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Prepared for the U.S. Department of Energy **October 1978**

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

Enhanced Recovery of Unconventional Gas

The Program — Volume II (of 3 Volumes)

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Enhanced Recovery of Unconventional Gas

The Program — Volume II (of 3 Volumes)

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NOTE: This document was prepared for the Energy Research and Development Administration (ERDA) prior to the activation of the Department of Energy (DOE) by the Energy Reorganization Act. Therefore, wherever ERDA is mentioned, its functions have been transferred to DOE.

MARGIN INDEX

REVIEW DRAFT NOTE

This report consists of three volumes:

Volume I: Executive Summary

Volume II: The Program

Volume III: Methodology

Because of demand for the results of this study, review drafts of the first two volumes are being published before Volume III is complete. A draft of Volume III will be issued shortly, at which time it will receive the same distribution as Volumes I and II.

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CHAPTER ONE

SUMMARY OF THE REPORT

I. INTRODUCTION

As the conventional domestic natural gas supplies dwindle, the nation must seek ways to slow these trends and to obtain new supplies. The choices faced are controversial, costly, and risky. They entail difficult balancing among higher prices, accelerated development, reliance on imports, and new technology.

This study* has been conducted to assist public decision-makers select among many choices by addressing two questions:

- *How severe is the need for additional future supplies of natural gas?; and*
- *What is the economic potential of providing a portion of future supply through enhanced recovery from unconventional natural gas resources?*

Beyond the analysis of these two questions, the study serves to assist the Department of Energy** to:

- *Design a cost-effective research and development program to stimulate industry to recover this unconventional gas and to produce it sooner.*

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* Attachment A to this chapter outlines the overall approach to the analysis.

** During the course of the study, the Energy Research and Development Administration (ERDA) became part of the Department of Energy (DOE).

II. BACKGROUND

Until recently, the more conventional sources provided enough natural gas to meet the nation's demands. It was neither necessary nor economic to develop anything more than the discovered, conventional reservoirs, or the "cream" of the unconventional resources.

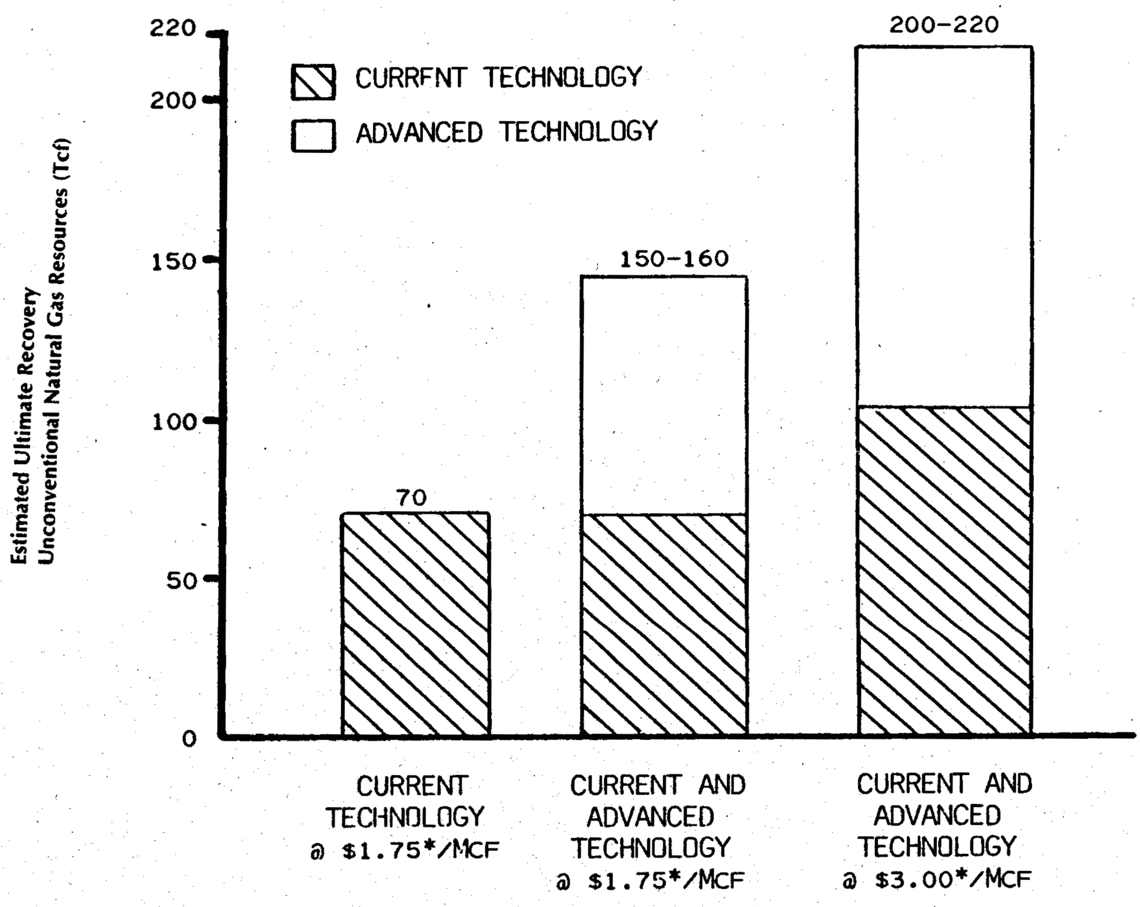
Now, sharply declining production necessitates re-examination of this posture. This study finds that research and technology development in enhanced gas recovery -- tapping unconventional gas sources -- can substantially augment domestic natural gas supply in the near term as well as the long term.

A combination of economic incentives and publicly sponsored R&D could ultimately add 200 to 220 Tcf (trillion cubic feet) of gas supply from unconventional sources (Exhibit 1-1).

- The contribution of the unconventional sources, even under current technology and gas price of $1.75/Mcf, is substantial -- 70 Tcf.
- Introducing advances in the technology increases the total to 150-160 Tcf.
- Combining a price of $3.00/Mcf (or its economic equivalent) with advanced technology raises the potential of gas from unconventional sources to 200-220 Tcf -- equal to current domestic proved reserves.

Exhibit 1-1

The Potential of Gas from Unconventional Sources

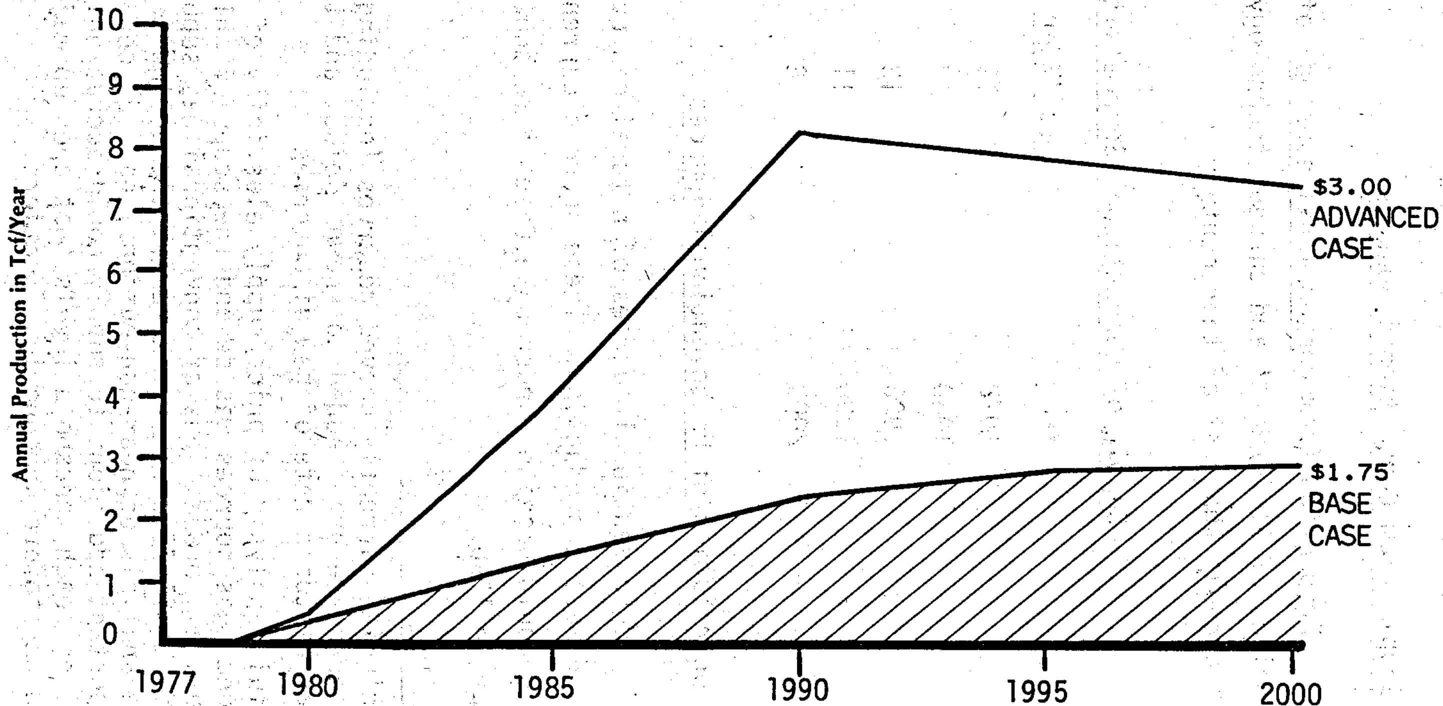


* IN CONSTANT 1977 DOLLARS.

Moreover, important quantities of this gas could be delivered in the near-term. As shown in Exhibit 1-2, unconventional gas could add 1 Tcf to 4 Tcf per year by 1985 and as much as 2 Tcf to 8 Tcf per year by 1990, depending on the specific economic and technology policies selected by public officials.

Exhibit 1-2

Annual Production from Unconventional Sources to the Year 2000 at $1.75 and $3.00/Mcf



III. DOMESTIC SUPPLIES OF NATURAL GAS

A. Supply From Conventional Sources

Production from conventional sources* of domestic natural gas under prices of $1.75/Mcf** and current technology shows a continuing downturn throughout the rest of this century.

Supply of Conventional Source Natural Gas

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

B. Contribution of Unconventional Sources

Unconventional sources of natural gas even now significantly contribute to domestic production. These sources currently provide about 1 Tcf per year and could provide, under Base Case*** technology assumptions, over 2 Tcf per year in 1990.

---

* Including currently proved reserves (excluding Alaska), inferred reserves added to known fields, and the seven-year historic rate of new discoveries.

** A full analysis of price/supply elasticity of conventional gas sources was beyond the scope of this study; thus, all projections of conventional gas supply were made at $1.75 per Mcf. However, the 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 Base Case assumes that, without a substantial Federal R&D role, industry as a whole would apply the technology that is currently the state of the art.

C. Total Domestic Natural Gas Supply

Combining production from the conventional and unconventional sources, total gas supply from domestic sources would be as follows (Exhibit 1-3):

Total Domestic Gas Supply From All Sources
(@ $1.75/Mcf)

Year	Conventional* Sources (Tcf)	Additional Base Case Unconventional Sources (Tcf)	Total Anticipated Domestic Supply (Tcf)
1980	17	**	17
1985	13	1	14
1990	11	2	13
2000	8	3	11

At this level of production from conventional and unconventional sources, domestic natural gas supply will be 6 to 8 Tcf below recent usage in 1985 and as much as 10 Tcf short in 1990. It is clear that additional action will need to be taken to avoid a serious natural gas shortfall.

