible to determine the amount of additional gas by multiplying the percentage change by the amount of gas present in the previous year.

For example, the additions (i.e., amount of gas added) in 1976 from fields discovered in 1945 would be:

$$g(1945, 30) \times (f(30))$$

$$g(1945, 30) = 13.89 \text{ Tcf (from Table XVII, API/AGA Bluebook)}$$

$$f(30) = 0.018$$

$$\text{Additions: } 13.89 \times 0.018 = 0.25 \text{ Tcf}$$

The procedure may be repeated to produce an estimate of the additions to fields discovered in 1945 for 1976-1977.* In general, the procedure may be repeated until the defined values of $f(t)$ are exhausted.

To continue the process into the next year, the following formula is used:

$$g(y, t+1) = g(y, t) + g(y, t) \times f(t)$$

* A full table of values for $f(t)$ may be found in Appendix I.

Thus, for the example, the revised estimate of ultimate recovery for fields discovered in 1945 as estimated in 1976 (i.e., at age 31) would be:

$$g(1945, 31) = 13.89 + 0.25 = 14.14$$

The grand sum of the increments for each discovery year would represent the estimate of additions due to revisions, extensions, and discoveries of small pools in existing fields.

In addition to this model, three variants were constructed:

- 50 term model: The model described above uses the arithmetic mean of year-to-year changes as an estimate of the value of $f(t)$. Because several of these estimates are based on less than five observations, the staff experimented with a model which used only values based on more than five points -- i.e., the first 50 values of $f(t)$ as shown in Appendix II.
- Negative exponential: A curve of the form:

$$f(t) = e^{-B(t+c)}$$

where B and c are variables

was fit to the values of $f(t)$ shown in Appendix I; the following values were obtained:

$$B = 0.781$$

$$c = +0.452$$

However, for values of t greater than 8, the empirically observed values of $f(t)$ are periodically positive and negative, resulting in a process of revisions and extensions that lasts over 50 years. The best fitting negative exponential curve implied that process of revisions and extensions would be completed within fourteen years.

- Damped harmonic motion: The fluctuations in the data following the eighth term suggested that the later years of reservoir development involved an adjustment process which might be modeled by the equations for damped harmonic motion (i.e., major extensions and revisions during the first ten years with minor positive and negative adjustments converging toward a final value during the remaining 45 years). Accordingly, a function of the form:

$$f(t) = e^{-B(t+c)} + D[\text{SIN}(\gamma t)] + E[\text{COS}(\gamma t)]$$

was fit to the data fielding:

$$B = 0.781$$

$$c = 0.452$$

$$D = 0.010$$

$$\gamma = 1.270$$

$$E = 0$$

Two experiments in curve-fitting did not produce functions which gave a close fit (using the sum of squared errors as the criterion). The failure of curve-fitting techniques to adequately fit the observed data points indicates that the process of determining inferred reserves does not follow any mathematical abstraction with simple form. Thus, the empirical estimates of $f(t)$ were seen as providing better insight into the nature of the process than the generalized curves. This is borne out in the analysis provided in the next section.

G. Analysis of the Incremental Models

The four incremental modeling approaches were compared using the previously established standards:

<u>Incremental Models</u>	<u>Standard One</u> (Tcf)	<u>Standard Two</u> (Tcf)	<u>Standard Three</u> (Tcf)
Standards for Comparison	76.0	43.8	4.2 to 6.2
• 55 term model	72.9	52.8	7.5
• 50 term model	72.5	52.6	7.1
• Negative exponential	15.5	6.8	4.1
• Damped harmonic	54.8	28.2	4.6

The 50 term incremental model best fit the three evaluation standards. It provided a better fit than the "ultimate fraction" model and was chosen for projecting the year-to-year total of [revisions, extensions, and discovery of small pools in existing reservoirs] inferred reserves.

The results obtained from the use of this model are shown in Exhibit 2-1, which charts the amount of production from "inferred reserves" between 1976 and 2000. It is estimated that 97.0 Tcf will be ultimately added to the existing natural gas resource base, of which 84 Tcf (87%) would be added between the year 1976 and 2000.

H. Comparison of Ultimate Predictions

A second use of the model is to estimate the "cumulative additions" -- the ultimate growth of 1 Tcf of newly discovered gas based on extension drilling, revisions, and additional discovery.

The ultimate additions predicted by the models considered in this paper are shown below: ,

<u>MODEL</u>	<u>CUMULATIVE ADDITIONS</u>
<u>"Ultimate Fraction" Models</u>	
Hubbert's Approach	4.95
Root	4.55
Lewin and Associates Adaptation of Root	4.18
<u>"Incremental" Models - Lewin and Associates</u>	
55 term model	3.93
50 term model	3.92
Negative Exponential	1.14
Damped Harmonic	2.73

The 50 term incremental model, representing the best match with history, would project that 1 Tcf of new gas found will eventually lead to 3.92 Tcf being booked due to extension drilling, recovery revisions, and additional exploration in the reservoir.

I. Production of Inferred Reserves from 1976 to 2000

The inferred reserves added to proved reserves were produced using a P/R ratio of 1 to 10, consistent with production from proved reserves (shown in Exhibit 2-1). They show that expected inferred

reserves will add 2.9 Tcf to production in 1985, 3.1 Tcf in the year 1990, and 2.5 Tcf in the year 2000, an important addition to natural gas production.

These production figures, however, are based upon the assumptions that (a) no new discoveries are made following 1975, and that (b) the changes in economics and technology for the recent 1966-1976 period continue through the year 2000.*

J. Confidence Limits

Because the model is empirical in nature and is based on the average of year-to-year estimates, the study staff sought to test the sensitivity of the model to error attributable to this averaging process. A Monte Carlo procedure** generated values of $f(t)$ which fluctuated randomly within the statistical limits.*** One thousand such computer runs were performed, the results of which are summarized below.

* Section V further discusses new discoveries and their ultimate growth through developmental drilling.

** For a discussion of Monte Carlo procedures, see B. F. Green, Digital Computers in Research, New York, McGraw-Hill, 1963, pp. 155-158.

*** Statistical limits refers to the Standard Error (SE) of estimate of each value of $f(t)$ computed from the data. SE is computed as the square root of the variance in estimates divided by the number of estimates. The Monte Carlo program sampled values from a normal distribution with parameters $f(t)$ and SE.

<u>Estimate of:</u>	<u>2.5% of Runs Less Than:</u>	<u>Average</u>	<u>2.5% of Runs Greater Than:</u>
• Ultimate Recovery from Inferred Reserves	89.10 Tcf	97.42 Tcf	105.75 Tcf
• Additions to Inferred Reserves to the Year 2000	78.00	84.41	90.82
• Cumulative Production from Inferred Reserves to 2000	56.80	61.17	65.55
• Total Production from Known and Inferred Reserves in 1985	10.52	10.71	10.90
• Total Production from Known and Inferred Reserves in 2000	3.87	4.08	4.30

These analyses showed that 95% of the simulation runs were within a very narrow band around the estimates. In the worst case, the fluctuation was less than 9% of the estimate, well within acceptable limits for a planning study.

K. Conclusions for Study of Inferred Reserves

The analyses found that the previous approaches to calculating inferred reserves, when subjected to tests against historical trends, provide estimates which may be as much as twice the actual volume.

A model which directly estimates the yearly change in reserves on an incremental basis was found to provide the best match with three separate "hind-casting" (i.e., forecasting known data) standards when compared with fraction of ultimate models as proposed by M. Hubbert.

The Monte Carlo simulation indicates that the 95% confidence interval of inferred reserves made by the model lies within a narrow band, 9% of the initial estimate. These methods have been untried in previous approaches and therefore represent a new contribution to the modeling of inferred reserves of natural gas.

The model generates the following predictions:

- Total of inferred reserves: 97 Tcf
- Additions to inferred reserves by the year 2000:
84 Tcf
- Cumulative production from additions to inferred reserves:
 - by the year 1985: 19 Tcf
 - by the year 2000: 63 Tcf
- Rate of production from inferred reserves:
 - in the year 1985: 2.9 Tcf
 - in the year 2000: 2.5 Tcf

V. ESTIMATES OF PRODUCTION FROM NEW DISCOVERIES

The analysis of undiscovered fields is the least predictable of the three components of production from conventional sources. There is a wide variety of alternative methodologies with results just as varied.

For purposes of this study, a simple extension of recent history was chosen. As shown in Exhibit 2-3, since 1970 discoveries in offshore areas have averaged slightly over 0.5 Tcf per year and discoveries in the onshore areas have averaged 1.0 Tcf per year.

Under a finite resource base, these averages would slowly decline, thus, new discoveries for the period 1977-2000 from conventional sources were set at 1.0 Tcf from onshore and 0.5 Tcf for offshore.

These new discoveries were permitted to accumulate inferred reserves. Production was based on the 10% decline model. The results are presented below (and form the basis for the production from new discoveries and extension of new discoveries curve in Exhibit 2-1):

- New Discoveries added, 1977-2000: 36 Tcf
- Inferred Reserves on New Discoveries:
 - Portion added between 1977-2000: 69 Tcf
 - Portion added after 2000: 36 Tcf

* New discoveries were added at a rate of 1.5 Tcf per year only to the year 2000.

EXHIBIT 2-3

NEW DISCOVERIES OF CONVENTIONAL SOURCE NATURAL
GAS IN THE LOWER 48 STATES

<u>Year</u>	<u>Total</u>	<u>New Discoveries (Tcf)</u>	
		<u>Onshore</u>	<u>Offshore</u>
1976	1.421	0.995	0.426
1975	2.402	1.270	1.132
1974	2.014	1.277	0.737
1973	2.151	1.599	0.522
1972	1.462	1.182	0.280
1971	1.317	0.676	0.641
1970	1.770	1.583	0.187
Sum of 8 Years Discoveries:		8.582	3.925
Average:		1.072	0.491

SOURCE: API/AGA Bluebooks

1970-1973 data estimated by taking offshore
 Gulf of Mexico data as 0.989 of Southern
 Louisiana discoveries

- Total Reserves Added, 1977-2000: 105 Tcf
- Production
 - Cumulative production from new discoveries between 1977-2000: 24 Tcf
 - Cumulative production from inferred reserves accruing to new discoveries, 1977-2000: 41 Tcf
 - Total production from new discoveries and their inferred reserves: 65 Tcf
- Remaining Reserves from New Discoveries and Inferred Reserves in the Year 2000: 40 Tcf

The annual production from these sources is given below in five-year intervals:

ESTIMATED ANNUAL PRODUCTION FROM NEW
DISCOVERIES AND THEIR GROWTH

<u>Year</u>	<u>New Discoveries (Tcf)</u>	<u>Inferred Reserves from New Discoveries (Tcf)</u>	<u>Total (Tcf)</u>
1980	0.6	0.5	1.1
1985	1.0	1.4	2.4
1990	1.2	2.1	3.3
1995	1.3	2.5	3.8
2000	1.2	2.8	4.0

VI. SUMMARY OF PRODUCTION FROM CONVENTIONAL SOURCES

The following table summarizes the production as estimated from the work reported in Sections III through V and illustrated in Exhibit 2-1.

NATURAL GAS PRODUCTION FROM SOURCE LISTED IN COLUMN HEADING

Year	Proved Reserves	Inferred on Proved	New Disc. Onshore	Inferred on New Disc. Onshore	New Disc. Offshore	Inferred on New Disc. Offshore	Total
1976	20.52	0.35	0.05	0.02	0.03	0	20.95
1977	18.47	0.98	0.14	0.07	0.07	0.03	19.76
1978	16.62	1.49	0.23	0.13	0.12	0.06	18.65
1979	14.96	1.90	0.31	0.22	0.15	0.11	17.66
1980	13.46	2.25	0.38	0.35	0.19	0.17	16.86
1981	12.12	2.53	0.44	0.46	0.22	0.23	16.01
1982	10.91	2.73	0.50	0.59	0.25	0.30	15.27
1983	9.81	2.84	0.55	0.72	0.27	0.36	14.54
1984	8.83	2.88	0.59	0.83	0.30	0.41	13.84
1985	7.95	2.91	0.63	0.93	0.32	0.46	13.20
1986	7.15	2.90	0.67	1.03	0.33	0.52	12.66
1987	6.44	3.04	0.70	1.13	0.35	0.56	12.23
1988	5.80	3.11	0.73	1.22	0.37	0.61	11.83
1989	5.22	3.12	0.76	1.31	0.38	0.65	11.43
1990	4.69	3.13	0.78	1.38	0.39	0.69	11.07
1991	4.22	3.15	0.80	1.44	0.40	0.72	10.74
1992	3.80	3.12	0.82	1.50	0.41	0.75	10.42
1993	3.42	3.03	0.84	1.55	0.42	0.78	10.05
1994	3.08	2.99	0.86	1.61	0.43	0.80	9.77
1995	2.77	2.93	0.87	1.65	0.44	0.83	9.49
1996	2.49	2.86	0.88	1.70	0.44	0.85	9.23
1997	2.25	2.75	0.90	1.74	0.45	0.87	8.94
1998	2.02	2.56	0.91	1.78	0.45	0.89	8.62
1999	1.82	2.49	0.92	1.82	0.46	0.91	8.42
2000	1.64	2.48	0.91	1.86	0.45	0.93	8.28

The analysis shows that between now and the year 2000 and under economic/technical conditions as of the end of 1977, the domestic lower-48 conventional natural gas resource base is 373 Tcf, as shown below:

Ultimate Recovery.

• Proved Reserves, December 1976 (excluding Alaska)	184 Tcf
• Inferred Reserves (added to reserves proved prior to 1977):	
-- added from January 1977 through December 2000	84
-- added after 2000	(13)
• New discoveries after 1977 at 1.5 Tcf/year through 2000	36
• Inferred Reserves (from discoveries after 1977):	
-- added from 1978 through 2000	69
-- added after 2000	(36)
• Total Domestic Natural Gas Reserves, 1976-2000	373

Nearly 80% of the total gas reserves, or 297 Tcf, would be produced by the year 2000; with new additions from inferred reserves or new discoveries having to account for over 40% of this total. Assuming a level natural gas demand, at current levels of 20 Tcf per year for 24 years, total potential demand would be 480 Tcf. Conventional sources under the economic/technical conditions as of 1977 could only meet about 60% of this demand.

	Cumulative Production to 2000 <u>(Tcf)</u>	% of Total Production 1977-2000 <u>(%)</u>
• Production from Reserves Proved Prior to 1977	169	57
• Production from Inferred Reserves Additions to Pre-1977 Reserves	63	21
• Production from New Discoveries After 1977	24	8
• Production from Inferred Reserves on Discoveries After 1977	<u>41</u>	<u>14</u>
TOTAL PRODUCTION 1977-2000	297	100%

YEAR TO YEAR ESTIMATES OF $f(t)$

AGE	74-75	73-74	72-73	71-72	70-71	69-70	68-69	67-68	66-67	Mean	V. A. R.
1	0.358	0.859	0.877	1.478	0.368	0.764	0.439	0.343	0.469	0.662	0.792
2	0.603	0.317	0.109	0.087	0.249	0.484	0.125	0.101	0.280	0.262	0.331
3	0.178	0.269	0.049	0.240	0.382	0.079	0.090	0.088	0.216	0.166	0.217
4	0.085	0.184	0.003	0.077	0.010	0.084	0.024	0.025	0.051	0.022	0.085
5	0.338	0.051	0.191	0.111	0.025	0.028	0.090	0.012	0.254	0.114	0.172
6	0.017	0.045	0.136	0.081	0.031	0.033	0.009	0.134	0.034	0.011	0.078
7	0.035	0.084	0.073	0.012	0.060	0.022	0.072	0.091	0.007	0.016	0.063
8	0.009	0.036	0.149	0.034	0.068	0.020	0.037	0.009	0.002	0.011	0.062
9	0.057	0.009	0.094	0.039	0.021	0.140	0.048	0.192	0.013	0.045	0.095
10	0.039	0.019	0.007	0.015	0.160	0.059	0.112	0.113	0.024	0.016	0.085
11	0.008	0.004	0.037	0.017	0.028	0.040	0.008	0.055	0.163	0.015	0.065
12	0.019	0.006	0.072	0.007	0.038	0.072	0.016	0.005	0.111	0.013	0.056
13	0.015	0.040	0.048	0.256	0.003	0.048	0.022	0.050	0.030	0.024	0.097
14	0.002	0.007	0.124	0.017	0.003	0.058	0.045	0.035	0.012	0.005	0.053
15	0.015	0.018	0.037	0.091	0.020	0.028	0.007	0.019	0.033	0.025	0.040
16	0.018	0.025	0.264	0.013	0.032	0.035	0.029	0.020	0.018	0.022	0.096
17	0.092	0.016	0.044	0.020	0.025	0.039	0.002	0.011	0.065	0.029	0.047
18	0.004	0.010	0.014	0.023	0.009	0.003	0.004	0.008	0.027	0.005	0.015
19	0.012	0.006	0.000	0.020	0.004	0.002	0.021	0.009	0.035	0.003	0.017
20	0.007	0.045	0.021	0.023	0.016	0.007	0.017	0.004	0.055	0.004	0.029
21	0.029	0.004	0.011	0.016	0.015	0.034	0.016	0.020	0.161	0.022	0.060
22	0.001	0.003	0.121	0.014	0.008	0.041	0.007	0.011	0.096	0.006	0.057
23	0.012	0.003	0.032	0.016	0.019	0.005	0.066	0.040	0.050	0.014	0.036
24	0.008	0.011	0.113	0.038	0.013	0.005	0.002	0.017	0.067	0.015	0.049
25	0.006	0.015	0.003	0.005	0.020	0.016	0.012	0.013	0.115	0.015	0.043
26	0.015	0.042	0.020	0.051	0.005	0.011	0.040	0.027	0.011	0.011	0.031
27	0.003	0.003	0.036	0.005	0.046	0.008	0.016	0.102	0.038	0.015	0.044
28	0.023	0.005	0.027	0.004	0.100	0.042	0.047	0.050	0.054	0.018	0.051
29	0.006	0.005	0.019	0.006	0.068	0.007	0.060	0.010	0.018	0.012	0.034
30	0.062	0.004	0.024	0.072	0.003	0.010	0.011	0.055	0.054	0.018	0.044
31	0.137	0.046	0.001	0.233	0.023	0.006	0.009	0.087	0.044	0.048	0.103
32	0.013	0.032	0.213	0.003	0.049	0.022	0.011	0.050	0.085	0.023	0.086
33	0.002	0.004	0.018	0.007	0.016	0.006	0.006	0.054	0.434	0.042	0.155
34	0.014	0.032	0.028	0.033	0.018	0.007	0.027	0.038	0.067	0.004	0.035
35	0.022	0.002	0.009	0.103	0.008	0.002	0.000	0.022	0.063	0.007	0.044
36	0.063	0.015	0.018	0.019	0.013	0.004	0.010	0.015	0.095	0.008	0.042
37	0.004	0.007	0.001	0.013	0.055	0.027	0.000	0.014	0.135	0.014	0.053
38	0.014	0.006	0.127	0.013	0.003	0.018	0.004	0.212	0.058	0.017	0.090
39	0.068	0.026	0.038	0.043	0.011	0.012	0.014	0.071	0.022	0.020	0.043
40	0.014	0.030	0.015	0.006	0.014	0.000	0.007	0.041	0.060	0.002	0.032
41	0.000	0.036	0.002	0.012	0.113	0.015	0.003	0.003	0.029	0.002	0.044
42	0.009	0.019	0.016	0.027	0.030	0.025	0.007	0.033	0.146	0.016	0.056
43	0.054	0.086	0.076	0.015	0.008	0.008	0.004	0.008	0.138	0.009	0.067
44	0.103	0.032	0.101	0.011	0.017	0.000	0.146	0.030	0.091	0.022	0.081
45	0.001	0.019	0.016	0.008	0.006	0.027	0.026	0.027	0.004	0.003	0.019
46	0.001	0.003	0.006	0.001	0.046	0.007	0.018	0.000	0.152	0.024	0.056
47	0.031	0.000	0.013	0.145	0.003	0.011	0.011	0.013	0.406	0.032	0.153
48	0.026	0.002	0.011	0.008	0.092	0.000	0.263	0.389	0.021	0.061	0.170
49	0.064	0.043	0.006	0.014	0.008	0.029	0.004	0.002	0.0	0.015	0.032
50	0.012	0.060	0.015	0.001	0.394	0.021	0.028	0.0	0.0	0.058	0.163
51	0.017	0.010	0.007	0.040	0.028	0.005	0.0	0.0	0.0	0.010	0.024
52	0.030	0.034	0.025	0.017	0.012	0.0	0.0	0.0	0.0	0.002	0.028
53	0.039	0.019	0.004	0.006	0.0	0.0	0.0	0.0	0.0	0.008	0.025
54	0.014	0.004	0.012	0.0	0.0	0.0	0.0	0.0	0.0	0.010	0.013
55	0.020	0.020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.020	0.024
56	0.005	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.005	0.0

CHAPTER THREE

METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM TIGHT GAS SANDS

INTRODUCTION AND SUMMARY

A geologic-engineering-economics approach was used in analyzing the potential of the tight gas sands. The approach was designed to immitate, on a scale commensurate with a planning study, the analyses and decision processes used by gas operators in evaluating such prospects. The analysis was conducted for two levels of technology (Base and Advanced) across several price scenarios. The results of this appraisal are reported in Chapter Three of Volume II. This chapter describes the basic methods, assumptions, and sensitivity analyses that led to those steps.

The analysis followed four basic steps:

- Collecting Basic Data: The initial step involved the collection and analyses of detailed geological and engineering data on each of the identified basins to define the size and reservoir characteristics of each.
- Defining Base Case Technology: The second step involved the definition of the major problems and constraints that limit full exploitation of these resources by industry and defined the current and near-term (next five years) technology and its application without Federal stimulus -- the Base Case.
- Defining Advanced Case Technology: The next step was to develop R&D strategies for overcoming current technical limitations and accelerating the development of the target basins -- the Advanced Case technology.

- Conducting the Economic Analysis: The final step was to simulate the production from each reservoir and the economics of production under Base Case and Advanced Case technologies to establish the economic potential of the tight gas basins.

Section I of this chapter describes the process of collecting and interpreting basic geologic data into reservoir descriptions suitable for computer simulation. Section II describes the reservoir simulator used to predict production for individual wells, along with the assumptions and sensitivity analyses that guided the reservoir modeling. Section III presents the economic, decision, and timing models used in the analysis.

I. THE RESOURCE BASE

A. Scope of the Study

The scope of the analysis of the tight gas sands was specifically delimited to those basins, sub-basin areas, and formations where sufficient data were available to support detailed engineering analyses. These limitations exclude those portions of the resource that are currently considered speculative and no attempt was made to extrapolate the findings of this analysis to these speculative areas.*

1. Basins

Previous study^{1/} has identified twenty basins containing gas reservoirs with permeabilities too low to permit economic recovery by existing, conventional technology. Exhibit 3-1 displays the basins and geologic ages so defined. The five "primary study areas" are those on which Federally sponsored research have been focused. Highest data collection priority was assigned to these.

Preliminary data collection efforts showed that, of the remaining fifteen basins, data were sufficient to support detailed engineering economics study of an additional eight basins. Thus, the scope of the present study of the tight gas basins addresses only the thirteen basins for which adequate data could be collected. This limitation does not imply limited potential of the seven basins outside this analysis or of other basins not yet identified. Some of the excluded basins (e.g., the Anadarko) are known to contain significant quantities of gas in tight formations.

For analysis and planning R&D programs, the basins were classified into resource targets with relatively homogeneous geologic/technological problems. Three basic geologic features were used to develop the classification:

* The projections presented in Volume II reflect the limitations imposed on the scope of this study.

EXHIBIT 3-1

LOCATION OF MAJOR TIGHT GAS BASINS

SOURCE: U.S. ERDA, WESTERN GAS SANDS,
PROJECT PLAN, 8/1/77

DOE's Primary Study Areas

Geological Age

A. Greater Green River Basin	Tertiary and Cretaceous
B. Piceance Basin	Tertiary and Cretaceous
C. Uinta Basin	Tertiary and Cretaceous
D. Northern Great Plains Province	Cretaceous
E. Williston Basin	Cretaceous

Additional Low-Permeability Areas in the Study

1. Big Horn Basin	Tertiary and Cretaceous
2. Cotton Valley Trend	Jurassic
3. Denver Basin	Cretaceous
4. Douglas Creek Arch	Cretaceous
5. Ouachita Mountains Province	Mississippian
6. San Juan Basin	Cretaceous
7. Sonora Basin	Pennsylvania
8. Wind River Basin	Tertiary and Cretaceous

Other Low-Permeability Areas Not Included in Study

a. Anadarko Basin	Pennsylvania
b. Arkoma Basin	Pennsylvania
c. Fort Worth Basin	Pennsylvania
d. Raton Basin	Tertiary and Cretaceous
e. Snake River Downwarp	Tertiary and Cretaceous
f. Wasatch Plateau	Cretaceous
g. Western Gulf Basin	Tertiary and Cretaceous

- Permeability. Basins were classified according to the average initial in situ permeability to gas of the major deposit. Formations with permeabilities greater than 1.0 millidarcy were regarded as commercial and were excluded from the analysis of tight gas formations (see below). Formations having permeabilities between 1.0 md and 0.05 md were considered "relatively tight" and those with average permeabilities less than 0.05 md as "very tight". The preponderance of the major gas pays analyzed in this study were found to be very tight.
- Depth. Due to the substantially different engineering problems associated with shallow versus deep formations, formations less than 2500 feet deep were categorized as shallow, those over 2500 feet as deep.
- Lenticularity. Sand discontinuity appears to be the single most severe geologic problem that must be overcome. Thus, the basins were classified as lenticular or "blanket-type" according to the nature of the major formations.

Using these three geologic conditions, five classes of basins, referred to as resource "targets", were established:

- Western Tight Gas Basins -- the three basins, Greater Green River, Piceance, and Uinta that originally attracted the attention of the FPC National Gas Survey.
- Shallow Gas Deposits -- the shallow, low production formations of the Northern Great Plains Province and the Williston Basin.
- Other Tight, Lenticular Gas Sands -- Sonora, Douglas Creek Arch, and the Big Horn Basins.

- Tight, Blanket Gas Sands -- the Denver, San Juan, Wind River, Cotton Valley Basins, and the Ouachita Mountain Province.
- Other Low Permeability Reservoirs -- the Bruckner-Smackover formation of the Cotton Valley Trend.

The tight gas basins initially identified but not included in this analysis due to insufficient data were the Anadarko, Arkoma, Fort Worth, Raton, Snake River, Wasatch, and Western Gulf Basins.

2. Formations Within the Basins

Within the basins included in the study, specific geologic ages, previously identified as the target of "tight gas sections", were considered candidate prospects. This served to focus the data collection on the areas of highest potential and promise. Formations with in situ permeability to gas greater than 1.0 md were excluded from the target sections. The assumption was that these higher permeability formations would be accounted for by projections of proved, inferred, or newly discovered conventional resources. An exception to this criteria was made in the case of the shallow, more permeable formations in the Northern Great Plains.

Exhibit 3-2 lists the specific formations of each basin included in the present study.

3. Areas Within the Basins

The gross areal extent of each basin was categorized in a scheme designed to be consistent with the reserve classification system of the Potential Gas Committee^{2/} and the well classifications of the American Association of Petroleum Geologists.^{3/} Four classes of acreage were defined for each basin:

EXHIBIT 3-2

TARGET FORMATIONS IN THE TIGHT GAS BASINS

1. WESTERN TIGHTS
 - a. Green River
 1. Ft. Union
 2. Almond A
 3. Almond B
 4. Erickson
 5. Rock Springs/Blair
 6. Other Mesaverde
 - b. Piceance
 1. Ft. Union
 2. Corcoran-Cozette
 3. Other Mesaverde
 - c. Uinta
 1. Wasatch
 2. Barren
 3. Coaly
 4. Castlegate
2. SHALLOW GAS
 - a. Northern Great Plains
 1. Judith River
 2. Eagle
 3. Carlisle
 4. Greenhorn/Frontier
 - b. Williston
 1. Judith River
 2. Eagle
 3. Greenhorn
3. OTHER TIGHT LENTICULAR
 - a. Big Horn
 1. Mesaverde
 - b. Douglas Creek
 1. Mancos
 2. Dakota
 - c. Sonora
 1. Canyon
4. TIGHT BLANKET
 - a. Cotton Valley "Sweet"
 1. Cotton Valley Sand Trend
 2. Gilmer Lime
 - b. Denver
 1. Sussex
 2. Niobrara
 3. Dakota
 - c. Ouachita
 1. Stanley
 - d. San Juan
 1. Dakota
 - e. Wind River
 1. Frontier
 2. Muddy
5. OTHER LOW PERMEABILITY
 - a. Cotton Valley "Sour"
 1. Bruckner/Smackover

- Proved acreage -- within the defined perimeter of existing fields.
- Probable acreage -- extensions of existing fields and obvious corridors between fields where the direction of recent drilling suggests the field will ultimately merge.
- Possible acreage -- areas outside proved or probable acreage where the subject formations have had gas "shows" or production but no multi-well fields have been developed.
- Speculative acreage -- areas in which drilling through the subject formations has yielded no show of gas and areas where no drilling has taken place.

To avoid "double-counting", proved acreage was excluded from the analysis. These proved areas were presumed to be included in the current AGA reserve estimates.

Speculative acreage was also excluded from the analysis. Such acreage is analogous to the basins and formations that were excluded for reasons of insufficient data. The absence of wells with gas shows argues that too little is known about these areas to support detailed analysis.

With these two exclusions, the area analyzed having at least definable gas shows becomes incremental to present proved areas -- the Probable and Possible categories. To account for the fact that vast areas are seldom fully successful when drilled, each acreage classification was weighted by the historical drilling success ratio for the states in which the basins lie

to yield "anticipated" acreage.* Probable areas were weighted by the success rates for developmental drilling. Possible areas were weighted by the average of within-field exploratory wells and rank wildcats. Exhibit 3-3 shows the anticipated productive area of each of the basins in the analysis.

4. Implications of the Scope Limitations

This analysis neither includes nor extrapolates to all domestic tight gas basins or formations. It represents, rather, a major sampling of such formations. Additional basins -- including the seven that have been identified but lacked sufficient data -- and additional formations and currently speculative portions even within the basins analyzed, may represent additional potential. While the R&D strategies aimed at developing the target basins actually analyzed may stimulate the development of other basins and formations, the potential of the tight sands in the present analysis is limited as described in this statement of scope.

B. Data Collection Methods

Data on the tight gas resource base were collected by teams of reservoir engineers and geologists who had previously worked in these basins.** Operators and others experienced in the basins contributed additional data and reviewed the data being collected by the teams. The data collection process was designed to produce consistent, detailed reservoir descriptions across the several basins and teams.

* Anticipated acreage is roughly analogous to "expected" acreage except that only point estimates of the means (no distributions) are available.

** Appreciation for data collection is expressed to the following organizations and individuals: Sandia, Inc.; CER Geonuclear, Inc.; C.K. Geonuclear, Inc.; Gruy Federal, Inc.; Mitchell Energy, Inc.; the Godsey-Earlougher Division of Williams Brothers Engineering, Inc.; the Bartlesville Energy Research Center; and independent geologists Gene Foss, Tom Beard, and Alan Hansen.

EXHIBIT 3-3

ANTICIPATED AREAL EXTENT OF TIGHT GAS BASINS

<u>TARGET/BASIN</u>	<u>PROBABLE AREA*</u>		<u>POSSIBLE AREA*</u>		<u>TOTAL ANTICIPATED* AREA (Mi²)</u>
	<u>Area (Mi²)</u>	<u>Weight (%)**</u>	<u>Area (Mi²)</u>	<u>Weight (%)**</u>	
<u>WESTERN TIGHT</u>					
Green River	454	78	416	25	870
Piceance	395	78	460	25	855
Uinta	699	78	297	25	996
Subtotal	1,547		1,173		2,720
<u>SHALLOW GAS</u>					
Northern Great Plains	3,660	60	13,900	21	17,560
Williston	0	60	6,520	21	6,520
Subtotal	3,660		20,420		24,080
<u>OTHER TIGHT LENTICULAR</u>					
Big Horn	81	78	680	25	761
Douglas Creek	252	78	117	25	369
Sonora	890	85	1,070	31	1,960
Subtotal	1,223		1,867		3,090
<u>TIGHT BLANKET</u>					
Cotton Valley (Sweet)	1,225	78	1,026	29	2,251
Denver	1,966	74	625	20	2,591
Ouachita	0	70	113		113
San Juan	266	93	564	41	830
Wind River	82	78	383	25	465
Subtotal	3,539		2,711		6,250
<u>OTHER LOW-PERMEABILITY</u>					
Cotton Valley (Sour)	569	78	642	29	1,211
TOTAL	<u>10,538</u>		<u>26,813</u>		<u>37,351</u>

* After application of anticipated success ratios

** Success ratios developed from American Association of Petroleum Geologists data

The teams had access to publicly available data, although the quality and quantity of such data varied considerably among the basins, reflecting differences in state reporting requirements and the amount of activity in the basin. They supplemented these public data with maps and well-records purchased from commercial organizations.

The data collection process consisted of five basic steps, described below.

1. Areal Interpretation

Geologic and field maps of each basin, along with available cross sections and geologic interpretations, were studied to establish:

- The gross areal extent of the geologic age of interest, as established by the outcropping of the formation.
- The target areas in which gas was potentially present. This was generally done by moving inside the outcrops to a point where gas shows had been established.
- Four areal classifications were used:
 - Proved, having a developed, multi-well field
 - Speculative, having no wells drilled
 - Probable, likely extension drilling and corridors between fields
 - Possible, likely future areas having gas shows in the target formation.

2. Selection of Wells

Well maps and computerized well-data bases* were queried to identify wells that were classed as wildcat, step-out, or extension, penetrated the target geologic age, and had at least "shows" of gas. These criteria were established in order to focus data collection in the areas for which the projections would be made. From the wells meeting these criteria, a number were selected in order to achieve geographic dispersion across the area held to be prospective from Step 1.

The number of wells selected was governed by the amount of drilling in the respective basins, the availability of data, and their priority in the present analysis. A large number of wells were selected for study in the Western and Shallow Basins due to their higher priority and larger amount of existing research based on on-going Federal geologic study.

3. Collection of Well Data

After the available data for the selected wells were collected and analyzed, the first step was to define the prospective intervals in terms of the specific geological formations which had either gas production or gas shows. Data from Petrowell Libraries, Petroleum Information, Inc., and individual operators were transcribed for each formation and well. Exhibit 3-4 shows the well data worksheet.

4. Construction of "Typical" Wells

The raw well data were compared to examine the extent to which the key reservoir properties controlling gas in place and production (e.g., porosity, saturations, thickness, and permeability) varied from well to well.

* FPC Form 15 file, Petroleum Information System file, Petroleum Information, Inc., Petro-Well library, and state completion reports.

EXHIBIT 3-4

WELL RECORD WORKSHEET

Basin _____ Sub-Division _____ Field _____ Sub-Division _____

Formation _____ Sub-Division _____

WELL RECORDS

	1	2	3	4	Calc/Notes
Well Identification					
Well Location					
Operator					
Completion (Acid, Expl/Hydraulic)					
A. Gal. of Fluid					
B. Lb. of Proppant					
C. Date of Completion					
Reservoir/Gas Data					
A. Interval (S) - Ft. to Ft, Ft to Ft					
B. Reservoir Temp - °F					
C. Orig Reservoir Press - Psig					
D. Curr Reservoir Press - Psig					
E. Porosity - %					
F. Permeability (dry) - Md (Circle Kg)					
G. Sw - %					
H. Drainage Area/Spacing					
I. Gas Gravity (dry) (air = 1.0)					
J. Gas-Oil Ratio					
Potential					
A. Pre-Frac Test - Date					
1. COFP - Mcfd					
2. N					
B. Immed Post-Frac Test - Date					
1. COFP - Mcfd					
2. N					
C. Latest Test - Date					
1. COFP - Mcfd					
2. N					
Performance - Current Stat (P, SI, PA)					
A. Cumulative - Mcf					
B. Date of Cumulative					
C. Production in:					
First 30 Days - Mcfd					
1st Year - Mcfd					
2nd Year					
3rd Year					
4th Year					
5th Year					
6th Year					
7th Year					
8th Year					
9th Year					
10th Year					

Where a particular formation showed relatively little variation, an average was used. This average was considered "typical" for that formation. Where considerable variation was present, separate sub-areas, with relatively homogeneous characteristics, were defined, with separate "typical" formations for each. Where only one formation was included in the analysis, the typical formation was defined as the typical well for use in the analysis. In areas having multiple formations, a vertical set of typical formations was constructed to identify the formation overlap. Further areal subdivisions to ensure relative homogeneity of reservoir characteristics for all formations in a given areal subdivision were made. Gas-in-place was calculated for each areal unit. The "typical" data for each formation within each areal unit were transcribed only the form shown as Exhibit 3-5. These forms, along with the data supporting them, constituted the draft resource descriptions for each basin.

5. Validation

These draft descriptions were submitted to geologists and engineers active in the basins for review. These outside sources critiqued the data and frequently provided additional data. These reviews and discussions assisted the study to develop improved reservoir parameters and more precise delineation of the sub-areas.

C. Interpretation of the Data

1. The Issues

After data collection, the data were analyzed and further interpreted to a form suitable for modeling. Four issues had to be addressed analytically to ensure a useable and valid set of data, namely:

- The permeability to gas is often reported as laboratory-based dry permeability to air. Since in situ conditions of confining pressure and water saturation are known to

EXHIBIT 3-5

NON-ASSOCIATED GAS "RESERVOIRS" --
FIELD/SUB-BASIN DATA FORM

*Basin _____ *Sub-Division _____ *Field Name _____ *Segment _____

Location -- in notes, show counties, township, and range or other designation

GEOLOGIC TARGET

*Age/System _____	*Formation Name or Subdivision _____
*Depth _____ ft (Avg or Top, check)	Depth range _____ to _____ ft
*Gross thickness _____	Percent Gross Pay: Sand _____
Stratigraphic _____	Limestone _____
Structural _____	Shale _____
*Area _____ acres	Siltstone _____

GAS PAY (Mark X or Percent)

Sandstone _____	Layered deposits _____
Limestone _____	Lenticular deposits _____
Shale _____	Fractured: Occasionally _____
Siltstone _____	Intensively _____
*Est. net pay _____ ft	Dispersal of pay: from _____ to _____ ft
*Est. no pay zones _____	_____ Fairly evenly
* % net to gross _____ %	_____ Fairly concentrated
	_____ Very irregular

PAY QUALITY

*Porosity _____ to _____ %; Avg _____ %	Water Salinity _____ PPM
*Water Saturation _____ to _____ %;	Clay Content _____
Avg _____ %	Minor _____
*Permeability Avg. _____ Md Dry (one phase)	Significant _____
Perm. to Gas in situ w/ conn. water _____	Type _____
*Initial reservoir temp. _____ °F	Spec. Gravity of Gas (Water=1.0) _____
*Initial Reservoir Pressure _____ Psig	

FOR DEVELOPED(ING) RESERVOIRS ONLY

*Cumulative recovery _____ Mcf, as of _____	Recovery Factor _____
*Current Reservoir Pressure _____ Psig	Current No. Wells _____ Producing
*Remaining Reserves _____	_____ SI _____ PRA
*Typical Stimulation: _____ Acid	Average Spacing _____ Acres
_____ Explosive	* _____ Gal. of Fluid
_____ Hydraulic	* _____ Lb. of Proppant
*Dry Hole Rate _____ %	
*Frac Success Rate _____ *	
Predominant Operators _____	

*Computed Original Gas in Place _____ Mcf (Attach calculations)

*Highest Priority

NOTES:

reduce bench-measured permeability, the first issue was: how should the data be adjusted to account for permeabilities under in situ conditions?

- Considering that drilling generally proceeds from better toward worse prospects, the "typical" reservoir properties, being derived from the records and experience of drilling to date, are likely to reflect the better position of the reservoir. The second issue, then, was: how could average data based on existing wells be adjusted to reflect the expected distribution of reservoir conditions for the undeveloped area?
- Even in blanket-type formations, and certainly in lenticular formations, dry areas had to be expected. How could this expectation be incorporated into the analysis?
- Given that a formation was known to be lenticular, how could that fact be explicitly addressed in the model?