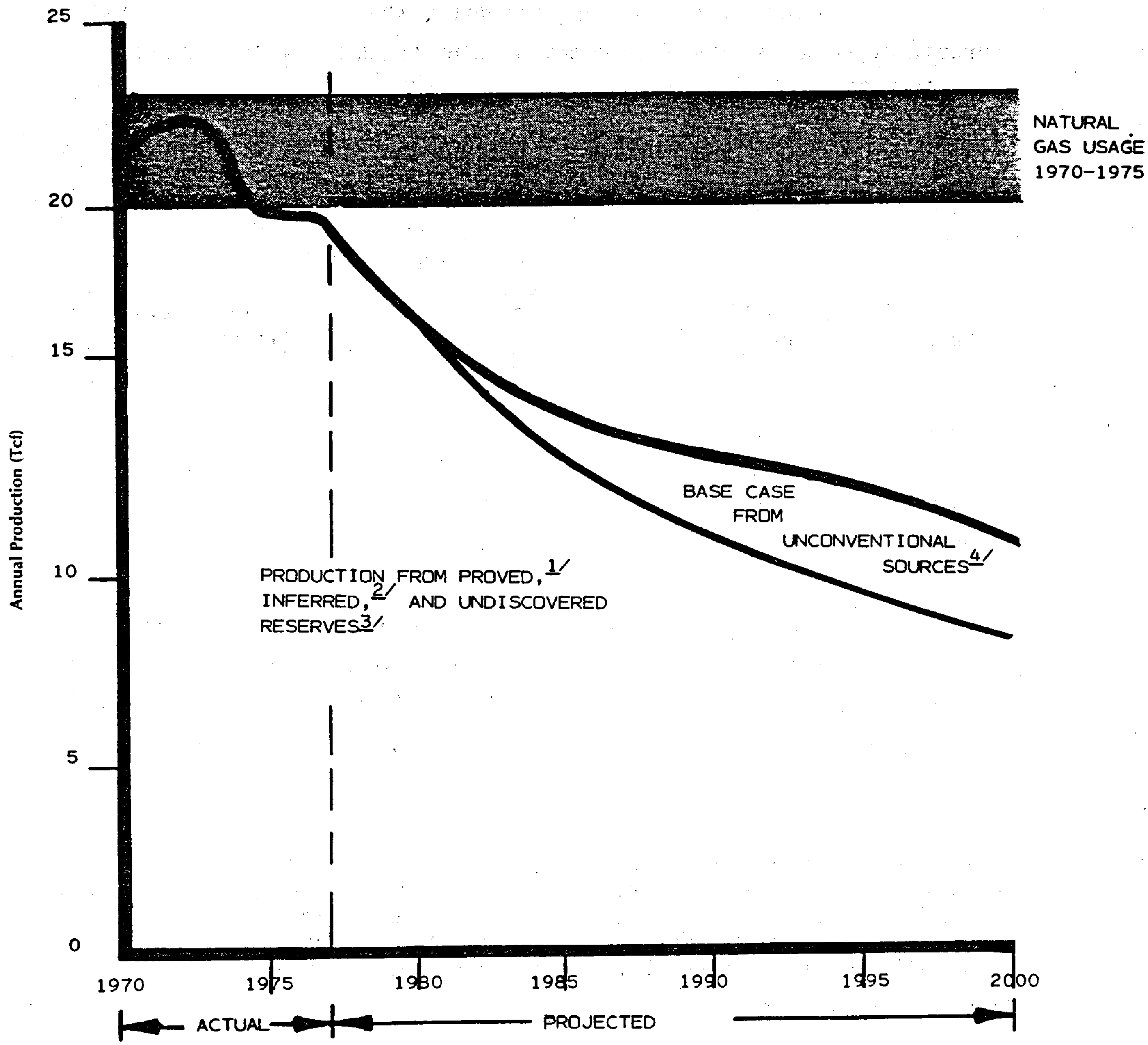
---

* The supply from conventional sources already includes some unconventional resource gas, calculated at 1 Tcf in 1977. The gas from unconventional sources estimated by this study is in addition to the amounts already proved and being produced from unconventional sources.

** Less than 0.5 Tcf.

Exhibit 1-3

Total Domestic Gas Supply — Conventional and Unconventional Sources (at Gas Prices of $1.75/Mcf and Current Technology)



1/ BASED ON AGA/API/CPA, RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN THE UNITED STATES AND CANADA, DECEMBER 31, 1970 THROUGH 1976.

2/ BASED ON THE 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, REPORTED IN VOLUME III OF THIS REPORT.

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 RESPECTIVELY THROUGH DEVELOPMENTAL DRILLING.

4/ FROM THE 1978 STUDY OF ENHANCED GAS RECOVERY FROM UNCONVENTIONAL SOURCES BY LEWIN AND ASSOCIATES, INC.

D. Substitute Sources of Energy

Conversion to other fuel sources, such as imported oil, nuclear, and coal, can begin to substitute for a portion of this unmet gas demand, but this will be slow, costly, and may entail environmental and balance of payment risks.* Seeking additional supplies of domestic natural gas, where economical, is by far the most cost-effective near-term alternative.

E. Stimulating Domestic Gas Production

Five major options must be assessed by public policy-makers for increasing gas supply:

1. Stimulating additional gas recovery from unconventional sources. Accelerating the recovery of natural gas from unconventional sources appears to be a viable and economic target for offsetting a significant portion of the likely shortfall. Exhibits 1-4 and 1-5 show the contribution of unconventional sources of natural gas under advanced technology (the Advanced Case)** at prices of $1.75 and $3.00 per Mcf.

2. Improving the economic incentives for natural gas production. Increased gas prices may have only limited effect unless they are high enough to bring on a new threshold of resources.

---

* It would require considerable time and cost to replace the existing infrastructure of natural gas pipelines, industrial equipment, and gas-powered home appliances. Costs to consumers could be nearly three times higher for electricity than for an equivalent amount of energy from natural gas. The level of air pollutants and wastes could be three to thirty times as high for these other energy sources as for natural gas.

** The Advanced Case for unconventional sources includes the Base Case as well as additional stimulation by accelerated public research in enhanced gas recovery.

Exhibit 1-4

The Potential of Unconventional Sources Under Advanced Technology at Gas Prices of $1.75/Mcf

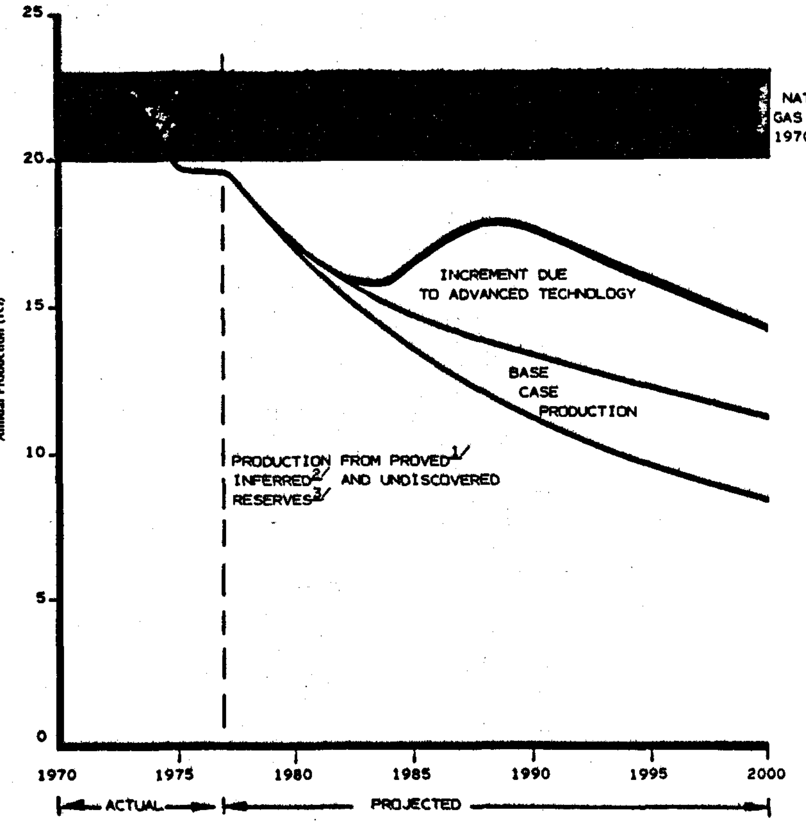
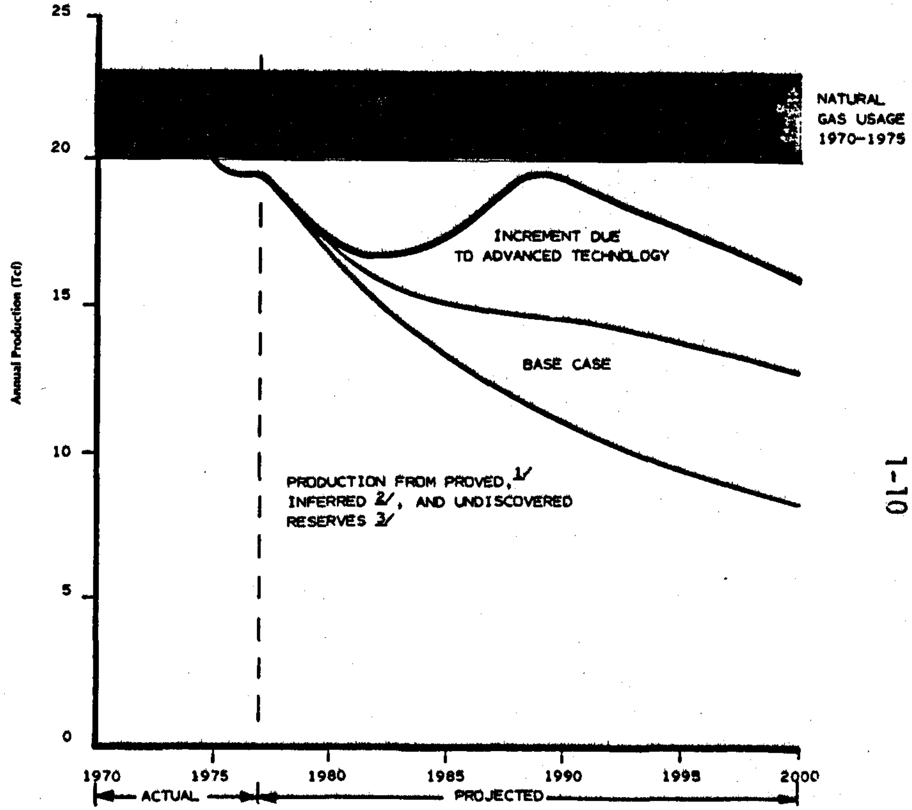


Exhibit 1-5

The Potential of Unconventional Sources Under Advanced Technology at Gas Prices of $3.00/Mcf



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.

4/ CONVENTIONAL SOURCE GAS IS ESTIMATED AT $1.75 PER MCF.

3. Increasing the pace of offshore leasing. Even as gas is discovered in these areas, it will be costly to produce and its recovery is likely to be delayed many years while platforms and pipelines are constructed.

4. Obtaining gas supplies from outside the contiguous states. This is a costly, though possibly an inevitable option. Imports of natural gas from Canada and Mexico are being negotiated on a BTU equivalency with imported fuel oil, \$2.50 to \$3.00 per Mcf. Imported LNG from Algeria is being considered at \$4.50 per Mcf. Gas from Alaska is estimated at \$3.50 to \$5.50 per Mcf, delivered.

5. Developing technologies for manufacturing synthetic gas. Gasification of coal or heavy crudes will require substantial capital investment and prices of \$4.50 per Mcf or more.

F. Summary

For an equivalent amount of energy between now and 1990, the unconventional gas sources under advanced technology and at gas prices up to \$3.00 per Mcf provide as low or lower cost to the public than any substitute energy source.

However, even with these additions to supply, the projections above show that gas supply remains below 1977 usage levels. Thus, it will be essential to consider a mix of gas supply programs, such as LNG, coal gasification, electricity, and gas imports to fill the gap and provide the nation with adequate energy supplies.

IV. GAS FROM UNCONVENTIONAL SOURCES -- A DETAILED VIEW

A. Background

The term "enhanced recovery from unconventional gas resources" may conjure visions of massive, unproved new technologies applied to a speculative, unknown resource. In reality this is not so.

The production technology required to recover the gas has been formulated and in several cases has been subjected to practical test.* Although additional development is required, the primary technological need is for judicious demonstration and custom application of the best of the new gas recovery techniques to specific field settings. The resource base provides the major uncertainty. While substantial gas resources are known to exist, their detailed characteristics, particularly those which would encourage development, are inadequately defined.

---

* The better portions of the "unconventional sources" of gas have been under active exploitation or study for many years:
  - Almost 3 Tcf of gas have been produced from the Devonian shales since the turn of the century, with another 1 Tcf in proved reserves yet to be produced.
  - Drilling in the more favorable portions of the low permeability tight gas basins has been underway for over 30 years and has yielded over 10 Tcf.
  - Methane emissions from coal seams -- an historic hazard to coal mining -- have averaged about 0.1 Tcf per year, although none is currently captured for commercial markets.
  - Finally, even the geopressured aquifers, the least defined of the unconventional natural gas sources, have been placed under testing during the past year.

B. Assessment of the Potential

- Under the Base Case, unconventional sources would produce from 2 to over 3 Tcf in 1990.
- With the stimulation of a highly focused, vigorous and collaborative Federal/industry program of research and development, gas from unconventional sources could provide 6 to 8 Tcf by 1990.
- Ultimately, these sources could add 70 to over 100 Tcf to total recovery without a federally sponsored program -- and 150 to 220 Tcf with such a program at gas prices* between $1.75 and $3.00 per Mcf.** Thus, production from unconventional sources under advanced technology could provide a much needed additional source of natural gas supply.