The first three of these questions were addressed through adaptations of the basic resource data in the analysis, described below in this section. Adjustments for the fourth issue, lenticularity, were intimately related to production simulation, so were handled in that phase of the analysis, as described in the next section of this chapter.

2. In Situ Permeability

Thomas and Ward^{4/} have demonstrated the marked reduction in gas permeability as measured in cores under typical surface-level conditions when returned to reservoir conditions. Specifically, net confining pressure and water saturation are seen to dramatically reduce in situ gas permeability.

The "typical" permeability data provided by the data collection teams were, in most cases, measured at surface conditions as dry cores. In some cases, these key data items were missing, so appropriate analogues (with an adjustment for in situ conditions) were needed to permit production simulation.

The findings of Thomas and Ward for the Fort Union sandstone are summarized in Exhibit 3-6. Net confining pressure and the permeability ratio (in situ permeability divided by permeability at surface conditions) show a negative exponential relationship. The higher the water saturation, the more pronounced this relationship. This figure was the basis for the assumptions used in adjusting measured permeabilities to in situ conditions. Additional adjustments were made for the shaly sands and to reflect the nature of the data being gathered by the study team. Exhibit 3-7 tabulates these adjustments. Exhibit 3-8 provides a plot of these assumptions for the shaly case and shows that, under extreme conditions, measured permeability is reduced two orders of magnitude. The shaly condition was assumed to correlate with measured permeabilities of less than 0.5 md. because generally it is the presence of clays and shales in the sands that contributes to their tightness.

Where permeability data were absent, an approximation was made by taking the reported permeability for an analogue formation. The data from the analogue formation was corrected to surface conditions (using the correction assumptions in Exhibit 3-7) and re-corrected to the confining pressure and water saturation of the formation whose permeability was to be estimated.

3. Distribution of Reservoir Qualities

After discovery, drilling is generally first directed toward the most promising prospects and then proceeds to portions of the resource expected to be lower in quality. Thus, the characterization of a resource based on existing wells at any time before the resource is fully drilled is most likely to be biased in the direction of the more favorable reservoir qualities.

EXHIBIT 3-6

EFFECT OF CONFINING PRESSURE ON THE PERMEABILITY OF
FORT UNION FORMATION SANDSTONE SAMPLES

SOURCE: R. D. Thomas and D. C. Ward, "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", Journal of Petroleum Technology, February, 1972.

EXHIBIT 3-7

ADJUSTMENT FACTORS FOR REDUCING BENCH-MEASURED
PERMEABILITY TO IN SITU CONDITIONS

<u>Confining Pressure</u> psi	<u>Depth</u> ft	<u>Water Saturation</u> %	<u>Factor*</u>	
			<u>Clean</u>	<u>Shaley</u>
1,000	2-4,000	60	.07	.06
		50	.12	.10
		40	.2	.17
		30	.3	.25
		20	.4	.35
2,000	4-6,000	60	.06	.05
		50	.1	.08
		40	.15	.13
		30	.20	.17
		20	.25	.20
3,000	6-8,000	60	.05	.04
		50	.09	.07
		40	.12	.10
		30	.16	.13
		20	.2	.16
4,000	8-10,000	60	.04	.03
		50	.07	.05
		40	.10	.07
		30	.13	.10
		20	.15	.12
5,000	10-12,000	60	.03	.02
		50	.05	.03
		40	.07	.05
		30	.09	.07
		20	.10	.08

* Corrects bench lab dry gas permeability to in situ gas permeability under confining pressure and water saturation

Bench permeability x factor = in situ gas permeability

EXHIBIT 3-8

ASSUMED RELATIONSHIP BETWEEN REPORTED PERMEABILITY
AND IN SITU GAS PERMEABILITY

Moreover, reservoir qualities are known to vary substantially in even relatively small geographic areas. Failure to account for this variation would ignore a major cause of the economic sensitivity revealed by most extractive industries. Thus, it was necessary to determine means for converting the reservoir data as reported by the data collection teams into a distribution of reservoir characteristics.

The Wattenberg field, a tight gas field in the Denver Basin, was chosen to serve as the analogue for developing the required distributions and corrections.* A series of reservoir simulations were run, using a range of reservoir conditions typical of the Wattenberg, to prepare a series of type-curves of production as a function of reservoir properties. Since the production data ranges from a few months to less than four years, a series of projection factors, prepared by dividing each month's cumulative recovery by the estimated ultimate recovery, were developed to match short term performance with ultimate recovery. Exhibit 3-9 shows one of these projection factors.

Next, twenty-nine townships, about 1000 square miles, containing the Wattenberg field and its immediate periphery, were identified. One or more wells from each township were selected so that they all were producing from the "Muddy J" formation and had reasonably similar stimulation treatments. Using cumulative recovery and time in production, each well was projected to its 30-year recovery by dividing the actual cumulative production by the appropriate projection factor.

These projections were then extrapolated to the respective townships and cumulated to show the distribution of 30-year recoveries. Exhibit 3-10 shows the distribution developed through this analysis.

* The Wattenberg field of the Denver Basin is one of the few tight gas resources to be relatively complete in its development. Substantial amounts of data are, therefore, available in published materials and state records.

EXHIBIT 3-9

EXAMPLE OF PROJECTION FACTOR FROM THE WATTENBERG FIELD
 (Percent of 30 Year Recovery by Given Months)

<u>Month</u>	<u>Percent</u>	<u>Month</u>	<u>Percent</u>
1	07.9	37	17.1
2	08.1	38	
3	08.4	39	
4	08.6	40	17.9
5	08.9		
6	09.2	48	19.9
7	09.4		
8	09.7	60	23.0
9	09.9		
10	10.1	72	26.1
11	10.4		
12	10.7	84	29.2
13		96	32.2
14			
15	11.5	108	35.3
16			
17		120	38.4
18			
19		240	69.2
20	12.7		
21		360	99.9
22	13.3		
23			
24	13.8		
25	14.0		
26	14.3		
27	14.5		
28			
29			
30	15.3		
31			
32			
33			
34			
35	16.6		
36	16.9		

EXHIBIT 3-10

PROJECTED CUMULATIVE PERCENT AREA VERSUS CUMULATIVE PERCENT
RECOVERY FOR WATTENBERG FIELD AND ITS PERIPHERY

This distribution of recovery served to provide the basis for establishing distribution of the reservoir properties and provides confirmation to the hypothesis that data sampled from existing wells will tend to reflect the more favorable characteristics.

- One-half the total production (the median) from the 1000 square miles will come from twenty percent of the area.
- The mean of the production from the twenty-nine wells sampled falls at the thirty-second percentile.
- The severe skew of this distribution defines the shape of the distribution for all the analogue areas in the analysis.
- Typical well data from the data collection effort will ultimately define the twenty-fourth percentile of total data for the field as projected from the detailed study.

The next step was to develop a method for converting the reported data into an appropriate distribution of reservoir characteristics. Because all the sampled wells had approximately the same depth and pressure, the variation in production performance was assumed to vary with net pay thickness, permeability, and gas filled porosity (initial gas saturation times porosity).

a. Distribution of Pay Thickness

An isopach map prepared by Matuszczak^{5/} was used to estimate the distribution of net pay thickness for the total reserves, as follows:

<u>Net Pay Thickness</u> (ft)	<u>Cumulative Percentage of Recovery</u> (%)
0 - 10	31
10 - 30	84
30 - 50	98
>50	100

The reported average thickness of 27 feet would represent the best third of the resource; thus, analytic adjustment would be required to accurately reflect the lower quality, thinner sections of the resource.

b. Permeability

In situ permeability to gas for Wattenberg (as reported by Fast, et. al.^{6/}) ranges by a full order of magnitude, from 0.005 to 0.05 md, with the larger portion of the resource at the lower end of the range. The reported average permeability of 0.02 md was in the middle of this range.

c. Gas-Filled Porosity

Variation in gas-filled porosity was unpublished but its range and correlation with permeability were established through discussions with engineers active in the Wattenberg. Since the reported datum was closer to the favorable end of the distribution, a modification was made to account for the log normal shape of the resource curve.

d. Summary

Combining the above findings regarding the distribution of reservoir characteristics and its relationship to the reported data, a series of pay quality cases were defined as functions of the data reported by the field teams. To keep the computations manageable, five levels of pay quality were assumed to be sufficient. These five cases were defined as follows, where thickness (h), gas-filled porosity (ϕ_g), and in situ gas permeability (kg) were taken as reported for the arithmetic average case:

<u>Pay Quality Case</u>	<u>Definition</u>			<u>Distribution (% of Area)</u>
	<u>h</u>	<u>ϕg</u>	<u>kg</u>	
Hi/Hi	1.25	1.05 ϕg	3.0 kg	5
Av/Hi	h	1.05	3.0	10
Av/Av	h	ϕg	kg	18
Av/Lo	h	0.8	0.33	33
Lo/Lo	0.5	0.8	0.33	34

Using the information gained from the Wallenberg study, one-third of the area was assumed to be as good or better than the reported data, having thicker pay, and higher porosity and permeability. One-third was somewhat lower than the reported average quality, being tighter and less porous. Finally, one-third was assumed to have substantially lower pay quality. These factors were assigned to each "typical well" area in the above proportions, to generate the analytic equivalent sub-areas.

4. Areal Adjustment for Dry Holes

An areal success factor was developed to account for the presence of dry areas within the areas to be analyzed. This factor was developed from AAPG drilling success statistics for each region reported. The regional developmental drilling success rate was used for Probable areas; the average of the regional within-field exploratory rate and the rate for rank wildcats was used for Possible areas. This "success" factor was used to reduce the gross acreage to an "anticipated" acreage, as described above in the discussion of the scope of the analysis and as displayed in Exhibit 3-3, above.

D. Preparing the Data for Analysis

1. Example of Data Adjustments

The following outlines an example of the adjustments used for a typical sub-area of the Piceance Basin under Base Case assumptions.

- Data As Submitted

	<u>Corcoran Cozette</u>	<u>Mesaverde</u>
Area (A)	163,840	163,840
Depth (ft)	6,000	8,000
Gross Interval (ft)	50	2,200 (4 intervals, 550 each)
Initial Reservoir Pressure (psi)	2,600	3,400
Reservoir Temperature (°F)	145	170
Gas Permeability (μ d)	25	20
Gas Porosity ($\phi \times (1-S_w)$)	5.8	5.1
Net Pay (ft)	30	220 (55 in each interval)
Pay Type	Blanket	Lenticular
Acreage Category	Probable	Probable

- Areal Adjustments

-- Adjustment for anticipated developmental success (given the acreage is classified as probable)

Total area x success factor = anticipated area

$$163,840 \times 0.78 = 127,795 \text{ A}$$

- Areal Units (assume that for 15% of the area, the reservoir properties are better than Av/Av and that for 67% of the area, the reservoir properties are less favorable).

<u>Pay Quality Case</u>	<u>Area Weight</u>	<u>Anticipated Area/Units</u>	
		<u>(Acres)</u>	<u>(Sections)</u>
Hi/Hi	0.05	6,390	10
Av/Hi	0.10	12,780	20
• Av/Av	0.18	23,003	36
Av/Lo	0.33	42,172	66
Lo/Lo	<u>0.34</u>	<u>43,450</u>	<u>68</u>
Total	1.00	127,795	200

- Assignments of Pay Qualities to Areal Units (combining the two adjustments):

<u>Pay Quality Case</u>			<u>Characteristics of Formations</u>					
<u>Areal Extent</u>	<u>% of Total</u>	<u>No. Sections</u>	<u>Corcoran-Cozette</u>			<u>Mesaverde</u>		
			<u>h</u> <u>(ft)</u>	<u>φg</u> <u>(%)</u>	<u>kg</u> <u>(μd)</u>	<u>h</u> <u>(ft)</u>	<u>φg</u> <u>(%)</u>	<u>kg</u> <u>(μd)</u>
Hi/Hi	5	10	38	6.1	75	275	5.4	60
Av/Hi	10	20	30	6.1	75	220	5.4	60
• Av/Av	18	36	30	5.8	25	220	5.1	20
Av/Lo	33	66	30	4.6	8	220	4.1	7
Lo/Lo	34	68	15	4.6	8	110	4.1	7

- Estimation of Gas in Place

Apply the adjusted reservoir parameters to the five analytically discrete areas to calculate a revised gas in place.

<u>Pay Quality Case</u>	<u>GIP/Section (Bcf)</u>	<u># Sections</u>	<u>Total GIP (Bcf)</u>
Hi/Hi Case:			
- Corcoran-Cozette	11.2	10	112
- Mesaverde	<u>87.0</u>	10	<u>870</u>
Total	98.2		982
Av/Hi Case:			
- Corcoran-Cozette	9.0	20	180
- Mesaverde	<u>69.6</u>	20	<u>1,392</u>
Total	78.6		1,572
• Av/Av Case:			
- Corcoran-Cozette	8.5	36	306
- Mesaverde	<u>65.7</u>	36	<u>2,365</u>
Total	74.2		2,671
Av/Lo Case:			
- Corcoran-Cozette	6.8	66	449
- Mesaverde	<u>52.8</u>	66	<u>3,485</u>
Total	59.6		3,934
Lo/Lo Case:			
- Corcoran-Cozette	3.4	68	231
- Mesaverde	<u>26.4</u>	68	<u>1,795</u>
Total	29.8		2,026
Total Corcoran-Cozette		200	1,278
Total Mesaverde		200	<u>9,907</u>
TOTAL			11,185

- Recovery Estimates (described in Section II)

Calculate recovery, under conventional technology (2 wells per section with 1,000' fractures) for each reservoir and each analytic unit:

- Blanket formations, assume that the wellbore is in contact with total of the gas reservoirs in the section
- Lenticular formations, assume that the wellbore intersects lens of the dimension 20' x 400' x 4,000' net pay; 2 wells per section will be in contact with 17.2% of the gas reservoirs in the section
- Use 30 years of production for total recovery (with 8 Mcfd as the economic limit).

- Summary of the Example

- Total Area: (Corcoran-Cozette and Mesaverde)
 - Unadjusted GIP = 19,044 Bcf
 - GIP adjusted for success rate = 14,854 Bcf
 - GIP adjusted for pay quality = 11,190 Bcf
 - GIP contacted by wellbore (320 A spacing) = 2,943 Bcf
 - Total recovery* = 1,270 Bcf or 11.4% of adjusted GIP

* Based on area by area computer simulation.

-- Corcoran-Cozette (Blanket formation):

- GIP adjusted for pay quality = 1,278 Bcf
- GIP contacted by wellbore (320 A spacing) = 1,278 Bcf
- Total recovery = 579 Bcf or 45%

-- Mesaverde (Lenticular):

- GIP adjusted for pay quality = 9,907 Bcf
- GIP contacted by wellbore (320 A spacing) = 1,665 Bcf
- Total recovery = 691 Bcf or 7%

2. The Data Base

Comparable adjustments were made to all the reported data. These resulted in a total of 622 analytic reservoirs (formations times sub-areas and pay qualities). Exhibit 3-11 provides a summary of the resulting reservoir properties used in the analysis.

3. Computer Input

The adjusted reservoir data and the specification of the level of technology to be simulated were tabulated using a data sheet, as shown on Exhibit 3-12. The production of each analytic unit was, then, simulated under Base Case and Advanced Case technologies using fracture length, fracture conductivity, and drainage area assumptions, as described in Volume II. These simulations provided a series of annual production estimates (along with other data) for each analytic unit. These data were then combined for

EXHIBIT 3-11 RESERVOIR CHARACTERISTICS OF TIGHT GAS FORMATIONS

TARGET/BASIN	AREAL UNITS	FORMATION	DEPTH (ft)	GROSS INTERVAL (ft)	NET PAY (ft.)	NATURE OF PAY	IN SITU GAS PERM. (μ d)	GAS- FILLED POROSITY (%)	RESERVOIR PRESSURE (psi)	RESERVOIR TEMPERATURE ($^{\circ}$ F)
<u>WESTERN TIGHT GAS SANDS</u>										
1. Greater Green River	36	Ft. Union	5700-9000	500-2630	21-625	Lenticular	1-50	3.4-5.0	3150-6334	135-194
		Almond A	8000-10,700	400-500	9-20	Blanket	9-50	4.1-4.5	4200-6200	180-215
		Almond B	8000-10,700	400-500	18-45	Lenticular	9-50	4.5-5.4	4200-6200	180-215
		Erickson	8400-11,400	350-400	35-68	Lenticular	7-20	4.1-5.4	4400-6500	186-231
		Rock Springs/Blair	9700-12,500	1500-2500	19-80	Lenticular	7-8	4.1-5.4	5000-7200	206-248
		Other Mesaverde	9000-12,700	2150-5000	28-164	Lenticular	1-9	3.4-4.5	5850-8250	194-220
2. Piceance	25	Ft. Union	5000	600	18-44	Lenticular	3-27	4.0-5.2	2100	135
		Corcoran-Cozette	6000	50	10-38	Blanket	8-75	4.2-6.1	2600	145
		Other Mesaverde	6900-9100	800-2200	40-275	Lenticular	3-60	3.6-5.4	3000-3400	160-170
3. Uinta	32	Wasatch	6500	500	43-156	Lenticular	56-600	4.4-5.8	2795	175
		Barren	7500	500	43-156	Lenticular	30-270	3.8-5.0	3225	195
		Coaly	8500	500	43-156	Lenticular	10-90	3.2-4.2	3655	214
		Castlegate	9500	250	25-75	Blanket	3-30	2.6-3.4	4275	233
<u>SHALLOW GAS BASINS</u>										
1. Northern Great Plains and Williston	27	Judith River	600-1600	30-50	8-20	Blanket	17-1000	5.2-13.7	270-680	80-85
		Eagle	1800-2000	30-60	3-25	Blanket	17-10,000	7.4-12.2	800-900	90-100
		Carlisle	1500	30-50	4-10	Blanket	0-900	5.4-7.1	670	85
		Greenhorn/Frontier	2000-2600	30-50	3-29	Blanket	17-2700	5.4-7.8	900-1130	100
<u>OTHER TIGHT LENTICULAR GAS SANDS</u>										
1. Big Horn	5	Mesaverde	2285 ^{1/}	645	110-275	Lenticular	13-120	6.6-8.7	1100	95
2. Douglas Creek Arch	5	Mancos	2845-4045	2400	120-300	Lenticular	7-60	4.8-7.5	437	120
		Dakota	7545	72	4-9	Lenticular	10-90	3.6-4.7	1100	240
3. Sonora	10	Canyon	6000-7000	600	30-103	Lenticular ^{2/}	8-84	4.4-6.3	2100-2700	145
<u>TIGHT BLANKET GAS FORMATIONS</u>										
1. Cotton Valley "Sweet"	10	Cotton Valley Sand	9000	1100	35-88	Blanket	3-30	4.0-5.3	6000	250
		Gilmer Lime	11,000	350	20-50	Blanket	3-30	5.6-7.4	5400	280
2. Denver	5	Niobrara	2300	67	11-28	Blanket	3-30	2.6-3.5	950	110
		Sussex	4460	50	11-26	Blanket	3-30	3.6-4.7	1500	185
		Dakota	8000	50	14-34	Blanket	5-50	4.0-5.3	2900	260
3. Ouachita	15	Stanley	4600-9000	6000-7200	186-465	Blanket	1-5	3.7-5.1	1700-2200	148-160
4. San Juan	5	Dakota	7180	173	35-88	Blanket	10-90	5.8-7.6	3090	222
5. Wind River	5	Frontier	1441 ^{1/}	153	20-50	Blanket	33-300	6.5-8.5	550	99
		Muddy	2529 ^{1/}	100	10-25	Blanket	1-9	8.8-11.6	1000	109
<u>OTHER LOW PERMEABILITY GAS FORMATIONS</u>										
1. Cotton Valley "Sour"	5	Bruciner-Smackover	12,000	900	18-44	Blanket	44-400	8.0-10.5	5600	290

1/ Data as reported -- considerable portions of these formations are much deeper, e.g., 4000-6000 feet

2/ Canyon lenses are very large relative to the drainage area and substantially broader than the other lenticular formations

EXHIBIT 3-12 PRODUCTION MODEL INPUT DATA SHEET

BASIN _____ FORMATION _____ INTERVAL NO. _____ LENTICULARITY _____
 PAY QUALITY CASE H: _____ ØK: _____ TECHNOLOGY CASE _____ I.D. CODE NO. _____

GENERAL RESERVOIR DATA

Depth _____ Ft
 Original Pressure _____ Psi
 Gas Permeability _____ Md
 Gas Porosity _____ %
 Net Gas Pay _____ Ft
 Gross Formation Thickness _____ Ft
 Wellbore Radius _____ Ft
 Reservoir Temp. _____ °F
 Gas Gravity (Air = 1.0) _____
 Frac Gradient _____ Psi/Ft
 Mole % H₂S in Gas _____ %
 Mole % CO₂ in Gas _____ %
 Mole % N₂ in Gas _____ %

RESERVOIR GEOMETRY

Drainage Area _____ Acres
Effective Fracture Length _____ Ft
 Fracture Proppant Agent (Type) _____
Effective Fracture Fluid Volume* _____ M Gal.
 Average Proppant Concentration #1 _____ Lb./Gal.
 #2 _____ Lb./Gal.
 Effective Initial Fracture Conductivity _____ Md-Ft
 Effective Final Fracture Conductivity _____ Md-Ft
 Drainage Area Shape _____
 Length Parallel to Fracture _____ Ft
 Length Perpendicular to Fracture _____ Ft

SKETCH:PROGRAM CHARACTERISTICS

Maximum Initial Flow Rate _____ Mcfd
 Minimum Flowing Bottom Hole Pressure _____ Psi
 (OR) Timing of Compression _____ Year
 "Economic" Limit _____ Mcfd
 Rate When Compressor Installed _____ Mcfd

REMARKS:REMARKS:

* Implied Fracture Height _____ Ft

ECONOMICS MODEL INPUT DATA:

Dominant State _____ State No. _____ Region _____ Region No. _____ Applied Frac Size _____ M. Gal. _____

o. Identical Intervals _____ At Depths: _____ Ft
 (same data)

No. Lenses This Interval _____ Ft

No. Non-Identical Intervals
 THIS WELL (separate data) _____

Total No. Intervals THIS WELL _____

horizontal "stacks" of formations and analyzed in the economics model. The economics model, the first place in the analysis in which all horizontally adjacent formations are considered together, performs two calculations that affect the production estimate:

- First, the combined production of all horizontally adjacent formations is analyzed in the economics model. The combined flow is allowed only a maximum rate considered feasible in terms of engineering. Deferred production arising from this capacity constraint serves to prolong the maximum production until all deferred production is exhausted, when the decline curve of the combined formations is obtained.
- Second, the combination of producing formations is optimized (at each analyzed gas price) to define which specific combinations of formations is most economic to develop as a "package" through multiple completions.

The next section describes the reservoir simulator in detail and sets forth the assumptions used in projecting production.

II. PRODUCTION AND RECOVERY MODELS
FOR TIGHT GAS SANDS

A. Overview

The discussion of production and recovery models for the tight gas sands is organized around five major topics:

- Description of the reservoir simulator used for estimating gas production
- General validation of the model using:
 - comparisons with published analytic solutions
 - comparisons with models used by industry
 - comparisons with more complex (two-phase) versions of the model.
- Specific validation of the model for application to continuous, "blanket" tight gas reservoirs.
- Specific validation for simulation of discontinuous, lenticular sand bodies.
- Analysis of key technical assumptions used in the analysis:
 - expected length of the fracture in a given sand body
 - number of sand bodies a fracture is likely to encounter
 - well spacing to maximize contact with gas in place.

Each of these topics is discussed in a separate section below.

B. The Reservoir Simulator

1. Overview

The reservoir simulator used in this study was developed at Texas A&M University by Drs. Steven Holditch and Richard Morse.* It is a single-phase, two-dimensional, finite difference model that mathematically simulates the flow of gas in porous media. In the tight sands analysis the model simulated a single, hydraulically fractured well in a bounded reservoir.

The model assumes that the fracture extends equally on both sides of the wellbore and is propped over its entire length. The reservoir is assumed to be horizontal, homogeneous, isotropic, and initially filled with gas at a constant pressure. The dimensions of the drainage area depended on the type of formation (blanket or lenticular), the dimensions of lenses, and the assigned well-spacing.

2. Model Description

The model is based on a simultaneous solution of a set of finite difference equations that mathematically describe the flow of fluid in porous media. To solve these equations for a fractured system, a direct solution technique is required to assure convergence in a reasonable amount of computing time. The finite difference equations were derived using a mass balance equation and Darcy's Law. The reservoir is divided into a grid system and an

* Dr. Holditch and his staff at Sovereign Engineering, Inc., performed much of the reservoir engineering analysis and simulation for the study.

equation is written for each grid block. The equations are formulated and solved as functions of time. By using pressure-dependent fluid properties and utilizing sufficiently small increments in both time and space, the true performance of a fractured gas or oil well can be simulated with a high degree of accuracy.

In many cases, especially for low permeability gas reservoirs, only one fluid phase is mobile. The water present in tight gas reservoirs is normally found to be at the irreducible saturation level. Therefore, the actual well performance may be accurately predicted using a single phase model.*

Although the model is proprietary, it is essentially the same as many in use in industry, as described in the discussion of the model's validation below. The discussion below is to highlight the special features that mark this model.

a. Grid System

The reservoir is divided into a system of blocks in the form of a grid. Each block represents a portion of the reservoir in which all conditions are uniform at any stage in the simulation.

Exhibit 3-13 provides a plan view of the fractured reservoir. The wellbore is in the upper left hand block, cell (1,1) in the Exhibit. In this system, only one quarter of a square or rectangular drainage pattern is simulated. The results are multiplied by a factor of 4 to obtain the correct values for gas in place, flow rate, and cumulative gas produced for the full drainage pattern.

* See Section F for analysis of this assumption.

EXHIBIT 3-13

SCHEMATIC REPRESENTATION OF PLAN VIEW SIMULATION

The fracture was placed in the $Y = 1$ row of grid cells, as shown. The dimension of this first row of cells was set equal to one-half of the fractured width (in fractions of one foot). When running the model using the plan view grid pattern, the well radius was set equal to zero.

To obtain a high degree of accuracy, a grid pattern of 20 cells in the X-direction and 15 cells in the Y-direction was used. Normally, the fracture was broken into 10 cells. (A fine grid breakup in the X-direction is required near the wellbore and near the fracture tip; a fine grid breakup in the Y-direction is required near the fracture.) To minimize numerical inaccuracies, no single block contained more than 4 percent of the total gas-in-place.

b. Time Step Control

The basic mechanism for time step control consists of three input parameters, namely minimum time step, maximum time step, and the time step multiplier. The minimum time step size is defined in days. Normally, a value ranging from .01 to .0001 days was used as the minimum. The time step size increases for each successive step by the time step multiplier. Thus, the current time step size is equal to the previous time step size multiplied by the time step multiplier. This procedure continues until the maximum time step is reached, which is then constant to the end of the run. For long runs (e.g., simulation of the life of the well), the maximum time step was set equal to 365 days.

When pressures are changing rapidly, large time steps can cause error in the solution, so additional time-step controls were employed. These time step adjustments are controlled using the input parameters of the maximum pressure change in a cell, per step, and the maximum production per step. The maximum gas produced during a time step, expressed in percent of original gas-in-place, was normally set at 5.0 percent, to assure the time step size does not become too large during transient flow.

c. Flow Rate

In the typical analysis, the program begins with a constant flow rate until the wellbore pressure is reduced to a pre-set level. The program then sets the constant bottom hole pressure equal to the minimum pressure (defined as either the back pressure of the surface flow lines or the minimum level at which compression is considered feasible), and the remainder of the run is at constant pressure with decreasing flow rate, as illustrated in Exhibit 3-14.

d. Non-Darcy Flow

The flow of gas in tight gas sands is marked by non-Darcy conditions. Because the model is based on Darcy's law, a correction factor was used to modify the equations to include the effects of non-Darcy flow in the solutions. Because the derivation of this factor is reported at length elsewhere,^{7/} only the factor and its supporting empirical equations are described here. The non-Darcy factor is:

EXHIBIT 3-14

TYPICAL PRESSURE AND PRODUCTION PROFILES

$$F_{ND} = \frac{K_T}{K_D} = \frac{1}{1 + \frac{5.6555 \times 10^{-9} \beta \rho v K_D}{\mu}}$$

Where:

F_{ND} = non-Darcy factor

K_T = permeability required in Darcy's law to provide correct values under non-Darcy flow conditions, md

K_D = permeability measured under Darcy flow conditions, md

β = empirical factor* defined below, atm - sec²/gm

ρ = density, lb/cu ft

v = velocity, ft/D

μ = viscosity, cp

* The factor varies depending on whether the cell is in the fracture or in the matrix, as described below.

Quoting from the above cited source:

The non-Darcy factor is a measure of the degree of non-Darcy flow through porous media. If the β factor or velocity (v) approaches zero, then the non-Darcy factor approaches one and the pressure drop can be calculated using Darcy's law. If the velocity is high, then the value of the non-Darcy factor will be smaller than one. As the degree of non-Darcy flow increases, the value of the non-Darcy factor decreases. For example, if the non-Darcy factor is equal to 0.1, the pressure gradient will be 10 times the value calculated using Darcy's law...

To apply [the equation], the density, velocity, permeability, and viscosity were calculated in the model for each grid block based on the data from the previous time step. [The equation] was solved for each grid block and the non-Darcy factor was then used to modify the flow coefficients between the grid blocks. This procedure allowed the model to calculate the correct pressures and rates under non-Darcy flow conditions.^{8/}

The parameter, β , is a rock property and must be calculated from empirical equations. When a cell is included in the fracture, Cooke's equation is used to calculate the β factor.

$$\beta = b/k^a$$

Where:

k = permeability in Darcys

and a and b are determined as follows:

<u>Sand Size</u>	<u>a</u>	<u>b</u>
8 - 12	1.24	3.32
10 - 20	1.34	2.63
20 - 40	1.54	2.65
40 - 60	1.60	1.10

If a cell is in the matrix, Geertsma's equation is used to calculate the β factor.

$$\beta = \frac{.00156949}{\phi^{5.5} k^{0.5}}$$

Where:

ϕ = porosity, fraction

k = permeability, md

To include non-Darcy flow in the simulation, values for a and b must be input. The proper values were selected from the above table depending on the propping agent size. The values for β factor in the matrix are calculated based on the values of porosity and permeability input for the reservoir rock.

e. Fracture Closure

After creating a hydraulic fracture, the pressure drawdown in the fracture during production will tend to crush and embed the propping agent into the fracture face. The closure pressure, the difference between the bottom hole treating pressure and the pore pressure in the fracture, will decrease the permeability in the fracture. Data on fracture permeability as a function of closure pressure have been published by Cooke.^{9/} The following table illustrates typical values for fracture closure.

<u>Closure Pressure (psi)</u>	<u>Fraction of Permeability Remaining</u>		
	<u>20-40 sand</u>	<u>40-60 sand</u>	<u>Bauxite</u>
0	1.00	1.00	1.00
1000	.90	.95	.95
2000	.78	.89	.90
3000	.65	.80	.85
4000	.50	.71	.80
5000	.34	.59	.75
6000	.23	.47	.70
7000	.15	.36	.65
8000	.10	.25	.60
9000	.07	.16	.55
10,000	.05	.09	.50

When using fracture closures, the input value for fracture permeability should be the permeability (md) at zero closure pressure. The model then uses the input value of bottom hole treating pressure and the calculated pressure in the fracture to determine the permeability in the fracture.

The next section describes the steps used in validating this model for application to tight gas sands in general. Subsequent sections describe its more detailed validation for tight blanket sands and tight lenticular sands, respectively.

C. General Validation of the Reservoir Simulator*

Validation of the reservoir model described above for application to tight gas basins was based on four broad criteria:

- How well has the model been tested and applied by the petroleum engineering industry?
- How well does the model match predictions derived from published analytic solutions for the behavior of fractured wells?
- Do the model's predictions compare favorably with those of simulators used by producers who are active in the tight sands?
- Does the simpler, single phase version of the model provide sufficiently accurate results in comparison with a more complex, costly two-phase (gas-water) model?

* Additional validation and adaptation of the model for blanket and lenticular sands, respectively, are described in later sections. These analyses are also reported in S. A. Holditch and W. L. Laufer, "The Analysis of Fractured Gas Wells Using Reservoir Simulation" (SPE 7473), presented at the SPE-AIME 53rd Annual Fall Technical Conference and Exhibition, Houston, Texas, October 1-3, 1978.

1. General Professional Acceptance

The model has been accepted for publication in the petroleum engineering professional literature (October 1976, Journal of Petroleum Technology, SPE-AIME), is used in coursework and research in the School of Petroleum Engineering at Texas A&M University, and is applied to specific field cases and feasibility studies in behalf of both producers and investors.

2. Match With Analytic Solutions

The model has been tested against analytical solutions such as Darcy's Law for steady-state linear flow and semisteady-state radial flow.

To check the accuracy of the model for non-Darcy flow, several sets of analytical and laboratory data have been matched with the model. Two sets of these data can be found in the October 1976 article cited above.^{10/}

Additional verification of the accuracy of the model is in the matching of recently published analytical solutions for wells containing finite conductivity, vertical fractures. These analytical data were published by Cinco, et. al.^{11/} The model matched these curves almost exactly, as shown in Exhibit 3-15.

EXHIBIT 3-15

TYPE CURVE MATCH USING GAS PROPERTIES (Points Represent Model Predictions)

This graph represents data for dimensionless pressure versus dimensionless time as a function of dimensionless fracture conductivity. The solid lines on the graph represent the analytical solutions of Cinco et. al. The data points on the graph represent the output from the reservoir simulator used in this study.

A close observation of the Exhibit reveals that a few of the data points do not fall exactly on the analytical solution. These minor differences were caused by the grid pattern, which was 20×15 for these runs. To perfectly match the analytical data over the entire time interval, a much finer grid system is required. To match the early time data ($t_D < .1$), a fine grid pattern near the wellbore and fracture is required. At a later time ($t_D > 1.0$), the flow in the reservoir is more radial and a fine grid is required both near the fracture and in the reservoir away from the fracture. (Computer runs have been made using a grid system of 30×20 cells and the data match was, as expected, even better than those illustrated in the Exhibit.)

3. Match With Producer's Model

The reservoir simulator used in the study was tested against the reservoir model used by a major producer for developing tight gas reservoirs. Predictions from the producer's model and the model used in this study for a range of field data were essentially identical.

4. Water Production

The model used in this study considers the movement of a single phase -- gas -- in a porous medium. This is tantamount to assuming that connate water is immobile. More complex, two-phase (gas and water) models are available that do not make this assumption. Sensitivity analyses were conducted to address two key questions affecting the issue of water production:

- Is the single-phase model, which ignores the effects of mobile water, suitable for the present study?
- Is water production likely to represent a serious operating problem in producing tight gas formations, or -- more severely -- is formation water likely to "choke" production?

Two finite difference reservoir simulators were used to address these issues. The first was the single phase, two dimensional model that was used throughout the study to determine the effects of formation permeability, fracture length, and original pressure on the performance of a fractured well. The second, for contrast, was a two-phase (gas-water), two dimensional, fully implicit model. It was employed to investigate the effects of water saturation, relative permeability, and capillary pressure. Two analyses were conducted.

a. Analysis I

The first analysis examined the magnitude of the effects of water mobility and capillary pressure on gas production. Exhibit 3-16 shows the input data assumed for the comparisons. The assumed relative permeability and

EXHIBIT 3-16

INPUT VARIABLESConstant for Analyses I and II

Depth of Well	9,000 feet
Net Pay Thickness	100 feet
Fracture Height	400 feet
Drainage Area	160 acres
Flowing Bottom Hole Pressure	1,000 psi
Reservoir Temperature	200°F
Gas Gravity	0.6 (air=1.0)
Original Fracture Conductivity	2,400 md-ft
Propping Agent	20-40 Mesh Sand
Producing Life	30 years
Fracture Gradient	0.7 psi/ft
Original Pressure	4,500 psi
Fracture Length	1,000 feet

Conditions for Analysis I

Total Porosity	= 10%
Water Saturation	= 55%
Total Permeability	= .039216 md
Relative Permeability to Water	= .0075
Relative Permeability to Gas	= .1275
Water Permeability	= .00029412 md
Gas Permeability	= .005 md
Gas-In-Place	= 7.688 Bcf
Water-In-Place	= 6.603 MMBbls

Variations in Analysis I

<u>Case</u>	<u>Capillary Pressure</u>
Ia	-
Ib	No
Ic	Yes

capillary pressure curves are shown in Exhibits 3-17 and 3-18, respectively. The data have been extracted from a sample tight gas reservoir. Three cases were run:

- Case Ia used the single-phase model
- Case Ib used the two-phase model, without capillary pressure
- Case Ic used the two-phase model and assumed capillary pressure.

The analyses shown on Exhibit 3-19 show that water has only a minor effect on the gas production rate, well within the tolerance of the geologic input data. The analysis also points out the important, favorable effect of capillary pressure on water production:

- Case Ib was run assuming there was no capillary pressure. For this situation, the fractured well produced 21,716 barrels of water for the entire 30 year period, at a rate of about 5.22 B/MMcf.
- When capillary pressure was included in the calculations, Case Ic, the well produced about 6 barrels of water during the first year. Water broke through after the first year and the rate increased to a maximum of 3 barrels/MMcf after 5 years, then decreased to zero after 23 years.

While the change in water production has only a minor effect on gas production, the level of capillary pressure controls the amount of water which will be produced:

EXHIBIT 3-17

TYPICAL RELATIVE PERMEABILITY FOR TIGHT GAS SANDS

EXHIBIT 3-18

TYPICAL CAPILLARY PRESSURE CURVE FOR TIGHT GAS SANDS

EXHIBIT 3-19

RESULTS FOR ANALYSIS I

<u>Time (Years)</u>	Ia	Ib		Ic	
	<u>Gas Rate</u> (Mcf/Day)	<u>Gas Rate</u> (Mcf/Day)	<u>Water Rate</u> (B/MMCF)	<u>Gas Rate</u> (Mcf/Day)	<u>Water Rate</u> (B/MMCF)
1	1,246	1,265	4.84	1,094	0.18
5	603	593	5.23	565	3.07
10	401	395	5.24	381	2.69
15	294	290	5.25	281	1.94
20	224	223	5.30	216	1.16
25	177	176	5.37	171	0
30	142	142	5.43	142	0
30-Year Cumulative Gas Production (Bcf)	4.33	4.26		4.10	
30-Year Cumulative Water Production (Bbls)	-		21,716		7,453

- When the capillary pressure is high, a large capillary end effect between the fracture and the reservoir tends to cause a "water bank" at the outlet of the matrix into the fracture. Only after the water saturation in this region increases to a certain level (which depends on the permeability and the flow rate) will any water be produced.
- When the capillary pressure is low, only a small draw-down is required to overcome the end effect, and small quantities of water will be produced during the entire life of a well.

b. Analysis II

When the gas pay is fractured, a portion of the fracture may propagate into rock that is not considered to be productive. This type of rock will be lower in porosity and permeability and will contain higher water saturations than the gas pay itself. To study the behavior of the "non-pay" portion of the reservoir, a second set of cases were analyzed.

The input data for these simulations was the same as noted in Analysis I except as contained in Exhibit 3-20. The relative permeability data was chosen such that the K_{rg} and K_{rw} curves crossed at 75 percent water saturation, as illustrated earlier.

Exhibit 3-21 shows that, for Cases IIa-d, approximately 1 Bcf of gas and 60-90,000 barrels of water are produced during the 30 year life. The effect of capillary pressure (Cases IIb and IIc) is small for these low quality sections.