C. Contribution of the Various Unconventional Sources

The projection of new gas supplies from unconventional sources represents an aggregation from numerous sources, ranging from some near-conventional formations in the tight gas basins to the unexplored potential of geopressured aquifers. Four broad targets were examined:

---

* The term "price", used in the paper, serves to summarize any combination of economic incentives such as market price, tax provisions, public subsidies, etc. that can be expressed in "price to the public" equivalent terms.

** Price is stated in 1977 dollars and assumed maintained in constant dollars through the period of analysis. For example, a $1.75 price under 6 percent inflation would need to be $2.75 as expressed in 1985 dollars; a $3.00 price under the same conditions would become $4.80 in 1985 dollars.

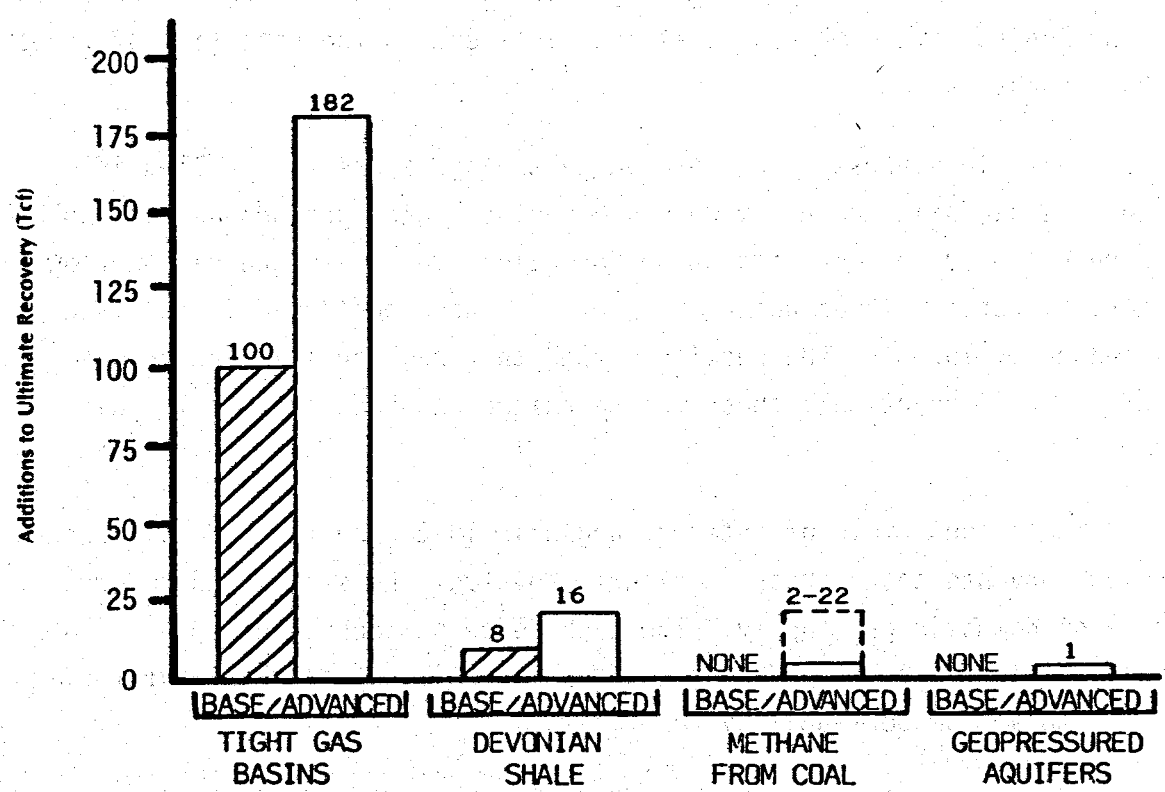
- Tight Gas Basins
- Devonian Shale
- Methane from Coal Seams
- Methane from Geopressured Aquifers

Exhibit 1-6 shows the contribution of these unconventional sources to domestic gas supply, at $3.00 per Mcf under Base Case and Advanced Case technology, in terms of additions to ultimate recovery.

The following sections summarize the background and potential for each of these four unconventional gas resources.

Exhibit 1-6

Ultimate Recovery at $3.00/Mcf by Unconventional Target



V. TIGHT GAS BASINS

A. Background

Substantial quantities of natural gas exist in tight (low permeability) formations, but the natural gas flow in these formations is too low to support economic recovery under conventional technology. The rapid decline of conventional gas production, higher gas prices, and the advent of new recovery technologies have combined to attract interest in the potential of these tight gas resources.

Initial interest was generated by the operators who drilled into the tight gas sands in the Rocky Mountain basins. Underground nuclear explosions were employed to rubbelize these formations to enable the gas to flow at commercial rates. Three nuclear experiments were performed in the late 1960's and early 1970's. The results showed that nuclear stimulation was ineffective and impractical; thus, the technique has been essentially discarded.

The second cycle of interest began in 1972 when the Federal Power Commission convened task forces of experts to study the status and future potential of domestic gas supply. The task force on technology identified massive hydraulic fracture (MHF) as a potential stimulation technique for developing these low permeability reservoirs.

The contribution of the task force was to suggest that hydraulic fracturing be applied with volumes of treatment an order of magnitude (or more) larger than was conventional to stimulate production from low permeability basins.

The task force estimates of the potential from three such basins -- the Piceance, the Greater Green River, and the Uinta (referred to as the Western Tight Gas Basins) -- suggested a total gas in place of nearly 600 Tcf, and a recovery of 180 to 300 Tcf (between 30 and 50 percent of the gas in place), under the assumption of successful MHF technology and adequate prices.

As a consequence of the FPC study, a joint government-industry test of MHF was conducted in the Piceance Basin in 1974. Since that time, a series of industry and joint government-industry tests have been conducted. The technology has advanced enough that it has become standard practice in fields with low permeability in conjunction with other, more favorable geologic conditions. The most notable of these are the Wattenberg Field (north of Denver), several fields in the Sonora Basin in southwest Texas, and the Cotton Valley Trend in east Texas and northern Louisiana.

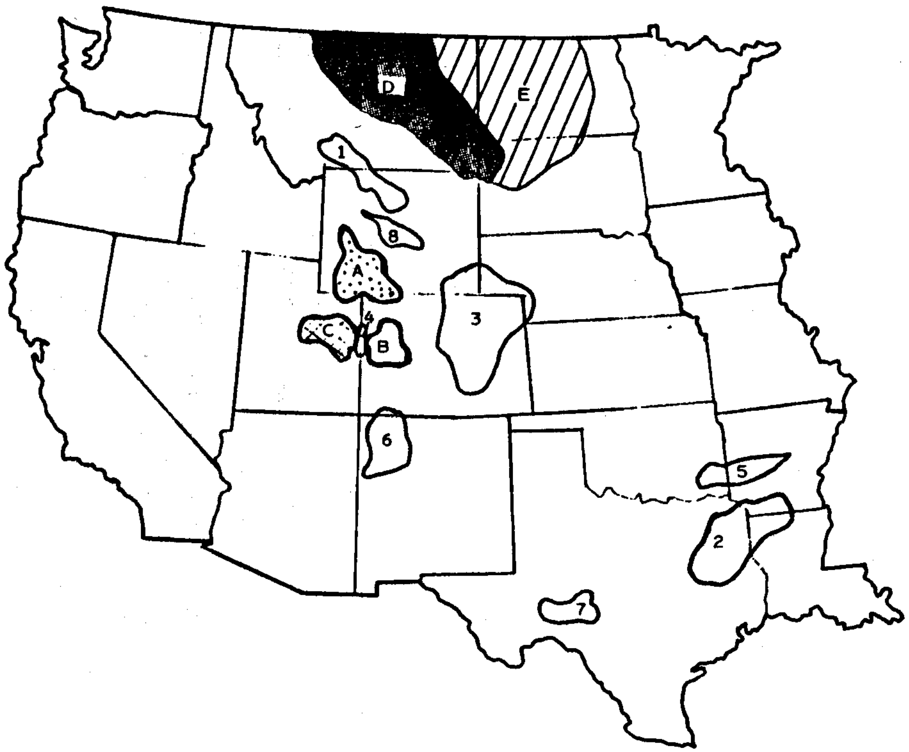
The Western Tight Gas Basins that originally attracted the attention and large portions of the other domestic tight gas basins remain unproved. The challenges posed by the difficult geological setting -- the tight, lenticular, low quality gas pays -- have yet to be overcome. Further, even in the more geologically favorable basins -- in the less tight, blanket deposits -- fundamental issues of recovery technology, such as fracture control, remain. Finally, major opportunities exist in these basins for optimizing the recovery technology and accelerating the recovery of much needed domestic gas supplies.

B. The Resource Base

The resource base consists of twenty basins identified as having permeabilities too low to permit economic recovery by existing, conventional technology. Of these, thirteen were included in the present analysis (Exhibit 1-7). Data available to the study on the remaining seven basins were inadequate to support detailed analysis.

Exhibit 1-7

Location of Major Tight Gas Basins



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

Low-Permeability Basins

<u>ERDA'S PRIMARY STUDY AREAS</u>	<u>GEOLOGICAL AREA</u>
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

<u>ADDITIONAL LOW-PERMEABILITY AREAS IN THE STUDY</u>

1. BIG HORN BASIN	TERTIARY AND CRETACEOUS
2. COTTON VALLEY TREND	JURRASSIC
3. DENVER BASIN	CRETACEOUS
4. DOUGLAS CREEK ARCH	CRETACEOUS
5. OUACHITA MOUNTAINS PROVINCE	MISSISSIPPIAN
6. SAN JUAN BASIN	CRETACEOUS
7. SONORA BASIN	PENNSYLVANIAN
8. WIND RIVER BASIN	TERTIARY AND CRETACEOUS

<u>OTHER LOW-PERMEABILITY AREAS NOT INCLUDED IN STUDY</u>

a. ANADARKO BASIN	PENNSYLVANIAN
b. ARKOMA BASIN	PENNSYLVANIAN
c. FORTH WORTH BASIN	PENNSYLVANIAN
d. RATON BASIN	TERTIARY AND CRETACEOUS
e. SNAKE RIVER DOWNWARP	TERTIARY AND CRETACEOUS
f. WASATCH PLATEAU	CRETACEOUS
g. WESTERN GULF BASIN	TERTIARY AND CRETACEOUS

These thirteen basins were grouped into five classes of basins (referred to as resource "targets") based on common geologic characteristics:

1. Western Tight Gas Basins. The three basins (Greater Green River, Piceance, and Uinta) that originally attracted the attention of the FPC task force are deep, low permeability, and lenticular.

2. Shallow Gas Deposits. The shallow, low production formations of the Northern Great Plains Province, which includes a large portion of the Williston Basin, vary in permeability from near conventional to very tight, but are generally blanket-type depositions.

3. Other Tight, Lenticular Gas Sands. Although probably having as low permeability as the Western Tight Basins, these basins (Sonora, Douglas Creek Arch, and the Big Horn) are shallower and contain larger lenses.

4. Tight, Blanket Gas Sands. These basins (Denver, San Juan, Wind River, Cotton Valley, and the Ouachita Mountain Province), although deep and having low permeability, are favored by highly continuous, blanket-type gas formations.

5. Other Low Permeability Reservoirs. This category, currently containing only the Bruckner-Smackover formation of the Cotton Valley Trend, consists of gas reservoirs with permeabilities between 0.5 and 1.0 millidarcies.

The specific target reservoirs within these basins that were included in the present analysis are shown in Exhibit 1-8. These basins cover a total of more than forty thousand square miles, containing over 400 Tcf of gas in place* (Exhibit 1-9). The portion of this gas that is recoverable depends on the interaction of geology, reservoir characteristics, recovery technology, and economics.

The reservoir characteristics of the formations included in the analysis are displayed on Exhibit 1-10. The ranges on the parameters arise from differences among sub-basin areal units of the specific formations. In general:

- The in situ gas permeabilities of the major formations rarely exceed 100 microdarcies.** Outside of the shallow basins, the few higher permeabilities are found only in the relatively small, most favorable geographic areas.

- Much of the area where the net pay is greatest is also highly discontinuous, or lenticular.

- All the basins are marked by low gas-filled porosities (high water saturation with low total porosities).

Such reservoirs pose substantial technological problems for economic MHF technology. Two cases were defined to represent the level of technology that could be applied in these basins:

---

* Geologic study subsequent to the groundbreaking FTC study has reduced the size of the resource base in the Western Tight Gas Basins.