EXHIBIT 3-20

INPUT DATA FOR ANALYSIS IIConstant for All Analysis II Cases

Porosity 8 percent

Water Saturation 75 percent

Variations by Case

	<u>IIa</u>	<u>IIb</u>	<u>IIc</u>	<u>IId</u>	<u>IIe</u>
Total permeability (md)	.01	.01	.02	.02	.00417
Gas permeability (md)	.0005	.0005	.001	.001	.003
Water permeability (md)	.0005	.0005	.001	.001	.003
Water saturation (%)	75	75	75	75	96
Capillary pressure	No	Yes	No	Yes	Yes
Gas-in-Place (Bcf)	3.403	3.403	3.403	3.403	0.543
Water-in-Place (MMBbls)	7.204	7.204	7.204	7.204	9.221

EXHIBIT 3-21
RESULTS FOR CASE II ANALYSES

Production Rates

Time (Years)	Case IIa		Case IIb		Case IIc		Case IIId		Case IIe	
	Gas Rate (MCF/D)	Water Rate (B/MMCF)	Gas Rate (MCF/D)	Water Rate (B/MMCF)	Gas Rate (MCF/D)	Water Rate (B/MMCF)	Gas Rate (MCF/D)	Water Rate (B/MMCF)	Gas Rate (MCF/D)	Water Rate (B/MMCF)
1	239	73.7	222	57.6	352	73.2	327	63.3	9.4	6,347
5	105	74.2	106	65.9	157	73.0	163	67.5	3.8	7,262
10	82	72.9	79	65.6	121	71.7	119	66.7	2.7	7,523
15	69	72.0	66	65.3	98	71.4	96	66.3	2.3	7,611
20	60	71.6	58	65.0	33	71.4	81	66.0	2.0	7,556
25	54	71.3	52	64.8	71	71.4	69	65.8	1.8	7,416
30	49	71.2	47	64.5	61	71.4	60	65.4	1.6	7,234

30-Year Cumulatives

Case	Gas Produced (BCF)	Water Produced (MMBLS)
IIa	.940	.068
IIb	.911	.058
IIc	1.352	.097
IIId	1.322	.086
IIe	.033	.234

Case IIe represents a portion of a reservoir that is essentially water filled. The completely wet zone (100 feet thick) will produce 234,320 barrels of water in 30 years. The water rate is about 1,000 BPD after one day but declines to 200 BPD after one month. At the end of the first year, the water rate is about 60 BPD.

c. Conclusions from the Analyses of Mobile Water

The foregoing analyses argue for two broad conclusions:

- First, the single-phase simulator appears to provide accurate results within the tolerance of the input geologic data; however, detailed reservoir studies prior to pilot project initiation may well benefit from the added complexity (and computation cost) of explicitly accounting for mobile water (using a two-phase model).
- Second, assuming either that the initial gas flow is adequate -- at least 150 Mcf/day -- or that pumping facilities are installed, the potential of mobile water accumulating in the wellbore or fracture system, "choking off" gas production, appears to be low for formations typical of most tight gas sands.

* * * * *

Based on the foregoing test, the single-phase, two dimensional model was selected as appropriate for analyses of the tight gas sands. It was further tested for specific application to blanket sands and lenticular sands, as described below.

D. Validation for Continuous Tight Gas Sand Reservoirs

1. Introduction

Stimulation of continuous "blanket" tight gas sands using small-volume hydraulic fracturing is an established industrial practice. The goals of the R&D program in this area are to apply this technology on a massively larger scale and in more difficult geological situations.

One of the most advanced and well published applications of this technology has been in the Wattenberg Field of the Denver Basin. This field provides a valuable set of process and production performance data with which to calibrate and test a simulation model. Thus, a history matching exercise was conducted to further calibrate the reservoir model used in the study and to confirm the fracture length and conductivity assumptions set forth in the literature.

2. Analysis of the Wattenberg Field

The published data for the Muddy "J" formation in the Wattenberg Field were used to validate the reservoir simulator in continuous sand reservoirs.^{12/} The first step was to determine the propped fracture length versus fracture fluid volume actually used in a typical Wattenberg fracture treatment. For this, a computer program based on the equations of Geetsma and de Klerk^{13/} was used to calculate the fracture dimensions. Using the reservoir data shown below, the fracture design from the computer program correlated well with the fracture designs described by Fast et. al.

Formation Depth - feet	7680
Original Pressure - psi	2900
Bottom Hole Temperature - °F	260
Gas Gravity - Air = 1	0.6
Flowing Bottom Hole Pressure - psi	250
Producing Life - years	30
Formation Fracture Gradient - psi/ft	0.7
Fracture Height - feet	130
Modulus of Elasticity - psi	1.5×10^6

The second step was to use these volume/length correlations in the reservoir simulations along with published data on drainage area, fracture length, fracture conductivity, formation permeability, and porosity to estimate gas production and recovery efficiency. The results of the analysis are shown below.

SUMMARY OF RESERVOIR SIMULATION RESULTS
WATTENBERG FIELD

<u>Case</u>	<u>Lf</u> (ft)	<u>Spacing</u> (acres)	<u>h</u> (ft)	<u>k</u> (md)	<u>φg</u> (%)	<u>Cum. Gas</u> <u>Produced</u> (BCF)	<u>Recovery</u> <u>Efficiency</u> (%)
1	1800	320	22	.04	6.6	2.03	67
2	1800	320	17	.01	4.5	.898	56
3	2500	320	22	.04	6.6	2.335	77
4	2500	320	17	.01	4.5	1.061	67

Comparing the results of this analysis to the data in the paper by Fast, et. al., the simulated well performance matches closely with the actual field data. Exhibit 3-22 compares the flow rates for one of the cases (Case 3) to the typical Wattenberg well performance.

Exhibit 3-23 compares the results of the cumulative gas production data to the actual field data reported by Fast, et. al. Case 3 provides an excellent match to Well A-2, but Case 1 indicates higher productivity than actually observed in Well A-3. The actual Well A-3 data could be more closely matched by reducing the formation permeability to a range between 0.04 and 0.01 in the simulation model.

The history matching indicates that the reservoir and process parameters used in simulating the production practices in the Wattenberg Field can be used to generate "typical" production curves representative of actual Wattenberg Field well performance. However, to match the data for a specific well, detailed information concerning in situ formation permeability, net gas pay, gross formation thickness, etc., would be required.

The results from this analysis confirm the tenet that well performance in continuous sand reservoirs can be accurately predicted using the simulator employed in the present study. No alteration was made in the model. Actual field data were used to simulate the performance of the respective blanket-type sands. The fracture designs (length and volumes) assumed for the respective cases are discussed at length in Chapter Three of Volume II.

EXHIBIT 3-22

COMPARISON OF SIMULATION RESULTS WITH FIELD DATA - CASE 3

EXHIBIT 3-23

COMPARISON OF SIMULATION RESULTS WITH FIELD DATA - CASES 1, 2, 3

E. Validation and Adaptation for Lenticular Gas Reservoirs

1. Introduction

Although the preponderance of industry's development programs in tight formations have been in the continuous, blanket sand reservoirs, much of the target gas in place is in discontinuous, lenticular sand body reservoirs.

Since past production efforts in these lenticular sand bodies have met with generally disappointing results, numerous "rules of thumb" have begun to emerge for accounting for the lenticularity phenomena. Gidley, et. al.,^{14/} for example, have suggested that simply reducing predictions made for otherwise comparable blanket reservoirs by 25% may represent a reasonable estimate for lenticular pays.

One of the purposes of this study was to analytically describe the effects of lenticularity on well performance. This information could help design an R&D program to overcome or mitigate these lenticularity effects.

The most dominant feature of lenticularity is the limited volume of gas in place which is in communication with the wellbore. Assuming that a typical lens in the Mesaverde sections of the Western Tight Gas Basin might have areal dimensions of 400 feet in width by 6000 feet in length and a sand thickness of 20 feet,^{15/} these dimensions result in a drainage area of 55 acres.

Using the reservoir properties shown below, a blanket sand would produce about 8 Bcf.

INPUT DATA FOR SENSITIVITY ANALYSES

Depth - feet	9000
Initial Pressure - psi	4500
Flowing Bottom Hole Pressure - psi	1000
Net Gas Pay - feet	100
Total Porosity - percent	10.0
Gas Gravity - Air = 1.0	0.6
Water Saturation - percent	55.0
Fracture Gradient - psi/ft	0.7
Producing Life - years	30
BHT - °F	200
Permeability - μ d	5
Spacing - A/well	320
Fracture Half-Length - ft	1000

A lenticular sand reservoir, using the same data, would produce less than 2 Bcf per well. The reason for this difference can be explained as follows:

	<u>Blanket Sand</u>	<u>Lenticular Sand</u>
Quality of Continuous Gas Pay Within Single Well		
Drainage Area	320 acres	55 acres
Gas in Place		
-- total per 320 acres	16 Bcf	16 Bcf
-- in contact with well	16 Bcf	3 Bcf
30 Year Recovery Per Well	8 Bcf	2 Bcf

Since sand lenses are randomly oriented with respect to fracture azimuth across all horizontal planes and possibly in any particular horizontal section, a single hydraulic fracture will probably "cut across" the lens rather than propagate "down" the lens.

These problems suggested that certain modifications in the simulator or in the use of its predictions would be needed to adequately model lenticular sands.

2. Analysis of Well No. 212*

To investigate the effects of lenticularity, field production data from a lenticular formation in the Uinta Basin (Utah) were history matched using the numerical simulator described above. Well No. 212 was completed in the Lower Mesaverde formation by Chevron Oil Company and put on production in 1966. Basic information on Well No. 212 is summarized in Exhibit 3-24. The No. 212 well had been perforated in four sand members and three of these sands were fracture treated, as summarized below:

<u>Sand</u>	<u>Depth</u> (ft)	<u>Fracture Treatment</u>	
		<u>(gals)</u>	<u>(lbs of sand)</u>
1	9160 - 9185	11,600	10,400
2	9270 - 9290	15,000	14,000
4	9500 - 9530	9,500	8,510

Since the orientation of the hydraulic fractures and the permeability of the Mesaverde sands were unknown, the reservoir model sought to match the production data in Exhibit 3-24 by varying the fracture orientation and the formation permeability.

* Well No. 212 was selected for preliminary investigation through history matching because it was in one of the target lenticular formations, had long enough production history to provide a base of actual production data, and was particularly well documented.

EXHIBIT 3-24

INPUT DATA - WELL No. 212Reservoir Data

Depth	9,300 feet
Permeability to Gas	.01-.005 md
Porosity	10%
Water Saturation	50%
Original Pressure	4,300 psi
Bottom Hole Temperature	200°F

Reservoir Geometry

Lens Thickness	20 feet
Lens Width	400 feet
Lens Length	6,000 feet
No. of Lenses	4

Production Data

<u>Year</u>	<u>Yearly Production</u> (MMcf)	<u>Cumulative Production</u> (MMcf)
July-December, 1966	200	200
1967	300	500
1968	160	660
1969	140	800
1970	120	920
1971	110	1030
1972	100	1130
1973	90	1220
1974	80	1300
1975	70	1370
1976	60	1430

To match the data, computer runs were made assuming that the fracture cut perpendicularly across the lens with an effective fracture half length of 200 feet. The formation gas permeabilities used for these two runs were .005 and .01 md -- the range suggested for the Mesaverde formation. However, as shown on Exhibit 3-25, the simulated well performance for these two cases did not match the field production data. A permeability of .09 md was required to match the field data, shown in Exhibit 3-25 and Exhibit 3-26.

Additional computer runs were made to determine if an adequate match could be obtained by assuming the fracture went down the lens, rather than across the lens. For this investigation, the permeability in the formation was fixed at .01 md and the fracture length was varied. The results of these runs, presented in Exhibit 3-27, show that the shape of the simulated production curves do not match the shape of the actual production curve. Assuming a gas permeability of .01 md, the fracture half length would need to exceed 1500 feet to recover 1.4 Bcf in 10 years. Given the size of the actual treatments, such a fracture length is not possible.

The results of these simulations indicate that for Well No. 212, the gas permeability is about .09 md and the effective fracture half length is about 200 feet. Considering the small treatment volumes and lack of data on fracture orientation, it is possible for the fracture to have gone down the lens or across it at an angle. An analysis of a pressure build-up test of Well No. 212 could provide further insight into this question.

This investigation confirmed that lenticular gas sand reservoirs could not be modeled adequately without making several additional assumptions. Specifically, assumptions are required to answer four key questions:

EXHIBIT 3-25

HISTORY MATCH ANALYSIS OF CUMULATIVE PRODUCTION FOR WELL No. 212

EXHIBIT 3-26

HISTORY MATCH ANALYSIS OF DAILY PRODUCTION FOR WELL No. 212

EXHIBIT 3-27
HISTORY MATCH ANALYSIS OF FRACTURE LENGTH FOR WELL No. 212

- Given the probable random relationship between fracture azimuth and lens orientation, for what distance can the fracture be expected to remain in the lens?
- Given the expected fracture length in the gas-bearing lens (and other reservoir properties), how must the model be modified to predict production?
- How many lenses, including those not encountered at the wellbore,* can a fracture of specified length be expected to penetrate?
- What is the optimal well spacing to maximize the amount of gas in place exposed, via the fracture, to a wellbore?

Each of these assumptions was based on analysis of the available data, as described in the next section.

F. Key Technical Assumptions

1. Adjustment for Effective Fracture Length

The simulations of Well No. 212 showed a strong relationship between production and the orientation of the fracture relative to the lens. A massive fracture perpendicular to the lens can have an effective half-length of only one half of the width of the lens, while one parallel to the lens may be effective for its full distance. Thus, an expected, effective fracture length must be

* Testing this assumption remains a critical R&D objective to be incorporated into the R&D program.

computed. The general assumption was that the fracture azimuth and the orientation of the lens were randomly related because each was controlled by factors from grossly different geologic periods.* For lenticular formations, a two-step procedure was followed:

- The first step was to calculate the expected fracture length, assuming a random relationship between the lens orientation and fracture azimuth. Exhibit 3-28 illustrates the methodology used for determining effective fracture length for a 1000 foot (half-length) fracture in a lens 400 by 6000 feet.
- Because the model permits the fracture only one orientation relative to the reservoir, the second step was to calculate the proportion of fractures running parallel and perpendicular to the lens that would yield the equivalent of the expected fracture length. This was done by solving for the parameter p in the following equation:

$$\text{Expected fracture length} = p (0.5 \text{ lens width}) + (1-p) (\text{fracture length})$$

Where:

p = proportion of fractures perpendicular to lens

$1-p$ = proportion of fractures parallel to the lens

(0.5 lens width) = half-length of fracture perpendicular to the lens, the remaining length lying outside the gas-bearing pay.

The solution to this equation depends upon the dimensions of the lenses and length of the fracture, as described in Chapter Three, Volume II. Given the parameter p and fracture length, the simulation model could be modified to predict the performance of individual lenses, as described in the next section.

* The fracture azimuth is determined by local subsurface stress and Poisson's ratio. The lens orientation has been determined by the depositional history.

EXHIBIT 3-28

ANALYSIS OF EFFECTIVE FRACTURE HALF-LENGTH
FOR A 1000-FOOT FRACTURE

2. Correcting Production Estimates for Expected Fracture Length

The simulation of Well No. 212 showed clearly that the production rate is highly responsive to whether the fracture is perpendicular or parallel to the lens. Thus, it is necessary to correct the simulator's predictions to reflect the previously assumed random relationship between fracture azimuth and lens orientation. This was done by computing a "lens correction function" that corrected annual production simulated for a parallel fracture to annual production from the weighted average fracture length, or the expected fracture length.

Given p , the proportion of fractures perpendicular to the lens, and $1-p$, the proportion parallel to the lens as computed above (from fracture length and lens geometry), the lens function was defined as:

$$LF_i = \frac{p (CP_i) + (1-p) (DP_i)}{DP_i}$$

Where:

LF_i = lens function as an annual fraction of production of a fracture cutting down the lens (parallel to the lens)

CP_i = annual production from a fracture cutting across the lens (perpendicular)

DP_i = annual production from a fracture cutting down the lens (parallel to the lens)

Given the dimensions of the sand lens typical of the Mesaverde, cross-cutting fractures are expected to be about three times as frequent as parallel fractures. The production estimates were then modified by the lens correction equation derived from the above equation, as shown in Exhibit 3-29.

EXHIBIT 3-29

LENS CORRECTION FUNCTION FOR .05 MD,
1000 FT FRAC AND 55 ACRE DRAINAGE

<u>Year</u>	<u>Lens Function</u>	<u>Year</u>	<u>Lens Function</u>
1	.415	16	.994
2	.527	17	.997
3	.634	18	1.000
4	.734	19	1.004
5	.815	20	1.007
6	.873	21	1.010
7	.912	22	1.014
8	.938	23	1.018
9	.954	24	1.022
10	.966	25	1.026
11	.974	26	1.030
12	.980	27	1.035
13	.984	28	1.040
14	.988	29	1.044
15	.991	30	1.049

Different lens functions were generated to account for different permeabilities and for a variety of lens geometries. When a specific case was investigated, a computer run was made in which the fracture was oriented down the long axis of the lens. Then the relevant lens function was used to "correct" the annual production for the probabilistically most likely average fracture length. The corrected production data were then used to predict production and ultimate recovery.

The lens function substantially alters the initial production rates and the cumulative production. If the fracture propagates down the lens, a majority of the gas will be produced during the first 2-3 years. Using the lens function, this production would be reduced by about a factor of 2 during the first three years to account for lens orientation. However, in later years, the lens function shows more production than that for fractures directly down the lens. This is due to the slower drainage rate of the cross-lens fractures.

Gas recovery in lenticular reservoirs is limited by the effective acreage (or gas in place) which is in communication with the wellbore and by the difference in fracture and lens orientation. These two factors combined appear to be the primary cause for the lower than expected performance from the Mesaverde formation when massive hydraulic fracture treatments are performed.

3. Expected Number of Lenses Intersected by the Fracture

a. Statement of the Issue

One of the key technical issues addressed by the study was: Within a given area, what is the expected number of sand bodies that will be contacted by a fracture of a given length?

b. Development of a Theoretical Basis of Probability Functions for Lenticular Sand Bodies

The first step is to develop a probability function for the expected number of sand bodies (of dimension "x" by "y") that will be intersected by a fracture of length "S" in an area which has "p" percent of its total area composed of sand bodies where:

p = the proportion of the volume composed of
sand bodies based on geologic interpretation

x = the "length" of an "average" sand body

y = the "width" of an "average" sand body

S = the fracture length

The function is developed in three steps:

- STEP 1: The likelihood of a given line segment (A) intersecting fixed parallel lines given that A may have varying orientations.
- STEP 2: Defining a sand body as a polygon and the likelihood that any side of the polygon will intersect a fixed line.
- STEP 3: The expected number of sand bodies in a fixed area which will be intersected by the fracture.

STEP 1: Intersection of a Line Segment of Given Length With a Pair of Fixed Parallel Lines

The following diagram illustrates the assumptions and terminology necessary for this step:

Line segment "A" is of length " ℓ " and is oriented at an angle θ measured relative to each of two parallel lines (P_1, P_2) which are separated by a distance "d"; "m" represents the distance from the midpoint of line "A" to P_1 or P_2 , whichever is closer.

As long as the distance "m" remains smaller than the quantity $[(\ell/2) \sin \theta]$, line "A" will intersect with either P_1 or P_2 . Thus, a necessary condition for intersection is:

$$m < (\ell/2) \sin \theta$$

It is possible to plot the graph of all lines of "m" which satisfy this relationship for all possible orientations " θ " and fixed length " ℓ ".

For each value of θ , the maximum possible value of "m" lies along a circle of radius $d/2$. The values for which intersection takes place are bounded by the curve $m = (\ell/2 \sin \theta)$. If we assume that all orientation (θ) are equally likely, the probability of an intersection can be computed by integral calculus, as follows:

- Assume a uniform density for θ -- i.e., any particular orientation is equally as likely as any other: the density function $F(\theta) = 1/\pi$
- The integral of the density function over all values in which intersection does take place is given by:

$$A = \int_0^\pi \int_0^{\ell/2} F(\theta) \, dr \, d\theta$$

Since $F(\theta)$ is independent of "r" this becomes

$$= \int_0^\pi [(\ell/2)\sin\theta] F(\theta) \, d\theta \quad \text{Substituting } F(\theta) = 1/\pi$$

$$= \frac{\ell}{2\pi} \int_0^\pi \sin\theta \, d\theta$$

$$= \frac{\ell}{2\pi} [-\cos(\pi) - (-\cos(0))]$$

$$= \frac{\ell}{2\pi} [-(-1) - (-1)] = \frac{\ell}{2\pi} [2] = \ell/\pi$$

- The integral of the density function over all possible values of "m", including those in which interaction does and does not take place, is given by:

$$B = \int_0^\pi \int_0^{d/2} F(\theta) \, dr \, d\theta$$

$$= \int_0^\pi (d/2) F(\theta) \, d\theta$$

$$= \frac{d}{2\pi} \int_0^\pi d\theta = \frac{d}{2\pi} [\pi - 0] = d/2$$

The probability of an intersection occurring is given by A/B:

$$\text{Probability of intersection} = \frac{\ell/\pi}{d/2} = \frac{2\ell}{\pi d} \quad (\text{Equation 1.0})$$

- Thus, the probability of any line segment of length " ℓ " intersecting one of two parallel lines separated by a distance " d " is given by: $2\ell/\pi d$

STEP 2: Postulate the average sand body as a convex polygon of " n " sides.

Assume that a sand body (A) lies in a general area, $S \times h$, surrounding a fracture, F:

Further, assume that the fracture may lie anywhere in the area but that the sides of the rectangle are drawn to be parallel with the fracture. Finally, we assume that " h " is large enough to include the sand body within the rectangle.

The analysis proceeds as follows:

- Let P_{ij} be the probability that a given line "F" intersects both side "i" and "j" of the sand body.
- For a polygon of n sides, the quantity:

$$\sum_{i=1}^n \sum_{j=1}^n P_{ij} \quad \text{is exactly twice the probability of intersection of the polygon with the line (because } P_{ij} = P_{ji} \text{)}$$

- The probability of intersection of a given polygon with a line is:

$$P(\text{polygon intersection}) = 1/2 \sum_{i=1}^n \sum_{j=1}^n P_{ij}$$

- For any side " i_0 ", the quantity P_{i_0} is as follows:

$$P_{i_0} = \sum_{j=1}^n P_{i_0 j}$$

- Since side " i_0 " is simply a line segment of length, ℓ_{i_0} , we may use the results from Step 1 to compute the probability that the side " i_0 " of length " ℓ_{i_0} " intersects the line "F".
- Substituting from equation 1.0:

$$\ell_i \text{ for } \ell$$

$$h \text{ for } d^*$$

$$P_i = \frac{2\ell_i}{\pi h}$$

* h is the "maximum" separation between the fracture and the bounding rectangle taking into account the assumption that the fracture could lie anywhere in the rectangle.

and the probability that the entire polygon will intersect the line is given by:

$$\begin{aligned}
 P &= 1/2 \sum_{i=1}^n \sum_{j=1}^n P_{ij} = 1/2 \sum_{i=1}^n P_i \\
 &= 1/2 \sum_{i=1}^n \frac{2\ell_i}{\pi h} = \frac{1}{\pi h} \sum_{i=1}^n \ell_i
 \end{aligned}$$

Adopting the shorthand convention:

$$\sigma = \sum_{i=1}^n \ell_i$$

- The final expression for the intersection of an individual sand body with the fracture is:

$$P = \frac{\sigma}{\pi h}$$

STEP 3: The Expected Number of Sand Bodies Intersected by A Fracture

From Step 2, for any particular location of the fracture (F), the probability of intersection with the fracture was calculated to be:

$$P (\text{sand body intersection}) = \frac{\sigma}{\pi h}$$

If the fracture "F" has a finite length "S", the likelihood that the polygon touches line "F" is computed as follows:

$$\begin{aligned}
 P (\text{A touches "F" of length S}) &= P (\text{A in space bounded by F}) \\
 &\quad * P (\text{A touches F})
 \end{aligned}$$

- The probability that "A" lies in the space "bounded" by "F" is simply the ratio of the areas of the rectangles bounding the fracture and the sand body:

Assuming*

Sh = area of rectangle bounding the fracture

Wh = area of rectangle bounding the sand body

and P is $\frac{Sh}{Wh} = S/W$

The probability of any sand body (A) of perimeter σ touching a fracture "F" of length "S" is given by:

$$P (A \text{ intersects } F) = \frac{S}{W} * \frac{\sigma}{\pi h} = \frac{S\sigma}{\pi Wh} \quad (\text{Equation 3.1})$$

- Now, consider an area in which it is known that sand bodies cover some fraction "P" of the total area and that the average sand body has area " A_s ". If the total area has dimensions of "w" and "h" as above, the number of sand bodies is given by:

$$N_S = \frac{hwp}{A_s} \quad (\text{Equation 3.2})$$

Where:

hw = total area

hwp = area covered by all sand bodies

* As in Step 2, we assume that "h" is sufficiently large to include both the sand body and the fracture.

- The expected number of sand bodies touching a fracture of length "S" is calculated by multiplying the total number of sand bodies by the likelihood that an individual sand body will connect with the fracture. Combining equation 3.1 with 3.2:

$$N_F = N_S P (A \text{ intersects } F)$$

$$= \frac{hwP}{As} \times \frac{S\sigma}{\pi nh}$$

$$= \frac{SP\sigma}{As\pi}$$

- Thus, the expected number of sand bodies to be intersected is a function of:

S - the fracture length

σ , As - the perimeter and area of a typical sand body

P - the proportion of total area covered by sand bodies

- To account for the cases where the sand body extends beyond the area bounded by the fracture ("end point effects"), we consider the "typical" sand body to be a rectangle of width "x" and length "y". Thus:

$$A_s = xy \quad \sigma = 2(x+y)$$

And Equation 3.3 becomes:

$$N_F = \frac{2Sp(x+y)}{\pi xy}$$

Given: $x \gg y$

Case 1: If $S < y$
$$N_F = \frac{2Sp(x+y)}{\pi xy} + p$$

Rationale: If the fracture length is extremely small, then the fracture may lie entirely within a sand body, much like a single well. Thus, the expected number of sand bodies interconnected is augmented by "p", the expected number of sand bodies contacted by a single well.

Case 2: If $S > x$
$$N_F = \frac{2Sp(x+y)}{\pi xy} + 2p$$

Rationale: If the fracture length is much larger than the sand body, then it has two end-points which may behave as in Case 1.

Case 3: $y < S < x$
$$N_F = \frac{2Sp(x+y)}{\pi xy} + p \left(1 + \frac{S-y}{x-y}\right)$$

Rationale: This is a straight line interpolation between Case 1 and Case 2.

c. Example

Assume the average sand body is 400' x 4000'; the sand fraction is 30% and the fracture is 1,000'. Then, the expected number of sand bodies touched would be (with the simple formula):

$$N_F = \frac{s_{p\sigma}}{\pi A_S} = \frac{1}{\pi} \times \frac{(1000') (0.30)}{400 \times 4000} (2 \times (400 + 4000)) = 0.53$$

The correction term for end-point effects would be approximately:

$$0.3 \left(1 + \frac{1000 - 400}{4000 - 400} \right) = 0.35$$

So, the total expected sand bodies encountered would be:

$$N \approx 0.53 + 0.35 = 0.88$$

Almost three times as many sand bodies might be touched by a 1000' fracture ($N = 0.88$) as compared to a single well* ($N = 0.30$).

Should the fracture half-length be 1,500' ($N = 1.18$), nearly four times as many sand bodies might be in contact with a wellbore as compared to a single well ($N = 0.30$).

d. Findings

If a fracture can enter sand bodies after propagating through shale, a massive hydraulic fracture has the potential of contacting two to four times as many sand bodies as might be connected to a well with no fracture or a small fracture.

* i.e., a single well may intersect only one sand body. Since the area is presumed to be 30% sand bodies, the probability of a single well intersecting a sand body is 0.30. The expected number of intersections is therefore $(1) \times (0.30) = 0.30$.

Given the considerable uncertainty on this issue, the study staff determined that the most likely performance would be as follows:*

- At a spacing of two wells per section and using fracture half-lengths of 500-1,000 feet (Base Case technology), no additional sand lens would be intersected beyond those contacted by the wellbore.
- At a spacing of six wells per section and using fracture half-lengths of 1500 feet (Advanced Case technology), an average one additional lens would be intersected for every two lenses exposed by the well, i.e., on average, each well will expose approximately half again more sand than encountered at the well by exposing remote lenses.

The effect of this assumption in lenticular formations is as follows:

- Under the Base Case (2 wells/section, no additional lens intersection), the wells would be in contact with 17% of the lenticular gas pay.
- Under the Advanced Case (6 wells/section and the above additional lens intersection), the wells would be in contact with 80% of the lenticular gas pay; without the additional lens intersection, the wells would be in contact with about 50% of the pay.

Further analysis of well spacing effects on the connection of wellbores to sand pay is provided below.

* The basis for the assumption of fracture performance was derived from the initial analysis performed by C. Knutson and the judgments of the study staff. Further verification of this assumption rested on the internal staff work by D. Cox, as reported in the next section.

4. Well Spacing Considerations for Lenticular Sand Bodies

a. Statement of the Issue

Given a set of lenticular sand bodies of given dimensions and properties (length, width, and permeability and net/gross ratio), what is the optimal plan for developing this resource in terms of:

- Well spacing
- Fracture size

At issue is the trade-offs between contacting the greatest amount of sand volume and the potential for interference of closely spaced wells.

b. Analysis of the Issue

Given the uncertainties associated with the properties of lenticular sand bodies, it is virtually impossible to provide a deterministic solution to the problem of optimal well spacing and fracture size. However, it is possible to employ statistical techniques to provide a heuristic solution to the problem.

The method employed in this analysis involved a set of statistical simulations which are often grouped under the rubric of "Monte Carlo Analysis". The method involved three steps:

- Step One: Sand bodies of fixed dimensions were randomly distributed on a fixed volume (simulating the random orientation of sand lenses).
- Step Two: A grid of wells was overlayed onto the random array of lenticular sand bodies. Grids with 1, 4, 9, 16 and 25 wells were employed.

- Step Three: The total percentage of sand area which was in contact with each well was calculated under assumptions of "fractured" and "unfractured" conditions.

The methodology and detailed findings from this analysis are discussed below.

c. Random Distribution of Sand Bodies

C. F. Knutson^{16/} has prepared maps of "random" sand layers based on studies of tight gas sands in the Uinta Basin in Utah. Typically, these sand bodies are about twenty times as long as they are wide.

The use of the twelve Knutson maps and the assumptions of an average or "typical" lense of 3000 foot length constitutes the first stage of Monte Carlo sampling -- i.e., sampling over uncertainty associated with resource configuration. For the more general case where "L" represents the length of the sand lens, the following adjustments should be made:

- Number of Wells: All figures for number of wells should be multiplied by $(L/3000)^2$
- Distance: All distances should be multiplied by $(L/3000)$

d. Random Placement of Wells

A grid of wells was placed in varying orientations on each of the Knutson maps. The "grids" were constructed to simulate the effects of drilling 1, 4, 9, 16, and 25 wells in each of the areas. This step constitutes the second stage of sampling in the Monte Carlo process -- i.e., sampling over uncertainty associated with well placement.

e. Number of Monte Carlo Trials^{17/}

Each "well-grid" was used in eight orientations on each of the twelve maps. Thus, there are a total of 96 trials in each case (i.e., 1, 4, 9, 16, and 25 wells). These are sufficient trials to establish the central tendency of estimates of sand contact with wells.

f. Method of Well Evaluation

For each well located by orientation of the grid-overlay with the Knutson maps, a sand contact function was defined as the macroscopically tortuous distance from the wellbore through interconnected sand bodies. The diagram below illustrates one horizontal plane of sand body and fracture orientation. In the Mesaverde, similar patterns would be expected throughout the gross sand-shale sequence.

NOTE: In the 30% sand case there would be approximately 19 lenses/section.
In the 20% sand case there would be approximately 12 lenses/section.

As shown, well "A" has been drilled into a sand lens which is interconnected to an additional lens. Thus, for well "A", the macroscopically tortuous distance from the wellbore is shown by the path marked by arrows.

If two wells shared the same "tortuous" path, then they were defined to be in "interference". The amount of distance separating the two was divided equally between the wells. In the diagram, wells "C" and "D" interfere.

Only wells in sand lenses were assumed to be capable of being fractured. For the study, a fracture half-length of 1500 feet was assumed. Fracture orientation was assigned randomly:

- 75% of the fractures were perpendicular to the long side of the sand lens, as illustrated in well "E".
- 25% of the fractures were parallel to the long side of the sand lens.

It was assumed that a fracture was capable of entering a sand lens after propagating through shale and shown by well "E" that interconnects with two additional sand lenses.

In the diagram, well "H" was drilled into a sand lense at two-thirds of the length. (From 0' to 1000' radially from the wellbore there is an equal volume of sand on each side of the well. From 1000' to 2000' there is sand only to the left of the well.)

Using the figures shown above, it is possible to plot: cumulative total sand contacted (ordinate) versus radial distance from wellbore (abscissa). Such a plot of well "H" is shown assuming the 20% case.

Exhibit 3-30 provides the relationship of the connected length of sand bodies (radial distance or length along flow path) as a function of permeability and years of production.

For the cases in which multiple wells (4, 6, 9, 16, 25) were drilled per section, a "well contact" function was defined as the arithmetic mean of the total sand contact function for all wells. Thus, the following terminology holds:

- Well-sand contact function: Relationship between cumulative percent of total sand contacted by a single given well as a function of radial distance from the wellbore.
- Section sand contact function: The algebraic sum of all well sand contact functions for a given project (i.e., 4, 6, 9, 16, 25 wells).
- Typical well contact function: The section sand contact function divided by the number of wells.

These functions were evaluated on each of the Monte Carlo trials and provide solutions to four basic cases:

- Typical Well Contact Function - Fractured Case
- Typical Well Contact Function - Unfractured Case
- Section Sand Contact Function - Fractured Case
- Section Sand Contact Function - Unfractured Case

EXHIBIT 3-30

DEVIATION IN CUMULATIVE PRODUCTION FROM
INFINITE RESERVOIR CASE; FINITE LINEAR SYSTEM

($\phi = .10$, $m = .014$ cp, $c = .00025$ psi⁻¹)

g. Well Contact

The well contact functions for both the fractured and unfractured conditions are presented in Exhibits 3-31 and 3-32, respectively.

Exhibit 3-31, for six fractured wells per section, shows that a single well with 3,000' flow path will be in contact with 9 to 13% of the total pore volume in the section.

Exhibit 3-32, for unfractured wells, shows that six wells per section is the minimum well-spacing in the unfractured condition since no real deviation from the one well per section spacing would be seen in the well contact function curve (i.e., on the average, with six unfractured wells per section, negligible pressure interference between wells would occur). At eight wells per section, however, definite pressure interference would occur between wells, reducing the amount of gas each well can produce. Hence, the optimum spacing for unfractured wells in this example would be between six and eight wells per section. (This would also be the case for fractured wells when the fracture effectively communicated with only one sand body per layer.)

h. Sand Contact

The sand contact functions are shown in Exhibits 3-33 (Fractured Case) and 3-34 (Unfractured Case).

By comparing the sand contact curves for the fractured well case with the unfractured well case, six fractured wells per section in the 20% sand case would have a similar recovery to seven or eight unfractured wells; after which interference can begin to be observed. Hence, for the 20% sand case, six fractured wells per section would be essentially an optimum. In the 30% sand case, six fractured wells per section would have a similar recovery to nine or ten unfractured wells and the wells now exhibit definite pressure interference. Thus, six fractured wells per section is slightly more than the optimum spacing in the 30% sand case.

EXHIBIT 3-31

WELL CONTACT FUNCTION: FRACTURED WELL CURVE

EXHIBIT 3-32

WELL CONTACT FUNCTION: UNFRACTURED WELL CURVE

EXHIBIT 3-33

SAND CONTACT FUNCTION: FRACTURED WELL CASE

EXHIBIT 3-34

SAND CONTACT FUNCTION: UNFRACTURED WELL CASE

III. THE ECONOMIC MODEL

A. Overview

The 622 analytic reservoirs in the tight gas sands served as the "units of analysis" in the study. A discounted cash flow model, based on 1977 exploration, development, and operating costs was used to determine the economic feasibility of each analytic unit.

A timing model was used to estimate the development and production of each analytic unit -- permitting estimation of aggregate production rates and ultimate recovery.

This section describes the economic and timing models. The discussion is organized as follows:

- General Structure
- Investment Costs
- Operating and Maintenance Costs
- Royalties, Taxes, and Financial Assumptions
- Procedures for Multiple Simulations
- Indices Used to Update Costs
- Aggregation and Timing

B. General Structure

The core of the Project Economics Model is a conventional discounted cash flow (net present value) model. Its unit of analysis is the individual well and its drainage area. Constant June 1977 costs are assumed throughout, i.e., costs and prices in the future are assumed to move proportionally to one another, cancelling the effects of inflation.

The basic structure of the model, used for estimating net present value given a single gas price, is as follows: A positive cash stream is established by multiplying the production per year (from the production model) by the appropriate gas price. This positive flow is offset by investment costs in the initial year, and operating costs, royalties, and allocated costs in each year to the end of the well's productive life.* The net cash flow is then discounted by the rate of return, or capital charge, to yield a net present value (NPV). Where the NPV of the cash flow is greater or equal to zero, the project is considered profitable and assumed to be developed.

Individual cash flows are derived as a function of the following parameters:

- Production, as governed by geology and technology
- Basic costs as influenced by regional cost factors and depth of well

* An economic limit is estimated based on daily production and attendant costs, or thirty-year productive life, whichever is shorter.

- Stimulation costs as determined by the size and depth of the fracture treatment.
- Special costs as occasioned by opportunity for multiple completions and requirement for compression to be producible at pipeline pressures.

C. Investment Costs

The Project Economics Model considers six categories of investment costs -- exploration, drilling and completion, dry-hole costs, stimulation, basic lease and well equipment, and compressor costs.

1. Exploration Costs

The costs of exploration are included in the model by the formula:

$$\text{Exploration Costs Per Successful Well} = \frac{\text{Number of dry (wells to condemn) a section} \times \text{Cost Per (Dry Well)} \times \text{Number (of Dry Sections)}}{\text{Total Number (Producing) Wells}}$$

- Model assumes that four dry holes will condemn a section.
- Dry hole costs are discussed in Section 3, below.
- If SR is the proportion of productive acreage and A is the total acreage, then the expression:

$$(1 - SR) \times A / 23,040$$
 is the number of dry sections.
 (1 section = 23,040 Ac)
- If "spacing" is the well spacing, then $\frac{SR \times A}{\text{Spacing}}$ is the number of producing wells.

Placing these in the above equation and clearing the acre term yields:

$$\text{Exploration Costs Per Successful Well} = 4 \times \text{dry hole cost} \times \frac{(1-SR)}{SR} \times \frac{\text{Spacing}}{23,040}$$

2. Drilling and Completion

The Joint Association Survey has published costs of drilling and completion of gas wells that include all costs through the "Christmas tree".* The latest publication of these data was for 1975. The costs are reported by state (and substate districts) and by depth. Regression analysis of the data for the areas of interest in the present study revealed that total drilling and completion costs fit relatively closely to a logarithmic function with well depth. Exhibit 3-35 shows this relationship for two example areas. Because the survey's costs are reported in 1975 dollars, these were updated by an appropriate inflation multiplier, as discussed below. Drilling and completion costs are computed by the following equation:

$$\text{Total drilling and completion costs} = [e^{(\text{intercept} + (\text{slope} \times \text{depth}))}] \times \left[\frac{\text{Drilling and Completion}}{\text{Inflation Multiplier}} \right]$$

Exhibit 3-36 shows the coefficients, squared correlation coefficient, and error of the equations used for the regions in the study.

3. Dry-Hole Costs

Beyond initial exploratory costs, described above, additional dry-hole costs are encountered in delineating the boundaries of the field. The dry-hole rate (relative to total wells drilled) used in the Base Case

* JAS instructions for this item: "Report all expenditures for drilling development wells including successful wells completed, dry-holes, and wells still drilling at the end of the year. Include: (1) expenditures for casing, tubing, and wellhead fittings associated with development wells; (2) expenditures for roads, grading, etc.; and (3) expenditures for drilling platforms and all other expenditures incident to development drilling. Exclude all expenditures for equipment beyond the Christmas tree and all expenditures for downhole pumping and artificial lift equipment which should be reported under B-2-b" (lease equipment expenditures).

EXHIBIT 3-35

DRILLING AND COMPLETION COSTS FOR TWO SAMPLE AREAS

SOURCE: JAS

EXHIBIT 3-36

DRILLING AND COMPLETION COST EQUATION COEFFICIENTS

<u>REGION/BASIN</u>	<u>SLOPE</u>	<u>INTERCEPT</u>	<u>r²</u>	<u>ERROR</u>
1. <u>Eastern Colorado</u> Denver	.000178	10.93008	.9573	1.10
2. <u>Eastern New Mexico</u> Raton	.000245	10.61257	.9654	1.28
3. <u>Northern Plains</u> (Montana) Northern Plains Williston	.000433	9.85365	.9684	1.16
4. <u>Oklahoma-Arkansas</u> Arkoma Ouachita	.000214	10.84532	.8856	1.50
5. <u>Oklahoma-Tex 10</u> Anadarko	.000214	10.63115	.9692	1.72
6. <u>Rockies</u> (Wyoming and Utah) Big Horn Douglas Creek Greater Green River Piceance Snake River Uinta Wasatch Wind River	.000220	11.26810	.9636	1.25
7. <u>Texas RRC6 and North Louisiana</u> Cotton Valley	.000303	9.88686	.9440	1.40
8. <u>Texas RRC7C</u> Sonora	.000244	10.29184	.9744	1.23
9. <u>Texas RRC9</u> Fort Worth	.000398	9.37392	.9971	1.04
10. <u>Western Gulf Coast</u> (RRC 2,3,4) Western Gulf Basin	.000265	10.32800	.9638	1.31
11. <u>Western New Mexico</u> San Juan	.000285	10.10926	.9595	1.27

was based on empirical data in the Tight Gas and the Appalachian Basins. The dry-hole rate in the Advanced Case, after assuming extensive resource characterization, was based on discussions with geologists familiar with the basins.

In basins having lenticular sands, a higher rate of developmental dry-holes was estimated to account for dry-holes within the defined perimeter of fields.

The dry-hole rates employed in the model are shown below:

	<u>Blanket Sands and Shale</u>	<u>Lenticular Sands</u>
Base Case	0.20	0.30
Advanced Case	0.10	0.20

In lenticular sands, the dry hole costs are based on 100% of the drilling costs plus the costs of stimulation.

In blanket sands where the absence of a gas show is generally taken as sufficient evidence to condemn the well, dry hole costs are based on 80% of drilling costs, since without a gas show casing is not run.

The dry-hole costs were computed by the following equations:

- Lenticular sand dry-hole costs = (dry-hole rate) x (drilling and completion costs + stimulation costs)
- Blanket formation dry-hole costs = (dry-hole rate) x 0.8 (drilling and completion costs)

4. Stimulation Costs

Current estimates of the costs of fracturing were obtained from a major well service company experienced in hydraulic fracturing. Exhibit 3-37 displays these estimates by size of fracture treatment and depth.

For tight sands, the Base Case assumed sand concentrations of two pounds of sand per gallon of fluid. The Advanced Case, to depths of 10,000 feet, used four pounds of sand per gallon of liquid; beyond 12,000 feet, a concentration of one pound of "super prop" (bauxite) per gallon of liquid is used in the Advanced Case. Between 10,000 and 12,000 feet, a mixture of the two is used, proportional to the depth of the interval. For calculation purposes, these costs were converted to linear functions by regression analysis. A linear form was used for the Base Case. For the Advanced Case, each function consists of three intervals, corresponding to the three types of proppant. Exhibit 3-38 displays these relationships for a 300,000 gallon fracture treatment. Exhibit 3-39 shows the coefficients of the equations for each fracture size and depth interval (0-10,000 feet; 10-12,000 feet; greater than 12,000 feet).

The model recognizes that a certain minimum size of fracture treatment is required in the tight sands. This minimum is a function of the depth and technology being considered. The following table presents the minimum fracture sizes required by depth and technology:

	<u>Depth Greater Than 3,000 Ft.</u>	<u>Depth Less Than 3,000 Ft.</u>
Base Technology	150,000 Gal.	20,000 Gal.
Advanced Technology	180,000 Gal.	35,000 Gal.

EXHIBIT 3-37
ESTIMATED FRACTURING COST FOR TIGHT GAS FORMATIONS

AVERAGE SAND CONCENTRATION 2 LB/GAL

Depth (Ft.)	<u>50,000 Gal</u>	<u>100,000 Gal</u>	<u>200,000 Gal</u>	<u>300,000 Gal</u>	<u>500,000 Gal</u>
6,000	\$20,000	\$33,000	\$61,000	\$ 90,000	\$150,000
8,000	24,000	40,000	75,000	108,000	185,000
10,000	28,000	45,000	82,000	120,000	200,000
12,000	32,000	50,000	90,000	130,000	220,000

AVERAGE SAND CONCENTRATION 4 LB/GAL

6,000	\$24,000	\$40,000	\$68,000	\$115,000	\$190,000
8,000	28,000	49,000	90,000	133,000	225,000
10,000	32,000	53,000	98,000	144,000	245,000
12,000	36,000	58,000	106,000	155,000	260,000

AVERAGE SUPER PROP CONCENTRATION 1 LB/GAL

12,000	\$75,000	\$133,000	\$258,000	\$385,000	\$640,000
14,000	85,000	152,000	290,000	430,000	725,000
16,000	95,000	165,000	310,000	460,000	775,000

EXHIBIT 3-38

EXAMPLE COSTS FOR ADVANCED 300,000 GAL. FRACTURE TREATMENT
OF TIGHT GAS SANDS

EXHIBIT 3-39

COEFFICIENTS OF THE FRACTURE COST EQUATIONS FOR TIGHT GAS SANDS

<u>Treatment Size (4 lbs/gal)</u>	(x) <u>Depth Range</u>	(m) <u>Slope</u>	(b) <u>Intercept</u>
50,000 Gal	0 $\leq x \leq$ 10,000'	2.0	12,000
	10,000' $\leq x \leq$ 12,000'	21.5	32,000
	12,000' $\leq x$	5.0	15,000
100,000 Gal	0 $\leq x \leq$ 10,000'	3.2	21,333
	10,000' $\leq x \leq$ 12,000'	44.0	53,833
	12,000' $\leq x$	8.0	38,000
200,000 Gal	0 $\leq x \leq$ 10,000'	7.5	25,332
	10,000' $\leq x \leq$ 12,000'	80.0	100,333
	12,000' $\leq x$	13.0	104,005
300,000 Gal	0 $\leq x \leq$ 10,000'	7.2	72,666
	10,000' $\leq x \leq$ 12,000'	120.5	145,167
	12,000' $\leq x$	18.7	162,508
500,000 Gal	0 $\leq x \leq$ 10,000'	13.7	110,000
	10,000' $\leq x \leq$ 12,000'	197.5	145,167
	12,000' $\leq x$	33.7	240,833

Treatment Size (2 lbs/gal)

50,000 Gal	0 $\leq x \leq$ 10,000	2.0	8,000
100,000 Gal	0 $\leq x \leq$ 10,000	3.0	15,333
200,000 Gal	0 $\leq x \leq$ 10,000	5.2	30,667
300,000 Gal	0 $\leq x \leq$ 10,000	7.5	46,000
500,000 Gal	0 $\leq x \leq$ 10,000	12.5	78,333

5. Lease and Well Equipment

Historical investments in lease and well equipment were developed by region through 1974,^{18/} in terms consistent with JAS definitions.* The 1974 figures were updated to June 1977 levels by the appropriate Lease and Well Equipment and Operating Cost inflation multiplier, as reported below. Exhibit 3-40 reports the costs for the regions used in this study.

* The JAS requires: "Report all lease equipment expenditures beyond the Christmas tree installation, including flow lines, flow tanks, field separators, heater-treaters, production platforms, and related field facilities. Include expenditures for all normal pumping and other artificial life equipment, including downhole installations required for primary production."

EXHIBIT 3-40

LEASE AND WELL EQUIPMENT COSTS BY REGION
(Dollars Per Well)

<u>REGION/BASIN</u>	<u>1974</u>	<u>Mid-1977</u>
<u>Eastern Colorado</u> Denver	27,530	36,560
<u>Eastern New Mexico</u> Raton	49,420	65,630
<u>Northern Plains (Montana)</u> Northern Plains Williston	22,540	29,933
<u>Oklahoma-Arkansas</u> Arkoma Ouachita	56,000	74,368
<u>Oklahoma-Arkansas</u> Anadarko	27,860	36,998
<u>Rockies (Wyoming and Utah)</u> Big Horn Douglas Creek Greater Green River Piceance Snake River Uinta Wasatch Wind River	48,220	64,036
<u>Texas RRC6 and Northern Louisiana</u> Cotton Valley	49,940	66,320
<u>Texas RRC7C</u> Sonora	49,420	65,630
<u>Texas RRC9</u> Forth Worth	49,940	66,320
<u>Western Gulf Coast (RRC 2,3,4)</u> Western Gulf Basin	49,940	66,320
<u>Western New Mexico</u> San Juan	48,220	64,036

SOURCE: Adapted from Gruy Federal, Inc./Chase Manhattan Study for DOE, in preparation.

6. Compressor Investment Costs

In shallow basins where the initial pressure is low, compression may be required from the beginning of production as normal operating procedure. To account for this contingency (in basins shallower than 3,000 feet), the model includes the cost of an appropriately sized compressor in the first year's investment outlays.

The horsepower requirement for the compressor was estimated by Kirkpatrick's method.^{19/} Assuming a line pressure of 500 psia, a wellhead pressure of 100 psia, a two-stage compressor, and temperature of 80°F (at 15.025 psia), this method yields a compression ratio of 2.236.

Kirkpatrick's method uses a series of constants to relate the compression ratio and flow rate to horsepower. Solution of these constants for the assumed compression ratio yields a constant of 108.0 which, multiplied by the rate of flow (in MMcf/D) to be compressed, yields the number of break horsepower required. The model further assumes that the compressor capacity would be "shared" across several wells, each of which declines rapidly to relatively stable rates. Thus, the throughput was assumed at the average of the first three years daily rate. The investment cost of one installed horsepower was estimated at \$440. Thus, the equation for computing compressor investment was:

Compressor investment cost =

$$\$440 \times (108.0) \times \left(\frac{\text{Sum of production years 1, 2, 3}}{3 \times 365 \times 1000 \text{ Mcf/D}} \right)$$

D. Operating and Maintenance Costs

1. Basic Operating and Maintenance Costs

Using data from 2,000 wells, Gruy Federal, Inc., developed operating and maintenance costs for gas wells by region and depth.^{20/} The costs include normal operating expenses, surface repairs and maintenance expenses, subsurface repair, maintenance and services, field (but not district or corporate) overhead, and ad valorem taxes. These costs were defined in 1976 dollars per month as logarithmic functions of depth for each region. These were updated to 1977 costs by applying the Lease and Well Equipment and Operating Cost multiplier. Thus, the equation for applying these costs took the form:

$$\begin{aligned} \text{Operating and Maintenance Cost/Year} = & \\ & 12 \times (e^{(\text{intercept} + (\text{slope} \times \text{depth}))}) \\ & \times \text{Lease and Well Equipment and Operating} \\ & \text{Cost Inflation Multiplier} \end{aligned}$$

Exhibit 3-41 shows an example of the costs per well per month (1976) for Colorado. Exhibit 3-42 provides the coefficients used to evaluate the above equation.

2. Compressor Operating Costs

Operating costs of the compressor, where applicable, are added to operating and maintenance costs. Compressor operating costs are a function of the daily production rate and the price of fuel. Assuming lease gas is used as fuel, the equation for compressor operating costs is as follows:

EXHIBIT 3-41
TYPICAL OPERATING COSTS FOR GAS WELLS
(Colorado)

EXHIBIT 3-42

COEFFICIENTS FOR CALCULATING OPERATING AND MAINTENANCE COSTS

<u>REGION/BASIN</u>	<u>SLOPE</u>	<u>INTERCEPT</u>
1. <u>Eastern Colorado</u> Denver	.0000311	5.857939
2. <u>Eastern New Mexico</u> Raton	.0000926	5.298317
3. <u>Northern Plains</u> (Montana) Northern Plains Williston	.0001312	5.521370
4. <u>Oklahoma-Arkansas</u> Arkoma Ouachita	.000525	5.480637
5. <u>Oklahoma-Texas RRC10</u> Anadarko	.0000859	5.192952
6. <u>Rockies</u> (Wyoming and Utah) Big Horn Douglas Creek Greater Green River Piceance Uinta Wasatch Wind River	.0000636	5.703781
7. <u>Texas RRC6 and Northern Louisiana</u> Cotton Valley	.0001497	5.298249
8. <u>Texas RRC7C</u> Sonora	.0000926	5.298318
9. <u>Texas RRC9</u> Fort Worth	.0001497	5.298249
10. <u>Western Gulf Coast</u> (RRC 2,3,4)	.0001497	5.298249
11. <u>Western New Mexico</u> San Juan	.0000636	5.703780

SOURCE: Gruy Federal

Compressor Operating Costs =

Annual Production x (0.024 + (0.097 x fuel price))

Costs equal the annual production times the incremental operating maintenance costs of operating a two-stage compressor (estimated at \$0.012 per Mcf per stage) plus the fuel costs for the BTU requirements (0.0972 x gas price) to compress 1 Mcf of gas.

E. Royalties, Taxes, and Financial Assumptions

Additional factors need to be considered in computing the discounted cash flow. These include royalties, taxes, and various allocations and accounting procedures.

1. Royalty Rate

Royalty payments, the compensation paid to the owner of the property, are set in the model at 12.5% of the gross value of production, paid in the year produced.

2. Severance Taxes

Production taxes paid to the state are based on the value of production after royalty. The state agencies in the relevant states were contacted to determine the rates. These are shown in Exhibit 3-43.

3. Allocation of General and Administrative/ Overhead Costs

General and Administrative or Overhead Costs. The costs of divisional and corporate burden are set at:

EXHIBIT 3-43

STATE SEVERANCE TAX RATES

<u>STATE</u>	<u>TAX RATE*</u>
Arkansas	.001
Colorado	.050
Idaho	0
Kansas	0
Louisiana	.070
Montana	.032
North Dakota	.050
Oklahoma	.071
South Dakota	.030**
Texas	.075
Utah	.022
Wyoming	.040

* Applied to gross value of production
less royalties

** Effective 1978

SOURCE: State Tax Authorities

- 20% of Total Operating and Maintenance Costs (including compressor operating costs, where applicable); plus
- 10% of Investment Costs (in the year of the investment).

4. Tangible and Intangible Costs and Depreciation

The models assume expensing of intangible costs for tax purposes using the following rules:

- Intangible costs are equal to 70% of drilling and completion costs, for productive wells.
- Tangible costs are equal to 30% of drilling and completion costs for production wells.
- Costs of dry-holes and exploration are expensed.
- Stimulation costs are expensed.

Tangible assets are depreciated using unit of production depreciation.

5. Federal and State Income Taxes

A federal income tax of 48% and the appropriate state taxes are applied to net income. The amount of the federal tax is reduced by accrued investment tax credits, at 10% of tangible investment.

Negative taxes may be earned by the projects and applied to other projects in the company.

The state tax rates used in the study are displayed in Exhibit 3-44.

6. Timing of Investment Costs

All investments are assumed to be incurred in one year prior to the first year of production.

7. Discount Rate

Two discount rates are used in computing the discounted net cash flows -- 20 percent in the Base Case and 10 percent in the Advanced Case. Because the costs and revenues are in constant (real) dollar terms, these rates are equivalent to 16% and 26%, respectively, under an inflation rate of six percent. The rationale for decreasing the discount rate in the Advanced Case is that improvements in resource characterization and the number of extensively reported successful demonstrations could lead the operators to use lower (risk-free) discount rates in evaluating projects.

EXHIBIT 3-44

STATE INCOME TAX RATES

<u>STATE</u>	<u>TAX RATE</u>
Arkansas	.05
Colorado	.05
Idaho	.05
Kansas	.04
Louisiana	.04
Montana	0
New Mexico	.03
North Dakota	.06
Oklahoma	.04
South Dakota	.04
Texas	0
Utah	.04
Wyoming	.05

SOURCE: State Tax Authorities

F. Procedure for Multiple Stimulations

In some basins, several intervals, either in different or the same formations, may be stimulated from a single well. Where the opportunity for multiple stimulations was present, a three step procedure was used.

1. Screening. Each interval was evaluated at its minimum possible marginal cost. The after-tax cost of stimulation was evaluated against the present value of the production stream, from the specific interval less royalty and severance taxes. If the present value of the production failed to exceed the marginal cost of stimulation, the interval was eliminated from further consideration.
2. Evaluation of combinations of intervals. The intervals that covered this marginal cost were grouped. Each of these combinations was evaluated as a complete project through the Project Economics Model. All stimulations other than the deepest were surcharged 25% to account for the cost of the packing and cleaning necessary for multiple stimulations. Any combinations that failed to yield a positive net present value were eliminated.
3. Selection. If more than one combination was economic, the one yielding the greatest net present value was selected and assumed to be developed.

G. Indices Used to Update Costs

The detailed engineering cost studies of lease development and field operations, on which the above estimated are based, were conducted throughout the 1970's. While the basic activities have remained essentially the same, the costs associated with these activities have changed materially. Therefore, a set of indices was used to update prior year costs to mid-1977 levels.

The steps involved in the updating process were as follows:

1. Inflation indices appropriate to each of the major cost categories were selected (see parts 1-a, 2-a, and 3-a of Exhibit 3-45).
 - Labor Costs - Bureau of Labor Statistics average weekly earnings for Oil and Gas Extraction (BLS Item No. 13); Crude Petroleum and Natural Gas Field Operations (BLS Item No. 131.2); and Oil and Gas Field Services (BLS Item No. 138).
 - Well Equipment Costs - Bureau of Labor Statistics Wholesale Price Index for Steel Pipe and Tube (BLS Item No. 33176).
 - Construction Costs - the Engineering News Construction Cost Index.
2. Where indices for mid-year 1977 (June) were unavailable, these were estimated by extrapolation from the figures that were available for 1977.

EXHIBIT 3-45
INFLATION INDICES

1. LABOR COSTS

A. Yearly Average of Weekly Earnings (Table C-2, Bureau of Labor
 Statistics Employment and Earnings) (Except Estimated
 Monthly Average for June 1977)

<u>BLS Item Number</u>	<u>Title</u>	<u>Est. June 1977</u>	<u>1976</u>	<u>1975</u>	<u>1974</u>	<u>1973</u>
13	Oil and Gas Extraction	288.87	259.78	237.10	214.97	181.47
131.2	Crude Petroleum & Natural Gas Field Operations	298.55	272.83	246.84	223.86	191.82
138	Oil and Gas Field Services	284.93	253.80	232.00	209.76	176.08

B. Multiplier Required to Equate Prior Year
 Wages to June 1977

13	Oil and Gas Extraction	-	1.112	1.218	1.344	1.592
131.2	Crude Petroleum & Natural Gas Field Operations	-	1.094	1.209	1.334	1.556
138	Oil and Gas Field Services	-	1.123	1.228	1.358	1.627

EXHIBIT 3-45 (Continued)

2. WELL EQUIPMENT COSTSA. Yearly Average Indices Except Estimated Monthly Average
for June 1977 (1967 = 100), Bureau of Labor Statistics
Wholesale Price Index

<u>BLS Item Number</u>	<u>Title</u>	<u>Est. June 1977</u>	<u>1976</u>	<u>1975</u>	<u>1974</u>	<u>1973</u>
33176	Steel Pipe and Tube Made in Steel Pipe and Tube and Other Industries	232.1	214.5	203.9	172.1	134.9

B. Multiplier Required to Equate Prior
Year Indices to June 1977

-	1.082	1.138	1.349	1.721
---	-------	-------	-------	-------

3. CONSTRUCTION COSTSA. Engineering News Record Construction Index
(June 1977 as Reported by Engineering News Record)

Yearly Average	2540.55	2401.00	2211.77	2019.31	1878.13
----------------	---------	---------	---------	---------	---------

B. Multiplier to Equate Prior Year Averages to June 1977

-	1.058	1.148	1.258	1.353
---	-------	-------	-------	-------

3. An updating multiplier was constructed for each index by dividing the index for June 1977 by the index for the year to be updated. See Parts 1-B, 2-B, and 3-B of Exhibit 3-45.
4. Each economic parameter (e.g., Drilling and Completion Costs) was analyzed to determine relative weights for each of the indices. Parts A and B of Exhibit 3-46 illustrate this step for Drilling and Completion Costs and for lease and well equipment.
5. A composite multiplier was developed for each economic parameter by combining the appropriate multipliers according to their relative weights. See Exhibit 3-47 for the composite multipliers for the following parameters:
 - Drilling and Completion
 - Lease and Well Equipment
 - Workover and Conversion Costs
 - Direct Operating and Maintenance Costs
6. The composite multiplier for each parameter was applied to that parameter's prior year costs to update them to mid-year 1977.

EXHIBIT 3-46

PART A: INDEX ALLOCATION FOR DRILLING AND COMPLETION COSTS

<u>Cost Item</u>	<u>Allocation for</u>	
	<u>Assigning Index</u>	<u>Weighting</u>
	<u>BLS Oil & Gas</u>	<u>BLS Wholesale</u>
	<u>Field Service</u>	<u>Price Index</u>
	<u>No. 138</u>	<u>No. 33176</u>
<u>Site Preparation:</u>		
Clearing Wellsite	X	
Surveying and Plat	X	
Damages	X	
Pit and Clean-Up	X	
Road Surveying	X	
Cattle Guards	X	
Roads	X	
Total Site Preparation		
<u>Drilling and Completion:</u>		
Rig Nondrilling	X	
Rig Drilling	X	
Transportation of Rig	X	
Drill Bits		X
Water	X	
Drilling Mud	X	
Cementing	X	
Evaluation and Completion Services	X	
Special Tool Rental		X
Engineering and Geological	X	
Surface Casing		X
Intermediate Casing		X
Production Casing		X
Total Drilling & Completion		
Total Site Preparation, Drilling and Completion	60%	40%

EXHIBIT 3-46 (Continued)

PART B: INDEX ALLOCATION FOR LEASE AND WELL EQUIPMENT COSTS

<u>Cost Item</u>	<u>BLS Labor Costs No. 131.2</u>	<u>BLS Wholesale Price Index No. 33176</u>	<u>Eng. News-Recd. Construction Cost Index</u>
<u>Production Equipment:</u>			
Wellhead & Miscellaneous			
Fittings	X	X	
Tubing	X	X	
Rods	X	X	
Pumps		X	X
Pumping Equipment	X	X	X
Sub-Total Producing Equipment			
<u>Gathering System:</u>			
Flowlines	X	X	X
Manifold		X	
Sub-Total Gathering System			
<u>Lease Equipment:</u>			
Producing Separator	X	X	X
Test Separator	X	X	X
Heater-Treater	X	X	X
Tanks	X	X	X
Water Disposal System	X	X	X
Fence	X	X	X
Sub-Total Lease Equipment			
TOTAL SURFACE EQUIPMENT COSTS	20%	60%	20%

EXHIBIT 3-47

CONSTRUCTION OF COMPOSITE MULTIPLIERS

		Multiplier Required to Equate Prior Year Costs to June 1977 Costs			
	Relative Weighting	<u>1976</u>	<u>1975</u>	<u>1974</u>	<u>1973</u>
1. <u>Drilling and Completion Costs</u>					
BLS Labor Costs #138 -- Oil and Gas Field Services	60%	1.123	1.228	1.358	1.627
BLS Wholesale Price Index #33176 -- Steel Pipe and Tube Made in Steel Pipe and Tube & Other Industries	<u>40%</u>	<u>1.082</u>	<u>1.138</u>	<u>1.349</u>	<u>1.721</u>
Composite Drilling and Completion Cost Multiplier Lease and Well	100%	1.107	1.192	1.354	1.665
2. <u>Equipment Costs</u>					
<u>Direct Operating and Maintenance Costs</u>					
BLS Labor Costs #131.2 - Crude Petroleum & Natural Gas Fields	20%	1.094	1.209	1.334	1.556
BLS Wholesale Price Index #33176 - Steel Pipe and Tube Made in Steel Pipe & Tube & Other Industries	60%	1.082	1.138	1.349	1.721
Engineering News Record -- Construction Cost Index	<u>20%</u>	<u>1.058</u>	<u>1.149</u>	<u>1.258</u>	<u>1.353</u>
Composite Multiplier	100%	1.080	1.154	1.328	1.614

H. Aggregation and Timing

The foregoing description of the economics model applies to the evaluation of a single project area. Each such project represents a specific sub-area of the basin. The aggregation and timing component of the model takes this evaluation and performs four basic tasks:

- Assigns the appropriate acreage to each "typical" area that proves to be profitable.
- Determining the total amount of acreage that is profitable, i.e., likely to be developed.
- Converts the acreage into the total number of wells to be drilled.
- Sequences drilling and production of these wells into the future under either Base Case or Advanced Case development schedules.

Phased development of drilling and production was accomplished through a series of timing algorithms. The proportion of wells drilled in a given areal unit in a given year is a function of:

- Technology: Base or Advanced
- Type of Acreage: Probable or Possible

Across all four combinations of technology and acreage, the earliest wells would be drilled in 1978 and all drilling would be complete by 2003.

- For probable acreage, Base Case drilling commences immediately and is concluded within seventeen years. Advanced Case drilling is lagged three years (i.e., starts in the third year after the Base Case) to account for the time it will take the R&D to have an effect, but is conducted at a more rapid pace, being completed within thirteen years.
- For possible acreage, Base Case drilling is lagged nine years, and is completed within 17 years. To model the combined effects of resource characterization and improved technology, drilling is lagged nine years but is completed within 15 years under the Advanced Case.

The thirty-year production streams for each well begins in the year after the well is drilled. Total production in any year reflects the combined yearly production from all wells which have been drilled to that date. Thus, all production will have ceased thirty-one years following the drilling of the last well (or in 2034).

Exhibit 3-48 sets forth the development schedule integral for the timing of basic development.

EXHIBIT 3-48
DEVELOPMENT SCHEDULE

YEAR	PROBABLE ACREAGE				POSSIBLE ACREAGE			
	BASE		ADVANCED		BASE		ADVANCED	
	% DRILLED IN YEAR	CUMULATIVE % DRILLED THRU YEAR	% DRILLED IN YEAR	CUMULATIVE % DRILLED THRU YEAR	% DRILLED IN YEAR	CUMULATIVE % DRILLED THRU YEAR	% DRILLED IN YEAR	CUMULATIVE % DRILLED THRU YEAR
1978	1.3	1.3	0	0	0	0	0	0
1979	2.5	3.8	0	0	0	0	0	0
1980	3.8	7.5	0	0	0	0	0	0
1981	5.0	12.5	2.0	2.0	0	0	0	0
1982	6.3	18.8	4.1	6.1	0	0	0	0
1983	7.5	26.3	6.1	12.2	0	0	0	0
1984	8.8	35.0	8.2	20.4	0	0	0	0
1985	10.0	45.0	10.2	30.6	0	0	0	0
1986	10.0	55.0	12.2	42.8	0	0	0	0
1987	10.0	65.0	14.2	57.1	1.3	1.3	1.7	1.7
1988	8.8	73.8	12.2	69.4	2.5	3.8	3.3	5.0
1989	7.5	81.3	10.2	79.6	3.8	7.5	5.0	10.0
1990	6.3	87.8	8.2	87.8	5.0	12.5	6.7	16.7
1991	5.0	92.5	6.1	93.9	6.3	18.8	8.3	25.0
1992	3.8	96.3	4.1	98.0	7.5	26.3	10.0	35.0
1993	2.5	98.8	2.0	100.0	8.8	35.0	10.0	45.0
1994	1.3	100.0	0	100.0	10.0	45.0	10.0	55.0
1995	0	100.0	0	100.0	10.0	55.0	10.0	65.0
1996	0	100.0	0	100.0	10.0	65.0	10.0	75.0
1997	0	100.0	0	100.0	8.8	73.8	8.3	83.3
1998	0	100.0	0	100.0	7.5	81.3	6.7	90.0
1999	0	100.0	0	100.0	6.3	87.8	5.0	95.0
2000	0	100.0	0	100.0	5.0	92.5	3.3	98.3
2001	0	100.0	0	100.0	3.8	96.3	1.7	100.0
2002	0	100.0	0	100.0	2.5	98.8	0	100.0
2003	0	100.0	0	100.0	1.3	100.0	0	100.0

CHAPTER THREE

BIBLIOGRAPHY

- 1/ U.S. Energy Research and Development Administration, Western Gas Sands Project Plan, August 1, 1977.
- 2/ Potential Gas Committee, Potential Supply of Natural Gas in the United States, Colorado School of Mines, Golden, Colorado, 1977.
- 3/ American Association of Petroleum Geologists, Bulletin, August, 1976, Vol. 60, No. 8.
- 4/ Thomas, R.D. and Ward, D.C., "Effect of Overburden Pressure and Water Saturation on Gas Permeability of Tight Sandstone Cores", Journal of Petroleum Technology, 1972, Vol. 24, p. 123.
- 5/ Matuszczak, R.A., "Wattenberg Field, Denver Basin, Colorado," The Mountain Geologist, Vol. 10, No. 3, July 1973, pp. 99-105.
- 6/ Fast, C.R., Holman, G.B., Covin, R.J., "The Application of Massive Hydraulic Fracturing to the Tight Muddy 'J' Formation", Wattenberg Field, Colorado, Journal of Petroleum Technology, January, 1977.
- 7/ Holditch, S.A. and Morse, R.A., "The Effects of Non-Darcy Flow on the Behavior of Hydraulically Fractured Gas Wells," Journal of Petroleum Technology, SPE-AIME, October, 1976, pp. 1169-1178.
- 8/ Ibid, p. 1170.
- 9/ Cooke, C.E., Jr., "Conductivity of Fracture Proppants in Multiple Layers," Journal of Petroleum Technology, SPE-AIME, September, 1973, pp. 1101-1107.
- 10/ Holditch and Morse, Op. Cit.
- 11/ Cinco, L., Samaniego, V.F., Dominquez, A., "Transient Pressure Behavior for a Well with a Finite-Conductivity Vertical Fracture", Society of Petroleum Engineers Journal, August, 1978, pp. 253-264. First presented in October 1976 at SPE Annual Fall Meeting, SPE 6014.
- 12/ Fast, C.R., Holman, G.B., and Colvin, R.J., "The Application of Massive Hydraulic Fracturing to the Tight Muddy 'J' Formation, Wattenberg Field, Colorado", Journal of Petroleum Technology, January 1977, pp. 10-16.

- 13/ Geertsma, J and de Klerk, F., "A Rapid Method of Predicting Width and Extent of Hydraulically Induced Fractures", Journal of Petroleum Technology, December 1969, pp. 1571-81.
- 14/ Gidley, John L., Mutti, D. H., and Nierode, D.E., "Tight Gas Stimulation by Massive Hydraulic Fracturing - A Study of Well Performance," SPE Paper 6867 presented at the 52nd Annual Fall Meeting of the SPE in Denver, Colorado, October 9-12, 1977.
- 15/ Knutson, C.F., "Modeling of Noncontinuous Fort Union and Mesa Verde Sandstone Reservoirs, Piceance Basin, Northwest Colorado", SPE Paper 5024 presented at the 49th Annual Fall Meeting of the SPE in Houston, Texas, October 6-9, 1974.
- 16/ Ibid.
- 17/ Personal communication with David Cox, October 2, 1978.
- 18/ Gruy Federal, Inc. and Chase Manhattan Bank for the Department of Energy. Report in preparation.
- 19/ Kirkpatrick, C. K., "Gas Life", Chapter 5 in T. C. Frick (ed.) Petroleum Production Handbook, Volume I.
- 20/ Gruy Federal, Inc., report for DOE, in preparation.

CHAPTER FOUR

METHODS USED IN ANALYZING PRODUCTION AND RECOVERY
FROM DEVONIAN SHALE

INTRODUCTION AND SUMMARY

The traditional way of estimating the original size and production capacity of a gas field is to: first, collect key volumetric data (e.g., porosity, net pay, areal extent, etc.) which enable the resource in place to be estimated; second, analyze core and well test data to determine the properties (e.g., permeability, pressure, etc.) that govern gas flow rates; and third, estimate production and ultimate recovery by reservoir engineering analysis.

Limited data is available on the resource characteristics of the Devonian shale, and additional reservoir data and improved ability to model the resource are required before the traditional approach for estimating the productive capacity of the Devonian shale can be attempted. Thus, the analysis of this study relied on an empirical approach using a representative sample of production histories from the nearly 10,000 productive wells drilled in the shales.

The empirical approach followed by the study consisted of five basic steps:

- Definition of geographic scope.
- Refinement of the geographic area into analytic Areas of relatively homogeneous conditions, based on the density and productivity of producing wells.
- Sampling of production histories of wells within the analytic Areas.

- Adjusting the historical data to reflect anticipated differences between older and future wells. These adjustments account for advances in technology and the changing nature of the remaining prospects.
- Economic appraisal of the gas production under various gas price, production cost, and technology assumptions.

The first two steps were based on published geological studies, discussions with geologists engaged in DOE-sponsored appraisal of the shales, and interviews with engineering staffs of gas producers active in the area. In all, twelve analytic Areas were defined, one of which is fully drilled.

The basis of the production estimates used in this study was historical well data acquired from various gas production companies on 250 individual wells. The data included annual production, reservoir pressures, and line pressures which enabled development of production curves for each of the analytic Areas. These curves were smoothed to remove statistical randomness of individual wells in the sample.

Next, the basic production curves were modified to reflect that wells tend to be less productive as drilling moves into extension and step-out areas, and production from wells stimulated by hydraulic fracturing is generally higher and occurs sooner than production from wells stimulated by shooting. Production Multiplier Values (PMVs) were derived to account for these two factors.

The modified production curves were used as input to the economic model developed for the tight gas sands, with appropriate adjustments to reflect recent cost experience of operators in the Devonian shales.

The above approach to the analysis was based on empirical data from historic production. It was complemented by a variety of supplemental analyses which were designed to validate the approach and to address different interpretations on the nature and production mechanisms of Devonian shales. They involved history matching using reservoir simulation and basic reservoir engineering appraisals.

The next section of this chapter details the approach used to analyze the resource base and the resulting production curves. The subsequent section reports the results of the various supplemental analyses. The last section describes the modification of the economic model for application to the Devonian shales.

I. THE RESOURCE BASE

A. Scope of the Analysis

The purpose of this study is to estimate the economic recovery of methane from Devonian shale from the present through the year 2000.

Devonian shales are considered a prospective gas resource in the Appalachia, Michigan, and Illinois Basins. The latter two basins were excluded from the present study because they are insufficiently developed to provide an empirical basis for analysis.

The Appalachian Basin covers approximately 210,000 square miles and includes all or parts of ten states. Published geological studies and experts in both public and private sectors were consulted to determine the portions of the Basin that can be considered prospective for gas from the Devonian shales. This resulted in approximately 148,000 square miles of the 210,000 square mile area being classified as speculative or having little or no production potential. These areas are shown on Exhibit 4-1 and described below.

- Area A - The eastern portion of the Basin between the Allegheny and Blue Ridge Fronts (65,000 square miles). The brown/black Upper Devonian shales outcrop, while the deeper Middle Devonian shales have been subject to intense structural deformation culminating in typical Appalachian thrust-faulted folds. Trapping of gas accumulations is not deemed likely, and no significant productivity has been encountered in this region.
- Area B - The upper Devonian shales outcrop in the northern area of the Basin from Upper Erie across southwestern New York and northeastern Pennsylvania (44,000 square miles). The deeper middle Devonian shales have had a similar history

EXHIBIT 4-1

GEOLOGICAL DISTRIBUTION OF THE DEVONIAN SHALES
OF THE APPALACHIAN BASIN

SOURCE: deWitt, W., Perry, W., and Wallace, L. G., "Oil and Gas Data from Devonian and Silurian Rocks in the Appalachian Basin", USGS, 1975.

to those in Area A and volatile hydrocarbons have possibly escaped. Experienced geologists in the New York State Geological Survey have reported there is no substantial gas production from black shale in New York. Studies are currently underway to determine and characterize the resource. Currently, gas is produced from Devonian sands, e.g., Bradford 3rd, Onondaga, and Oriskany.

- Area C - The western flank of the Basin between the outcrops of Devonian brown/black shale and the Cincinnati Arch (18,000 square miles). The Devonian shales have played out and cannot be found in cross-sections.
- Area D - The southern portion of the Basin between the Allegheny Front and Cincinnati Arch from eastern Kentucky to Alabama (21,000 square miles). The shales are thin, averaging 25-50 feet in thickness, and represent a sub-marginal resource.

It is possible that some of the excluded areas have small gas traps as are occasionally found along the Allegheny Front near the Pine Mountain Overthrust. However, these small discoveries have been episodic and provide no systematic evidence of continuous shale sequences.

Included in the above areas are 48,000 square miles, primarily in Areas A and B, that were classified as speculative. These areas may potentially be productive, but little is known about the resource currently and there is no significant production.

The remaining 62,000 square miles of the Devonian shales in the Appalachian Basin were studied in detail. After excluding 5,000 square miles as having already been drilled or found dry, the remaining 57,000 square miles became the area analyzed for gas potential.

The characterization of the total 210,000 square mile area is summarized below.

<u>Definition of the Area</u>	<u>Area, sq. mile</u>	<u>Scope of Study Undertaken</u>
• Unproductive	100,000	Excluded because geology indicated the shale is thin, absent, or the likelihood of gas is low.
• Speculative	48,000	Insufficient data is available to define the economic potential of the area. Hence, excluded from this study.
• Proved/Developed or Found Dry	5,000	Gas potential already included in proved reserves or past production.
• Probable/ Possible	57,000	Included in the study as the potential source of additional gas.

B. Definition of Analytic Areas

Relatively homogeneous areas, in terms of geologic conditions, were defined for the 62,000 square miles of the Appalachian Basin with actual or potential gas production. The basis for this classification was:

- Regional tectonic activity
- Thickness of the shales
- Depth of the shale markers

Since fracture porosity, permeability, and shale thickness seem to control production, and depth of deposition governs drilling and operating costs, these geologic features were taken to be the dominant parameters. To examine shale depth and thickness, detailed cross sections were examined.^{1/} To assess the intensity of natural fracturing, maps of tectonic activity and field delineation were analyzed. Based on these data together with the density and productivity of producing wells, twelve Areas were defined, as shown in Exhibit 4-2. The principal characteristics of the Areas are:

- Area I - Eastern Kentucky, within the heart of the Big Sandy Field; 2164 square miles, of which 1050 square miles are undrilled.
- "Brown Shales"* dip as they reach the Allegheny Front and become thin.

* The use of the term brown/black shales probably originated with drillers to identify dark colored shale formations. In current literature the terms are used interchangeably, or to distinguish the Upper Devonian shales (brown) from the deeper Middle Devonian shales (black). The USGS uses the term black shale to designate all Devonian shales of rich organic content. Typically, brown shale may be defined as younger shale, which has more hydrocarbons in the organic material than black shale where the organic material is closer to elemental carbon. Brown and black shales may be interbedded. In this study, brown/black shale refers to organic shales in general. Where the discussion involves "brown shale" as used in driller's nomenclature, it is in quotation marks.

EXHIBIT 4-2

AREAL EXTENT OF STUDY

- Area II - Eastern Kentucky, southwestern periphery of the Big Sandy Field; 2089 square miles, of which 1609 square miles are undrilled.
 - "Brown shales" in the northern area merge into oil producing zones without significant gas shows.
 - Southern "brown shales" approach the outcrop area and thin into less than 100-foot intervals.
 - The Pine Mountain Overthrust in the southeastern region serves as a boundary for development drilling.
- Area III - Southwest West Virginia, northeastern periphery of the Big Sandy Field; 1771 square miles, of which 1098 square miles are undrilled.
 - The three extensive "brown shales" of Ohio and eastern Kentucky (Cleveland, Upper, and Lower Huron) are in the western portion, but disappear before reaching the eastern section, reducing the sequences to only one producing horizon.
 - Southeastern boundary is the limit of known drilling.
- Area IV - Southwestern West Virginia, east of Area III, northeast of the Big Sandy Field is known to have brown shale deposition; 871 square miles, of which 848 square miles are undrilled.
 - "Brown shales" thin as they outcrop along the Allegheny Front.

- Area V - Central West Virginia, north of the Big Sandy Field; 1811 square miles, of which 1690 are undrilled.
 - Eastern boundary is found where the brown shale deposits thin and a facies change occurs with the shale going into coarser sands.
 - Southern boundary approximates the division between producing areas in Area III and very scattered sporadic production of Area IV.
 - Northern boundary is outside the Cottageville Field, where production is scattered and mostly undrilled.
- Area VI - Northwest West Virginia; 2067 square miles, of which 2032 are undrilled.
 - Eastern boundary lies along the facies change of "Brown Shales" into sands.
- Area VII - Central and eastern Ohio; 15,575 square miles, of which 15,261 square miles are undrilled.
 - The area contains continuous deposits of Upper and Lower Ohio shales, the "Big and Little Cinammon".
 - Little or no observable major faulting, anticlines, or synclines.