** Conventional gas reservoirs would have in situ gas permeabilities an order of magnitude higher.

Exhibit 1-8

Composition of Tight Gas Targets

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

Exhibit 1-9

Areal Extent and Gas in Place — Tight Gas Basins

TARGET/BASIN	ANALYTIC UNITS	TOTAL ANTICIPATED AREA (Mi^2)	EXPECTED GAS IN PLACE (Tcf)*
WESTERN TIGHT			
Green River	216	870	91
Piceance	75	855	36
Uinta	128	996	50
SUBTOTAL	419	2,720	176
SHALLOW GAS			
Northern Great Plains	68	17,560	53
Williston	40	6,520	21
SUBTOTAL	108	24,080	74
OTHER TIGHT, LENTICULAR			
Big Horn	5	761	24
Douglas Creek	10	369	3
Sonora	10	1,960	24
SUBTOTAL	25	3,090	51
TIGHT, BLANKET GAS			
Cotton Valley (Sweet)	20	5,127	53
Denver	15	2,591	19
Ouachita	15	113	5
San Juan	5	830	15
Wind River	10	465	3
SUBTOTAL	65	9,126	94
OTHER LOW-PERMEABILITY			
Cotton Valley (Sour)	5	1,211	14
TOTAL	622	40,227	409

* Totals may not add due to rounding

Exhibit 1-10

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. (μd)	GAS-FILLED POROSITY (%)	RESERVOIR PRESSURE (psi)	RESERVOIR TEMPERATURE (°F)
WESTERN TIGHT GAS SANDS										
1. Greater Green River	36	Ft. Union	5700-9000	500-2680	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	66-600	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
SHALLOW GAS BASINS										
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	10-900	5.4-7.1	670	85
		Greenhorn/Frontier	2000-2600	30-50	3-29	Blanket	17-2700	5.4-7.8	900-1130	100
OTHER TIGHT LENTICULAR GAS SANDS										
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
TIGHT BLANKET GAS FORMATIONS										
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
OTHER LOW PERMEABILITY GAS FORMATIONS										
1. Cotton Valley "Sour"	5	Bruckner-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

- Base Case. The level of the technology expected to be attained by industry during the next five years without active federal involvement.

- Advanced Case. The level of the technology expected to be attained by virtue of active federal-industry collaboration.

Each of these cases was analyzed using a reservoir simulator and an economic model to determine the amount of the resource that would be economic at current and advanced technology. Three gas prices, $1.75, $3.00, and $4.50 per Mcf, were analyzed to examine the economic sensitivity of these estimates.

C. Estimates of the Potential for Economic Recovery

1. Overall Potential

Under current and near-term (Base Case) technology, industry will produce substantial quantities of natural gas from the tight basins (Exhibit 1-11):

- At $1.75 per Mcf, nearly 70 Tcf will ultimately be recovered.

- Raising the gas price to $3.00 per Mcf increases Base Case ultimate recovery by 30 Tcf, to about 100 Tcf; raising price further adds little additional recovery.

Improvements in the technology (the Advanced Case) increases ultimate recovery by about 80 Tcf over the corresponding Base Case:

- At $1.75 per Mcf, the total Advanced Case is about 150 Tcf.

- At $3.00, the total ultimate recovery exceeds 180 Tcf; raising price to $4.50 per Mcf adds only 6 Tcf.

In addition to increasing ultimate recovery, technological advances also increase the annual rate of production (Exhibit 1-12):

- At $1.75 per Mcf, the 1990 Advanced Case production rate is 6.3 Tcf, compared to 2.2 Tcf under Base Case technology.

- At $3.00 per Mcf, the Advanced Case recovery in 1990 is 7.7 Tcf, compared with 3.2 Tcf in the Base Case; higher prices beyond $3.00 per Mcf add little to the 1990 production rate.

2. <u>Potential by Target</u>

The major portion of the Base Case production will be recovered from the Tight, Blanket sands and the Shallow Gas Basins (Exhibit 1-13):

- The Tight, Blanket sands will produce from 30 to 50 Tcf and the Shallow Basins over 20 Tcf at gas prices of $1.75 to $3.00 per Mcf.

- The Other Tight, Lenticular Basins and Other Low-Permeability formations will provide from 12 to nearly 20 Tcf at gas prices of $1.75 to $3.00 per Mcf.

Exhibit 1-11

Ultimate Recovery (at Three Prices) From Tight Gas Basins

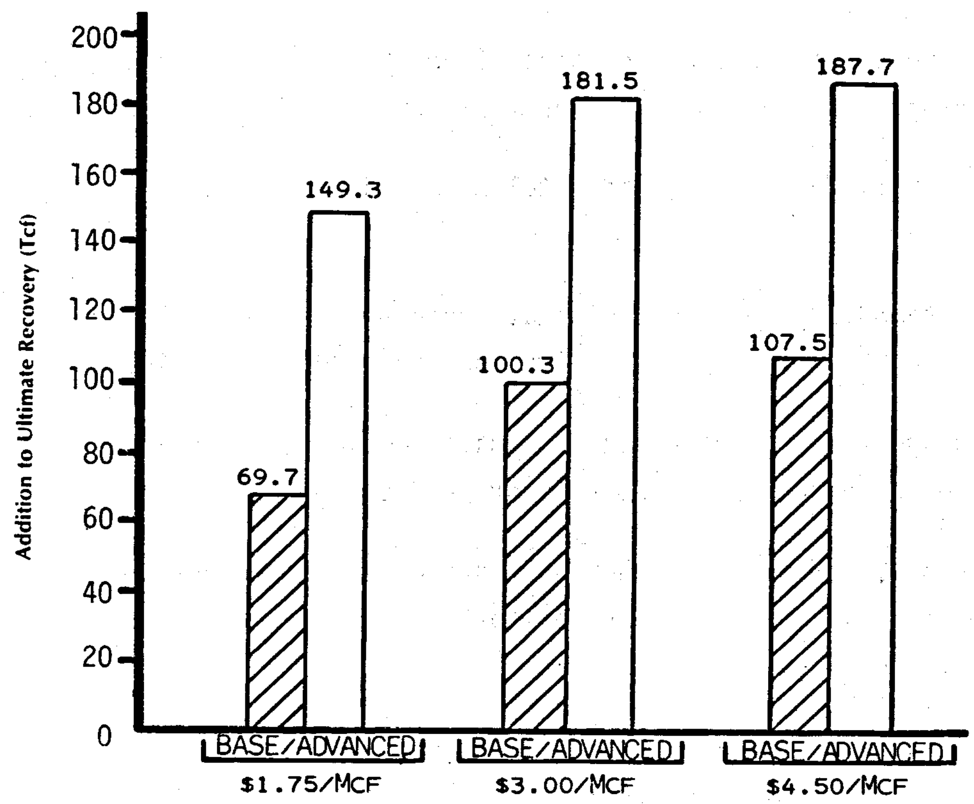
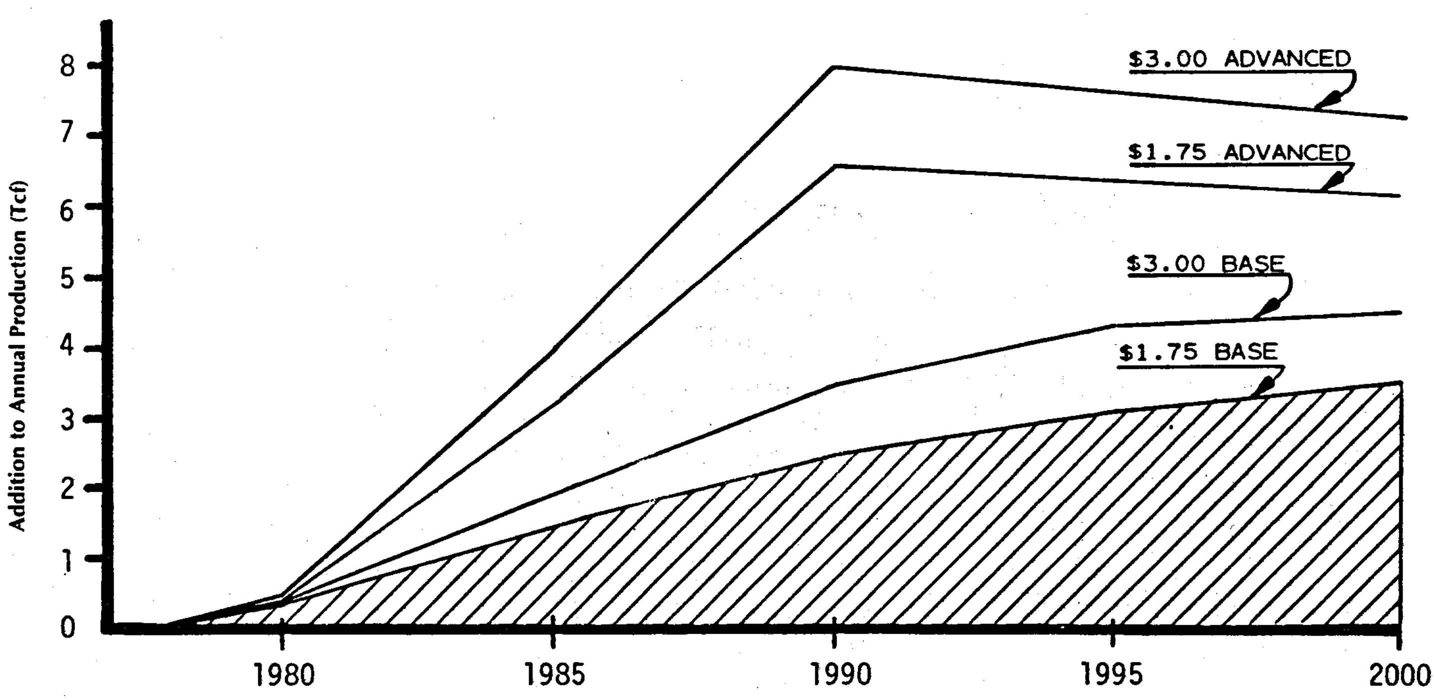


Exhibit 1-12

Production from the Tight Basins to the Year 2000 (at $1.75 and $3.00/Mcf)



- Only a small portion of the vast resource in place in the Western Tight Basins is recoverable under Base Case technology.

Advances in resource characterization and improvements in technology -- the Advanced Case -- improve ultimate recovery in all five tight gas targets (Exhibit 1-14):

- At $1.75 per Mcf, application of Advanced Technology increases ultimate recovery for the Western Tight Basins almost ninefold, to 38 Tcf. At $3.00, the ultimate recovery is 50 Tcf for these basins.

- At $3.00 per Mcf, the Shallow Basins will ultimately recover half again more gain, although the gain is small at lower gas prices.

- Ultimate recovery from the Tight, Blanket formations nearly doubles under Advanced Case technology, to almost 60 Tcf, at $1.75 per Mcf. At $3.00 per Mcf, increased gas prices have shifted much of the target to the Base Case, with recovery of 50 Tcf. Even here, however, advanced technology provides opportunities for improving recovery efficiency, adding 15 Tcf over the Base Case ultimate recovery.

- The other two resource targets also show substantial increases (depending on gas price) as advanced technology is applied.

Exhibit 1-13

Base Case Ultimate Recovery — By Tight Gas Resource Target

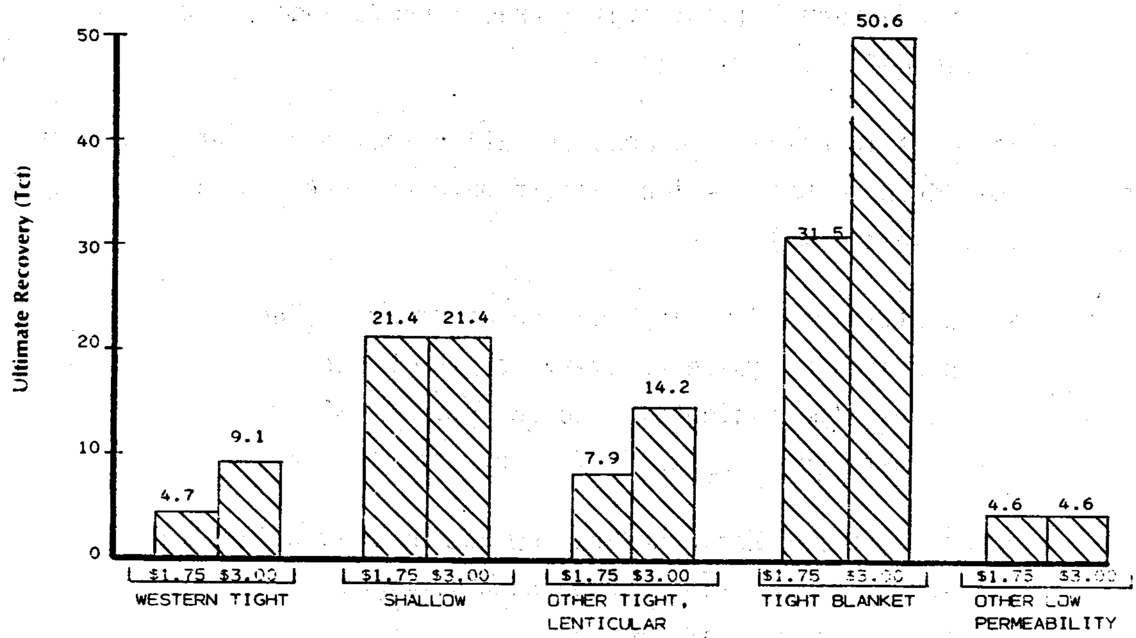
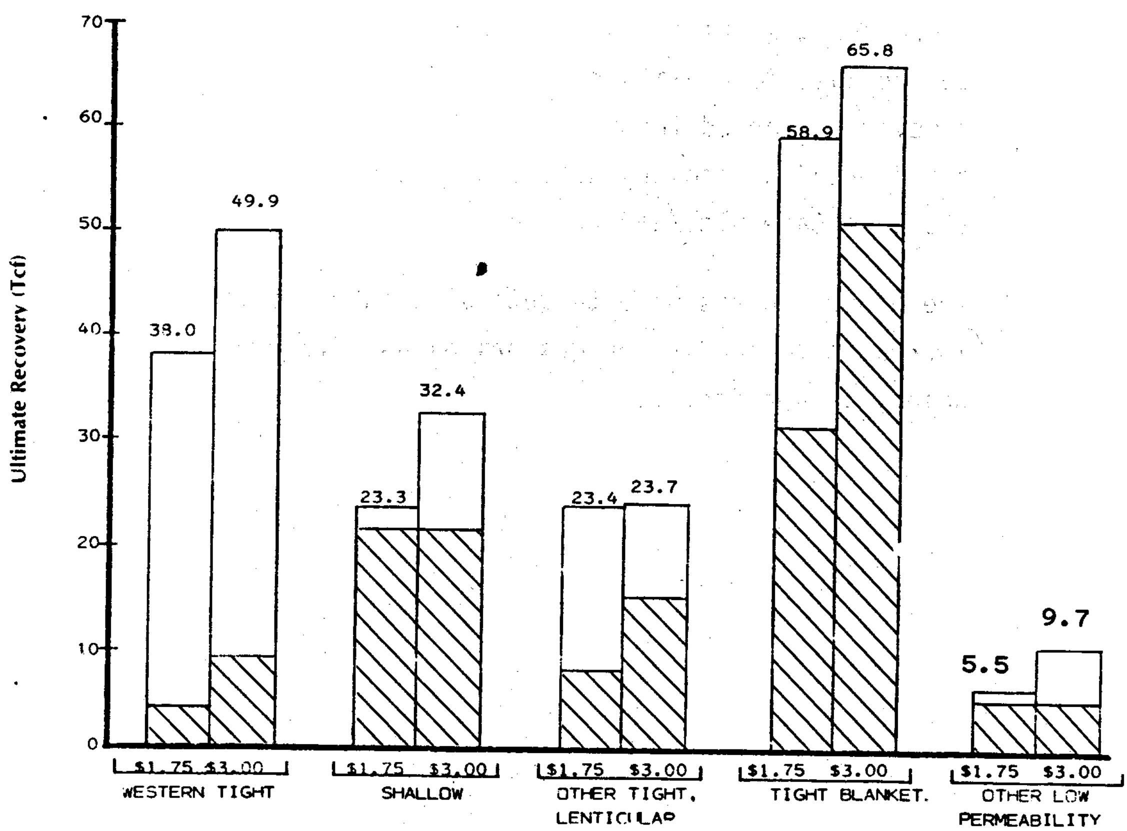


Exhibit 1-14

Ultimate Recovery — By Tight Gas Resource Target



The accelerating effects of the Advanced Case (Exhibits 1-15 and 1-16) are most marked in the Western Tight Gas Basins and the Tight, Blanket Sands:

- The Advanced Case increases 1990 annual production from the Western Tight Gas Basins to 2.7 Tcf from the 0.4 Tcf in the Base Case.

- In the Tight, Blanket Sands, 1990 production increases from the Base Case 1.6 Tcf to 2.8 Tcf through application of Advanced Case technology.

The economic potential of the Tight Gas Basins even under current and near-term technology is substantial. Accelerated, collaborative government-industry research and development could double the base potential. At 180 Tcf, the size of this potential approaches the current proved reserves of the "lower 48" states.

Exhibit 1-15

Base Case Estimates of Annual Production From the Tight Basins to the Year 2000 at $3.00/Mcf

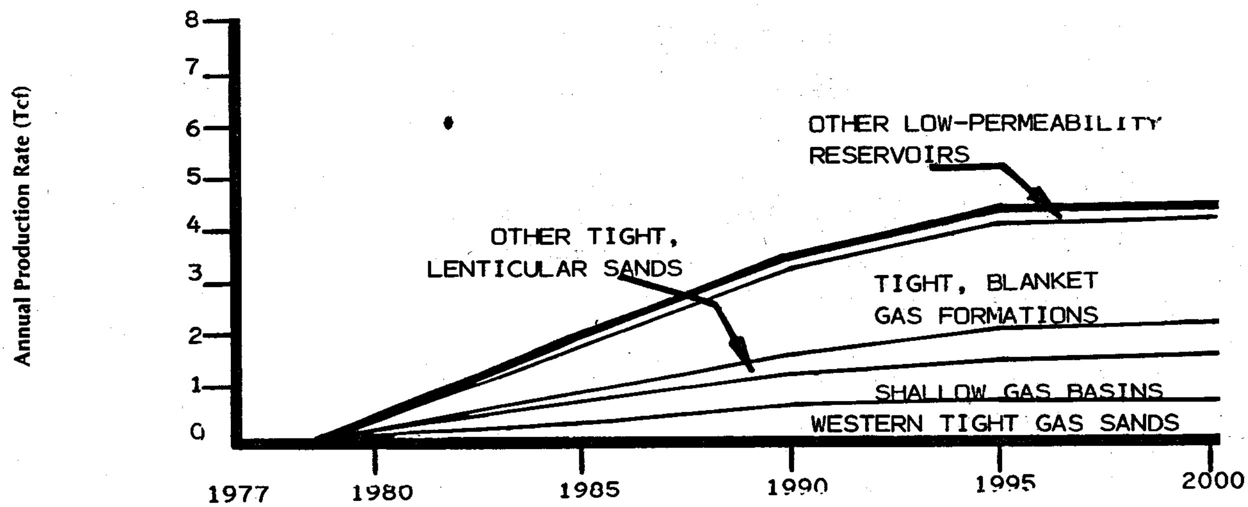
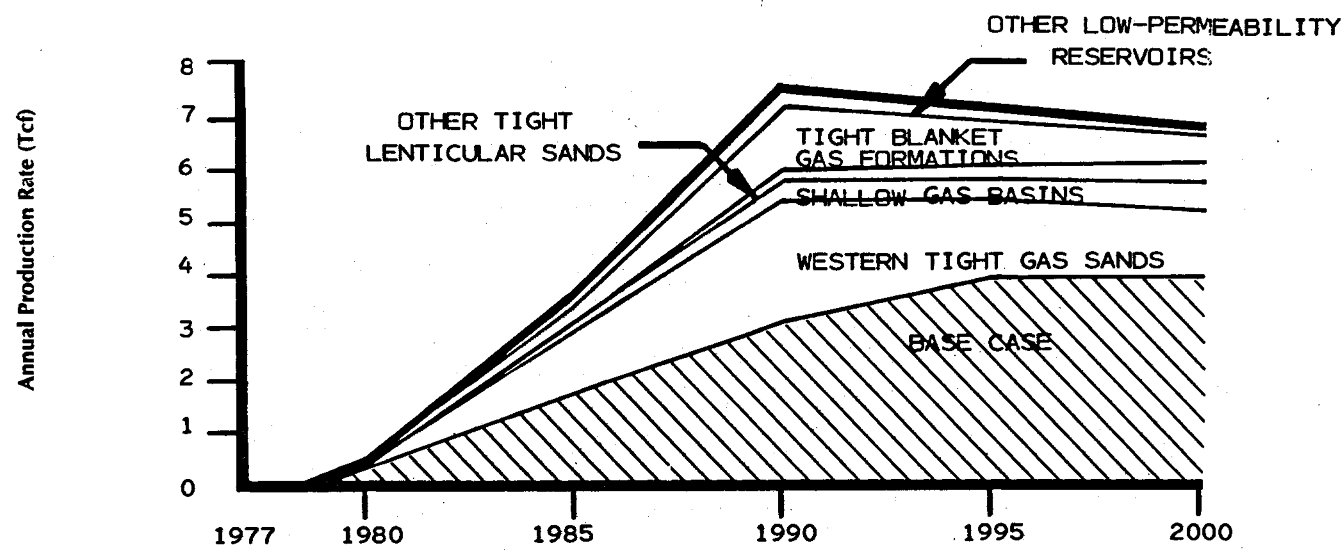


Exhibit 1-16

Advanced Case Estimates of Annual Production from the Tight Basins to the Year 2000 at $3.00/Mcf



VI. DEVONIAN SHALE GAS OF THE APPALACHIAN BASIN

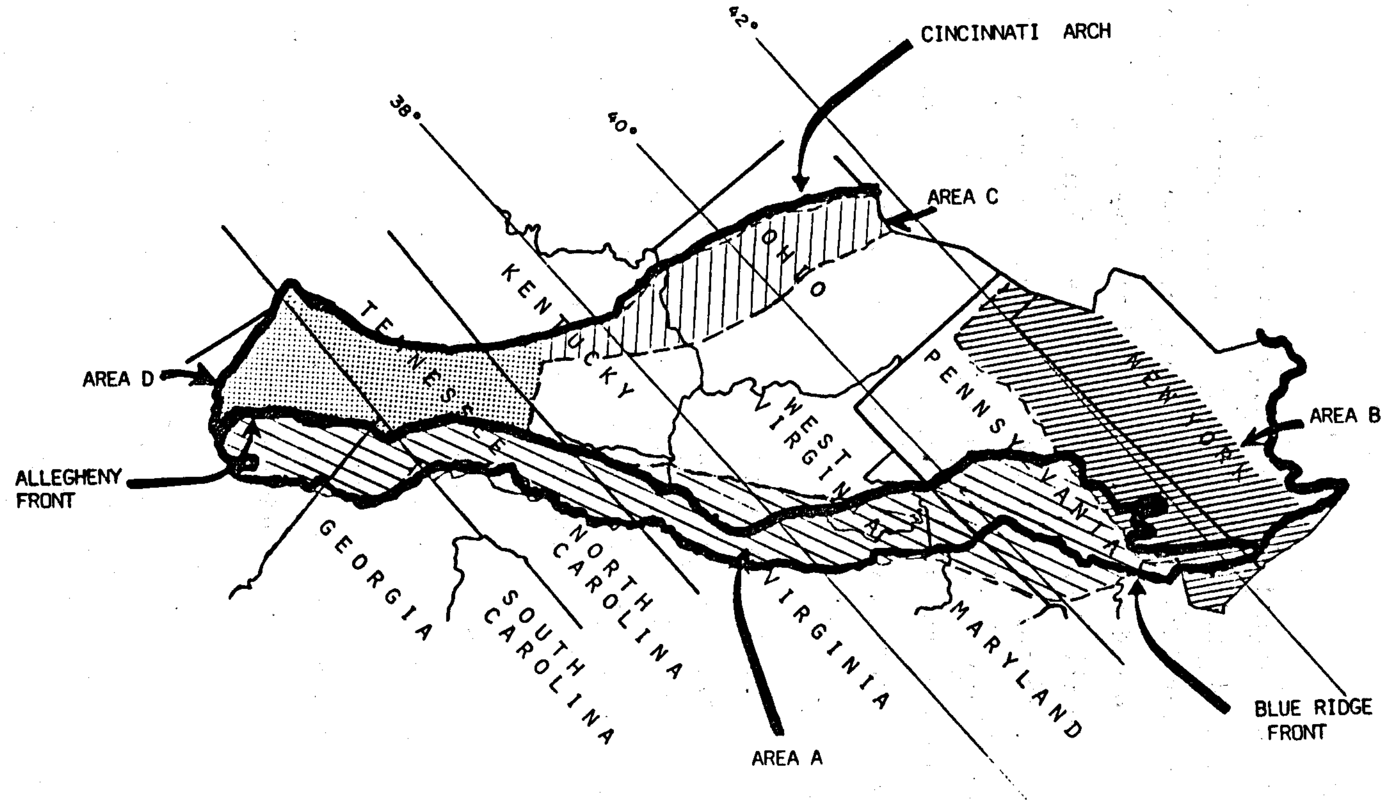
A. Background

The gas industry, especially small independent drillers, have long been aware of the gas potential in shales located in eastern Kentucky, southwest West Virginia, and Ohio. Historically, only in eastern Kentucky, which lacks the higher quality sands and silt beds found in other parts of Appalachia, have the Devonian shales been a primary exploratory and development target. With the decline in gas production and the devasting impact of gas curtailments on the Ohio and Appalachian areas, this now has begun to change. Much of the impetus is due to the joint Federal/industry research and development program that is seeking means for increasing recovery of this gas.