- Area VIII - Lake Erie and northern Ohio; 3,093 square miles, of which 2,955 are undrilled.
 - Shallow shale deposition.
 - Isolated small gas wells.
- Areas IX and X - Northcentral West Virginia and southwestern Pennsylvania; 17,776 square miles are undrilled.
 - Thinning out and disappearance of "Brown Shales".
 - Continuous deposition of deeper Marcellus/Harrel shales.
- Area XI - Eastern West Virginia; 12,332 square miles are undrilled.
 - Deep Marcellus/Harrell shales.
 - No Upper Devonian "Brown Shales".
- Area XII - Northeastern Kentucky; 2,634 square miles, fully drilled.
 - Shales are oil bearing without associated gas.
 - Gas deposits depleted in northeastern segment.

Exhibit 4-3 summarizes the location, the total acreage, and the undrilled acreage in each analytic Area. Only undrilled acreage was analyzed in the present study to avoid inclusion of presently proved reserves, already depleted areas, and known dry areas.

EXHIBIT 4-3

AREAL EXTENT OF ANALYTIC UNITS

<u>ANALYTIC AREA</u>	<u>LOCATION</u>	<u>AREAS IN SQUARE MILES</u>	
		<u>TOTAL</u>	<u>UNDRILLED</u>
I	Eastern Kentucky	2,164	1,050
II	Eastern Kentucky Extension	2,089	1,609
III	S.W. West Virginia	1,771	1,098
IV	Eastern Extension of Area III	871	848
V	Central West Virginia	1,811	1,690
VI	N.W. West Virginia	2,067	2,032
VII	Central and Eastern Ohio	15,575	15,261
VIII	N.E. Ohio	3,093	2,955
IX and X	N.W. West Virginia and Pennsylvania	17,776	17,776
XI	Eastern West Virginia	12,332	12,332
XII	N.E. Kentucky	<u>2,634</u>	<u>-</u>
TOTAL		62,183	56,651

C. Development of Decline Curves

1. Method

The basis of the production analysis is empirical well data from 250 individual wells, including annual production, reservoir pressure, and line pressure. This data enabled development of specific production decline curves for each of the eleven analytic Areas that are not fully drilled. Wells that could satisfy the following five criteria were included in the data base:

- They were individually metered.
- Shale production was distinguishable from other producing horizons.*
- Production records of at least 25 years for older fields and 15 years for newer fields were available.
- Both high, average, and low producers were included.
- There were at least 4-6 wells for each county within an analytic Area if the Area was productive.

Annual production for each of the eleven Areas was defined as the average production from the wells included in the base. Cumulative production curves were smoothed using Marquardt's Algorithm,** and the resulting curves were disaggregated into annual production for thirty years. Although

* Brown^{2/} has observed that as much as 25% of the gas attributed to shale production may in fact be from other formations.

** The cumulative production was fit to a curve of the form $f(t) = (1 - e^{-Bt})$ using a non-linear least-squares method.

Devonian wells frequently produce for longer than thirty years, production beyond this period would affect neither the economics of production, due to discounting, nor annual production in the period of this study.

2. Production Curves

The following is a summary of the decline curves and thirty years production for each of the analytic Areas:

AREA I - Decline curves were based on well records from Kentucky Counties Pike, Martin, Floyd and Knott (Area A), and Letcher and Perry (Area B); the two areas were weighted according to their geologic representativeness as follows:

- 0.5 for Area A
- 0.5 for Area B
- Average 30 year recovery: 411 MMcf

AREA II - Decline curves were estimated using curves from Areas A and B, weighted as follows:

- 0.2 for Area A
- 0.8 for Area B
- Average 30 year recovery: 349 MMcf

AREA III - Decline curves were based on well records of Lincoln, Wayne, Mingo and Logan, West Virginia (Area C), Cabell and Boone, West Virginia (Area D):

- 0.6 for Area C
- 0.4 for Area D
- Average 30 year recovery: 348 MMcf

AREA IV - Decline curves were based on well records of Mingo, Logan, and Boone Counties, West Virginia:

- Average 30 year recovery: 376 MMcf

AREA V - Decline curves were based on well records of Kanawha, Cabell, and Putnam Counties, West Virginia, and Lawrence County, Ohio:

- Average 30 year recovery: 338 MMcf

AREA VI - Decline curves were based on well records of Jackson County, West Virginia (Area E), Meigs County, Ohio, and Area V, weighted as follows:

- 0.4 for Area E
- 0.3 for Meigs County
- 0.3 for Area V
- Average 30 year recovery: 264 MMcf

AREA VII - Decline curves were based on well records of Meigs and Licking Counties, Ohio:

- 0.6 for Licking
- 0.4 for Meigs
- Average 30 year recovery: 96 MMcf

AREA VIII - Decline curves were based on Medina County, Ohio wells:

- Average 30 year recovery: 362 MMcf

AREAS IX, X - No historic production data was available. Area V decline curve was applied:

- Average 30 year recovery: 338 MMcf

AREA XI - No actual production data available. Decline curves were based on data from Morgantown Energy Technology Center:

- Average 30 year recovery: 267 MMcf

AREA XII - Fully drilled. No decline curves estimated.

These decline curves fit within the range previously developed by Brown, Ray, Ryan and Bagnall^{3/} on samples totalling nearly 10,000 wells. The average initial open flows of the 250 wells analyzed in this study range from 200 to 300 Mcf/d. The 250 wells represent only shot wells.

3. Well Spacing

As of December, 1974, there were about 10,000 wells in Kentucky, West Virginia, and Ohio known to be producing from the Devonian shales. Eight thousand of these wells exist in and around the Big Sandy, Ashland, and Cottageville Fields. Exhibit 4-4 shows the drilling density. Each square of the grid represents four square miles (a 2 mile by 2 mile area) and the number inside each square indicates the number of producing shale wells. In the better portions of the fields, the average number of wells is 17 per 4 square miles. This is equivalent to 150-acre spacing per well. The overall average is about 295-acre spacing per well for the 3,700 square miles developed to date. A spacing of 150 acres per well was assumed in estimating the recovery potential from each Area. This is equivalent to the spacing in the most productive areas. A sensitivity analysis of infill drilling is described in Section III of this chapter.

EXHIBIT 4-4

DEVONIAN SHALE WELLS AS OF DECEMBER, 1974

D. Adjustments to the Empirical Production Curves

1. Production Curve Adjustments

The use of average production data from older fields to project future production may have two biases:

- Prospect quality. The wells drilled to date represent the decisions of operators attempting to find and develop their best prospects. As these become exhausted, operators consider less promising prospects. Thus (as initially identified for the tight gas analysis), it is probable that historic wells are geologically more favorable than future wells. Using unadjusted historic data would tend to overestimate the gas potential.
- Technology improvement. Nearly all Devonian shale wells require stimulation to be economic. During the period when the wells in the empirical sample were producing, conventional practice was stimulation by "shooting". Although "shooting" continues to be commonplace, the Basin's leading producers are increasingly stimulating wells by hydraulic fracturing. This method is still being developed, and promises to increase well production in some geologic settings.

The basis for the prospect quality and the technology improvement adjustments are discussed below.

2. Prospect Quality: The Play-Out Factor

Historical records for wells in the Devonian shale show that the geographic distribution of well production is not uniform on a micro-scale. Wells with high production can be located close to poor wells. However, some trends are apparent for the distribution of gas in the Devonian shales. For example, Kentucky wells historically averaged initial open flows near 330 Mcf/d. Recently drilled wells are in the range of 100-275 Mcf/d, suggesting less production as drilling moves away from the currently most productive areas. The decreasing production as reservoir boundaries are approached is known as field play-out.

It is reasonable to assume that in any geographic location, out-step drilling stops as results are poorer than expected and continued exploration and development becomes uneconomic. This deterioration in exploration results leads operators to discontinue their efforts in this geographic location and to start a new play in another area. Such a phenomena has been encountered often and is typical of any oil and gas field where favorable reservoir characteristics deteriorate as field limits are approached.

Because of this recovery phenomena, the gas potential was assumed to play-out in the study in areas considered to be outside the main resource areas. Substantial demonstration of this effect is available in a study for Jackson and Mason Counties.^{4/}

On a micro-scale, the Devonian shales are a heterogenous gas resource with no geographic correlation on well productivity. This non-uniformity of Devonian shale gas production over small areas has been demonstrated in many studies. One of the oldest is that of C. D. Hunter and D. M. Young.^{5/} They found a significant variation in well productivity

for a 36 square mile area near Mud Creek, Floyd County, Exhibit 4-5. Further, there was no overall areal trend in well performance, viz., good wells were not surrounded by a ring of poorer wells, which in turn were not surrounded by a ring of still poorer wells. Instead, there was a random pattern over the 36 square mile area with pockets of good wells and contiguous areas of poorer wells juxtaposed to better wells.

A 1977 study by deWye and Shumaker^{6/} of a 25 square mile area in Mason and Jackson Counties, Exhibit 4-6, shows a more orderly variation in well production on a small scale, although the distribution of production does not show a single area of good wells surrounded by rings of successively poorer quality wells. However, pockets of progressively better quality wells occur as the area is traversed.

On a larger, multi-county scale, however, the distribution of well quality can be observed. The heart of the Big Sandy Field in eastern Kentucky is Floyd County, where the dry hole rate is only 7 percent. When the dry hole rate in peripheral counties is examined, distinct trends are observed. Starting with Martin County, East North East of Floyd, and proceeding clockwise, the following distribution results:

<u>County</u>	<u>Relative Direction</u>	<u>Dry Hole Distribution, %</u>
Martin	E, NE	7
Pike	E, SSE	12
Knott	S, SW	8
Magoffin	W, NW	31
Johnson	N	27

EXHIBIT 4-5

MUD CREEK AREA - FLOYD COUNTY, KENTUCKY
HIGH, MEDIUM, AND LOW PRODUCING AREAS

SOURCE: Coleman D. Hunter and David M. Young, AAPG, Vol. 37, No. 2, February 1953, p. 282.

EXHIBIT 4-6

ISOCONTOURS OF TOTAL ACCUMULATED PRODUCTION
(Mason and Jackson Counties)

The frequency of dry holes increases rapidly to the North and Northwest, and although Johnson County has a few superior wells, they are concentrated close to the border of Floyd County. Similarly, drilling completions and productivity of completed wells falls rapidly to the North and Northwest of Floyd. As a result, the further reaches of these counties have hardly been drilled (Exhibit 4-4). Martin County, on the other hand, is part of the Big Sandy Field which extends into West Virginia and the dry hole rate is low. Pike County wells fall off in productivity to the East and South, and drilling completions also fall off. There is virtually no production in the counties to the East and South of Pike. Finally, Knott County completions are virtually as dense as they are in Floyd County, but fall off in the Northwest Corner. Thus, a definite trend in dry hole frequency and drilling activity occurs along lines radiating out from Floyd County. Analytic Area I corresponds approximately to these six counties.

As a second demonstration of play-out, using data provided by Columbia Gas Research on anticipated ultimate recovery of methane,* a definite trend can be observed from the data.

<u>County</u>	<u>Ultimate Recovery</u> (MMcf/well)
Floyd	692
Martin	514
Pike	371
Knott	567
Johnson	818 (avg. of two wells)
Lawrence	683
Letcher	330 (data from one well)

* This data is for the ultimate recovery over the well life, and may be larger than the 30-year production estimates of this study.

The last two counties, Lawrence and Letcher, are further removed from Floyd than the others. Lawrence is North of Martin, and the data is from six wells located in an extension of the Big Sandy. Letcher is South of Knott and Southwest of Pike, on the far edge of the Big Sandy Field.

A distinct trend in well performance corresponding to the dry hole trends is evident if smooth, ultimate production contours are drawn for Area I, Exhibit 4-7. An area with high ultimate recovery is surrounded by areas of decreasing well productivity for the Big Sandy Field. Thus, although the quality of wells is distributed randomly within small areas, distinct trends are observable on a larger scale.

The wells in the empirical data base show a comparable trend. Aggregated to the county level, the sample wells for the four primary counties comprising the Big Sandy Field were found to have a 30 year average of 512 MMcf, while those in outer counties were found to have 30 year averages of 255 MMcf, or about 50% less.

Thus, the logic of drilling sequence, and data concerning dry hole rates, drilling density, and average productivity all argue for a need to account for degeneration of prospect quality over extended areas. Hence, a play-out factor is required when estimating ultimate recovery based on well data from the drilled acreage.

EXHIBIT 4-7

PRODUCTION CONTOURS FOR AREA I

Ultimate Recovery, MMcf/Well

There is a distinct possibility of a reoccurrence of fracture porosity beyond the limits of proven acreage. Therefore, rather than decreasing production trends to zero at the edge of the analytical Areas, a more gradual fall-off in performance, limited to 50% of the maximum productivity of any analytic Area, has been postulated -- consistent with the Big Sandy data.

It is very probable that all reservoirs in the Devonian shale are still not discovered, but it is less likely that large, high-quality reservoirs have yet to be discovered. For this study it is assumed that the undrilled acreage is, at best, of the same quality as the already drilled acreage,* and that the decline curves developed previously are representative.

The foregoing investigations guided the assumptions concerning the play-out of Areas I and III, the areas for which the most data were available. Production curves from Areas I and III, the most productive extensions from the Big Sandy Field, were modified by the following play-out factors:

<u>Percent of Area</u>	<u>Play-Out Factors</u>
50%	1.0
25%	0.8
25%	0.5

Half of Areas I and III were assumed to produce at the maximum production, while a quarter of the areas were assumed to produce at 80% and 50% of the maximum, respectively.

* In 1976, additions to new discoveries, both associated and non-associated gas, reached the lowest level since 1940. Kentucky had no discoveries of non-associated gas in 1975 -- for the first time since pre-1920 -- and only a small addition in 1976.

Other Areas are not as productive as Areas I and III, which suggests that they would be somewhat lower in quality. The play-out factors assumed were:

<u>Percent of Area</u>	<u>Play-Out Factor</u>
33%-	1.0
33%	0.7
33%	0.5

Sufficient comprehensive data were not available to repeat the contouring of ultimate production in detail for each of the analytic Areas, although additional qualitative information is available for some. For example, shale thickness maps for northern Ohio, Area VIII, show a noticeable thinning trend toward the West and shale thickness and depth maps for central Ohio, Area VII, show consistent thinning and decrease in depth from East to West.

For all other Areas, except Area VIII, the play-out factors and areal factors were assumed to be the same as above.*

3. Technology Improvement: Hydraulic Stimulation

Traditionally, the Devonian shale wells have been stimulated by "shooting". The level of increase in production, along with subsequent analyses by reservoir simulation, strongly suggest that shooting overcomes wellbore damage (the low permeability skin created by drilling) rather than creating any substantial additional fracturing.**

* In Area VIII, this procedure was modified since major exploration activities have been undertaken to discover gas in sands underlying the Devonian shale. To reflect this extensive drilling, the play-out factors were assumed to be 90, 70, and 50 percent, respectively, for a third of the Area.

** History matching of the Devonian shale with a reservoir simulator provided a performance match only by assuming either an enlarged wellbore radius or small, horizontal fractures and radial flow.

Higher gas prices and improvements in technology have encouraged some operators to experiment with small hydraulic fracturing. In hydraulic fracturing the interval to be treated is isolated by pressurized packers and fluid is injected into the wellbore at increasing pressure until the formation breakdown point is reached and a fracture is created in the formation. Sand is simultaneously injected as a propping agent to prevent closure of fractures when the pressure is decreased.

A typical stimulation, designed to create a 100 to 200 foot fracture, uses about 1,000 barrels of fluid (42,000 gallons) and a maximum of 2 lbs. of sand per gallon of water.

The successful use of small hydraulic fracturing in eastern Kentucky may accelerate adoption of this technique by operators in other regions of Appalachia. The effect of fracturing in the eastern Kentucky field has been demonstrated to increase recovery during the first years of well production.^{7/} Open flows in fractured wells are comparable to open flows in shot wells. Wells of similar Initial Open Flow (IOF) can therefore be compared for their volume of production over time.

The data shows that hydraulic fracturing may increase recovery over shooting by 16 to 24 MMcf (cumulative) over the first five years, as shown on Exhibit 4-8, or from 17 to 46 percent. The largest improvements occur in the lower producing wells.

More experience, however, is required to explain these production increases in the early years. The increases could be attributable to either of two mechanisms:

EXHIBIT 4-8

COMPARISON OF FIVE-YEAR CUMULATIVE PRODUCTION
OF WELLS STIMULATED BY FRACTURING AND SHOOTING

Year	Initial Open Flow: 100-200 Mcf/D				Initial Open Flow: 200-300 Mcf/D			
	Fractured MMcf	Shot MMcf	Δ Due to Frac MMcf	% Change	Fractured MMcf	Shot MMcf	Δ Due to Frac MMcf	% Change
1	15.7	13.7	2.0	15%	26.3	24.4	1.9	8%
2	30.4	25.0	5.4	22%	48.5	45.1	3.4	8%
3	47.7	35.0	12.7	36%	72.3	63.5	8.8	14%
4	62.4	44.6	18.3	41%	90.7	80.2	10.5	13%
5	78.0	53.5	24.7	46%	110.0	94.4	15.6	17%

SOURCE: Ray, E. O., "Devonian Shale Production, Eastern Kentucky",
The Future Supply of Nature-Made Petroleum and Gas,
 UNITAR Conference, Pergamon Press, New York, 1976.

- The fracture increases the early rate of recovery by providing a high permeability path to the wellbore for gas that otherwise would have had to move through the lower permeability fracture network. Production is accelerated during the early life of the well but only a small increase in overall recovery efficiency is achieved.
- The fracture places the wellbore in contact with fracture porosity that is not contacted by shooting, thereby increasing ultimate recovery.

Today many wells are still being shot rather than fractured. Three major reasons for this are:

- Shooting costs less than a small fracture.
- The return from incremental production due to fracturing appears economic only at gas prices higher than have traditionally been achieved in the Appalachian area, even though fracturing accelerates production.
- General reluctance to use a water based fracturing technique in a low pressure, shale formation.

However, confidence that fracturing can improve recovery, together with higher gas prices, is encouraging the use of fracturing techniques. It is likely that small, multiple hydraulic fracturing will become standard practice in the next five years. The present study, accordingly, increased the empirical production rates to account for the improved recovery due to fracturing.

The very limited data on the effects of fracturing relative to shooting permit a variety of theoretic interpretations. For use in this study, Ray's^{8/} empirical findings -- that more productive wells were less improved by fracturing -- were used as guidelines. For wells with production during the first five years of less than 100 MMcf, Ray's upper bound of a 50% increase was assumed. Wells with production during the first five years of more than 300 MMcf were assumed to produce an additional 15% by fracturing, equal to Ray's lower bound. Between these two extremes of 15% and 50%, ultimate production was increased by an interpolated factor based on ultimate recovery and analytic Area. These factors are summarized on Exhibit 4-9.

The factors due to increased production by fracturing were multiplied by the annual recovery, adjusted for the play-out factors, to derive average production curves for each Area.

E. Final Devonian Shale Production Curves

The geological interpretations that defined the analytic Areas together with the empirical weighted average production curves, and the adjustment factors for play-out and fracturing technology produced the production curves used in the study. Exhibit 4-9 summarizes these calculations for ultimate recovery. The corresponding annual recoveries were used in the analyses of the economic potential.

The next section details the history matching analysis, the resulting reservoir description, and supplemental analyses based on history matching and reservoir engineering. The purpose of these various analyses was, collectively, to validate the empirical approach.

EXHIBIT 4-9

BASIS OF DEVONIAN PRODUCTION AND RECOVERY ESTIMATES

AREA	UNDRILLED ACREAGE	OF AREAL UNIT	30 YEAR RECOVERY SHOT WELL DATA (MMcf)	FIELD PLAYOUT PMV	PRODUCTION INCREASE- FRACTURING	FINAL PMV	ESTIMATED 30 YEAR RECOVERY/ FRACTURED WELL (MMcf)
I	1,050	50	411	1.0	15	1.15	472
		25		0.8	25	1.00	411
		25		0.5	40	0.70	288
II	1,609	33	349	1.0	15	1.15	411
		33		0.7	30	0.91	318
		33		0.5	40	0.70	244
III	1,098	50	348	1.0	15	1.15	400
		25		0.8	25	1.00	348
		25		0.5	40	0.70	244
IV	848	33	376	1.0	15	1.15	434
		33		0.7	30	0.91	343
		33		0.5	40	0.70	264
V	1,690	33	338	1.0	15	1.15	389
		33		0.7	30	0.91	308
		33		0.5	40	0.70	237
VI	2,032	33	264	1.0	15	1.15	337
		33		0.7	30	0.91	267
		33		0.5	40	0.70	205
VII	15,261	33	96	1.0	40	1.40	134
		33		0.7	50	1.05	100
		33		0.5	50	0.75	71
VIII	2,955	33	362	0.9	15	1.04	377
		33		0.7	25	0.87	315
		33		0.5	40	0.70	253
IX & X	17,776	33	338	1.0	-	1.00	338
		33		0.7	-	0.70	237
		33		0.5	-	0.50	169
XI	12,332	33	267	1.0	-	1.00	267
		33		0.7	-	0.70	211
		33		0.5	-	0.50	102

II. PRODUCTION AND RECOVERY MODELS
FOR DEVONIAN SHALE

A. Use of History Matching

A standard procedure in reservoir engineering is to estimate reservoir parameters by matching past well performance with the theoretical response of a reservoir with assumed reservoir parameters -- history matching. Once the reservoir parameters have been matched, future production can be calculated.

To predict the performance of a gas reservoir using history matching, the following parameters must first be determined: drainage area, net thickness, initial reservoir pressure and temperature, and well pressure.* It is then possible to vary porosity (ϕ), permeability (k), and wellbore radius (R_w) to achieve a match with actual data.

The preliminary analysis** of the shales' production curves was done with an isotropic, linear flow, reservoir simulation model modified to accept homogeneous and non-homogeneous flow.***

* For analysis of the recovery mechanism, it is assumed the drainage area is 150 acres, the net thickness 500 feet, and the initial pressure and temperature 500 psi and 100°F, respectively. The wellbore pressure over most of the life of the well is assumed to be 100 psi.

** The analysis was performed for Lewin and Associates, Inc., by Dr. S. A. Holditch, Texas A&M University, and W. L. Laufer, Sovereign Engineering International.

*** The reservoir simulator used in the analysis is described in Chapter Three of Volume III.

1. Homogeneous Model

Based on a correlation of production with the density of natural fractures, the Devonian shale reservoir was first assumed to be a network of fine, intercorrected fractures through which gas flows to the producing well. The flow through such a network can conceptually be approximated by radial flow of fluids through a uniformly distributed interstitial porosity such as that of a sandstone. It is thus possible to analyze the performance of a Devonian shale gas reservoir much as one would analyze the performance of a gas filled sandstone reservoir.

Because the reservoir is tight, it can be inferred that the wells are producing in an unsteady state flow regime, with the pressure at the boundary of the drainage area being virtually unaffected despite the time the well has been producing and that the drainage radius is in fact a no-flow boundary across which no fluid flows in either direction. Therefore, the analysis can be performed using the analytical expression for unsteady state flow that can be derived from the continuity equation, Darcy's law, and the solutions for the radial diffusivity equation developed by Hurst and vanEverdingen.* The compressibility of the gas under such flow conditions is that of the gas at original reservoir conditions, and the average pressure used in the solutions is the arithmetic average of the initial pressure and the wellbore pressure.

A reservoir with an enlarged wellbore radius, due to shooting, was used for the homogeneous case.

* The analytic equation used in the reservoir simulator differs from the Hurst and vanEverdingen solution, by adjusting for the compressibility drive effects prevalent in low pressure formations.

2. Non-Homogeneous Model

As a test of the analytic approach, a second reservoir geometry was analyzed -- a non-homogeneous reservoir consisting of a system of natural, horizontal fractures having radii of 15 to 50 feet spaced throughout the pay interval.

B. The Results of History Matching

Initially, three typical Devonian wells (with high, medium, and low production levels), each having 30 years of production (shown on Exhibit 4-10), were history matched using the two reservoir geometries.

The analytic approach provided an extremely good history match to long-term production and potentially a unique solution.* Homogeneity appears to have little effect on the matching of reservoir parameters.

A history match of long term production data can be realistically divided into two parts. The early production data (0-5 years) is dominated by the permeability-thickness product (kh) of the reservoir and by the wellbore geometry (R_w). Different values for wellbore radius, fracture length, etc., will result in different values of formation permeability. However, all combinations of kh and R_w that can be used to match historic production data will result in the same thirty-year production curve. To obtain a unique match of early data requires a series of well tests and/or a long term pressure build-up test.

* The report concluded that: "It is possible that slightly different values of gas in place and recovery efficiency could be obtained, if the parameters such as original pressure, reservoir temperature, flowing bottom hole pressure, etc., were altered. However, assuming the input data are valid, the established withdrawal rates and reservoir decline rates are of sufficient duration to provide unique solutions for ϕh and kh ."

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

EXHIBIT 4-10

HISTORY MATCH OF SIMULATION AND FIELD DATA -
THREE TYPICAL DEVONIAN WELLS

The later production (5-30 years) or the reservoir decline rate is dominated by the formation porosity-thickness product (ϕh), which is used to determine the original gas in place. A history match of 30 years of production is a significant achievement, and there is a high probability that the assumed model provides a unique solution under such circumstances.

The values calculated for porosity were insensitive to the wellbore geometry. Permeability, however, did vary slightly according to the wellbore geometry, but in general, the range of variation was not significant.

C. Results of the Initial Analysis

Several major conclusions emerge from this initial history matching:

- Combining the three parameters that most directly affect production, porosity (ϕ), permeability (k), and net pay (h), the following reservoir parameters best describe the Devonian shale:

<u>Well Production</u>	<u>Porosity-feet</u> (ϕh)	<u>Millidarcy-feet</u> (kh)
High	4	12
Medium	3	11
Low	1-2	10

- The high values of kh compared to the low values of ϕh indicate that these typical Devonian shale gas reservoirs consist of a vast network of interconnected, natural fractures. Since

all of the production can be accounted for by the gas required to fill the fracture or other interconnected porosity at initial reservoir pressure, the contribution of diffusion to ultimate recovery can be disregarded.*

- The wellbore appears to be in contact with the full horizontal extent of the fractures in the drainage area; however, it may be possible for additional fracture systems to exist in a vertical plane and not be connected to the wellbore.
- The reservoir data from history matching of well performance are in accord with the initial reservoir values obtained from field tests on pressure build-up and from laboratory tests using restored-state pressure conditions:

<u>Reservoir Properties</u>	<u>Pressure Build-Up Data</u>	<u>Reservoir Simulation</u>
Porosity	0.8 to 1.9%	0.3 to 0.8%
Permeability	0.01 to 0.18 md	0.02 to 0.03 md

* The extent to which diffusion can contribute to ultimate recovery is discussed later.

D. Additional Analysis

1. Purpose

Subsequent to the initial analysis, three additional analytic Areas were history matched:

- Area V, to assess the potential of the northern step-out area.
- Areas VII and VIII, to assess the reliability of the assumed production data in Ohio.

2. Results

The data used for these analyses are shown on Exhibit 4-11.

The results of the history-match are shown on Exhibits 4-12, 4-13, and 4-14.

3. Findings

History matching leads to the following findings:

- The reservoir parameters that best describe the Devonian shale for Areas V, VII, and VIII are:

	<u>Porosity-feet</u> (ϕh)	<u>Millidarcy-feet</u> (kh)
Area V	2.4	7.5
Area VII	2.0	30.0
Area VIII	2.5	87.5

EXHIBIT 4-11

RESERVOIR DATA

	<u>Area V</u>	<u>Area VII</u>	<u>Area VIII</u>
Original Reservoir Pressure (psi)	632	197	421
Flowing Bottom Hole Pressure (psi)	100	50	100
Reservoir Temperature (°F)	100	100	100
Net Formation Thickness (ft)	500	200	500
Gas Gravity	0.6	0.6	0.6

PRODUCTION DATA

<u>Year</u>	<u>Cumulative Gas Produced, MMcf</u>		
	<u>Area V</u>	<u>Area VII</u>	<u>Area VIII</u>
1	21.8	8.1	70.8
5	98.4	34.7	240.2
10	174.1	57.9	321.3
20	277.0	83.8	357.9
30	338.0	95.6	362.0

EXHIBIT 4-12

HISTORY MATCH OF AREA V

KEY: ○ model results
— actual data

EXHIBIT 4-13
HISTORY MATCH OF AREA VII

KEY: ● model results
— actual data

EXHIBIT 4-14

HISTORY MATCH OF AREA VIII

KEY: ○ model results
— actual data

- Based on the values of ϕh and kh , Area V appears to be similar to the Medium Production Case, discussed above. Areas VII and VIII, however, differ considerably from the earlier three cases. The values of ϕh for Areas VII and VIII are similar to the other cases but the values of kh are an order of magnitude larger. This leads to the conclusions that: (1) the reservoir in each area consists of a vast network of interconnected fractures, and (2) fractures in Areas VII and VIII are more conductive than the fractures in the three Cases.
- The results in this study are considered to be accurate and unique for Area V; however, some doubt exists concerning Areas VII and VIII. The history-match of these Areas is not as "perfect" as the other matches. The shape of the decline curves for Areas VII and VIII indicate that these reservoirs performed more like hydraulically fractured systems than like radial systems.

E. Prospects for Improving Recovery Efficiency

The analysis indicates that the Devonian shales are a traditional, low pressure and low permeability gas reservoir where the natural fracture system provides the permeability and gas storage porosity.*

* It may be that the matrix is porous and contains additional gas. However, this matrix porosity does not appear to contribute appreciably, through diffusion, to production. Adding one more fracture plane to a well-drainage area containing several hundred such fractures could not be expected to appreciably interconnect occluded areas.

Under current production practices, the shales are already being efficiently drained of the gas in place. Further improvements are possible, however, at higher gas prices, particularly due to infill drilling, dual completions, and improved fracture design. The major unknown is whether the wellbore is in contact with the full vertical extent of the natural fracture system in a drainage area. This question could be further examined by the R&D programs recommended for the Devonian shales in Volume II.

Thus, analyses were conducted for the Low and High production curves to explore the implications of improving recovery through well stimulation and infill drilling.

1. Recovery Efficiency of Shot Wells

The following recovery efficiencies were determined for shot wells (four foot radius or, equivalently, six horizontal natural fractures) at 150-acre spacing:

	<u>Gas in Place</u> (MMcf)	<u>30 Year</u> <u>Production*</u> (MMcf)	<u>Recovery</u> <u>Efficiency*</u> (%)
High Production	880	410	47
Low Production	350	220	65
Area V	670	340	51
Area VII	170	70	41**
Area VIII	450	340	76

* To economic limit of 7 Mcfd or 30 year production

** The Area VII well has a technical 30 year recovery efficiency of nearly 60%

These recovery efficiencies provide a baseline for comparison with alternative stimulations and spacing.

2. The Efficiency of Small Fractures for Stimulating Recovery

At 150-acre spacing, small fractures stimulate additional recovery. Production estimates for small (100 feet half-length) vertical fractures were estimated by numerical simulation as:

	<u>Gas in Place</u> (MMcf)	<u>30-Year Production*</u> (MMcf)	<u>Recovery Efficiency*</u> (%)
High Production	880	500	57
Low Production	350	240	69
Area V	670	430	64
Area VII	170	**	**
Area VIII	450	**	**

* To economic limit of 7 Mcfd or 30 year production.

** Additional analysis was also conducted on the wells in Ohio. Since technical recovery efficiencies using shooting range from 60% to 80%, significant improvements in recovery efficiency was not economically feasible.

In general, small vertical fractures yield effective drainage of the fields with recovery efficiencies of 60-70%. Such stimulation improves 30 year recovery by about 20% over the shot case for high and moderate production wells, but only accelerates recovery in the low production wells, as shown below.

	<u>High Case</u>	<u>Low Case</u>	<u>Area V</u>
Incremental Production Increases Due to Small Fracs (MMcf)	90	20	90
Additional Recovery as Percent of Original Recovery (%)	22%	9%	26%

Because either shooting or fracturing appears to yield recovery efficiencies of 60-70%, the more costly massive fracturing was not analyzed.

3. Improving Recovery Efficiency Through Infill Drilling

An additional means for improving 30 year recovery efficiency could be closer well spacing. To evaluate this, the analytic Areas were developed on 75 rather than 150 acres, using small fractures.

The simulation showed that 30 year recovery in the high production case could be further improved, from a base of 57% (due to small fracs) to 70%. Smaller improvements were realized in the medium production case, from a base of 65% (no small fracs) to 74%, while the low production case showed essentially no change because of the economic limit.

- Reduced Spacing (75 acres) with small fractures:

	<u>Gas in Place</u> (MMcf)	<u>30 Year</u> <u>Production</u> (MMcf)	<u>Recovery</u> <u>Efficiency</u> (%)
- High Production	440	310	70
- Low Production	175	125	71
- Area V	335	245	73

- Using an economic limit of 7 Mcf/day, the incremental gas recovery due to infill drilling (with small fractures) is:

	<u>High Case</u>	<u>Low Case</u>	<u>Area V</u>
- Incremental production due to infilling (MMcf)	120	10	60
- Additional recovery as percent of recovery due to small fracs (%)	24%	4%	14%

At higher gas prices, the combined effects of additional gas recovery and accelerated production appear to make infill drilling an attractive opportunity for improving gas recovery from the Devonian shales.

4. Conclusions

These simulations argue that improvements in recovery efficiency can be obtained by using small fractures in combination with infill drilling in the more productive areas of the shales. The use of small fractures in combination with closer spacing can raise recovery in the more productive areas from a base of 47% (by shooting) to 70% of the gas in place. In less productive regions, however, the potential for improvement appears to range from small to modest.

F. Validating Empirical Estimates of Reservoir Production Through Engineering Analysis

To ensure that the empirically derived estimates were based on sound reservoir engineering foundations, three issues were examined:

- The extent to which diffusion through the shale matrix and eventual desorption from the mineral surfaces can be the controlling production mechanism in the Devonian shales.
- The extent to which basic reservoir engineering theory using the laws of fluid flow through porous media can account for the production mechanism in Devonian shales.
- The additional recovery that can be obtained by inducing one additional fracture plane in areas where the natural fracture system is limited.

1. The extent to which diffusion through the shale matrix and eventual desorption from the mineral surfaces can be the controlling producing mechanism in the Devonian shales.

Devonian shale gas wells show a marked decline in production rates during their first few years of production. Following this steep decline, production rates show a very small decline rate over the rest of their life, which may be thirty years or longer.

This slow decline in production has been attributed to methane being produced from the Devonian shale as a result of diffusion through the mineral matrix and eventual desorption from the exposed mineral surfaces and not from a natural fracture system, as indicated by the history-match. The hypothesis that diffusion is the controlling production mechanism in the Devonian shale was, therefore, examined.

Diffusion is the process by which material is transferred from one point to another under the influence of a concentration gradient. The rate at which material is transferred is given by the following mathematical equality, which also serves to define the diffusion coefficient:

$$\frac{dv}{dt} = K * A * \frac{dc}{dx}$$

The term (dv/dt) is the rate at which gas is being transferred, (L^3/t) ; dc/dx is the concentration gradient in the solid, $(1/L)$; A is the area through which the gas is diffusing, (L^2) ; and K is the diffusion coefficient.

The solution of the differential equation for heat loss (or equivalently, for the release of methane upon instantly lowering and then maintaining the concentration in the gas phase at a new value) has been given by Carslaw and Jaeger^{9/} for the case of an initial, static equilibrium concentration of

methane in a gaseous phase in contact with a solid in which is dissolved and/or sorbed a uniform concentration of methane. The solution is presented in graphic form on Exhibit 4-15 using dimensionless units. The ordinate is dimensionless loss or the difference between the solid's methane content in the initial and final equilibrium conditions divided by the initial methane content. If the methane is assumed to be an ideal gas, then the partial pressure of the methane is equal to the concentration, and the ordinate can be described as the fraction of the total gas that would be released. The abscissa is dimensionless time (Kt/L^2), where L is the thickness of the solid slab if it is sealed on one face, or half the thickness if it is open to the gaseous phase on both faces.

Until some 50% of the gas is released, the slope of the fractional release vs. dimensionless time is 0.5 on log-log paper. Thereafter, the slope gradually decreases to zero. Thus, a diffusion controlled process, in which the pressure in the gas phase is maintained at some constant value, has as a characteristic that initially twice as much time will be required to produce the same amount of gas as was produced in the preceding time interval.

If the total amount of gas that could diffuse through the solid is not known, then the log of the gas production can be substituted for the log of the fractional release of gas without affecting the resulting slope and only the intercept of the line will be shifted.

When a Devonian shale gas well is opened to production, the pressure within the porosity of the reservoir does not drop suddenly to the final pressure, but gradually decreases. The well head pressure may be held constant, but this does not reflect constant pressure in the porous reservoir. There is a pressure drop within the reservoir, and between the shale face and the

EXHIBIT 4-15

RELATIONSHIP OF RECOVERY EFFICIENCY VERSUS TIME

(Fraction of Heat Loss From A Slab With Surface Temperature Kept at $T = 0$, As A Function of Kt/L^2)

SOURCE: Derived from Carslaw and Jaeger, Conduction of Heat in Solids, Oxford, 2nd Edition, 1959, Chapter III, pp. 92-102. Equivalently substitute units for any diffusion phenomenon, viz., fraction of adsorbed material lost.

well head; both drops being a function of flow rate. As a result of the continuous reservoir pressure drop, the relationship between gas release and dimensionless time on log-log coordinates will no longer display a slope of 0.5 over the entire life, although total gas recovery is the same for an infinite amount of time. The relationship will, however, start below a value of 0.5, then increase as the reservoir pressure drops. The changing slope is due to the continuous decrease in pressure as opposed to a sudden jump. Assuming a linear decrease in pressure, the amount of gas diffused out of the shale is initially the same for each constant time interval. Thus, cumulative gas production is linear when plotted on cartesian paper, Exhibit 4-15. On log-log paper this appears as an increasing slope. As production decreases, the curve shows an inflection point past which the slope will decrease and eventually reach the initial hypothetical curve. These curves are shown qualitatively on Exhibit 4-16.

If the well's production is controlled by diffusion of methane through the shale (no resistance to flow at all within the porous network leading to the wellbore), Exhibit 4-17 would represent the typical history of gas production from a Devonian shale gas well.

The representative production histories of Devonian shale gas wells, however, do not show a slope of 0.5 when the log of production is plotted as a function of dimensionless time. The slope of the representative High and Low Case wells (described previously under history matching) start out with an initial value of 0.9; then continuously decline to values of 0.6 to 0.4,* respectively, over a period of 20 years. A group of fractured wells (using novel techniques) in Kanawha County, Exhibit 4-18, have a slope of 0.9 for the first 5 years of production. The difference between a slope of 0.5 and 0.9 is significant and too large to be explained by poor data.

Based on the relationship of gas production and time for the Devonian gas wells, the analysis concludes that diffusion does not appear to be the controlling production mechanism.

* Provided by Columbia Gas Research.

EXHIBIT 4-16

LOG-LOG PLOT OF RECOVERY VS. TIME WHEN DIFFUSION
IS THE CONTROLLING PRODUCTION MECHANISM

EXHIBIT 4-17

LOG-LOG PLOT OF RECOVERY VERSUS TIME
FOR TYPICAL SHOT DEVONIAN WELLS

EXHIBIT 4-18

KANAWHA COUNTY - SHALE PRODUCTION
(Gas and Methanol Fracs)

SOURCE: Columbia Gas Research

2. The extent to which basic reservoir engineering theory using the laws of fluid flow through porous media can account for the production mechanism in Devonian shales.

Reservoir simulation showed that gas production could be accounted for by free gas in natural fractures. The underlying basic reservoir engineering theory is examined in this section.

A porous reservoir produces gas as a result of fluid flow under a pressure gradient developed by providing a pressure sink, the wellbore. The mathematical equations and analytical solutions of radial flow and constant terminal pressure that form the basis of gas production and flow through a porous medium were developed by Hurst and vanEverdingen.^{10/}

Using this basic theory, the pressure history within a reservoir produced under static boundary conditions and having statistically uniform fluid and rock parameters is shown on Exhibit 4-19.