The Devonian shale resource target examined by the study consists of undrilled probable and possible areas in the Appalachian Basin. Of the basin's 210 square miles, 100,000 square miles were judged to be barren of producible shale (designated as Areas A, B, C and D of Exhibit 1-17); 48,000 square miles were judged as speculative (shown as the shaded area between the Blue Ridge Front and the Allegheny Front in the Exhibit); 5,000 square miles have already been drilled or found non-productive (shown below in Exhibit 1-18) -- leaving 57,000 square miles of shale deposit as the study area. Within this area, the resource target is the free gas in place in the natural fractures and that can be placed in contact with the wellbore (using current as well as improved drilling and completion practices).

Exhibit 1-17

Geological Distribution of the Devonian Shales of the Appalachian Basin



SOURCE: deWitt, Wallace, and Perry,
USGS, Map I-917B

Historically, West Virginia and Kentucky have provided the bulk of the Devonian shale gas production. Based on AGA and API data gathered in 1976, 3.9 Tcf of gas have already been produced or are currently booked in proved reserves from the Devonian shales, as follows:

State	Produced to Date (Tcf)	Proved Reserves (Tcf)	1976 Estimate of Ultimate Recovery (Tcf)
West Virginia	1.0	0.6	1.6
Kentucky	1.7	0.5	2.2
Ohio	*	*	0.1
TOTAL	2.7	1.1	3.9

* Less than 0.05 Tcf

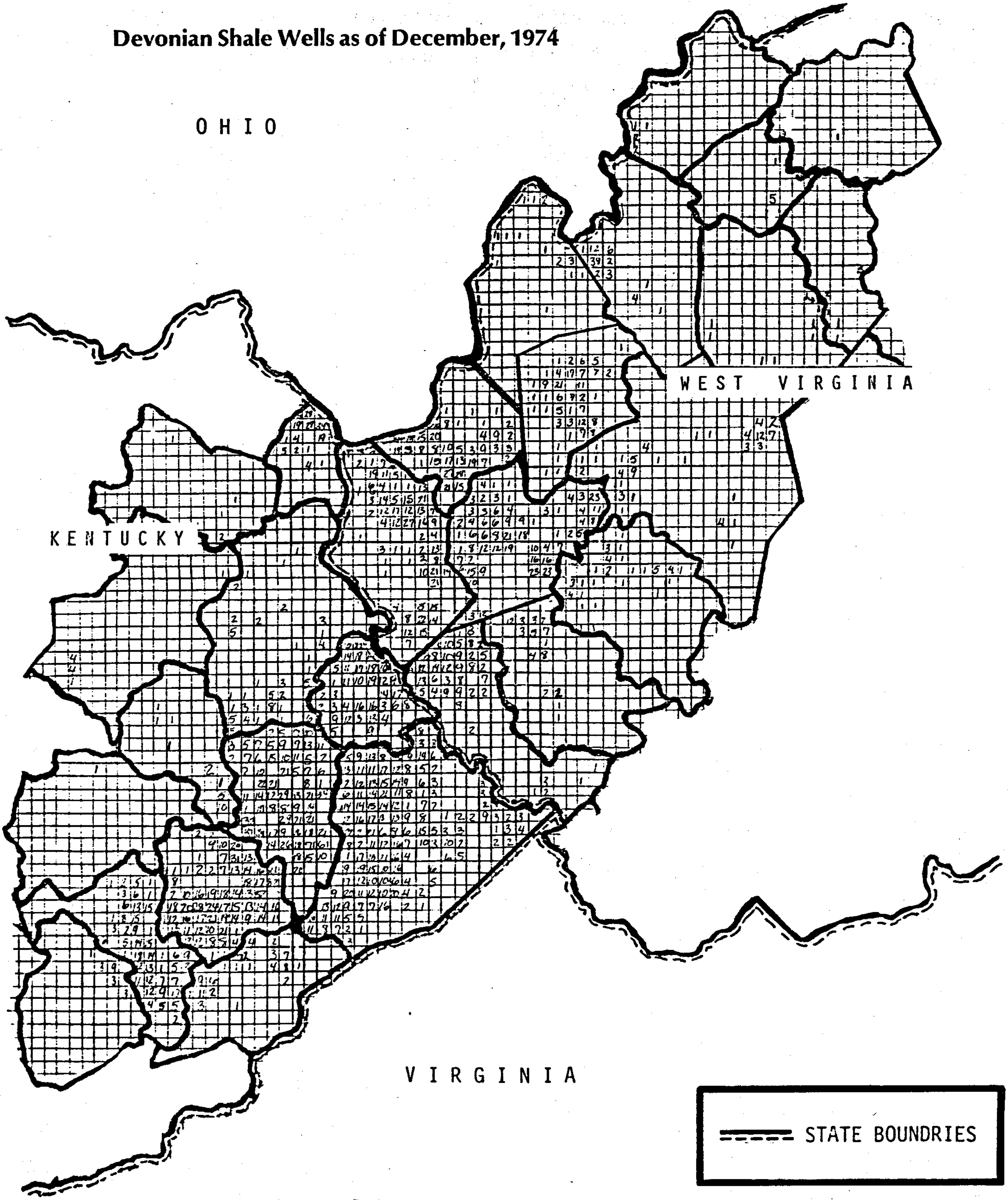
In 1976, these three states together produced an estimated 0.1 Tcf of natural gas from the Devonian shales.

B. Trends in Development Drilling

As of December, 1974, there were about 9,500 known Devonian shale wells in Kentucky, West Virginia, and Ohio. Eight thousand of these wells exist in and around the Big Sandy, Ashland, and Cottageville Fields. Exhibit 1-18 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, or 150 acre spacing. The overall average is about 295 acre spacing per well for the 3,700 square miles developed to date.

Exhibit 1-18

Devonian Shale Wells as of December, 1974



SOURCE: Industry Data

While the detailed well drilling data has not been compiled, it appears that about 200 new shale wells are being drilled per year in these three states. At an average of 150 acre spacing and an ultimate recovery of 300 MMcf per well, about 50 square miles are being developed and about 60 Bcf of new reserves are being added per year.

With yearly production from the proved reserves of 100 Bcf, the new additions of 60 Bcf in the recent years are not keeping pace; the total reserve is declining.

As the primary producing area becomes depleted -- about two-thirds of the land in the four counties comprising the center of the Big Sandy Field appears fully developed -- new production will need to come from:

- Extension drilling toward the borders of the currently developed area.

- Stepout and exploratory drilling into new areas.

- Improved recovery efficiencies.

C. The Resource Base

The lack of a body of data on reservoir characteristics of the shale (e.g., permeability, porosity, water saturation, joint and fracture system) has prevented thorough understanding of the actual resource in place. Because of the absence of such reservoir data, this study relied on empirical production data to reconstruct the nature of the reservoir. Performance data on 250 individual wells were collected from several production companies to form the data base for analyzing the resource.

The Basin was divided into eleven producing regions based on geologic and tectonic characteristics (Exhibit 1-19) and then further divided between drilled and undrilled areas (Exhibit 1-20). Production curves were established for each region from wells producing within that region, thus avoiding indiscriminate use of data from one part of the Basin to another. The decline curves were increased to represent additional gas from new stimulation technologies (namely hydraulic fracturing of about 1000 barrels) based on field test results to date.

Each of the eleven regions was designated as either an area industry would continue to develop (Base Case) or an area that would require government research and development as a prerequisite to exploitation by industry (Advanced Case). Three R&D programs have been developed to stimulate additional production from these regions:

- The first program in eastern West Virginia and Pennsylvania is directed at extension drilling in the deep shale that appears economic only at prices higher than $3.00 per Mcf. (The benefits of this program are expressed as a range to reflect present uncertainty about the extensiveness of the natural fracture network and the presence of producible gas.)

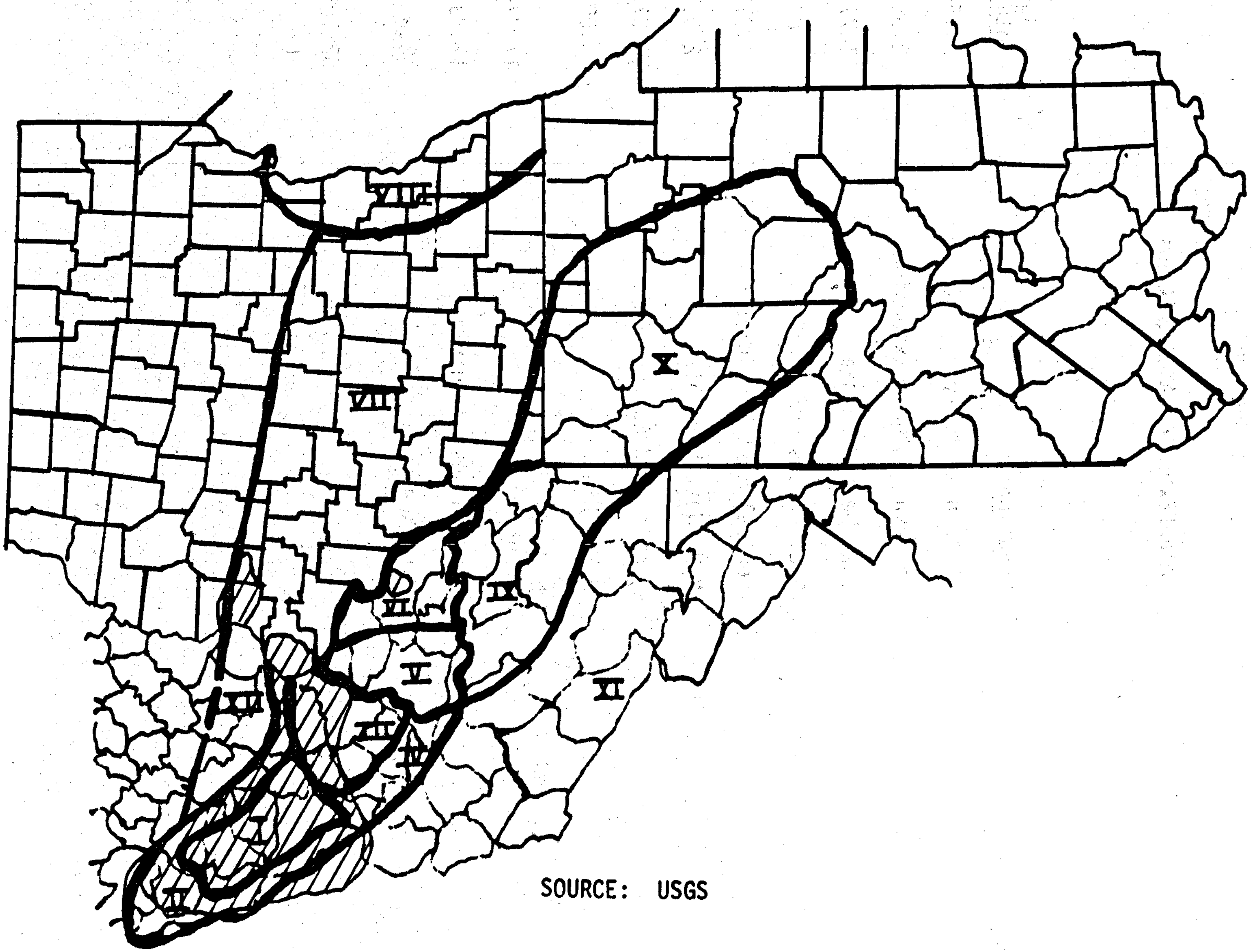
  -- Ultimate recovery due to this R&D program would range from 0 to 7 Tcf at a gas price of $4.50 per Mcf.

  -- The 1990 production rate would be below 0.1 Tcf.

Exhibit 1-19

Areal Extent of Study

(Shaded Areas — Big Sandy, Ashland, and Cottageville Fields)



SOURCE: USGS

Exhibit 1-20

Areal Extent of Analytic Units

Analytic Area	Location	Area in Square Miles Total	Undrilled
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	S.E. Extension	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
XIII	N.E. Kentucky	2,634	-
	TOTAL	62,183	56,651

- The second program (in Ohio) depends on dual completions of wells in the shales, underlying sandstone, and limestone gas reservoirs, thus permitting the shales to be produced at only the marginal costs of stimulation.