Initially, shown as (a) and (b) on Exhibit 4-19, the reservoir is producing in a transient state as from an infinite reservoir. Once the pressure begins to fall at the effective reservoir boundary shown as (c) and (d), the drainage area of the well has reached its maximum value, viz., there is no influx of fluids from beyond the effective boundary. In a reservoir in which there are multi-well completions, the analysis of any one "representative" well can be assumed to be replicated by all other wells once the condition of zero pressure gradient at the effective reservoir boundaries has become established.

EXHIBIT 4-19

PRESSURE DISTRIBUTION IN RESERVOIR
PRODUCING AT CONSTANT TERMINAL PRESSURE

$\left(\frac{dp}{dr}\right)_{r_e} = 0$ is condition for no flow from or into adjacent wells' drainage volumes, viz. the reservoir

The complex solutions to the differential equation for flow under a pressure gradient are best represented by graphically plotting dimensionless recovery, W_D , and dimensionless time, t_D , as shown on Exhibit 4-20. The family of curves are generated by different values of r_e/r_o where r_e is the radius of the effective reservoir boundary and r_o is the wellbore radius. The limiting value of W_D is reached when the reservoir boundary pressure has fallen so much that flow can no longer be sustained at the imposed terminal (wellbore) pressure.

For any given reservoir, dimensionless time, t_D , can be set equal to:

$$t_D = (\text{Constant}_1)(k/\phi) (1/r_o^2) t$$

and W_D , dimensionless recovery, equal to:

$$W_D = (\text{Constant}_2) W_e/(r_o^2 \phi)$$

where W_e is the recovery and the constants are determined by already known reservoir parameters and the choice of units.

It follows that if recovery versus time can be matched to a particular $\log W_D$ vs. $\log t_D$ curve, the curve describes the subject well performance. The value of r_e/r_o is determined by the match. Since r_e (the drainage radius) is known, r_o can be calculated. Knowing r_o , ϕ can be calculated from the dimensionless recovery equation, and then knowing ϕ , k can be calculated from the dimensionless time equation.

These equations and the use of type curves provided the basis for the initial analysis of the Devonian shale wells and provided values for permeabilities from 0.02 to 0.03 millidarcies and values for porosities from 0.005 to 0.02.

EXHIBIT 4-20

DIMENSIONLESS WATER INFLUX, CONSTANT TERMINAL
PRESSURE CASE, RADIAL FLOW

SOURCE: Hurst and vanEverdingen

In using the preceding analytical equations for a gas filled reservoir, an approximation had to be introduced by using an average compressibility. An average compressibility is a good approximation for liquid filled reservoirs since the compressibility is small and varies little with pressure. However, in the case of gas the compressibility is equal to $(1/\text{Pressure})$ and varies greatly through the reservoir.

To verify these initial estimates of permeability and porosity derived from analytical fluid flow theory, and to incorporate the effects of compressibility, a mathematical simulator was employed. Using a high speed computer, the analytical equations can be solved between sub-divisions (grid blocks) of the reservoir without assuming an average value for compressibility. The results indicate that the porosity of the Devonian shale gas reservoirs was in a somewhat lower range (0.003 to 0.008), but the permeability range is essentially the same (0.0175 to 0.025 md). The results of the numerical simulation were presented earlier and led to the conclusion that Devonian shale gas production could be accounted for by the fracture porosity. Thus, these simulator results are equivalent to the results obtained from basic reservoir engineering theory.

3. The additional recovery that can be obtained by introducing an induced fracture plane when the natural fracture system is limited.

Recovery using a diffusion controlled model requires there be an extensive natural fracturing system. Using published data, one can calculate the volume that must be present to produce a given amount of methane in a given period of time. From this, one can calculate the overall fracture density that must be present or induced to support a given amount of cumulative recovery from a Devonian shale well.

a. Methane Concentration

Using results from the degassing of core samples canned on location, Columbia Gas (in an analysis of 353 cores) reported an average value of 0.21 gas volumes per reservoir volume, ranging from 0.009 to 0.69,^{11/} Mound Laboratories reported C₁ to C₇ hydrocarbons ranging from 0.5 to slightly less than 1,^{12/} and Battelle, after correcting for oxygen and other contaminants, reported a range of 0.14 to 0.91 (the latter in an Illinois basin core).^{13/} While these values may be low because of the loss of gas prior to canning, there is also the possibility, especially when noting the frequent contamination by oxygen and nitrogen, that gas is actually picked up from drilling fluids as the core expands upon release of overburden pressure. TerraTek has reported "fracturing" of cores in surface handling, and TerraTex and Morgantown Laboratories have reported a high percentage loss in porosity when Devonian shales are subjected to overburden stress.^{14/}

If Columbia's average value of 0.21 gas volumes per reservoir volume is used, then the dissolved gas content in 150 acres of 500 foot shale is 700 million cubic feet.* Using a diffusion constant of 1×10^{-10} , it is then possible to calculate the number of fractures required to provide the area for sufficient desorption to result in the production of 300 million cubic feet of gas in 30 years. The fraction of the original sorbed gas so produced would be 0.43, and therefore Kt/L^2 must be equal to 0.19, Exhibit 4-15. Knowing both K and t, L is calculated to be 0.7 cm. In other words, there would have to be a fracture every 1.4 cm running the entire length and thickness of the formation.

* Assumed concentrations of 3 ccs. per cc. of native shale^{15/} are one order of magnitude higher than actually observed. The results were derived by extrapolation of atmospheric adsorption data on ground and dried shale on the assumption that adsorption is linear with pressure. Adsorption is generally not linear, exhibiting a Langmuir type isotherm, and reaches an asymptotic level. Further, the drying and grinding of the shale has undoubtedly activated adsorption.

Using a reservoir model comprised of parallel fractures, fracture spacings of 1.4 cms. will result in the permeability of 0.025 mds. derived from history matching only if the fracture width is 1.5×10^{-4} cm. and the porosity is 1.1×10^{-4} .* This is not a rational physical model for the Devonian shale. It must also be noted that a parallel fracture model is not a viable representation of a reservoir with a k of 0.025 and a ϕ of 0.005, since this would require a reservoir with fractures spaced 5×10^{-3} cms. apart and a width of 2.5×10^{-5} cm. It is more likely that the true reservoir is not uniformly fractured over its entire length, but that the fractures are tortuous, interconnecting paths concentrated in a fracture facies of productive wells.

b. Diffusion Constant

Diffusion constants reported for Devonian shale are as high as 5×10^{-7} . It is believed that this is probably higher than the actual value, because of the following considerations:

- The effect of surface conditions. The method used for measuring the diffusion constant requires the shale to be dried and ground (or cleaved by a chisel for larger sample sizes). The diffusion constant is measured by desorbing methane that has been adsorbed on the prepared sample. Since methane is not being returned to solution in the kerogen, the measured diffusion constant is that for methane diffusion out of adsorbed layers on the

* Muskat's equation^{17/}, rewritten as follows, relates fracture parameters to permeability and porosity:

$$k = \frac{\phi^3 \times S^2 \times 10^{11}}{12} \text{ mds.}$$

where ϕ = fractional porosity and S is the spacing between fractures.
 $\phi \times S$ is equal to the fracture width.

surface of the prepared clay, and does not reflect in situ desorption from dispersed kerogen in a siliceous matrix.

- The effect of particle size. In order to calculate the diffusion constant, measured parameters are multiplied by the size (thickness of the slab or radius of the sphere) of the adsorbing particles. The effective size of the actively adsorbing solids may be less than the assumed size because of micro-cracks and laminae separation in the worked samples. Also, the shale being basically a laminar material probably is comminuted to platelets rather than spheres, with consequent greater surface (or effectively smaller radius) per volume. The discrepancy between the assumed radii and the true values is probably far greater for the larger particles. Hence, the calculated values for the diffusion constant decrease with decreasing particle size. Finally, even the orientation of the bedding plane is significant in affecting laboratory derived diffusion constants. The diffusion constant of a zeolite plug cut parallel to the bedding plane is reported to be an order of magnitude greater than the diffusion coefficient of a sample cut perpendicular to the bedding plane.^{18/}

A diffusion coefficient for a solute-solvent system, chloroform in polystyrene (possibly relevant to a methane-kerogen system) is on the order of 10^{-10} . Diffusion coefficients for methane in coal have been reported variously as of the order 10^{-8} to 10^{-13} ^{19/} with a few larger values for

large samples for which the effective length characteristic was probably far less than the macroscopic value. As noted above, laboratory measurements of diffusion of methane in ground and dried samples of shale cannot be assumed to be characteristic of in situ conditions, and it is difficult to arrive at a true value for the diffusion coefficient of methane in the kerogen distributed in the inorganic shale.

However, the exact level of the diffusion coefficient is not of great significance where there is no natural fracture network since stimulation of a diffusion process requires the creation of a huge surface area. This can be achieved only by inducing a density of fractures that is beyond economic realization.

4. Conclusion

The analysis of methane production from Devonian shale presented herein is consistent with available data, and has been generated using ordinary reservoir engineering analyses techniques.

The insight gained from this analysis together with the economic model provides a basis for evaluating the potential for economic production of gas from Devonian shale in the near term and under an accelerated DOE technology development program. The study has not attempted to evaluate the size of the resource in speculative areas, or any developments that would take place past the year 2000.

III. THE ECONOMIC MODEL

A. Introduction

The project economics model used in the analysis of the tight gas sands was adapted for the economic evaluation of the Devonian shales. As this model is fully described in the Tight Gas Sands chapter, this section only summarizes and describes the modifications.

The production stream of an individual well representing an analytic Area is multiplied by the wellhead gas price to generate the positive cash flows. Cash outflows are based on cost estimates for exploration, dry holes, drilling and completion, well stimulation, surface equipment, operations and maintenance, administrative costs, and taxes. The annual net cash flows can then be computed and discounted to a reference point at the appropriate capital charge. Wells with net present value greater than zero are deemed economic. The analytic Area represented by the well is then developed according to a timing algorithm. Finally, production from producing wells is summed for all Areas to derive annual recovery figures.

The cost data were derived from basic engineering estimates and then verified through extensive consultation with operators active in the Appalachian Basin. While it was initially thought that the standard practices used for conventional eastern wells were not the standard practice for shale wells, these consultations led to relatively few modifications of the average regional data used in deriving preliminary economics.

B. Major Elements in the Model

The major cost elements consist of:

- Exploration costs
- Drilling and completion costs
- Development dry hole costs
- Stimulation costs
- Lease and well equipment costs
- Operating and maintenance costs
- Taxes and royalties

These costs are discussed in the following sections.

1. Exploration Costs

Exploration costs are included in the model by the formula:

$$\text{Exploration Costs Per Successful Well} = \frac{\text{Number of dry wells to condemn a section}}{\text{Cost per (Dry Well)}} \times \frac{\text{Number (of Dry) Sections}}{\text{Total Number (Producing) Wells}}$$

- The model assumes that four dry holes will condemn a section.
- Dry hole costs are discussed in Section 3, below.

- If A is the total acreage and SR is the fraction of productive acreage, then the expression:

$$(1 - SR) \times A / 23,040 \quad (1 \text{ section} - 23,040 \text{ Acres})$$

is the number of dry sections.

- If "spacing" is the well spacing, then $\frac{SR \times A}{\text{Spacing}}$ is the number of producing wells.

Placing these in the above equation yields:

$$\frac{\text{Exploration Costs}}{\text{Per Successful Well}} = 4 \times \text{dry hole cost} \times \frac{(1-SR)}{SR} \times \frac{\text{Spacing}}{23,040}$$

The quantity $\left(\frac{1-SR}{SR}\right)$ is the ratio of unsuccessful to successful drill. The success rate for economic production was based on company data and was assumed to be 85-95% in the probable areas and 80% in the possible areas.

2. Drilling and Completion Costs

Drilling and completion costs were based on smoothing of data published by the API-AGA Joint Association Survey. The equation takes the form:

Total drilling and completion costs =

$$e [\text{Constant} + (\text{slope} \times \text{depth})] \times \left[\frac{\text{Drilling and Completion}}{\text{Inflation Multiplier}} \right]$$

For Appalachia, the slope is 0.000308, the constant is 10.03356, and the multiplier to update costs to mid-1977 levels is 1.102. (The r^2 is 0.9904.)

3. Developmental Dry Hole Costs

Wells in the Devonian shale may remain uneconomic after stimulation and these post-exploration dry holes are costed by using the equation:

$$\text{Developmental dry-hole costs} = (\text{dry-hole rate}) \\ * 0.8 * (\text{drilling and completion costs})$$

The 80% cost factor is to account for the reduced costs of uncased dry holes.

4. Stimulation Costs

Actual production records were used to estimate fracturing costs for Devonian shale wells. This was necessary because Joint Association Survey (JAS) costs reflect the dominance of explosive stimulation in the Appalachian Basin and this form of stimulation requires considerably less casing than fracturing. Analyses of cost data for fracturing lead to a constant term of \$23,500 (which includes hauling, cementing, CBL logs, separator, tool rental, clean-up, and a 1000 bbl sand/water frac) and a variable term, reflecting the cost of 4" casing of \$3.12/ft. Thus, the fracturing cost for Devonian shale wells was calculated as:

$$\text{Fracture Cost} = \$23,500 + (\$3.12) * (\text{depth in feet})$$

5. Lease and Well Equipment Costs

Regional averages for lease and well equipment costs were found to be inadequate in the Devonian shales due to the dominance of higher production, conventional gas wells. Accordingly, operator data were used to make the estimates. In Kentucky, \$13,750 was used; \$12,000 was more typical of other states.

6. Operating and Maintenance Costs

Annual operating and maintenance costs were estimated by the equation:

$$\begin{aligned} \text{Annual operating and maintenance} = & \\ & 12 * (\exp^{(\text{intercept} + \text{slope} * \text{depth})}) \\ & * \text{lease and well equipment and operating} \\ & \text{cost inflation multiplier} \end{aligned}$$

The basic data were derived from a study by Gruy Federal^{20/} and verified with operator data. For the Appalachian Basin, the slope was 0.0000654, the intercept 5.430636, and the appropriate inflation factor 1.08.

7. Other Costs and Assumptions

- Royalties are a standard 12.5% of gross value on production.
- State taxes were calculated from state records. Severance taxes in Kentucky and Pennsylvania are zero, Ohio 10%, and West Virginia 7.5% (an average of 85% of production taxes at 8.6%). State income taxes for Kentucky, West Virginia, Ohio, and Pennsylvania were all equal to 5%.

- General Administration/overhead was based on 10% of total investment for the first year and 20% of annual operating and maintenance cost for all subsequent years.
- All other costs, tax, accounting, timing, and development assumptions are the same as described in the chapter on Tight Gas Sands in this volume.

CHAPTER FOUR

BIBLIOGRAPHY

- 1/ Patchen, D., "Subsurface Stratigraphy and Gas Production of Devonian Shales in Appalachia," Eastern Gas Shales Project, MERC/CR-77/5.

Bagnall, W. and Ryan, W., "The Geology, Reserves, and Production Characteristics of the Devonian Shale in Southwestern West Virginia," MERC Proceedings, 1976.

Martin, P. and Nuckols, E. B., "Geology and Oil and Gas Occurrence in the Devonian Shales: Northern West Virginia", MERC Proceedings, 1976.

Ohio Geological Survey, "Gamma Ray Log Cross Sections Showing Distribution of Major Radioactive Zones in Devonian Shales in Eastern Ohio," Geological Note No. 3.

deWitt, W., Perry, W. J., and Wallace, L. G., "Oil and Gas Data From Devonian and Silurian Rocks in the Appalachian Basin", USGS, 1975.
- 2/ Brown, P., "Energy from Shale -- A Little Used Natural Resource", NAS, 1976.
- 3/ Bagnall and Ryan, Op. Cit.; Brown, P., Op. Cit.; and Ray, E. O., "Devonian Shale Production, Eastern Kentucky", The Future Supply of Nature-Made Petroleum and Gas", UNITAR Conference, Pergamon Press, New York, 1976.
- 4/ deWys, J. Negus and Shumauker, R. C., Pilot Study of Gas Production Analysis Methods Applied to Cottageville Field, West Virginia University, Geology Department, Morgantown Energy Research Center Publications, 1977.
- 5/ Hunter, C. and Young, D., "Relationship of Natural Gas Occurrence and Production in Eastern Kentucky (Big Sandy Gas Fields) to Joints and Fractures in Devonian Bituminous Shale", Bulletin of American Association of Petroleum Geologists, Vol. 37, No. 2, February 1953.
- 6/ deWys, J. Negus and Shumauker, R. C., Op. Cit.

- 7/ Ray, E. O., Op. Cit.
- 8/ Ibid.
- 9/ Carslaw and Jaeger, Conduction of Heat in Solids, Oxford, 2nd Edition, 1959.
- 10/ Hurst and vanEverdingen, Fundamentals of Reservoir Engineering, Elsevier, 1978.
- 11/ Columbia Gas Company, Monthly Progress Report, October 1976, Columbia-ERDA Massive Hydraulic Fracture Program.
- 12/ Zielinski, R. E., Proceedings of the 3rd ERDA Symposium, Tulsa, Oklahoma, August, 1977.
- 13/ Snyder, M. J., Proceedings of the 3rd ERDA Symposium, Tulsa, Oklahoma, August, 1977.
- 14/ Komar, C. A., Morgantown Research Laboratory, private communication.
- 15/ Schlettler, P., reports prepared under ERDA Contract DY-76-S-05-5197, Juniata College, Huntington, Pennsylvania.
- 16/ Ibid.
- 17/ Muskat, M., Flow of Homogeneous Fluids Through Porous Media, Edwards, 1946.
- 18/ Barrer, Diffusion in Solids, Cambridge, 1941.
- 19/ Sevenster, P. G., Fuel, V. 38, 403, 1959.
Nandi, S. P. and Walker, P. L., Activated Diffusion of Methane from Coals at Elevated Pressure, Pennsylvania State University, May 1974.
- 20/ Gruy Federal, Inc., report for DOE, in preparation.

CHAPTER FIVE

METHODS USED IN ANALYZING PRODUCTION AND RECOVERY
FROM COAL SEAMS

INTRODUCTION AND SUMMARY

Methane released from coal stems primarily from the coal seam itself where the methane is adsorbed in the structure of the coal and is released when the coal is mined. Thin sand lenses adjacent to the coal seams and fractures where methane has accumulated by desorption may serve as reservoirs for small additional quantities of released gas.

Since coal is impermeable, producible gas must flow either through the natural fracture system in the coal (the butt and face cleats) or must flow through the microporous structure of the coal. Unless an area is naturally highly fractured, such as in the Big Run Field of West Virginia, unstimulated vertical holes drilled into the coal will not release appreciable amounts of methane.

Although several approaches have been tried that have produced gas, none, as of yet, have demonstrated economic feasibility as purely a gas recovery project. Production rates and duration of production have been too low or too uncertain to offset the costs of well drilling, water removal, stimulation, compression, piping, gas purification, and gathering costs associated with commercial recovery of methane from coal.

In addition, rapid development of the resource is hampered by an inadequate definition of the resource, uncertainties in recovery technologies for the deep coal, and the time required to construct a collection system for numerous low production, low pressure wells.

It is estimated that 170 trillion cubic feet of gas is associated with coal, and a substantial potential could exist for this resource. However, additional information must be gathered on the key properties that control economic gas production before the potential can be determined.

The material in this chapter seeks to provide a basis and a structure for an initial appraisal of the gas associated with coal. It is organized as follows:

- Resource Base
- Production and Recovery Models for Methane from Coal Seams
- Economic Models

I. THE RESOURCE BASE

A. General Information

1. Basic Evidence for Methane Adsorption

There is considerable evidence that the bulk of methane associated with coal production is held as a sorbed "liquid" in the coal. Assuming an average of 200 standard cubic feet of gas per ton of coal (8 SCF/CF)^{1/}, a seam pressure of 500 psi and a temperature of 80°F, this amount of gas would require a porosity of 28% if the methane were not adsorbed. At 150 psi, the pressure recorded in several of the BOM tests, a porosity of 90% would be required. With 600 standard cubic feet of gas per ton of coal (24 SCF/CF)^{2/} and a seam pressure of 500 psi, the porosity must be 85%. Since coal is not that porous, the habitat of the methane in coal seams must be gas adsorbed to coal facies and held as a sorbed "liquid" in the coal itself.

The gas content of coal is believed to be dependent upon rank and depth of burial,^{3/} although further work is required to develop statistically reliable correlations of gas content and geological properties.

2. Detailed Examination of the Data

The basic data gathered by the Bureau of Mines has been used to quantify the gas potential from four types of coal resources:

- Methane in deep, unminable coal seams
- Methane in thin coal seams
- Methane in shallow, minable coal seams
- Methane emissions in association with mining.

Each of these resource areas is further examined below.

B. Deep, Unminable Coal Seams

1. Gas in Place

Coal seams are called unminable when they are too deep to be mined economically. Although volumetric data on unminable coal is sketchy, the available data^{4/} is useful for making gross estimates of gas in place:

- The BOM has identified 388 billion tons of coal as being too deep (3,000 - 6,000 feet) to be mined economically. About 45% of this coal is ranked as bituminous or higher rank; the balance is subbituminous coals and lignite.
- Gas content of bituminous and higher rank coals averages 480 cf/ton, accounting in total for 80 Tcf.
- Gas content for subbituminous coals is substantially lower than that of bituminous and higher rank coals. Their high moisture content tends to limit their gas adsorption capacity. Assuming a gas content of 100 cf/ton,* about one-fifth that of bituminous coals, deep subbituminous coals would contain about 20 Tcf.

In total, the 388 tons of deep, unminable coal contain an estimated 100 Tcf of gas.**

* Personal correspondence with M. Deul, BOM.

** Previous estimates have used the same gas content for bituminous and subbituminous coals. This appears to overestimate the gas in place because of the higher moisture content of the lower grade coal. Using the lower gas content for subbituminous coal would reduce the estimate from 180 Tcf to 100 Tcf.

2. Key Reservoir Properties*

a. Coalbed Thickness of Bituminous Coals

Distribution of coalbed thickness was estimated based on data from Colorado and aggregated data from the three states of Colorado, New Mexico, and Utah. Colorado has about 70% of the bituminous coal and the three states combined have about 90% of the bituminous coal in the Western Basins. In Colorado and these three states, the distribution of thickness is estimated as follows:

<u>Coalbed Thickness, Feet</u>	<u>% of the Resource</u>	
	<u>Colorado</u>	<u>Three Western States</u>
0 - 15	52	61
15 - 50	36	33
>50	12	6

These data are plotted as cumulative percentage of the total resource versus coalbed thickness on Exhibit 5-1. The graph can be used to provide estimates of coalbed thickness between the three points in the table.

b. Gas Content of Deep, Unminable Coal

Assuming a methane content of bituminous and higher grade coals of 480 cf/ton, and a methane content of subbituminous coals and lignites of one-fifth that of higher grades, it is possible to estimate the gas content of deep, unminable coal seams for various acreage as follows:

* Given the scarcity of published data, much of this analysis was based on recent test data from state geological societies and BOM officials. Thus, only a preliminary appraisal can be made of the key geological variables that govern the economics of producing methane from deep, unminable coalbeds.

EXHIBIT 5-1

SOURCE: Booz, Allen and Hamilton, ERDA's Underground Coal
Gasification Program, Volume III - Resources, May, 1977.

- Thick Coal Seams: 40 ft. thick

Bituminous		Subbituminous	
Acres	Gas Content (MMcf)	Acres	Gas Content (MMcf)
80	2,700	80	500
160	5,400	160	1,100

- Typical Coal Seams: 10 ft. thick

Bituminous		Subbituminous	
Acres	Gas Content (MMcf)	Acres	Gas Content (MMcf)
80	700	80	100
160	1,300	160	300

c. Assessment of the Resource Base

The deep, unminable but thick coalbeds may possibly be an economic resource. However, there is only limited data available on the essential properties (e.g., permeability, fracture density, diffusion constants) to provide a reliable basis for estimating the economically productive capacity of the deeply buried coals. Therefore, this resource should be classified as speculative until further resource assessment is completed.

C. Thin Coal Seams

Approximately 290 billion tons of coal are in seams too thin (averaging 15 inches) to be economically mined. This coal contains an estimated 260 cf/ton of methane, or a total of about 70 Tcf.

However, the 70 Tcf of methane held in thin coal seams cannot be produced economically under any reasonable set of technological assumptions. At 260 cf/ton and an average well drainage area of 80 acres, the drainage

area will contain only 45,000 Mcf of methane.* Assuming deviated wells costing \$300,000 (2 wells drilled to 800 feet), operating, compressing, separating, and gathering costs of \$0.50 per Mcf, and 20% royalty and severance tax, the coal seam must be at least 32 feet thick for economic recovery.** Thin coal seams lack this minimum required coalbed thickness and they were therefore eliminated from further analysis as a potential resource of methane.

D. Shallow, Minable Coal Seams

The two most important coal seams in the Appalachian District of the United States are the Pittsburgh and the Pocahontas coal seams. The two coal seams are shallow, minable, and are potential sources of methane.

The Pittsburgh coal seam at the Loveridge Mine is reported to contain 160 SCF/ton of coal (6.4 SCF/cf). The depth is reported to be 607 feet where a methane pressure of 176 psi was measured. The seam is reported to be 96" in thickness.^{5/6/} The gas content of this coal, therefore, is for various acreages as follows:

-
- * The Gas in Place can be calculated from the following equation:
- $GIP = (\text{Drainage Area}) \times (\text{Methane Content per Cubic Foot}) \times (\text{Thickness})$
 - The drainage area in square feet equals: Acres $\times$ 43,560
 - The methane content per cubic foot equals:
 $(260 \text{ cf/ton} \times 80 \text{ lb/cf}) \div 2000 \text{ lb/ton} = 10 \text{ cubic feet of gas per cubic foot of coal (0.01 Mcf/cf)}$

- ** The calculation of the required thickness is:
- Required gas production @ \$1.75 Mcf to pay back costs = 330 MMcf
 - Required thickness to produce 330 MMcf in 10 years = $330 \text{ MMcf} \div [\text{Drainage area (in ft}^2\text{)} \times \text{gas in place (per ft}^3\text{)} \times 10 \text{ year recovery efficiency}]$
 - Required $h = \frac{330 \text{ MMcf}}{(3.5 \times 10^6 \text{ ft}^2)} \times \frac{1}{(0.01 \text{ Mcf/ft}^3)} \times \frac{1}{30\%} = 32 \text{ feet}$

GAS CONTENT OF PITTSBURGH COAL

<u>Acres</u>	<u>Gas Content</u> (MMcf)
80	178
160	357

The Pocahontas coal seam is deeper and gassier than the Pittsburgh seam. It is a low volatile bituminous coal whereas the Pittsburgh coal is a high volatile bituminous coal. It is reported to have a gas content of 435 SCF/ton of coal (17.4 SCF/CF).^{5/6/} The coal seam is 1,594 feet deep and has a methane pressure of 588 psi. Its thickness, 54", however, is less than that of the Pittsburgh. Its gas content for various acreages is as follows:

GAS CONTENT OF POCAHONTAS COAL

<u>Acres</u>	<u>Gas Content</u> (MMcf)
80	273
160	546

E. Methane Emissions in Association With Mining

The best source of coalbed methane in the near term consists of gas emissions in association with mining. Although the overall resource is large, the quantity that could be produced in any given year is directly dependent on the amount of mining. Thus, yearly production rates rather than volumetric estimates of the total resource are significant.

1. Resource Base

Basic studies of methane emission from U.S. coal mines^{7/} prepared by the Bureau of Mines, Department of Interior, supplemented by contacts with major coal mining companies, served as the data source for methane resources associated with mining.* This information showed that in 1975:

- About 200 bituminous coal mines in the U.S. emitted at least 100 Mcfd of methane each.
- Total emissions from these mines in 1975 was 216 MMcfd, or about 80 Bcf per year, and has remained stable at this level since 1971 (Exhibit 5-2).
- Methane emissions are concentrated in a limited number of mines; the 60 mines with emissions of 1 MMcfd or more accounted for 79 percent of total methane emissions; the 20 mines with the largest daily emission rates accounted for 48% (Exhibit 5-3).
- The Appalachian region accounted for 86% of total emissions. Exhibit 5-4 shows the locations of mines with the highest volume of emission.

* The recovery estimates for this now vented methane were based on a series of investigative reports by the BOM (R.I. 8195, R.I. 7703, R.I. 8047, R.I. 8174, R.I. 7968, and R.I. 8195, among others) and from personal correspondence and discussion with major coal production companies. Companies contacted as part of this study included: Bethlehem Mining Corp., Island Creek Coal Co., Lykes Resources, and United Gas Pipeline.

EXHIBIT 5-2

METHANE EMISSIONS FROM U.S. BITUMINOUS COAL MINES

SOURCE: Irani, M. C., Jansky, J. H., Jeran, P. W., and Hassett, G. L., Methane Emissions from U.S. Coal Mines in 1975, A Survey, U.S. Bureau of Mines, IC 8133, 1977.

EXHIBIT 5-3

METHANE EMISSIONS FROM U.S. COAL MINES

(20 Largest Methane Emission Coal Mines)

<u>Mine Name</u>	<u>Location</u>	<u>Coalbed</u>	<u>Methane Emission, MMcfd</u>
1. Loveridge	Marion Co., West Virginia	Pittsburgh	11.6
2. Humphrey No. 7	Monongalia Co., West Virginia	Pittsburgh	9.3
3. Federal No. 2	Monongalia Co., West Virginia	Pittsburgh	8.1
4. Blacksville No. 2	Monongalia Co., West Virginia	Pittsburgh	6.3
5. Osage No. 3	Monongalia Co., West Virginia	Pittsburgh	5.9
6. Beatrice	Buchanan County, Virginia	Pocahontas #3	5.6
7. Concord No. 1	Jefferson County, Alabama	Pratt	5.1
8. Olga	McDowell Co., West Virginia	Pocahontas #4	5.0
9. Robena	Green County, Pennsylvania	Pittsburgh	4.9
10. Blacksville No. 1	Monongalia Co., West Virginia	Pittsburgh	4.5
11. Bethlehem No. 32	Cambria County, Pennsylvania	Kittanning	4.5
12. Robinson Run No. 95	Harrison Co., West Virginia	Pittsburgh	4.3
13. Arkwright	Monongalia Co., West Virginia	Pittsburgh	4.0
14. Federal No. 1	Marion Co., West Virginia	Pittsburgh	4.0
15. Virginia Pocahontas No. 1	Buchanan County, Virginia	Pocahontas #3	3.9
16. Cambria Slope No. 33	Cambria County, Pennsylvania	Kittanning	3.9
17. Virginia Pocahontas No. 2	Buchanan County, Virginia	Pocahontas #3	3.4
18. Virginia Pocahontas No. 3	Buchanan County, Virginia	Pocahontas #3	3.3
19. L. S. Wood	Pitkin County, Colorado	Basin B	3.3
20. Gateway	Green County, Pennsylvania	Pittsburgh	2.7
TOTAL - Top 20			103.6
TOTAL - Top 20% of U.S.			47.8

5-12

SOURCE: Irani, M. C., Jansky, J. H., Jeran, P. W., and Hassett, G. L.,
Methane Emissions from U.S. Coal Mines in 1975, A Survey,
 U. S. Bureau of Mines, IC 8133, 1977.

EXHIBIT 5-4

LOCATION MAP OF COUNTIES WITH BITUMINOUS COAL MINES
EMITTING AT LEAST 100,000 cfd OF METHANE IN 1975

SOURCE: Irani, M. C., Jansky, J. H., Jeray, P. W., and Hassett, G. L.,
Methane Emissions from U.S. Coal Mines in 1975, A Survey,
U.S. Bureau of Mines, IC 8133, 1977.

- Mines in the Pittsburgh coalbed in southwestern Pennsylvania, eastern Ohio, and northern West Virginia accounted for almost one-half of total emissions; the second highest source, mines in the Pocahontas No. 3 coalbed in southern West Virginia and northwestern Virginia, accounted for about 13% of the total.

These estimates indicate that research into methane recovery in association with mining should focus, at least initially, on the Appalachian area. Because of the potential importance of the Pittsburgh and Pocahontas coal seams for methane recovery, these two coals are discussed in detail throughout the remainder of this analysis.

2. Methane Release During Mining

The flow of methane from working mines is greater per ton of coal mined than the values for adsorption reported in the literature. This is partly due to fracturing of the coal prior to mining. As the mine face advances, the coal ahead of the active face is relieved of stresses that result in the incipient rubbing which is subsequently observed for friable coals. Thus, the total methane observed flowing from active mines represents the methane given up by both the mined coal and the affected coal beyond the mine face. In addition, where roof caving occurs there is a liberation of methane from the fractured shales and clays. These sediments, having a high sorption and solution capacity in the contained water, may well be a reservoir for significant quantities of methane.

F. Summary

Although the U.S. has massive deposits of coal and the volumetric in-place estimates of methane contained in these coal seams is large, estimating the recovery of the associated methane, at economic prices, will require considerable additional information on the properties that enable methane to efficiently desorb and flow to a wellbore.

In addition to estimates of gas content, seam thickness, pressure, and coal volumes of the reservoir properties that determine the gas in place, a rigorous resource definition program is required to measure those characteristics that control flow, namely:

- The diffusion constant for different coal seams
- The intensity of the natural fracture system
- The permeability of the fracture system

The importance of these parameters on controlling rates of gas release and flow is discussed in the next section.

II. PRODUCTION AND RECOVERY MODELS
FOR METHANE FROM COAL SEAMS

A. Production Mechanisms

Methane held in coal as a sorbed "liquid" is released through diffusion. The flow of methane occurs in response to a concentration gradient that arises when a pressure sink is established in the gas phase bounding the solid. The diffusion of methane is maintained as long as the concentration of methane in the gas phase is less than within the surface layer of the coal.

After methane is desorbed from coal, it must flow through an existing permeable fracture network to the borehole for the diffusion process to continue. If the gas released by diffusion is not produced, the concentration gradient decreases until the diffusion of methane ceases. It is therefore possible for the production rate of methane through a borehole to be limited by either the rate of diffusion through the coal, or the rate of flow through the permeable network of the coal.

B. Diffusion Controlled Release of Gas

The controlling equation for the diffusion flow of a substance is:

$$dq = D * A * (dc/dx)$$

where dq is the volumetric flow rate of the gas leaving the solid, D is the diffusion coefficient, A is the area bounding the coal, and (dc/dx) is the concentration gradient within the coal. Graphic solutions of the diffusion equation for various boundary conditions can be used to investigate the rates of methane release from coal seams for alternate geometries of fractures in the coal seam.^{8/}

Since coal tends to display fractures that are relatively uniformly spaced, a coal seam can be conceptualized as a sheath of slabs with gas being liberated by flow through the broad faces of the slab. Under this geologic configuration, the rate of diffusion will be a function of (Dt/L^2) , where D is the diffusion constant (in centimeters squared per second), L is the half-width of the slab (in centimeters), and t is the time (in seconds).

1. Diffusion Constant

The first factor controlling the rate of release of methane from coal is the diffusion constant itself. A diffusion constant in coal of 10^{-13} $\text{cm}^2/\text{sec.}$ was reported by Sevenster in 1959.^{9/} He observed that lumps of coal were fractured and were therefore inappropriate for measuring diffusion coefficients. He showed that it is impossible to correctly measure or define the geometry of the fractures, including particles on the surfaces of the slabs from which gas is diffusing. Knowledge of the geometry is necessary to establish the surface area and to calculate the diffusion constant. He therefore reduced the coal to a powder of such particulate size that the presence of fractures was precluded and the geometry of the particulate coal could be determined.

Subsequent investigators^{10/} appear to have overlooked Sevenster's work, and report that the diffusion constant is a function of particle size, decreasing with decreasing superficial size, as would be expected from Sevenster's analysis. This has led to estimates for the diffusion constant in the range of 5×10^{-8} to 10^{-10} $\text{cm}^2/\text{sec.}$, which would appear to overstate the actual value.

The results of this analysis are shown for diffusion constants ranging from the largest reported, 5×10^{-8} $\text{cm}^2/\text{sec.}$, to Sevenster's estimate of 1×10^{-13} $\text{cm}^2/\text{sec.}$

2. Slab Thickness

The second factor controlling the release of methane is the slab thickness, $2L$. This variable governs the maximum distance (L) gas must diffuse through the solid coal to reach the pressure sink. The thickness of the slab also defines the surface area through which gas can diffuse. Coal seams with thick slabs would allow less gas production by diffusion than the same seams with thin slabs. The slab thickness is assumed to be the spacing between the natural fractures in the coal seam.

Bielecki, et. al.^{11/} reported the fracture spacings in the Pittsburgh seam to be $1/2''$ and in the Pocahontas No. 3 mines to be $1/16''$, based on observations on the fragmentation of mined coal. (The fracture density for the deeper, Western coals is reported to be much less.) These values appear to be extreme and would imply that the coal has essentially been rubbelized; however, since the scientific literature does not contain any other data, these values are used for analytic purposes. There are no direct studies available on the extent or displacement of these fractures in-situ. (See Section C, Permeability Controlled Release of Gas, for further validation of these observations.)

This analysis examines a range of fracture spacing from $1/16''$ (0.16 cm) to $6''$ (15 cm).

3. Pressure of Gas in the Fractures

At low pressures, the concentration of methane in the solid phase and the equilibrium pressure in the gas phase are linearly related. Therefore, pressure gradients and concentration gradients can be used interchangeably. Solutions to the diffusion equations are available based on the boundary condition that the pressure in the free gas phase is maintained at zero, or some other constant value. The recovery efficiency is the fraction of the

total amount of sorbed gas that can theoretically be released between initial pressure and the pressure maintained in the gas phase. (An infinite time period would be required to release the total theoretical quantity.)

When calculating the liberation of gas by diffusion, the pressure in the gas phase is assumed to be zero for purposes of this analysis. Thus, the calculated values are the theoretical maximum values of desorption.

4. Estimates of Percentage Recovery As A Function of Time

The percentage of gas in the coal that can be released by a diffusion controlled process is shown graphically as a function of dimensionless time on Exhibit 5-5. Using the fracture spacings and range of diffusion coefficients mentioned above, the results for Pittsburgh and Pocahontas coals are tabulated on Exhibit 5-6.

Assuming the Pittsburgh and Pocahontas coals have a slab thickness of 1/2" and 1/16",* respectively, effectively no gas would be produced through diffusion at the smallest diffusion constant analyzed, 1×10^{-13} . At the largest diffusion constant, 5×10^{-8} , essentially all the gas in place can be liberated in the first year. At the intermediate value of 1×10^{-10} , about a third (31%) of the gas has diffused out of the Pittsburgh coal after 10 years, while a majority (74%) of the gas is liberated from the Pocahontas coal after the first year. These results are shown on Exhibit 5-6.

* These dense fracture spacings may be representative of only episodic geological phenomena for areas where major tectonic movement has rubblelized the coal seam.

EXHIBIT 5-5

RELATIONSHIP OF RECOVERY EFFICIENCY VERSUS TIME

(From Fraction of Heat Loss from a Slab With Surface Temperature Kept at $T = 0$, As A Function of Dt/L^2)

SOURCE: Derived from Carslaw and Jaeger, Conduction of Heat in Solids, Oxford, 2nd Edition, 1959, Chapter III, pp. 92-102. Equivalently substitute units for any diffusion phenomenon, viz., fraction of adsorbed material lost.

EXHIBIT 5-6

METHANE RECOVERY FROM DIFFUSION

- Pittsburgh Coal Seam (assuming slab thickness of 1/2"):

<u>Diffusion Constant</u>	<u>Percentage of Gas in Place Liberated</u>		
	<u>1 Year</u>	<u>5 Years</u>	<u>10 Years</u>
1×10^{-13}	N/A*	N/A	N/A
1×10^{-10}	N/A	16	31
5×10^{-8}	≈100	≈100	≈100

- Pocahontas Coal Seam (assuming slab thickness of 1/16"):

<u>Diffusion Constant</u>	<u>Percentage of Gas in Place Liberated</u>		
	<u>1 Year</u>	<u>5 Years</u>	<u>10 Years</u>
1×10^{-13}	N/A*	N/A	N/A
1×10^{-10}	74	≈100	≈100
5×10^{-8}	≈100	≈100	≈100

* N/A = Negligible amount

C. Permeability Controlled Release of Gas

1. The Basic Flow Equation

When diffusion is assumed to be the controlling mechanism of methane production, the implicit assumption is that the permeability of the fracture network within the coal is sufficiently high to offer no restrictions on the flow of desorbed gas to the wellbore.