  -- Ultimate recovery from this second program would range from 3 to 6 Tcf, depending on gas price.

  -- The 1990 production rate would be 0.2 Tcf.

- The third program (in eastern Kentucky and western West Virginia) is to improve recovery efficiency in the heart of the currently developed area through optimizing stimulation, well spacing, and development practices.

  -- Increasing recovery efficiency would add about 2 Tcf at gas prices of $3.00 per Mcf.

  -- The 1990 production rate would be about 0.1 Tcf.

D. Economic Potential

1. Base Case Estimates

The amount of gas production and its rate in the Base Case are highly sensitive to gas price. As shown in Exhibits 1-21 and 1-22, additional recovery could range from less than 2 Tcf at $1.75 per Mcf to over 10 Tcf at $4.50 per Mcf; the production rate in 1990 would range from about 0.1 Tcf per year (at $1.75/Mcf) to 0.3 Tcf per year (at $4.50 per Mcf).

Exhibit 1-21

Devonian Shale Ultimate Recovery at 3 Prices — Base Case

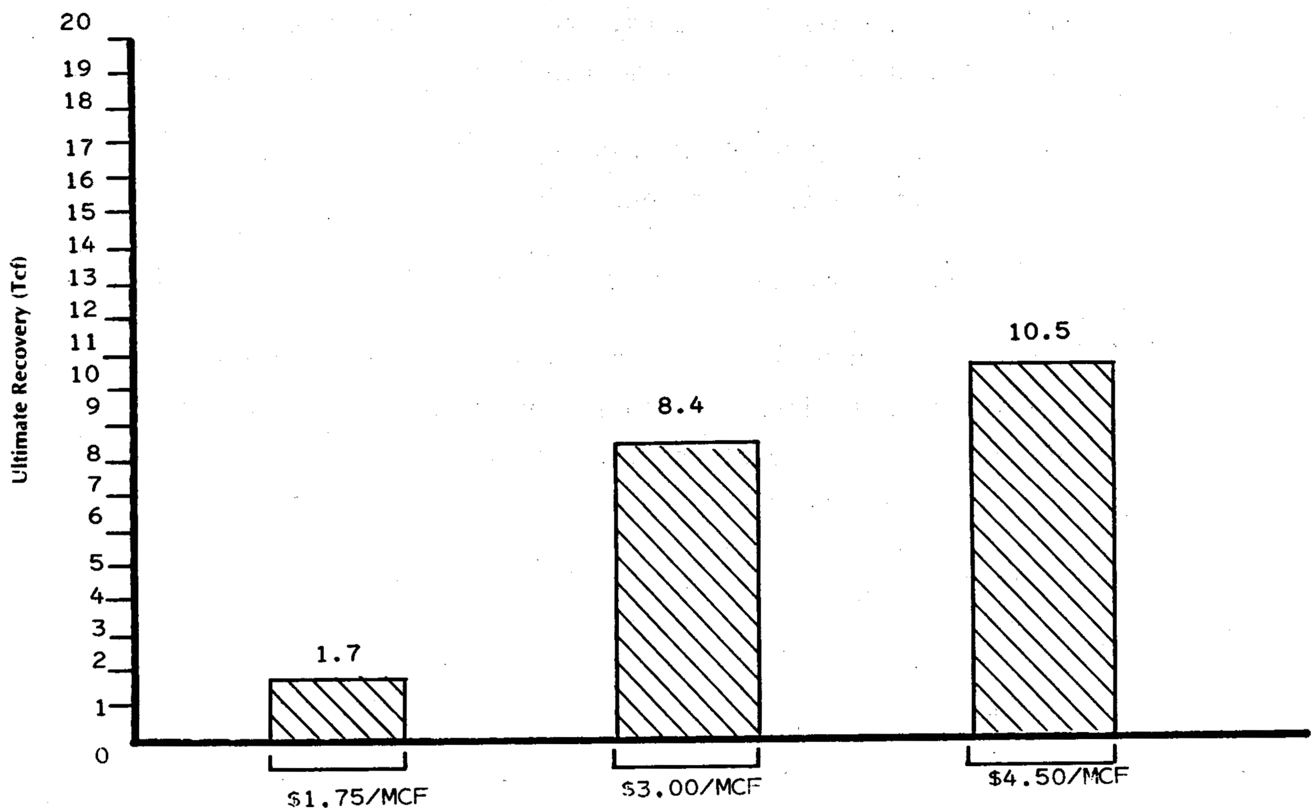
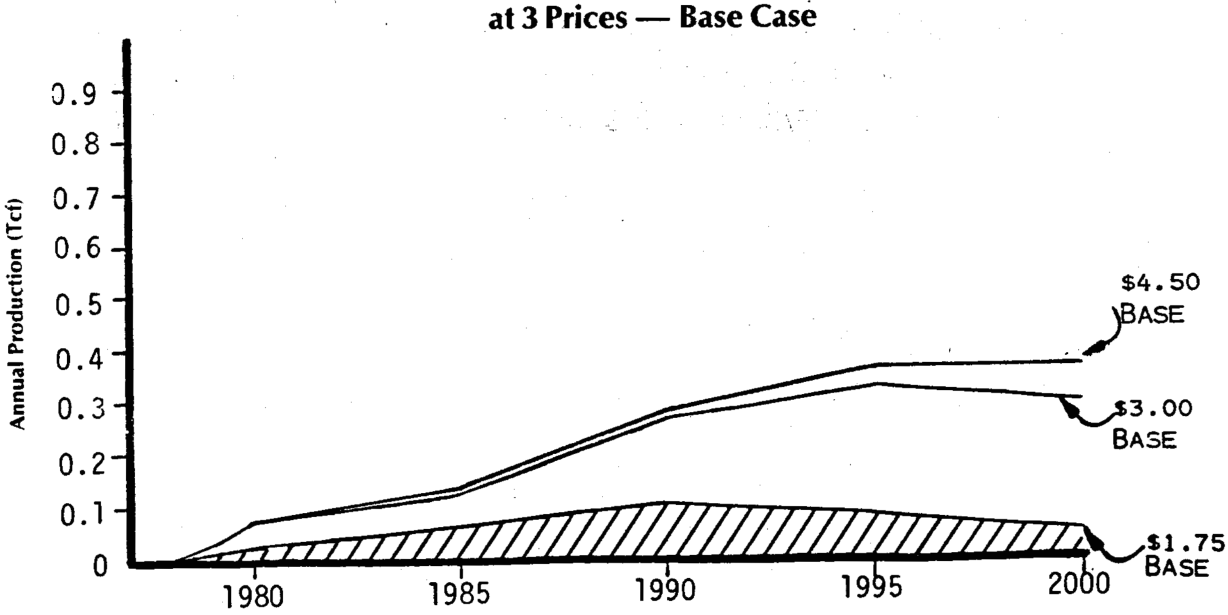


Exhibit 1-22

Annual Production from the Devonian Shale to the Year 2000 at 3 Prices — Base Case



- Ultimate Recovery. In terms of ultimate recovery (total production or reserve additions in 30 years' well life):

  -- About 2 Tcf will be economic at $1.75 per Mcf.

  -- Increasing the price of gas to $3.00 per Mcf would raise the estimate to 8 Tcf.

  -- At $4.50 per Mcf, estimated ultimate recovery would rise to 10.5 Tcf.

- Production Rates

  -- At $1.75 per Mcf, the Base Case production rates would peak at 0.1 Tcf in 1990 and decline thereafter.

  -- Higher prices would sustain production over a longer period, providing 0.3 Tcf per year in 1990.

2. The Advanced Case Estimates

Considerable amounts of additional gas could accrue from a successful R&D program in the Devonian shales -- the Advanced Case, as shown in Exhibits 1-23 and 1-24. (The difference between the Advanced Case and the Base Case estimates are the production benefits attributable to the R&D program.)

Exhibit 1-23

Devonian Shale Ultimate Recovery at 3 Prices

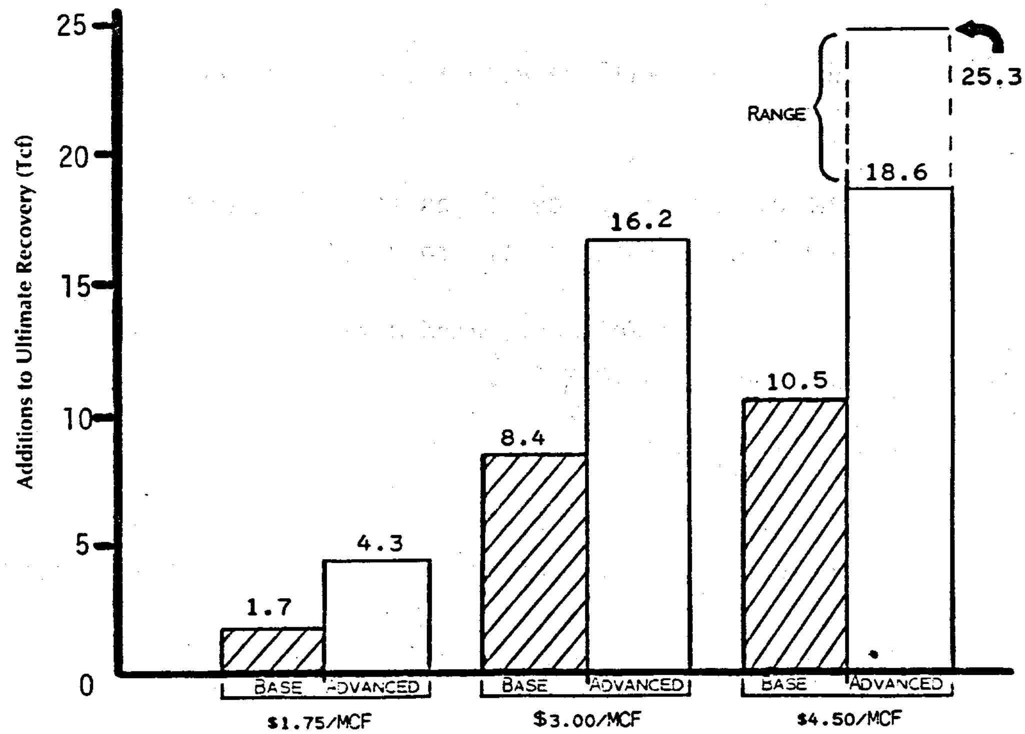
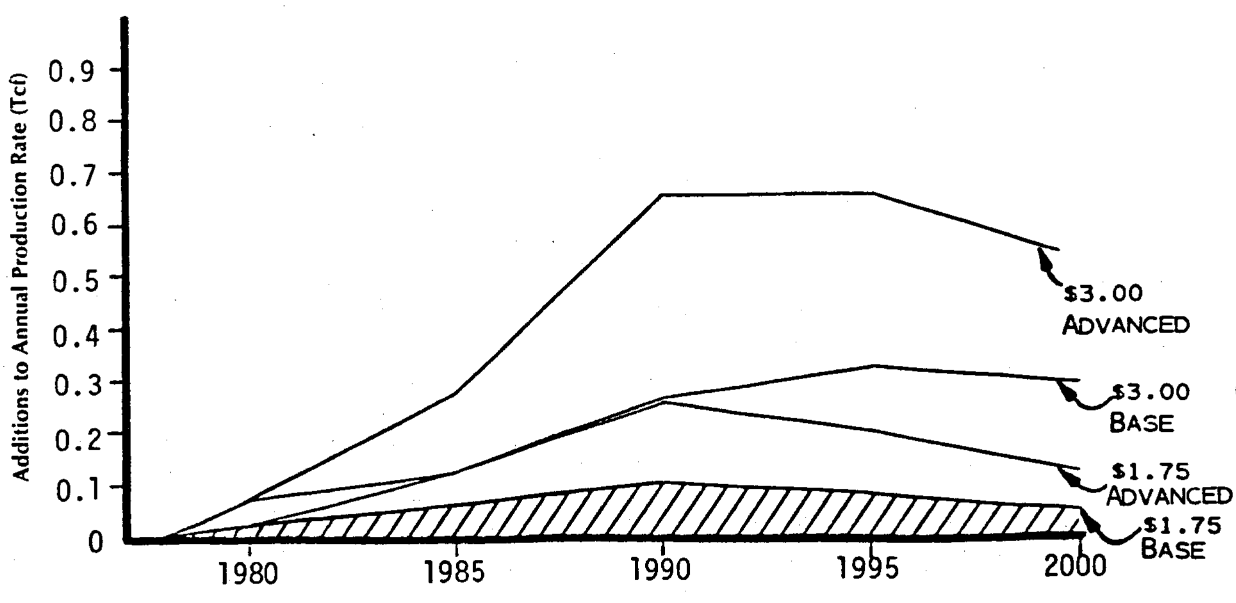


Exhibit 1-24

Annual Production from the Devonian Shale to the Year 2000 at $1.75 and $3.00/Mcf



- <u>Ultimate Recovery</u>. Under the Advanced Case assumptions, ultimate recovery at $1.75 rises to 4 Tcf from the Base Case estimate of 2 Tcf. At higher prices, considerably more recovery would be forthcoming:

  -- At $3.00 per Mcf, ultimate recovery rises to 16 Tcf (versus about 8 Tcf in the Base Case).