Whether the porous fracture network within the coal seam can accommodate this flow can be ascertained by using a simplified form of the unsteady state equation for the flow of gas, assuming constant terminal pressure:

$$Q_{\text{MSCF}} = \frac{0.111(\phi)(h)(r_{\text{we}}^2)(c)(P_i^2 - P_w^2) Q_{\text{td}}}{Z_{\text{avg}} T_f} \quad (\text{Equation 1})$$

Where:

Q_{MSCF} is the cumulative volume of recovered gas, Mscf

Q_{td} is the dimensionless cumulative recovery

ϕ is the porosity

r_{we} is the effective wellbore radius, ft.

c is the average compressibility of gas, psi^{-1}

h is the reservoir thickness, ft.

P_i is the initial reservoir pressure, psig

P_w is the producing well pressure, psig

Z_{avg} is the average Z-factor of the gas

T_f is the reservoir temperature, $^{\circ}\text{F}$

Dimensionless recovery, Q_{td} , is a function of real time, permeability, r_{we} , c , and ϕ . Dimensionless time, t_d , is equal to:

$$t_d = \frac{6.33 k t}{\phi \mu c r_{we}^2} \quad (\text{Equation 2})$$

Where:

t_d is the time, days

k is the permeability, darcies

μ is the gas viscosity, centipoise

The relationship between Q_{td} and dimensionless time, t_d , is shown on Exhibit 5-7 as a function of the dimensionless drainage radius, r_d .

Equation 1 can be solved to assess whether the flow of produced gas through the coal is greater or less than the gas that can be released by diffusion. To obtain this solution, it is necessary to define the permeability and porosity of the system. The other parameters are known or can be estimated with reasonable confidence.

2. Porosity

The actual porosity of coal is probably a fraction of one percent but it is not an adequate measure of the quantity of gas available for production or for the drive mechanism for fluid flow in Equation 1. As a result of diffusion, the porous structure in the coal seam is continuously resupplied with methane. To use the fluid flow equation, therefore, it is necessary to introduce an assumption about the effective value of the porosity.

EXHIBIT 5-7
 RELATIONSHIP BETWEEN Q_{td} AND DIMENSIONLESS TIME

SOURCE: Slider, H. C., Practical Petroleum Reservoir Engineering, Petroleum Publishing Company, 1976.

Kissel^{12/} has suggested assigning a pseudo-porosity to the system, equal to the porosity the adsorbed gas would have if all of it were released from the coal and held in the seam at reservoir pressure and temperature. In effect, the reservoir should be considered to have swollen to accommodate the free gas. For the Pittsburgh coal seam, this would mean a pseudo-porosity of 38%, and for the Pocahontas coal seam, 34%.

Using such a pseudo-porosity is probably an optimistic assumption since it assumes that all the gas is initially present in the permeably connected porosity, available for expansion from the moment the mine is opened.

3. Permeability

The second major reservoir property controlling flow rate is the in situ permeability of the coal seam. Of critical importance to overall gas flow is the permeability of the butt cleat natural fracture system, the presence of clay seams that might impede flow, and the effect of water.

a. Empirical Measures of Permeability

A paper by Fisekci and Barron^{13/} of the Department of Energy, Mines and Resources, Ottawa, 1975, reported measurements on the permeability of one coal mine in Canada and one in Australia. The Canmore mine in Canada is at 650 feet, and is the more "sheared" seam of the two (the term "sheared" is related to the subsequently observed friability of the coal). The permeability was measured by metering the flow of gas in a packed off wellbore for a short enough period of time so that the reservoir of gas behaved as an infinite reservoir. Simple use of the analytic flow equations permitted permeability to be measured. For the Canmore mine it was of the order of 5 millidarcies (md), and for the Australian mine somewhere between 0.001 and 0.01 md. (The Australian mine has 2000 feet of overburden and is less sheared than the Canadian mine.)

b. Indirect Measures of Permeability

An indirect measure of permeability for the Pocahontas No. 3 mine in the U. S. revealed a value of 0.75 md,^{14/} and the measurement of permeability on lumps of Pocahontas coal gave measurements ranging from 0.05 md to 250 md.^{15/} Seventy percent of the samples had values of less than 1 md and only 20% had values between 1 and 10 md.

Since the measurements appear to be sound in design and execution, a range of values from 0.001 md to 5 md will be used to assess whether the effective permeability of coal seams will permit passage of the maximum possible amount of gas released by diffusion.

c. Theoretical Calculation

One means for assessing whether these observations are reasonable is to correlate the measurements of permeability with a theoretical calculation of permeability based on observed fracture spacing.

Bielecki, et. al.^{16/} reported that the superficial fracture spacing is 1/2" for the Pittsburgh coal and 1/16" for the Pocahontas coal. If it is assumed that these fractures extend throughout the coal seam, are parallel, and are open to flow along their length, the permeability of the system can be calculated using the following equation:^{17/}

$$k = \frac{\phi^3 \times (2L)^2 \times 10^{-11}}{12} \quad \text{(Equation 3)}$$

Where:

k is the permeability, millidarcies

ϕ is the porosity

2L is the spacing between the fractures, cm

This equation can be used to test whether the higher end of the permeability range is reasonable. Assuming the value of 5 md for permeability, ϕ is calculated to be 0.07% and 0.30% for Pittsburgh and Pocahontas coals, respectively, and since porosity can be expressed as the product of fracture width and fracture density, the corresponding fracture widths of Pittsburgh and Pocahontas coals that account for the porosity are 0.0004 and .0002 inch, respectively.* The calculated values of fracture width do lend support to the observations of permeability of Dubbous, et. al.,^{18/} Price, et. al.,^{19/} and Fisecki, et. al.^{20/}

Although these values appear "reasonable", it is not likely that parallel, wide-open fractures exist throughout the coal. Thus, the preceding Equation 3 for permeability should be modified by placing a reduction factor, "f", with a value between 0 and 1, in front of the term on the right side of the equation.

Thus, the most likely value of the permeability of these coal seams is less than 5 md, and may be considerably less in areas where little or no displacement has occurred at the fracture planes.

4. Percentage Recovery As A Function of Inferred Permeability

Using a 1 to 5 millidarcy range of permeability for the coal seams, the calculated pseudo-porosities, and the reported properties of Pittsburgh (Loveridge) and Pocahontas No. 3 coal seams, the cumulative amount of gas that could be produced in ten years can be calculated, assuming recovery is permeability limited.

* Assuming the calculations of porosity of 0.07% for the Pittsburgh coal seam, a fracture density of 1/2" would lead to a fracture width of 0.00035 inches, rounded to 0.0004 inches.

- Example Solution. The calculation for one of the coals, the Pittsburgh coal seam, assuming 1 md permeability, a wellbore radius of 1 foot, and 80 acre spacing, is as follows:

$$Q_{\text{Mscf}} = \frac{0.111 (0.38) (8) (1) (7.83 \times 10^{-3}) (190^2 - 50^2) Q_{\text{td}}}{(0.95) (460 + 80)}$$

$$Q_{\text{Mscf}} = 0.155 Q_{\text{td}}$$

Where Q_{td} can be read from Exhibit 5-7 as a function of t_d and r_d

Where $t_d = \frac{\eta t}{r_{\text{we}}^2}$; $r_d = 1050$ (for 80 acres)

$$\eta = \frac{6.33k}{\phi \mu c} = 198$$

$$t = 10 \times 365 = 3,650 \text{ (days)}$$

$$r_{\text{we}}^2 = 1$$

and thus:

$$t_d = 723,200$$

From Exhibit 5-7:

$$Q_{\text{td}} = 1.065 \times 10^5 \quad \text{and}$$

$$Q_{\text{Mscf}} = 0.155 \times 1.085 \times 10^5 \text{ Mscf, or } 16.5 \text{ MMSCF}$$

- Pittsburgh Coal. The permeability-limited recovery for Pittsburgh coal is shown on Exhibit 5-8 as a percent of the Gas In Place together with the volume recovered. With a low gas content and a low initial pressure, the Pittsburgh coal requires a permeability of at least 5 millidarcy and effective wellbore radius of 1 foot on 80 acre drainage patterns to be able to produce in ten years a quarter (27%) of the gas contained in the drainage area. Increasing the effective wellbore radius to 10 feet would enable one-third (35%) of the gas to be produced in ten years.
- Pocahontas Coal. The permeability-limited recovery for Pocahontas coal is shown on Exhibit 5-9 as a percent of the Gas In Place together with the volume recovered. Should the Pocahontas coal seam have a permeability greater than 1 md, then one-third (31%), or greater, of the gas could be produced with eighty acre spacing. If successful fracturing could be achieved ($r_{we} = 10$ feet) with spacing of 80 acres and a permeability of 1 md, then 42% of the gas in place, or 113 million cubic feet, could be recovered in 10 years.

Although permeability data is limited for these two coal seams, the methane production in association with mining suggests that the Pittsburgh has a higher permeability than the Pocahontas coal seam, having an indirect measure of 0.75 md, as discussed above. Considerable additional measurement is required to establish representative permeability values and their distribution before any definitive conclusions can be offered about the role of permeability as the controlling production mechanism.

EXHIBIT 5-8

TEN-YEAR RECOVERY OF METHANE FROM PITTSBURGH COAL
USING VERTICAL WELLS

Permeability, mds.	Gas Recovered, Percent of Total					
	$r_{we} = 1 \text{ foot}$			$r_{we} = 10 \text{ feet}$		
	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	9	4	1	13	7	2
2	16	9	2	22	13	3
5	27	20	5	35	27	8

Permeability, mds.	Gas Recovered, MMSCF					
	$r_{we} = 1 \text{ foot}$			$r_{we} = 10 \text{ feet}$		
	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	16	14	14	23	25	28
2	26	31	28	39	46	43
5	48	71	7	62	96	114

Pittsburgh Coal:

Gas Content	160 SCF/Ton
Pressure	176 psia
Depth	607 feet
Thickness	8 feet
Temperature	80°F
Pseudo-porosity	34%
Gas Content in 80 acres	178 MMSCF
Producing Well Pressure	50 psig
Compressibility	$7.83 \times 10^{-3} \text{ psi}^{-1}$

EXHIBIT 5-9

TEN-YEAR RECOVERY OF METHANE FROM POCAHONTAS COAL
USING VERTICAL WELLS

<u>Permeability, mds.</u>	Gas Recovered, Percent of Total					
	$r_{we} = 1 \text{ foot}$			$r_{we} = 10 \text{ feet}$		
	<u>80 acres</u>	<u>160 acres</u>	<u>640 acres</u>	<u>80 acres</u>	<u>160 acres</u>	<u>640 acres</u>
1	31	17	4	42	23	6
2	49	33	8	59	40	12
5	66	53	18	74	64	25

<u>Permeability, mds.</u>	Gas Recovered, MMSCF					
	$r_{we} = 1 \text{ foot}$			$r_{we} = 10 \text{ feet}$		
	<u>80 acres</u>	<u>160 acres</u>	<u>640 acres</u>	<u>80 acres</u>	<u>160 acres</u>	<u>640 acres</u>
1	85	93	87	113	128	128
2	134	180	175	162	216	245
5	180	289	395	202	351	543

Pocahontas Coal:

Gas Content	435 SCF/Ton
Pressure	588 psia
Depth	1600 feet
Thickness	54 inches
Temperature	100°F
Pseudo-porosity	38%
Gas Content in 80 Acres	273 MMSCF
Producing Well Pressure	50 psig
Compressibility	$2.95 \times 10^{-3} \text{ psi}^{-1}$

D. Comparative Analysis of Production Mechanisms

As discussed above, methane recovery from coal seams is either controlled by diffusion or permeability. Ten-year recovery with diffusion as the controlling process is shown on Exhibit 5-6, and with permeability as the limiting process on Exhibits 5-8 and 5-9. The relative dominance of these two processes is compared below for Pittsburgh and Pocahontas coals.

1. Pittsburgh Coal

Ten-year recovery, assuming diffusion is the limiting factor, varies from a negligible amount to nearly 100% over the broad range of diffusion coefficients examined, Exhibit 5-6. Part of this Exhibit is repeated below:

	Diffusion Constant		
	1×10^{-13}	1×10^{-10}	5×10^{-8}
Ten Year Recovery, %	≈ 0	31	≈ 100

- Diffusion Control Analysis. Recovery from the Pittsburgh coal is essentially restricted to zero for diffusion constants smaller than 1×10^{-13} and not restricted at all for constants larger than 5×10^{-8} . Between this range, the maximum recovery varies from zero to 100 percent, and at 1×10^{-10} , the recovery is 31 percent.
- Permeability Control Analysis. Recovery as a percent of total gas volume, assuming permeability is a restricting factor, is shown quantitatively on Exhibit 5-8 and graphically on Exhibit 5-10. For the permeability, the wellbore radii, and the drainage areas examined, recovery varies from about zero to about 35 percent.

- Diffusion/Permeability Control Analysis. The combination of parameters that result in either diffusion or permeability controlling recovery can be established from Exhibit 5-10. At a diffusion constant of 1×10^{-10} , recovery is 31 percent. A horizontal line through this point on the graph will divide the area into two parts. Points on the permeability curves that fall below the line denote that permeability-controlled is less than diffusion-controlled recovery. Permeability is therefore controlling. For a diffusion constant of 1×10^{-10} , permeability is the controlling variable for the ranges examined, except for a permeability higher than 4 md, a 10 foot well radius, and 80 acre spacing.

Similar lines for diffusion constants of 1×10^{-13} and 5×10^{-8} show that in the former case diffusion is controlling, and in the latter case, permeability is controlling. Curves similar to Exhibit 5-10 can be developed for the diffusion controlled process from Exhibit 5-6, and an analysis similar to the one just performed can be done to interpolate between the diffusion constants examined.

2. Pocahontas Coal

Pocahontas coal is gassier than Pittsburgh coal, but the fracture spacing is smaller. The ten-year recovery of methane from Pocahontas coal -- whether it is diffusion- or permeability-controlled -- is discussed in the following for the same range of values used for Pittsburgh coal.

- Diffusion Control Analysis. Recovery from Pocahontas coal ranges from about zero with a diffusion constant of 1×10^{-13} to nearly 100% with a diffusion constant of 1×10^{-10} . At this and higher values, recovery is essentially not limited by diffusion. The recovery from diffusion is shown on Exhibit 5-6.
- Permeability Control Analysis. Recovery with permeability as a limiting factor is shown quantitatively on Exhibit 5-9 and graphically on Exhibit 5-11. The recovery ranges from 4% to 74% for the permeability, drainage areas, and well radii examined.
- Diffusion/Permeability Control Analysis. The combination of parameters that result in either diffusion or permeability controlling recovery can be established from Exhibit 5-11. Diffusion is the controlling process for a diffusion constant below 1×10^{-13} , where diffusion-controlled recovery is about zero. Between diffusion constants of 1×10^{-13} and 1×10^{-10} , diffusion-controlled recovery ranges from zero to 100%, and recovery changes from being diffusion- to permeability-controlled. Above diffusion constants of 1×10^{-10} , recovery is controlled by permeability.

Analyses similar to the above can be performed to interpolate between the diffusion constants of 1×10^{-13} and 1×10^{-10} using Exhibits 5-6 and 5-11.

EXHIBIT 5-10

TEN-YEAR RECOVERY OF METHANE FROM PITTSBURGH COAL
USING VERTICAL WELLS

EXHIBIT 5-11
TEN-YEAR RECOVERY OF METHANE FROM POCAHONTAS COAL
USING VERTICAL WELLS

3. Potential for Production Enhancement

When diffusion is controlling there is probably little that can be done to improve production performance by fracturing through a vertical borehole.

- If the coal seam already has high permeability due to natural fractures, then adding one more permeable path to the reservoir will do little to augment recovery.
- If the coal seam has undergone little tectonic displacement and thus has a limited natural fracture system, adding one more fracture plane to the system will contribute only a trivial amount of additional surface area for desorption. (For example, should the fracture be 4" apart, a coal seam of 80 acres already has over 5,000 fractures.)

Should permeability be controlling, the contribution of induced fractures appears to be limited to those situations where sufficient natural fracture density is in place but the flow path between the pressure sinks is tortuous and otherwise restricted in flow capacity. However, it may not be technically possible for an induced fracture to be able to connect these pressure sinks given a dominant face cleat system of the coal seam.

III. ECONOMIC MODELS

A. Introduction

This section analyzes the economics of recovering methane from coal seams. The analysis combines the previously discussed resource data and production and recovery models with basic gas recovery costs.

Recovery of gas from thin coal seams has already been shown to be uneconomic, and methane capture associated with mining is intrinsically limited to accompanying safety and efficiency benefits that serve to defray costs. This section will discuss the economics of the remaining two resource areas:

- Deep, unminable coal seams
- Shallow coal seams assuming:
 - Vertical wells, with no accompanying methane drainage benefits
 - Horizontal drain holes from an air shaft.

B. Deep, Unminable Coal Seams

Limited information is available on the key geological variables that govern the extraction and economics of recovering methane from deep, unminable coal seams. This analysis is therefore only a first approximation of the economic potential. Assuming thickness of the coal seam is the controlling variable and that all other geological features are favorable, the economic feasibility of extracting methane from deep, unminable coal seams will depend on finding coal deposits of sufficient thickness.

By estimating the investment requirements and the annual costs, the minimum 10 year production to yield a 10-year pay-back can be calculated as a function of price.* This, in turn, can be converted into minimum required coal seam thickness. The following analysis assumes that deviated wells are used to connect the natural fracture system. Should vertical boreholes with hydraulic stimulation obtain the same recovery efficiency, the minimum required coal seam thickness (or the gas content) could be reduced substantially.

This analysis makes several relatively optimistic assumptions for three variables that affect economic recovery, namely:

- Methane content -- assumes 480 cf/ton (bituminous and higher grades).
- Natural fracture system -- assumes the fracture system to be extensive enough to allow 30% recovery in 10 years; this requires that fractures exist one foot apart and extend uninterrupted through the drainage area of the well.

* $\text{Required Production} = (10 \text{ Year Production}) \times [(1 - \text{royalty and severance taxes}) \times (\text{gas price}) - \text{Unit Operating Costs}]$

$\text{Actual Production} = \text{Drainage Area} \times \text{Coal Seam Thickness} \times \text{Methane Content} \times \text{Recovery Efficiency (for 10 years)}$

- Effective drainage area where the pressure is sufficiently low to induce effective desorption is assumed to be 80 acres;
- Methane content is assumed to be 480 cubic feet per ton or 0.019 Mcf per cubic foot; and
- Recovery is calculated from using the recovery efficiency function on Exhibit 5-5; for 10 years (in seconds), recovery efficiency is 30%.

Minimum Thickness: Set required production equal to actual production and solve for coal seam thickness.

- Diffusion constant -- assumes D equals $5 \times 10^{-8} \text{ cm}^2/\text{sec}$.

With these assumptions the minimum coal seam thickness is:

<u>Price, \$/Mcf</u>	<u>Production, Mcf</u>	<u>Minimum Thickness, Feet</u>
1.75	670,000	34
3.00	320,000	16
4.50	190,000	10

Further details on the assumptions and analysis are:

- Required investment and costs:
 - Investment - \$600,000 for 2 wells drilled to 4,000 feet, then 1,000 feet into the coal seams
 - Operating Costs - \$0.50 per Mcf
 - Royalty and severance taxes - 20% of price
 - Investment review criteria - 5 year and 10 year payback

- Required revenues:

-- Under 10 year payback

$$\sum_{i=1}^{10} (q_i [(.8) p - 0.50]) > \text{Investment}$$

-- Under 5 year payback

$$\sum_{i=1}^5 (q_i [(.8) p - 0.50]) > \text{Investment}$$

where q_i is the gas volume in the i 'th year, p the gas price, and \$0.50 operating, compressing, separating, and gathering costs.

- Derivation of minimum thickness: Determine key reservoir properties to provide required quantity of production for a 10 year payback:

-- Required Production = Area x Thickness x Quantity x
Methane Content per Cubic Foot x Recovery

Assume:

-- A = 80 acres

-- Methane Content = 480 cubic ft/ton (bituminous coal)
equal to 0.019 Mcf/cubic foot*

Using:

-- $D = 5 \times 10^{-8} \text{ cm}^2/\text{sec.}$

$t = 10 \text{ years } (31.5 \times 10^6 \text{ sec. per year})$

$L = 15 \text{ cm. (assuming a fracture every 1 foot)}$

-- 10 year recovery efficiency (R_{10}) is 30%, determined as follows:

$$Dt/L^2 = \frac{(5 \times 10^{-8}) \times 10 \times 31.5 \times 10^6}{15^2} = 0.07$$

$$f(Dt/L^2) = 30\% \text{ (from Exhibit 5-5)}$$

* The Gas In Place (GIP) can be calculated from the following equation:

- $GIP = (\text{Drainage Area}) \times (\text{Methane Content per Cubic Foot}) \times (\text{Thickness})$
- The drainage area in square feet equals: Acres x 43,560
- The methane content per cubic foot equals:
480 cf/ton x 80 lb/cf/2000 lb/ton = 19 cubic feet of gas
(0.019 Mcf) per cubic foot of coal

- Calculate required coal seam thickness:

$$p = \$1.75 \text{ Mcf:}$$

$$670,000 = (80 \times 43,560) \times 0.019 \times .30 \times h$$

$$h = \frac{670,000}{19,863} = 34 \text{ ft.}$$

$$p = \$3.00/\text{Mcf:} \quad h = 16 \text{ ft.}$$

$$p = \$4.50/\text{Mcf:} \quad h = 10 \text{ ft.}$$

- To make the same calculation for a 5 year payback, assume the same parameters except that $t = 5$ years; then $Dt/L^2 = 0.035$ and 5 year recovery efficiency = 19%. Required coal seam thickness as a function of price increases 60% to:

$$p = \$1.75 \text{ Mcf:} \quad h = 53 \text{ ft.}$$

$$\$3.00 \text{ Mcf:} \quad h = 25 \text{ ft.}$$

$$\$4.50 \text{ Mcf:} \quad h = 16 \text{ ft.}$$

- The amount of the bituminous coal in the West that meets these thickness criteria can be derived from Exhibit 5-1.

<u>Gas Price, \$/Mcf</u>	<u>% of Resource That Meets Thickness Criteria</u>	
	<u>5-Year Payback</u>	<u>10-Year Payback</u>
1.75	5	20
3.00	25	40
4.50	40	50

C. Shallow Coal Seams

1. Methane Production With Vertical Wells

a. Capital Costs

An alternate (and less costly) way of implementing gas recovery from a coal mine is to drill a vertical well into the coal seam, much as one would drill a well into a gas reservoir.

For the Pittsburgh seam at a depth of 600 feet, the cost for completing a well is estimated to be \$48,000 (\$30 per foot and \$30,000 for site preparation and completion). Assuming a 10 year life and 20% discount factor, the annual cash flow from the production must be \$12,000.

The Pocahontas seam is deeper, but significantly gassier than the Pittsburgh. The cost of a vertical well drilled into the Pocahontas coal is estimated to be \$78,000. For a 10 year life at a 20% discount rate, the annual cash flow must be \$19,000.

b. Operating Costs

Assuming the capital cost for collecting and compressing the gas is included in the operating cost (through depreciation), the total cost, including the cost of labor, compression, collection, overhead, engineering, severance taxes, and water disposal is estimated to be \$0.50 per MSCF. Royalties are assumed to be 12.5%.

c. Investment Payback

The following table shows the fraction of the gas in place that must be recovered from Pittsburgh and Pocahontas coals over a 10 year period to provide sufficient economic attractiveness. The necessary recovery at various

prices has been calculated assuming operating costs are covered and that capital is invested at a zero and a 20% rate of return, before taxes;

RECOVERY REQUIRED FOR ECONOMIC DEVELOPMENT, % OF GIP

	<u>80 Acres Drainage</u>		<u>160 Acres Drainage</u>	
	Rate of Return: <u>0%</u>	<u>20%</u>	<u>0%</u>	<u>20%</u>
<u>Gas Price, \$/Mcf</u>				
<u>Pittsburgh Coal</u>				
1.75	26	65	13	33
3.00	13	32	6	16
4.50	8	20	4	10
<u>Pocahontas Coal</u>				
1.75	28	68	14	34
3.00	13	33	7	16
4.50	8	20	4	10

The ranges of the required revenues are highlighted below for the two coal seams.

- Pittsburgh coal seam. Necessary methane recovery for economic development of this seam (at 20% ROR) ranges from 65% of GIP at \$1.75 per Mcf and 80 acre drainage to 10% of GIP at \$4.50 per Mcf and 160 acre drainage.
- Pocahontas coal seam. The essential recovery efficiencies for economic viability of developing this coal seam (20% ROR) range from 68% of GIP at \$1.75 per Mcf and 80 acre drainage to 10% of GIP at \$4.50 per Mcf and 160 acre drainage.

Although Pocahontas coal is gassier than Pittsburgh coal, it is deeper and thus more costly to develop. As a consequence, there is little difference in the required recovery.

d. Requirements for Economic Production

The recovery of methane as a percentage of gas in place from Pittsburgh and Pocahontas coal seams has previously been calculated assuming vertical wells. This can be compared with the minimum recovery required for economic development already estimated. For the permeabilities and prices examined, the minimum price necessary for favorable economics at a 20% ROR is shown in the following tables for Pittsburgh and Pocahontas coals.

- Pittsburgh Coal Seam. The minimum price required for economic development with vertical wells as a function of permeability, drainage area, and fracturing is:

Permeability, md	Price Required for Economic Development, \$/Mcf			
	$r_{we} = 1$ foot		$r_{we} = 10$ feet	
	80 acre	160 acre	80 acre	160 acre
1	NS*	NS	NS	NS
2	NS	NS	4.50	4.50
5	4.50	4.50	3.00	3.00

*NS = \$4.50 per Mcf Not Sufficient for economic development

-- With an 80 acre drainage area, a r_{we} of 1 foot, a price of \$4.50 per Mcf, and a 20% ROR, the permeability must be 5 millidarcies before production is economic.

-- With an 80 acre drainage area, a r_{we} of 10 feet, a price of \$4.50 per Mcf, and a 20% ROR, production is economic at 2 millidarcies.

- Pocahontas Coal Seam. A similar comparison has been developed for Pocahontas coal:

<u>Permeability, md</u>	<u>Price Required for Economic Development, \$/Mcf</u>			
	<u>$r_{we} = 1$ foot</u>		<u>$r_{we} = 10$ feet</u>	
	<u>80 acre</u>	<u>160 acre</u>	<u>80 acre</u>	<u>160 acre</u>
1	4.50	3.00	3.00	3.00
2	3.00	3.00	3.00	1.75
5	1.75	1.75	1.75	1.75

-- With an 80 acre drainage area and a permeability of 1 millidarcy, production is economic at \$4.50 per Mcf with an r_{we} of 1 foot, and \$3.00 per Mcf with an r_{we} of 10 feet.

-- With an 160 acre drainage area and a permeability of 1 millidarcy, production is economic at \$3.00 per Mcf.

e. Results to Date from Vertical Wells Drilled Into Appalachian Coal Seams

Vertical wells have been drilled into coal seams in Alabama (Mary Lee), Pennsylvania (Greene, Cambria, and Washington Counties), West Virginia (Marion, Monongalia, Raleigh and Wetzel Counties), Illinois (Jefferson County), and Virginia (Buchanan County).

The vertical wells drilled in Alabama, Pennsylvania, and West Virginia exhibited erratic behavior and had post-fracturing recoveries that ranged from zero to 100 Mcf/D. The bulk of these wells have been abandoned. The wells in Pennsylvania (Cambria) and Virginia (Buchanan) were completed to drain gob gas from the mine after the advance of the long wall, and significant degassing of the mine was achieved.

Perhaps the most consistent and reliable data is that from the Big Run Field (Wetzel County, Pittsburgh Coal), where 23 wells were completed and operated since 1931 (19 completions since 1948). Initial rates ranged up to 25 MSFD, and most recently have averaged less than 5 MCFD. The average 30 year cumulative recovery is slightly below 100 MMSCF per well.

2. Methane Production from Horizontal Drain Holes Drilled From A Large Shaft

Of a distinctly different nature from the results reported above are those obtained from a degasification project in which horizontal drain holes averaging 600 feet in length (500 to 850 feet) were drilled out of an 18 foot diameter shaft in a Pittsburgh coal seam.

By the fifth year of operation, recovery of gas amounted to over 900 MMSCF, equal to 100% of the gas in this particular seam within a perimeter of 3000 feet, or 50% recovery from a drainage radius of 4200 feet. Such production would be anticipated if an effective well radius of some 300 feet were induced, and the diffusion constant was greater than 10^{-8} . (Natural fracture spacing is assumed to be 1/2", as reported previously for the Pittsburgh coal.)

Since other evidence for such a high value of the diffusion constant is tenuous and the results with the horizontal drain holes emanating from a large diameter shaft are very different from the results obtained by fracturing vertical boreholes, an alternate explanation of the phenomenal production from horizontal draining is suggested.

It is surmised that the production response from the drilling of a large shaft and horizontal drain holes is due to the stress relief engendered by the drilling of the large diameter shaft. In turn, this stress relief permits an expansion of the coal seam and spontaneous displacement (parting

of the coal). This is similar to what occurs as a mine face advances. A very large number of observations have indicated that the production of methane from active mines per ton of coal mined is greater than the quantities directly measured on core samples.^{21/} This can be rationalized by assuming stress relief at the mine face resulting in extensive microdisplacements occurring throughout the coal ahead of the mine face. This additional surface area for desorption, particularly when intersected by a drain hole (the horizontal wells) is a plausible explanation for the observed production response.

The prospect of such a technique becoming a standard production practice is limited by the high cost of shaft drilling and the problems of coordinating the completion of the shaft with mining operations. However, it does bear further investigation with the particular aim of validating the reasons for the favorable production response. Such studies could lead to conceptualization of a more economic and technically optimized means for draining methane from coal seams.

CHAPTER FIVE

BIBLIOGRAPHY

- 1/ Duel, M., "Degasification of Coal Beds," AGA Monthly News, May 1976.
- 2/ Kissel, F. N., McCulloch, C. M., and Elder, C. H., "The Direct Method of Determining Methane Content of Coalbeds for Ventilation Design," Bureau of Mines, R.I. 7767, 1973.
- 3/ Ibid.
- 4/ The basic data sources used consisted of:
 - Estimates of coal resources from: Averitt, P., Coal Resources of the United States, January 1, 1974. Geological Survey Bulletin 1412, 1975.
 - Estimates of methane content from: Kim, A. G., Estimating Methane Content of Bituminous Coal Beds from Adsorption Data, Bureau of Mines, R.I. 8245, 1977.
 - Estimates of distribution of coalbed thickness and rank from: Booz, Allen and Hamilton, ERDA's Underground Coal Gasification Program, Volume III - Resources, May 1977.
- 5/ Kim, Ann G., Op. Cit.
- 6/ Irani, M. C., Jeran, P. W., and Duel, M., Methane Emissions from Coal Mines, Bureau of Mines, R.I. 8659, 1974.
- 7/ Irani, M. C., Jansky, J. H., Jeran, P. W., and Hassett, G. L., Methane Emissions from U.S. Coal Mines in 1974, A Survey. U.S. Bureau of Mines IC 8133, 1977.
- 8/ Carslaw, H. S. and Jaeger, J. C., Conduction of Heat in Solids, Oxford, 1959.
- 9/ Sevenster, P. G., "Diffusion of Gases Through Coal", Fuel, Vol. 38, p. 403, 1959.

Chapter Five
Bibliography
Page 2

- 10/ Nandi, S. P., and Walker, P. L., Jr., Activated Diffusion of Methane from Coals at Elevated Pressure, Pennsylvania State University, May 1974.
- 11/ Bielicki, R. J., Perkins, J. H., and Kissel, F. N., Diffusion from Coal Fragments, Bureau of Mines, R.I. 7697, 1972.
- 12/ Kissel, F. N., Bureau of Mines Circular 7659, 1972; and Bureau of Mines Circular 7667, 1972.
- 13/ Fisecki, M. Y. and Barron K., Methane Pressure and Flow Measurements in Coal and Surrounding Strata, C.I.M. Bulletin, October, 1975.
- 14/ Price, H. S., McCulloch, R. C., Edwards, J. C., and Kissel, F. N., A Computer Model Study of Methane Migration in Coalbeds, C.I.M. Bulletin, September, 1973.
- 15/ Dabbous, M. K., Reznick, A. A., Taber, J. ., and Fulton, P. F., SPE Journal, Vol. 14, No. 6, December 1974.
- 16/ Bielicki, et. al., Op. Cit.
- 17/ Muskat, M., Flow of Homogeneous Fluids Through Porous Media, Edwards, 1946.
- 18/ Dabbous, et. al., Op. Cit.
- 19/ Price, et. al., Op. Cit.
- 20/ Fisecki and Barron, Op. Cit.
- 21/ Irani, M. C., et. al., BOM IC 8133, Op. Cit.

CHAPTER SIX

METHODS USED IN ANALYZING PRODUCTION AND RECOVERY FROM GEOPRESSURED AQUIFERS

INTRODUCTION AND SUMMARY

This chapter reports on the potential technical feasibility and economics of producing methane (natural gas) from geopressured aquifers along the inland coastal areas of the Gulf of Mexico.

The analysis considers three topics:

- Resource Base. The geology and properties of the reservoir dominate the feasibility of producing methane from geopressured aquifers. The section on the resource base provides the initial estimates of reservoir parameters of the geopressured aquifers including their areal extent, net thickness of productive sand, porosity, permeability, and effective compressibility.
- Production and Recovery Models. The second section combines reservoir parameters with basic laws of fluid flow to develop estimates of the production rates and cumulative production of geopressured aquifers.
- Economic Model. The third section provides estimates of the operating and capital costs of drilling and producing geopressured aquifers. A significant part of the operating costs is the cost of disposing of the large quantities of produced brines.

I. THE RESOURCE BASE

A. Areal Extent of Geopressured Aquifers

Bebout and his associates at the University of Texas have carried out some exemplary studies on regional and site specific sedimentology.^{1/} What appears to them to be a prime target as a geopressured aquifer occurs in the Austin Bayou prospect. Three individual sandstone bodies lie between 13,500 and 16,500 feet within an area of about 60 square miles. The largest of the three is a wedge shaped body 150 feet thick; the three sand bodies together total 300 feet.* While the total volume of the multi-story package is about 3.4 cubic miles, recent data indicate that the 60 square miles is comprised of four or more separate sand bodies. A well is expected to drain sands on average within a 15 to 16 square mile area and thus have a drainage volume of less than 1 cubic mile.

Very recently, Wallace (USGS)^{2/} has begun to identify the vertical extent and composition of Louisiana reservoirs. However, even though these formations are known to be highly faulted, little is known of the areal extent of these individual fault blocks.

To gain some insight into sizes of potentially similar structures in Louisiana, the areal distribution of the fault blocks that comprise the 31 largest oil fields in the Gulf of Mexico were examined (Exhibit 6-1). Based on 380 fault blocks in these 31 fields, covering 371 square miles, only one fault block met the minimum areal requirement of 10 square miles that could (when combined with thick pay and high permeability) support a production rate of 40,000 B/D.

* While geological analysis has inferred that there are some 800 to 900 net, but dispersed, feet of sands at the prospect location, only about 300 feet of pay appear to have adequate permeability to ensure economic flow.

EXHIBIT 6-1

DISTRIBUTION OF FAULT BLOCK SIZES, GULF OF MEXICO

<u>SIZE DISTRIBUTION</u> (Mi ²)	<u>NUMBER OF RESERVOIRS</u>	<u>TOTAL AREA</u> (Mi ²)	<u>PERCENTAGE</u>
0 - 1	292	146	40%
1 - 2	56	84	23%
2 - 3	15	37	10%
3 - 4	7	24	6%
4 - 5	1	4	1%
5 - 10	8	60	16%
>10	1	<u>16</u>	<u>4%</u>
TOTAL		366	100%

Should the same conditions hold for the geopressured water bearing aquifers as for oil bearing fault blocks, only a small portion of southern Louisiana's surface area would contain aquifers of sufficient size to provide economically attractive production rates.

Oil and gas accumulations are usually found at structurally high locations. Since there is no reason for accumulations of geopressured water to occur in corresponding positions, there is a possibility that size distributions for oil and gas reservoirs may not be a valid frame of reference for geopressured aquifers. On the other hand, the greatest body of evidence points to the fact that geopressured reservoirs were sealed early in their life.^{3/} This explanation simultaneously accounts for the occurrence of the geopressure, and the deviations of porosity and shale resistivity from their monotonic trends when a geopressured reservoir is encountered in the subsurface.

Fertl and Timko^{4/} also have observed that geopressured aquifers are usually associated with "super-pressures" (pressure gradients approximately above 0.85), and that super-pressure reservoirs usually show a quick depletion indicative of their small size.

Wilson and Osborne^{5/} estimated the probable sizes (volumes) of geopressured aquifers in the Gulf Coast by: (1) reviewing literature pertaining to the likely maximum sizes and frequency of sand and sandstone bodies in various deltaic complexes; (2) by reviewing sedimentological work concerning the Gulf Coast geopressured aquifers in terms of the likely original size and frequency of sandstone bodies; and (3) by considering post-depositional modifications which tend to reduce the effective size of these sandstone bodies.

The size or volume of the sandstone bodies within a given fairway system were assessed on three different scales: (1) the volume of an individual sandstone body; (2) the total volume of multi-story sandstone bodies within a site specific prospect; and (3) the total volume of sandstone bodies within a given fairway system (a total prospect or total composite sandstone system).

The results indicate that the maximum volume of individual sand bodies in the fluvially dominated deltaic facies and associated coastal barrier island complexes ranges from about 1.0 to 2.3 cubic miles, shown on Exhibit 6-2. However, the Sabine Bank consists of interstratified sand and mud, and the Galveston Barrier Complex contains only 0.33 cubic miles of sand. Realistic values for the volume of reservoir sand (within the individual sand body) are considerably less than the total volumes shown on the Exhibit and would be most likely on the order of 0.3 to 1.5 cubic miles.

Since the coarser-grained sediment is deposited at a distributary mouth, it is possible to vertically stack individual sand packages to form a multi-story sand body if the rate of deposition is approximately equal to the rate of subsidence.^{6/} However, the rate of deposition and the rate of subsidence is commonly interrupted and many of the sandstone packages will be separated by shale or mudstone interbeds.

The coastal (barrier) sheet sand and prodelta sheet sand bodies associated with the Rhone delta and St. Bernard delta have volumes from 2.4 to 4.0 cubic miles, respectively, prior to secondary (tectonic) modifications and mass movements. Both of these sand bodies were formed by marine reworking during periods of deltaic lobe abandonment or deltaic offlap.

EXHIBIT 6-2

ESTIMATED MAXIMUM SIZE OF INDIVIDUAL SAND BODIES
IN SELECTED DELTAIC FACIES

Stratigraphic Unit	Length (mi)	Width (mi)	Thickness (ft)	Volume (cubic miles)	Depositional Environment
La Fourche Delta (1)	15 - 20	3 - 5	200 max.	3.79	Fluvially dominated portion of delta
Bar Fingers	15 - 20	3 - 5	100 mode	1.89	
Niger Delta (1)	22.9 max.	7.44 max.	32.80	1.06	Beach ridge-barrier island complex
Galveston Barrier (2)	3 - 50	1 - 8	15 - 30	2.27*	Individual sand body
Rhode Delta (1)	31	12.4	32.8	2.39	Coastal barrier sheet sand
Heald Bank (1)	25	4 - 11	26	1.35	Banks reworked from seaward
Sabine Bank (1)	26	4 - 11	15 - 30	1.62	Projecting deltaic lobes
St. Bernard Delta (1)	74.52	8.69	32.80	4.02	Offshore, prodelta sheet sand

*Of this volume, only 0.33 cubic mile is clean well-sorted, fine to very fine grained sand.

- (1) Morgan, J. P., Editor, Deltaic Sedimentation, S.E.P.M. Spec. Publ. No. 15, 312 p.
- (2) Bernard, H. A., and others, 1970, Recent Sediments of Southeast, Texas: Guidebook No. 11, Bur. of Econ. Geol., Univ. of Texas at Austin.
- (3) Coleman, J. M., 1976, Deltas: Processes of Deposition and Models for Exploration, Continuing Education Publ. Co., Inc., Champaign, Ill., 102 p.

The initial areal distribution and volume of sedimentary packages would generally be disturbed by a variety of subaqueous movements that serve to modify normal deltaic depositional patterns, including:

- Peripheral faulting and rotational slumping
- Differential weighting and diapirism
- Radial graben and tensional faulting
- Massive mudflows
- Massive wasting and flowage induced by wave motion and degassing
- A variety of shelf edge arcuate slumping and contemporaneous faulting associated with the shelf edge.^{7/}

Although such mass movements may serve to concentrate sand along growth faults, such movements disrupt initial sandstone geometry and thereby reduce effective reservoir size, as shown by the major sand bodies along growth faults for the Hidalgo, Armstrong, and Brazoria Fairways.^{8/}

Using the distribution of hydrocarbon bearing reservoirs as an analogue, geopressured aquifers will be log normally distributed with respect to volume. Although there is insufficient data to develop an appropriate density function for aquifer volumes, the sand body volumes (which are prior to any secondary tectonics or mass wasting) are probably at the tail end of the higher values of a log normal distribution.

B. Other Key Reservoir Parameters

After areal extent, the next two most important variables are the thickness of the producible net pay and its permeability.

The pay thickness determines reservoir size and influences the production rate (kh) and the slope of the production decline curve. For example, a reservoir with 500 feet of pay (when combined with an area of 50 square miles and permeability of 20 md) will support a 50,000 B/D rate for 10 years; the same reservoir with 200 feet of pay will support a rate of 33,000 B/D for 10 years and one that steadily declines after that time.

Recent geologic data^{9/} indicate that pay thickness may be considerably lower than initially assumed. For example, the recovery estimates of 250 Tcf (Dorfman^{10/}) assumed 1,500 feet of pay. Recent data indicates high porosity, adequate permeability methane bearing pays are in the 300 foot range, about 20% of the initial estimates of pay thickness.

The permeability of a selected geopressed-geothermal interval determines the deliverability of the system and economic feasibility. Hsu shows that the burial of uncemented Pliocene sands in the Ventura Field of Southern California results in a marked decline in permeability with depth due to compaction and to early cementation.

The reported permeabilities for air are therefore higher than may be expected for the flow of aqueous brines. Temperature and pressure have a direct influence on permeability, therefore, laboratory determined values under non-restored conditions must be subject to considerable correction.^{11/}

Based on Hsu's and Bebout's work, corrected permeability for the geothermal systems in the Gulf Coast have reservoir temperatures above 250°F and are probably in a range of 20-30 md, with lower values for the southern Texas coastal area.

Swanson's^{12/} study of 100 wells along the Texas Gulf Coast reports no gas producing horizons below 10,000 feet to have a single-phase permeability as high as 10 mds.

The analysis shows that decreases in permeability can have significant effect on initial production rates. While the initial estimates of recovery were based on assumed permeabilities of 100 md, recent data gathered from geopressed aquifers^{13/} reveal that absolute single-phase permeabilities range from 1.5 mds to 50 mds in the Texas Gulf Coast. Higher permeabilities would be expected in Louisiana.

While the work to date by Bebout, Wallace, Hawkins, and others has greatly expanded the understanding of the geology and reservoir properties associated with geopressed aquifers, much remains to be defined by future research.

C. Geopressed Aquifers of the Texas Gulf Coast

Recently completed work by D. B. Bebout of the Bureau of Economic Geology (University of Texas at Austin) has identified five prospective geothermal/geopressed fairways in the Frio Formation (tertiary) of the Texas Gulf Coast, as shown on Exhibit 6-3. The methane content of the water and gas-in-place for the five identified prospects are as follows:

EXHIBIT 6-3

RESERVOIR PROPERTIES OF PROSPECTIVE FAIRWAYS IN TEXAS

<u>Prospective Fairway</u>	<u>Temperature (°F)</u>	<u>Pressure (psi)*</u>	<u>Dissolved Solids (ppm)**</u>	<u>Permeability (md)</u>	<u>Net Pay (ft)</u>	<u>Area of Individual Sand Body (mi²)</u>	<u>Areal Extent (mi²)</u>
• Hidalgo	300+	11,000	(20,000)	1.5	300	50	500
• Armstrong	250	10,000	(20,000)	20	300	50	50
• Corpus Christi	300	10,000	(20,000)	5	350	4	200
• Matagorda	350	12,000	(20,000)	35	30	4	100
• Brazoria							
- Austin Bayou	325	12,000	60,000	50	300	60	60
- Other	300	11,000	60,000	20	300	50	140

* Assuming a pressure gradient of 0.85 psi per 1,000 feet

** Estimated for Fairways 1-4

	Estimated Methane Content (Cu. Ft/Bbl.)	Gas in Place (Tcf)
• Hialog Fairway	45	6.7
• Armstrong Fairway	35	0.6
• Corpus Christi Fairway	40	2.2
• Matagorda Fairway	55	0.2
• Brazoria Fairway		
-- Austin Bayou	45	0.8
-- Other	40	1.7

D. Geopressured Aquifers of the Louisiana Gulf Coast

1. Analysis of Geopressured Aquifers - LSU

Two recent studies by Hawkins ^{14/} of Louisiana State University and Wallace of the U.S. Geological Survey have gathered valuable geological data on the geopressured reservoirs of Louisiana.

Eight large geopressured aquifers were located and defined by Hawkins in the Louisiana Gulf Coast area. In addition, 55 prospective areas were identified from sand count and pressure maps, however, further geological study is required to ascribe any volumes to these prospective areas.

Based on the available reservoir data on the eight identified areas, the natural gas content of the geopressured water is estimated by Hawkins at 13.6 Tcf. However, Hawkins qualifies this gas in place estimate with the following statement:

"The reader is cautioned to realize that these figures tell only the estimated total energy in place and that at this point very little is known about (a) the rate at which geopressed energy could be produced, and (b) the fraction of the total geopressed energy resource which occurs in aquifers which are large enough to warrant drilling even one well. . . much of this geopressed water is contained in aquifers far too small to justify the drilling and completion of a single well, much less a cluster of wells."

The methane content for these eight areas is estimated as follows:

Prospective Area	Reservoir Properties			Estimated Methane Content (Cu.Ft/Bbl)
	Temperature (°F)	Pressure (psi)	Dissolved Solids (ppm)	
• Newton	190	7,000	80,000	14
• S. Midland	250	10,000	80,000	21
• N. Lake Arthur	240	9,000	80,000	20
• W. Lockport	220	10,000	80,000	19
• W. Maurice	250	11,000	80,000	25
• S. White Lake	280	9,000	80,000	25
• Big Mouth Bayou	200	8,000	80,000	17
• SE Peron Island	270	12,000	80,000	28

2. Analysis of Geopressed Aquifers - USGS

A second effort currently underway by USGS (Wallace) involves analysis of over 1,000 wells covering about 75,000 square miles from onshore and off-shore Louisiana.

The analysis has identified about 6,000 Tcf of gas in place for the full depth interval of 2,000-19,000 feet. Approximately half of the area was onshore (half offshore), and the geopressured zone begins at about 10,500 feet of depth. Thus, about 800 Tcf of gas in place is in reservoirs that are both geopressured and onshore.

Using data on temperature, pressures, and salinities from USGS, the following methane concentrations were determined for the geopressured interval 10,500 to 19,000 feet:

Prospective Area	Reservoir Properties			Methane Content (Cu.Ft./Bbl)	GIP Onshore (Tcf)
	Temperature (°F)	Pressure (psi)	Salinity (ppm)		
10,500-11,000	210	8,000	110,000	16	95
11,000-12,000	220	9,000	100,000	18	160
12,000-13,000	230	9,000	90,000	19	150
13,000-14,000	240	10,000	90,000	21	115
14,000-15,000	250	11,000	80,000	26	90
15,000-16,000	260	12,000	70,000	31	85
16,000-17,000	220	13,000	50,000	37	60
17,000-18,000	280	13,000	50,000	42	25
18,000-19,000	290	14,000	50,000	47	20
TOTAL					800

Little data is available on areal size or permeability of the south Louisiana geopressured aquifers.

A. Calculation of Production Rates by Fluid Expansion

The mechanics of fluid flow through an aquifer were used to determine the potential producing or injection rates for geopressed aquifers. For purposes of this study, a pseudo-steady state formula was used to calculate fluid flow.

This pseudo-steady state formula describes the pressure behavior of a well producing from a bounded, uniform, homogeneous, isotropic reservoir, after the pressure disturbance of the well has reached the boundaries of the reservoir. The downhole pressure P_w^* of the well is given by:

$$P_w = P_i - \frac{70.6 q \mu}{kh} [\ln (A/r_w^2) + \ln (2.2458/(C_A)) + 2s] \\ - \frac{5.6146 qt}{\phi chA}$$

The range of application of this equation may be found for a variety of reservoir shapes.

* The surface, or wellhead pressure, in turn is equal to:

$$P_s = P_w - \text{Hydrostatic Head Friction Loss}$$

$$P_s = P_w - \rho gh - f \cdot q^2$$

Where h is the depth to the aquifer and f is a friction factor based on tubing size. For 5 1/2" tubing, $f = 9.7201 \times 10^{-7}$ with q in barrels per day.

To determine possible producing rates of aquifers, the above equation can be rearranged in a form more suitable for direct application. First, the following terms are defined:

PI - the productivity index:	$PI = q/h(P_i - P_w)$
η - the hydraulic diffusivity:	$\eta = .00633 \text{ k}/\phi\mu c$
C_A - the shape factor	$C_A = 30.8828$ for one well in the center of a square
r_{we} - the effective wellbore radius:	$r_{we} = r_w C_A e^{-s/C_A}$ for varying shape factor and skin effect
P_{DO} - a dimensionless function:	$P_{DO} = 1/2 [\ln(A/r_w^2) + \ln(2.2458/C_A) + 2s]$

With these definitions, the above equation may be restated as:

$$PI/\phi c \text{ (BPD/ft)} = 21.3/(t(\text{yr})/A(\text{AC}) + 18.97P_{DO}/\eta \text{ (ft}^2/\text{day)})$$

This equation can be used to determine the constant rate of production, q , that can be maintained from the reservoir for a period of time, t , given that $(P_i - P_w)$ has a maximum value. The maximum value of the latter is set by the value of P_i and the minimum value of P_w required to lift the fluid at a rate of q barrels per day to the surface.

The equation can be solved analytically, or graphs can be prepared for routine solutions.

In general, the pseudo-steady equation is sufficient for determining the possible long-term sustained production rate.

B. Additional Considerations

Two additional topics need development before these equations can be used for estimating production and injection.

First, the effective wellbore radius concept may be used to account for changes in formation properties near a well by using a skin effect, and also may be used to consider the effects of clustered producing wells, such as were described by Bernard.^{15/} The clustered wells equivalent wellbore radius is described by Muskat^{16/} for several cluster configurations, and the productivity index determined from the above equation using that effective radius will be the index for the entire cluster.

Second, reinjection of produced waters into the same aquifer from which they were removed should be examined. After the pressure distribution between the injection and production wells reaches a steady-state, the injectivity I is given by:

$$I \text{ (BPD/ft/psi)} = \frac{0.00708 \text{ } k \text{ (md)}}{\mu(\text{cp}) \ln \left[\frac{25260 \text{ } A(\text{Ac})}{r_{we}^2 \text{ (ft)}^2} \right]}$$

for a five-spot network, where the injectivity is defined as the production rate per well per foot of net pay interval divided by the downhole pressure differential between the injection and production wells.

C. Analysis of Production Rate

The rate of production from geopressed aquifers is determined by the interplay of numerous reservoir and fluid properties. Within the range of conditions expected to be encountered in the geopressed aquifers, however, many of these have relatively small effect. In general, production rate is governed by six critical factors:

- Compressibility
- Permeability
- Net pay thickness
- Area
- Porosity
- Pressure

The effect of these variables on the production rate is analyzed below.

To illustrate the results that can be calculated by the foregoing analysis, a geopressed reservoir with the following parameters will be considered:

Permeability	20 mds.
Porosity	21.6%
Compressibility	$11 \times 10^{-6} \text{ psi}^{-1}$
Wellbore radius	0.275 feet
Water viscosity	0.119 cp
Formation thickness	162 feet
Initial pressure	11,000 psi
Depth to formation	13,000 feet
Wellhead pressure	500 psi

1. Compressibility

The compressibility coefficient (c) is defined as the fractional change in the pore volume per unit change in pressure. It reflects the combined effects of water compression, rock matrix compression, and compaction of the formation.

While the compression coefficient of water is well known (at approximately $3 \times 10^{-6} \text{ psi}^{-1}$), little data exists regarding the compression coefficient for the matrix rock or the compaction coefficient for geopressured reservoirs, thus introducing an additional bound of uncertainty in estimates of potential production rate. A compressibility significantly greater than 10^{-5} would be anticipated only if the formation had not been at some time in its history subjected to compaction stresses and/or well consolidated.

The counterbalancing effects of high compressibility coefficients, however, could be severe:

- Permeability near the wellbore will be dramatically lowered as production draws down the reservoir pressure.*
- Risks of environmentally serious subsidence increase, probably necessitating reinjection of the produced water into the geopressured aquifer.
- High compression coefficients that imply "soft" reservoirs could, because of high sand flow, be rejected as technologically infeasible to complete or produce.

* Producing well problems are discussed further below.

Because of the vast unknowns concerning compressibility, a relatively optimistic coefficient of $11 \times 10^{-6} \text{ psi}^{-1}$ was assumed throughout the analysis.

As can be seen from Exhibit 6-4, the average production rates calculated for 10 and 20 years are not much different from the values in Randolph's base case^{17/} for $c = 11.12 \times 10^{-6} \text{ psi}$. The circles of Exhibit 6-4 are the result of solving the equation on page 6-17 for a declining production rate and constant well pressure by using an effective time equal to the cumulative production divided by the producing rate at any given time. The average producing rate calculated with this method is 29,300 BPD at 10 years and 25,700 BPD at 20 years.

This method can also be compared to computer simulation studies, such as those of Knapp, et. al.^{18/} The Knapp study was performed with a constant producing rate, but pressure differentials cannot be directly compared between the two methods because a simulator cannot properly account for a well; instead, a wellbore grid block (or rather large size) was used. At pseudo-steady state, though, the pressure decrease with time is constant throughout the reservoir; hence, the slope of the pressure line with time can be used to compare the two methods. The slope of the pressure curve for Run 1 of the Knapp study is about 620 psi/year; the slope predicted by the simplified model of equation is 630 psi/year for a typical water compressibility of $3 \times 10^{-6} \text{ psi}^{-1}$. This close agreement indicates both methods function in a similar manner.

It is also to be noted that compressibilities above 10^{-5} have a progressively smaller effect on 10 and 20 year production volumes.

EXHIBIT 6-4

EFFECT OF COMPRESSION DRIVE COEFFICIENT (C_e)
UPON PRODUCTION HISTORY

2. Permeability, Thickness, and Area

Assuming a fixed compressibility coefficient and the other baseline reservoir data on the sample reservoir, the production from geopressed aquifers is governed by permeability, thickness, and areal extent.

For analytic purposes, constant rates were estimated at permeabilities of 5, 10, 20, 50 and 100 md; net pay of 100, 200, 300, and 500 feet; and areas of 5, 10, 20, 50 and 100 square miles.

Exhibits 6-5 and 6-6 show the relationship of production rate to net pay and permeability for a small (5 square miles) and a large (50 square miles) reservoir.

3. Influence of Reservoir Parameters on Production Rate

The analysis shows that economic exploitation will require reservoirs of substantial size. Of the three parameters varied in the analysis, over the likely range of parameters considered, formation thickness (net pay) shows the most marked effect on production rates, followed closely by areal extent and permeability. If the lower methane content reservoirs (with gas contents of 40 cf/bbl or less) are to be produced at affordable gas prices, reservoirs of over 3 cubic miles (50 square miles x 300 feet in thickness) will be required to provide the minimum required flow rates to pay back investment.

D. Reinjection of Water Into the Producing Aquifer

The recovery efficiencies may be greatly increased by injecting the produced water into the geopressed aquifer. Exhibit 6-7 shows the steady-state injection rate for reinjection into the geopressed aquifer,

EXHIBIT 6-5

TEN YEAR AVERAGE PRODUCTION RATE AS A FUNCTION OF
NET PAY, PERMEABILITY, AND AREA

(Reservoir Area = 5 mi²)

EXHIBIT 6-6

TEN YEAR AVERAGE PRODUCTION RATE AS A FUNCTION OF
NET PAY, PERMEABILITY, AND AREA

(Reservoir Area = 50 mi²)

assuming the reinjected water has a temperature of 150°F and using the equation on page 6-18 to calculate injectivity. A well density of one well per section has been used. The reinjection curve stops at a surface injection pressure of about 6,500 psi to prevent fracturing of the formation. Such fracturing might allow the leakoff of injected fluid to other formations and reduce the recovery efficiency possible with reinjection. A transient period would occur before a steady-state pressure profile could be achieved and, during this transient period, a volume of water must be permanently removed from the geopressed aquifer and disposed to allow the average pressure to decline sufficiently that reinjection would occur at pressure below the fracture pressure. Exhibit 6-8 shows the amount of water which must be permanently removed from the geopressed aquifer and the resulting average reservoir pressure after removal of such water.

If the steady-state reinjection pressure were stabilized at 5,000 psi, then 20,000 barrels per day per producing well might be sustained (from Exhibit 6-8); in this instance, the 20-year cumulative production would correspond to about half of the in-place resource, compared to about 5% recovery for the same well density without reinjection. To achieve 5,000 psi surface injection pressure at steady-state, however, it would be necessary to dispose 3.8 million barrels of water per square mile of production.

E. Disposal of Produced Water

Water disposal into shallow (6,000 ft+), normally pressured aquifers may be feasible. Because parameters for the shallow aquifers are not available, a "best case" computation was made. If the shallow aquifers are 1,000 feet thick with a porosity of 30% and a permeability in excess of 100 md,

EXHIBIT 6-7
TYPICAL INJECTIVITY CURVES

EXHIBIT 6-8

AMOUNT OF WATER TO BE DISPOSED OF TO ALLOW
FORMATION OF A STEADY STATE PRESSURE PROFILE

then assuming one injection well per section, the 10- and 20-year injection rates may be estimated using the second equation. The quantity q is now the injection rate rather than the production rate. The injection rates for this "best case" are shown on Exhibit 6-7. High injection pressures would be needed to dispose of large volumes of water, even for this "best case" of aquifer parameters; however, Exhibit 6-7 shows that pressures are limited for injection into shallow aquifers. If surface injection pressure exceeds a value of about 2,000 psi, then the confining layers of the shallow aquifer would be hydraulically fractured and water would no longer be injected into the shallow aquifer, but rather into the created surface. At some point in time, the fracture might even extend to the surface. To avoid fracturing of the confining layers, exceedingly large volumes of water cannot be injected into the shallow aquifers; hence, they would probably be unsuitable for disposal of all produced water.

The analysis of the previous paragraph indicates that a combination of injection into shallow, normally pressured aquifers and reinjection into the producing geopressed aquifers might be the best course to pursue. An optimal course of action would consider the amounts of water which could be injected into the shallow aquifers without inducing fracturing, the costs of shallow aquifer injection and other methods of disposal compared to the cost savings of a reduced system pressure for reinjection into the geopressed aquifer, and the additional resource recovery possible with reinjection into the geopressed aquifer as compared to no injection into the geopressed aquifer.

F. Producing Well Problems

No changes in formation properties, as a result of production or injection, have been considered in the above analyses. In general, such changes would have the largest effects in the vicinity of wells and

may be estimated by using calculations based on the skin effect. The well known formula for the skin effect is:

$$s = (k/k_s - 1) \ln (r_w/r_w)$$

where the subscripts denote the damaged region. Thus, if a zone of 10 feet around a well radius to 0.2 ft. has a permeability reduction of 90%, the skin effect would be:

$$s = (k/(k - .9k) - 1) \ln (10/.2) = 35$$

Typically, the evolution of a free gas phase will reduce the relative permeability to water. The magnitude of this reduction may be estimated from the Wylie-Gardner relations,^{19/} although a significant gas saturation might cause only an 8% reduction in fluid permeability.

The permeability reduction, due to compaction, may be estimated by considering that permeability and porosity are related by a power law formula with an exponent on porosity of about six.^{20/} The reduction in permeability is then given by $1 = \exp (-6 c \Delta P)$; for a drawdown in fluid pressure of 5000 psi and a porosity compressibility of $10 \times 10^{-6} \text{ psi}^{-1}$, a 26% reduction in permeability due to compaction might be expected.

However, if migration of silts or clays or precipitation of salts* from solution reduced the porosity near a wellbore by a factor of two, then a 98% reduction in permeability might be expected. If such were the case, the effects of gas breakout and compaction on permeability could be neglected.

* Production of a geopressed system will result in a pressure differential occurring between the reservoir and the wellbore. This could result in the precipitation of CaCO_3 and SiO_2 , both of which are present in high concentrations for many of the geothermal prospects.

Exhibit 6-9 indicates the possible consequences of permeability reduction on producing rates. The effect of permeability reduction, near the well, is normally minor for small well spacing (1280 acres or less). For larger distances between producing wells, the effect may be considerable, amounting to three-fold reduction in the sustainable flow rate of a well if the permeability were reduced by 90% in a region of 10 feet around the well. A similar reduction in permeability for a reinjection scheme might reduce the rate by a factor of 8. Although the actual value of the skin factor must be determined from actual production or reinjection behavior, the results of these calculations indicate permeability in the vicinity of the well may markedly affect the sustained rates of the wells.

Compaction may be a problem if the compressibility of the geopressured aquifers is as high as has been assumed. The effective compressibility of the formation used in the fluid flow equations is:

$$c_e = c_p + c_w$$

where c_p is the formation or pore compressibility and c_w is the compressibility and saturation of water. If total reservoir compressibility is about 1.0×10^{-5} , then c_e is 7×10^{-6} . Further, if it is assumed that no lateral strain occurs, $\frac{\Delta h}{h} = c_f \phi$. For a porosity of 20% and a pressure drop of 5000 psi, $\frac{\Delta h}{h} = 7 \times 10^{-3}$. A 200 foot section would therefore compact 1.4 feet. Since this compaction would occur around the wellbore, a problem in maintaining the integrity of the linear might arise.^{21/}

However, the pressure drop through the reservoir, at the economic limit of operation (2 to 5% of the fluid removed), would be far less than 5000 psi, hence, no great problem due to subsidence would be anticipated; nor for the same reason would any great influx of water from the shales be expected as a result of pressure reduction-caused dewatering of the shales.

EXHIBIT 6-9

EFFECT OF PERMEABILITY PRODUCTION NEAR THE WELL
ON SUSTAINED PRODUCING RATE

G. The Potential for Producing Geopressured Aquifers at Gas/Water Ratios in Excess of Solution Values

Recently, the possibility that geopressured aquifers might be produced at gas/water ratios in excess of the ratio that exists in solution has been posed. This hypothesis stems from experience with the production of crude oil reservoirs where, following a decline in pressure below the bubble point (saturation pressure), the gas/oil ratio increases dramatically. With a decline in pressure, however, gas is released from solution, accumulates within the reservoir to reach a critical saturation (where gas flow ensues), and then because of its high mobility compared to crude oil, flows to the wellbore faster than does the crude. The additional gas (over the initial solution gas ratio) stems from crude oil deep within the reservoir and is not the gas originally associated with the produced oil.

Before the gas/oil ratio increases, a critical gas saturation must be reached, generally assumed to be about 2 to 3% of a pore volume. (There is a question about the real value since minute flows of gas in laboratory systems, where such measurements of critical gas saturation are made, may not be recognized.)

The essential question is: *How much production must occur below the bubble point pressure for the gas/oil (gas/water) ratio to increase significantly?*

Handy^{22/} has shown by simulating the depletion process in the laboratory that some 5 to 8% of the reservoir fluid had to be produced before the gas/oil ratio turned upwards. The gas saturation was about 5% when this increase occurred. The reasons given for this delay in high

gas/oil ratios were attributed to supersaturation effects and the fact that dispersed gas bubbles liberated around the well were driven into the well by the pressure gradients of the flowing fluid.

The second question, then, is: *What is the critical effective gas saturation?*

For crude oil reservoirs, with solution gas ratios in the hundreds and even as high as 1000 to 2000 cubic feet per barrel, there is no problem in accounting for the release of sufficient gas with continuing crude oil production to reach a critical gas saturation of 2 to 5%. However, in the case of geopressured brines containing only 40 cubic feet per barrel or less, reaching a critical gas saturation is more difficult. Should the reservoir pressure of a geopressured aquifer decrease from 11,000 psi to 6,000 psi (approximate economic limit), the equilibrium gas saturation decreases from 40 scf/B to 30 scf/B. At 6,000 psi, the released 10 scf/B will occupy a reservoir pore volume of only 0.7%. The value of 0.7% is significantly less than any reported or presumed value for an effective critical saturation.

It has been suggested, based on the performance of the Edna Delcambre, et. al. No. 1 well,^{23/} that the geopressured aquifers may contain initially a free gas saturation of 6%, or higher, which is nevertheless below the critical gas saturation for significant gas flow. On the release of a small (less than 1%) quantity of gas from solution, it has been suggested that the critical gas saturation is surpassed, resulting in high gas/water ration production. The data to date on the well is inadequate to confirm such a hypothesis. The equilibration times of the test were short, there was a large drawdown,

and no test was made of the possibility that communication behind pipe to a free gas cap or gas pocket may have been occurring.

A reservoir with a 6% free gas saturation would be, in effect, a geopressured gas reservoir and beyond the bounds of the resource analyzed in this study. Its size and economic potential should be analyzed with reference to the industry's conventional history of developing such wells.

II. PRODUCTION AND RECOVERY MODELS
FOR GEOPRESSURED AQUIFERS

III. THE ECONOMIC MODEL

A. Basis for the Derivation

Economic recovery of methane from geopressured aquifers depends on meeting two minimum conditions:

- That the economic value of the gas* contained in one barrel of produced water at least repay the operating costs of producing and disposing of that barrel of water; and
- That the rate of production be sufficiently high to repay the investment costs of the project.

These two factors, total methane content and production rate, are the two critical economic variables and provide a direct means for representing the numerous geologic and reservoir characteristics that influence these variables. In turn, the minimum required methane content and production rate are based on the operating, investment, and return on capital costs associated with the recovery technology.

* The analysis considered the production of methane as the primary purpose and did not consider either the cost or the output value of thermal or hydraulic energy recovery. This was done for two reasons. First, the examination of thermal/hydraulic energy recovery was specifically excluded from the scope of this effort. Second, much of the area defined as being geopressured had temperatures between 200-300°F and thus had relatively low potential for thermal energy output. (The theoretical thermal output at 200°F is about 1/5 of the thermal output at 325°F.)

1. Operating Costs

Overall operating costs are composed of four elements:

- General operating and maintenance costs (except for power).
- Capital depreciation on well production and disposal equipment (except for the well).
- Power costs involved in water disposal.

Estimates of these costs were developed from theoretical energy balance equations and from field experience with water production and disposal.

- General operating and maintenance costs, excluding power, to operate the water handling and methane extraction were estimated at \$0.0125 per barrel of water produced. Adding a factor of 20% to cover overhead costs raises this amount to \$0.015 per barrel of water.
- Capital depreciation costs were estimated at \$0.0125 per barrel of water produced. This cost assumes an initial investment (for separation and handling facilities) of \$20.00 per barrel of daily capacity (e.g., a 40,000 barrel per day facility would require \$800,000 of investment costs), a 20 year life, and a 15% return on capital. Adding a factor of 10% to cover overhead costs raises this cost to \$0.014 per barrel of water.

- Well operating and maintenance costs, to operate and maintain the production well and the four injection wells, were estimated at \$100,000 per year plus 20% for overhead costs. At production rates of 35,000 to 40,000 barrels per day, well operating and maintenance costs would be \$0.01 per barrel of water.
- Power costs* were derived from the energy required to inject water into a two thousand net foot, hundred millidarcy, shallow salt water aquifer. This cost assumes a required average disposal wellhead pressure of 1,000 psi and \$0.04 per Kw hr marginal cost for a newly built power plant dedicated to large industrial use electricity. Making power costs of disposal a direction function of gas price provides the following equation:

$$\text{Power costs} = [\$0.01 + \$0.005 (\text{price of natural gas in } \$/\text{Mcf})] \times \text{Disposal pressure } (P_i \text{ in ksi})$$

- Combining the four components provides the following cost equation:

$$\begin{aligned} \text{Total costs per barrel of water} = \\ \$0.04 + [0.01 + 0.005 (\text{price in } \$/\text{Mcf})] \times \\ P_i (\text{ksi}) \end{aligned}$$

* The power P_{wr} required to pressure the water for injection is determined from:

$$P_{wr}(\text{Hp}) = P_{inj} (\text{psi}) q (\text{BPD}) / 58766 \epsilon$$

OR

$$P_{wr}(\text{kw-hr/day}) = P_{inj} (\text{psi}) q (\text{BPD}) / 3284 \epsilon$$

Where ϵ is the efficiency of the pump. Pump efficiencies are commonly in the range of 80 to 90 percent for positive displacement pumps.

Since operating costs have such a major and direct effect on the economics of producing methane from geopressured aquifers, these costs were validated by comparison with actual costs of the major water disposal company in East Texas and with independently derived cost estimates by outside consulting engineers.

To obtain a check on the general O&M and power costs involved with water disposal, the study examined the operating costs of the East Texas Water Disposal Company, the major water disposal operator in Texas. In the first 10 months of 1976, this company disposed, on average, 583,000 barrels of water a day, at an average injection pressure of 1,000 psi, at an operating cost of \$4,560,000. This is equivalent to \$0.026 per barrel.

Four steps were taken to make these costs comparable to operating a geopressured production system:

- Costs of \$0.007 per barrel were added to cover the operating and maintenance on the production well.
- Costs of \$0.014 per barrel were added to account for depreciation of the separation and handling facilities.
- Costs were increased by 10% to account for inflation since 1976.
- The price of electricity was assumed at \$0.03 per Kw hour.

Using the East Texas Water Disposal Company costs as a base with the above four adjustments, the empirical costs would be:

$$\bullet \quad \$0.005 + \$0.014 + (1.1 \times \$0.026) = \$0.048$$

Adjusting the operating cost estimate in the study for lower capital cost electricity (from old plants) and using \$1.00 per Mcf equivalent for the fuel price, the 1977 operating costs used in the study are:

$$\bullet \quad \$0.04 + \$0.005 + \$0.005 (\$1.00) = \$0.05$$

Rounded to the nearest \$0.01, the study's operating costs are equivalent to the empirical costs experienced by the East Texas Water Disposal Company.

2. Investment Cost Estimate

The investment costs are based on drilling, completing, and equipping a 17,000 foot well, onshore, using 7.0 inch casing. The cost items are provided below:

• Drilling costs @ \$80 per foot	\$1,360,000
• Tubing and well equipment	960,000
• Reinjection costs Four 5,000 ft. wells @ \$40 per foot (drilled, completed, and equipped, including pump)	800,000
• Dry hole and uneconomic wells cost at 1 in 4*	<u>450,000</u>
Subtotal	\$3,570,000
• Overhead and G&A @ 10%	<u>357,000</u>
TOTAL	\$3,927,000

* The essentially exploratory nature of the envisioned drilling program, and the large (areal) step-outs required from one reservoir to another, may lead to large numbers of "dry" (uneconomic) wells. Hence, the dry hole rate could easily be substantially larger, raising the investment costs by \$1,000,000 over the numbers shown above.

For the analysis, the investment cost was set at \$4,000,000, incurred one year in advance of first year production. These data are consistent with Joint Association Survey cost data and industry estimates.

3. Decision Criteria

Because of the many major uncertainties still associated with the geology, engineering, and disposal requirements, the simple payback approach was adopted as the financial decision criterion. Two payback rates were used to reflect differing risk premiums: (a) 10 year payback, before tax (equivalent to a low risk rate of return of about 8-10%); and (b) 5 year payback, before tax (equivalent to a higher risk rate of return of about 20%).

Given the considerable uncertainties and risks inherent in recovering methane from geopressured aquifers, the current investment criterion would be a 5 year payback; successful research and development could, in time, lead to lower risk premiums, as posed in the Advanced Case.

4. Approach to the Analysis

The analysis followed three steps: (a) calculating the minimum required methane content per barrel of produced water to pay operating and water disposal costs; (b) determining the required production rate/methane content combination required to pay back the initial investment under high and low risk investment criteria; and (c) combining these analyses to compute the overall methane content and flow rate requirements. The analyses assumed a recovery efficiency of 85% of the methane dissolved in the brine, 12.5% royalty, and 8% severance and other taxes. The analysis was conducted for gas prices of \$1.75, \$3.00, and \$4.50 per Mcf.

B. Minimum Required Methane Content to Cover Operating Costs

Based on the above operating cost estimates, the following equations define the minimum required methane content to cover operating costs, assuming 1,000 psi injection pressure and 85% methane extraction efficiency:

- $0.8 (\text{price in } \$/\text{Mcf}) \times (\text{recoverable methane per barrel}) \geq \$0.04 + [\$0.01 + 0.005 (\text{price in } \$/\text{Mcf})] \times P_i (\text{ksi})$
- Methane content per barrel (in Mcf) $\geq \frac{\$0.073}{\text{price in } \$/\text{Mcf}} + 0.007$
(Assuming 85% recovery)

Solving for the three prices of \$1.75, \$3.00, and \$4.50 per Mcf provides the following minimum required methane content to cover operating costs, as a function of price:

<u>Price Per Mcf</u>	<u>Minimum Required Methane Content (cu. ft./bbl.)</u>
\$1.75	50
\$3.00	30
\$4.50	23

The production costs equation is assumed the same across all production rates.

C. Minimum Required Production Rate and Methane Content to Cover Investment Costs

Using the above investment cost assumptions, the following equation defines the minimum required production rate and total recovery to pay back investment costs:

$$\bullet \text{ Methane Content per Barrel of Water (Mcf)} \geq \frac{\$4,000,000}{(365 \times \text{Rate (B/D)} \times \text{Years}) \times 0.8 \text{ Price/Mcf} \times 0.85}$$

Solving the equation for four production rates of 20,000, 40,000, 60,000, and 80,000 B/D and for the 5-year and 10-year before-tax payback criteria, provides the following minimum required combinations of production rate and incremental methane content to cover investment costs, as a function of price:

<u>Price Per Mcf</u>	<u>Production Rate (B/D)</u>	<u>Minimum Required Methane Content (Cu. Ft./Bbl.)</u>	
		(10-year payback)	(5-year payback)
\$1.75	20,000	46	92
	40,000	23	46
	60,000	16	31
	80,000	12	23
\$3.00	20,000	27	54
	40,000	14	27
	60,000	9	18
	80,000	7	14
\$4.50	20,000	20	40
	40,000	10	20
	60,000	7	13
	80,000	5	10

The lower the production rate, the higher the required methane content. The shorter the payback requirement, the higher the required methane content. Both relationships are linear.

D. Minimum Required Production Rate/Methane Content
Combination to Cover Operating and Investment Costs

Combining the analysis of operating and investment costs establishes the minimum required combination of well production rate and methane content, as follows:

MINIMUM REQUIRED PRODUCTION RATE AND METHANE CONTENT

Price (\$/Mcf)	Rate (B/D)	Methane Content (Cu. Ft./Bbl.)			
		Coverage of Operating Costs	Payback of Investment Costs (10 yrs - 5 yrs)		TOTAL
\$1.75	20,000	50	46	- 92	96 - 142
	40,000	50	23	- 46	73 - 96
	60,000	50	16	- 31	66 - 81
	80,000	50	12	- 23	62 - 73
\$3.00	20,000	30	27	- 54	57 - 84
	40,000	30	14	- 27	44 - 57
	60,000	30	9	- 18	39 - 48
	80,000	30	7	- 14	37 - 44
\$4.50	20,000	23	20	- 40	43 - 63
	40,000	23	10	- 20	33 - 43
	60,000	23	7	- 13	30 - 36
	80,000	23	5	- 10	28 - 33

Exhibit 6-10 provides the graph of the minimum required production rate and methane content for the five year payback case (the current high risk situation). Exhibit 6-11 provides the graph for the 10 year payback case and assumes that future resource characterization, technology development, and demonstration will reduce the risk.

EXHIBIT 6-10

MINIMUM REQUIRED PRODUCTION RATE AND METHANE CONTENT
FROM GEOPRESSURED AQUIFERS (UNDER FIVE-YEAR PAYBACK)

EXHIBIT 6-11

MINIMUM REQUIRED PRODUCTION RATE AND METHANE CONTENT
FROM GEOPRESSURED AQUIFERS (UNDER TEN-YEAR PAYBACK)

CHAPTER SIX

BIBLIOGRAPHY

- 1/ Bebout, D. G., Loucks, R. G., and Gregory, A. R., "Geopressured Geothermal Fairway Evaluation and Test-Well Site Location - Frio Formation, Texas Gulf Coast", prepared for the U.S. Energy Research and Development Administration, May 1977.
- 2/ Unpublished work on over 1,000 well logs and records in Southern Louisiana.
- 3/ Powers, M. C., Fluid Release Mechanisms in Compacting Marine Mudrocks, AAPG, Vol. 51/7, July 1967, p. 1240.
- 4/ Timko, D. J., and Fertl, W. H., Relationship Between Hydrocarbon Accumulation and Geopressure and Its Economic Significance, JPT, XXIII, August 1971, p. 923.
- 5/ Wilson, T. and Osborne, "The Likely Sizes and Reservoir Parameters of Geopressured Aquifers", University of Southern California, 1977 (in press).
- 6/ Brown, W. M., Res. Memo No. 31, 1976, Hudson Institute, Croton on Hudson, New York. Also see Fortune Magazine, October 1976, p. 219.
- 7/ Coleman, J. M., Deltas: Processes of Deposition and Models for Exploration, Continuing Education Publication Company, Inc., Champaign, Illinois, 1976.
- 8/ Bebout, et. al., Op. Cit.
- 9/ Wilson and Osborne, Op. Cit.
- 10/ Dorfman, M. H., Gas Supply Review, Vol. 5, No. 6., March 1977, American Gas Association, Gas Supply Committee.
- 11/ Bebout, et. al., Op. Cit.

Chapter Six
Bibliography
Page 2

- 12/ Swanson, R.K., Oetking, P., Osoba, J.S., and Hagens, R.C., 1976, Development of an Assessment Methodology for Geopressured Zones of the Upper Gulf Coast Based on a Study of Abnormally Pressured Gas Fields in South Texas. Southwest Research Institute, San Antonio, Texas, prepared for ERDA, p. 75.
- 13/ Bebout, Op. Cit.
- 14/ Hawkins, Murray F., Investigation on the Geopressured Energy Resource of South Louisiana, ORO-4889-14, Louisiana State University, April 15, 1977.
- 15/ Bernard, W.J., "Reservoir Mechanics of Geopressured Aquifers," contained in Proceedings of First Geopressured Geothermal Energy Conference, University of Texas at August, June 2-4, 1975, pp. 157-171.
- 16/ Muskat, M., The Flow of Homogeneous Fluids Through Porous Media, McGraw-Hill Book Company, Inc., New York (1937), pp. 511-518, 537.
- 17/ Randolph, P.L., "Natural Gas for Geopressured Aquifers", paper SPE 6826 presented at the 52nd Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, Denver, Colorado, 1977.
- 18/ Knapp, R.M., Isokrari, O.E., Garg, S.K., and Pritchett, J.W., "An Analysis of Production from Geopressured Geothermal Aquifers", paper SPE 6825 presented at the 52nd Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, Denver, Colorado, 1977.
- 19/ Wylie, M.R.J., and Gardner, G.H.F., "The Generalized Kozemy-Carman Equation", World Oil, Vol. 146, March and April, 1958.
- 20/ Schlumberger, Limited, "Log Interpretation Charts", Schlumberger Ltd., 1972.
- 21/ Harville, D.W., and Hawkins, M.F., 1969, Rock Compressibility and Failure as Reservoir Mechanisms in Geopressured Gas Reservoirs, Journal of Petroleum Technology, December 1969.

Chapter Six
Bibliography
Page 3

- 22/ Handy, L. L., A Laboratory Study of Oil Recovery by Solution Gas Drive, AIME, Petroleum Trans., 213, 1958, p. 210.
- 23/ Gulf Universities Research Consortium, Houston, Texas, Report No. 161, September 1977.