  -- At $4.50 per Mcf, ultimate recovery would range from 18 to 25 Tcf (the range reflects geological uncertainties in the possible areas where little is known about the intensity of the natural fracture system).

- <u>Production Rate</u>

  -- In 1990, annual production under the Advanced Case and at $1.75 per Mcf is projected at about 0.2 Tcf.

  -- At $3.00, 1990 annual production is estimated at 0.6 Tcf.

  -- At $4.50 per Mcf, the annual production rate continues to climb past 1990, reaching a range of 0.7 Tcf to 0.9 Tcf in 1995.

VII. METHANE FROM COAL SEAMS

A. Background

Since the inception of underground coal mining, release of methane from coalbeds ("coal gas") has posed a hazard to mining safety. In response to this hazard, the Federal government has acted to require improved safety measures and to gather information on methane emissions. However, this information has been gathered from the perspective of safety, disposing of the unwanted methane in mines, rather than from the perspective of supply -- capturing the methane for increasing domestic gas supplies. Recovering currently vented methane could provide an important augmentation to local supplies of natural gas.

In addition to methane recovery in association with mining, additional potential sources of methane are in the deep, currently unminable coal seams of the West. Such coal seams are considered too thin or too deep for mining, but may contain methane resources that could be economically produced.

B. The Resource Base

1. Methane Recovery in Association With Mining

Methane, to varying extent, is contained in all coal accumulations and is released from the coal as well as the cap and base rocks of the coal seams as the mine face advances.

In Appalachia, coalbeds average 5 feet; at 200 cf of methane per ton of coal, a 100 acre "reservoir" would contain but 130 MMcf. Production of gas from such reservoirs without mining is uneconomic due to the considerable costs of surface equipment and gathering systems. At this time, the principal targets for recovering methane from Appalachian coalbeds must be the active mines in which it has been established that methane is released in significant quantities.

The economics of pursuing this activity will depend on benefits derived from increasing the rate of mining and improving safety due to diminution of gas in mines. In the near-term, because the supply will be erratic, the captured gas could be used as a supplement for local industry and household use. Beyond this, the gas supply could be converted to LNG or used for power generation. In the longer term it may be possible to introduce the methane directly into a pipeline or use it as a regional industry feedstock, such as for ammonia or methanol production.

The recovery of methane in association with mining would concentrate on the high-emission mines of the Appalachian Region that account for nearly 90% of total national methane emissions, as shown in Exhibit 1-25. The initial target would be the 30 mines with the largest methane emissions, concentrated heavily in the Pittsburgh, Pocahontas No. 3, Pratt, and Kittanning coalbeds. These alone account for over one-half of total emissions.

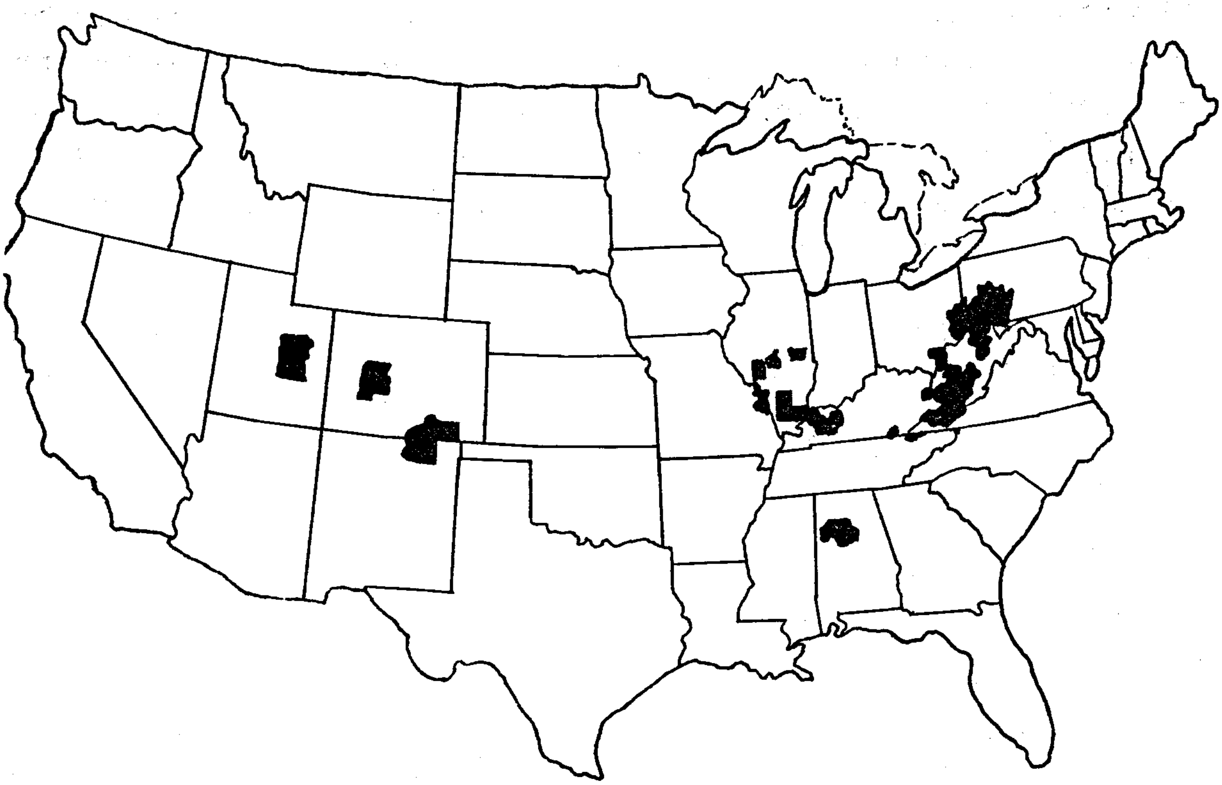
2. Methane Recovery from Unminable Coal

The economics of methane recovery from the unminable coal in the Western Basins will need to stand on their own, having no benefits accruing from improved mining productivity or safety.

Two types of unminable coal deposits have been identified as targets for the methane recovery program -- the thin coal seams (averaging

Exhibit 1-25

Location Map of Counties With Bituminous Coal Mines Emitting at Least 100,000 cfd of Methane in 1974



SOURCE: Irani, M.C., J.H. Jansky, P.W. Jeran, and G.L. Hassett, Methane Emissions from U.S. Coal Mines in 1975, A Survey. U.S. Bureau of Mines, IC 8133, 1977.

15 inches) that contain 70 Tcf of adsorbed methane, and the deep bituminous coal seams (between 3,000 to 6,000 feet) that contain 80 Tcf in place.*

Thin coalbeds could not be economically produced for their methane content. Coalbeds of 15 inches contain only about 40 MMcf of methane in the presumed drainage area of a single well. Assuming naturally highly fractured conditions, a single well could produce only about 12 MMcf in the first ten years, clearly insufficient to provide an economic return under any reasonable estimates of costs or prices.

The deep, thicker unminable coal seams having higher methane content offer a more favorable prospect. Assuming a favorable natural fracture system, a coal seam of about 20 feet thick could provide an economic payback at $3.00 per Mcf gas price.

The initial technological challenge is to intersect the natural fracture system (face cleats) that provide a high-conductivity path to the wellbore. At this time, deviated wells, drilled 1,000 feet into the pay (and possibly 2,000 feet in the future), appear to provide assurance of intersecting the natural fracture system. (Conventional hydraulical fractures would tend to parallel rather than intersect the existing fracture system, thus impeding optimum gas flow.) If means can be developed to use more conventional vertical wells, the minimum required economic thickness would be less.

An additional technological challenge is to install highly efficient recovery systems that will: (a) maintain a very low pressure at the face of the coal exposed to the fracture system to stimulate desorption;

* The deep, unminable sub-bituminous coals, assuming a methane content of 100 cf/ton, would contain 20 Tcf in place.

(b) ensure efficient water removal from the wellbore; and (c) purify and repressure the methane at low cost.

The recovery of methane from unminable coal would concentrate on the four western states of Colorado, New Mexico, Utah, and Wyoming, that collectively account for over 90% of the deep (over 3,000 feet of overburden) coal. Colorado, having by far the largest portion (about 70%) of the deep bituminous coal, would be the major target. Within Colorado, the San Juan, Uinta, and North Park Basins appear to offer sufficiently favorable characteristics to justify initial resource evaluation.

C. Estimate of Economic Potential

1. Methane Recovery Associated With Coal Mining

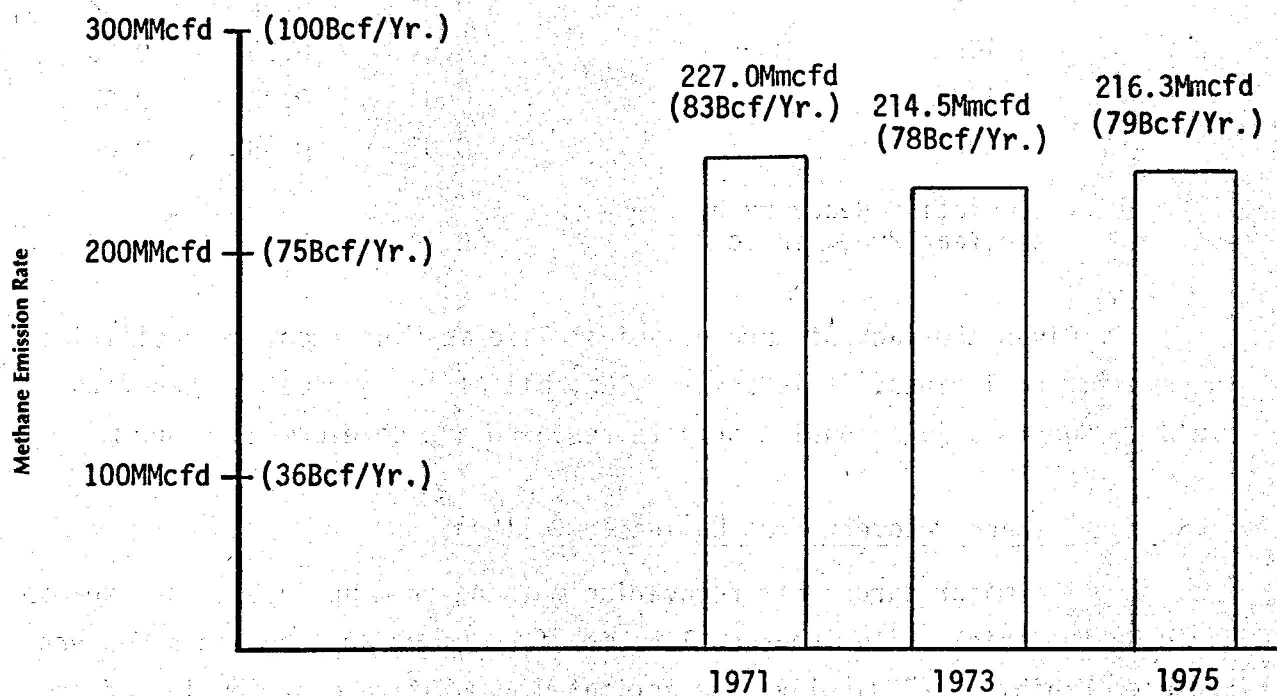
The initial target for recovering methane from coal seams is the 80 Bcf of methane emitted each year from working coal mines, shown in Exhibit 1-26.

Because the Appalachian Basin coal seams are too thin and too lean in methane content to economically support methane recovery on its own, estimates of recovery must be linked to the pace of current mining and the opening of new mines. Thus, only limited leeway in making production rate and recovery estimates is available.

Assuming a rigorous installation of facilities of methane emissions recovery in "gassy" coal, and a high rate of new mine openings, the following production benefits could accrue, at three natural gas prices:

Exhibit 1-26

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.

	Price Per Mcf		
	$1.75	$3.00	$4.50
• Ultimate (30 Year) Recovery, in Tcf	1.1	1.6	1.6
• Yearly Production Rates, in Tcf/Year			
1985	0.02	0.02	0.02
1990	0.04	0.05	0.05
1995	0.04	0.07	0.07
2000	0.05	0.08	0.08
• Cumulative Recovery by the Year 2000, in Tcf	0.64	0.91	0.91

Given the lack of currently installed methane recovery facilities in domestic coal mines, it is assumed that all of the production benefits would be due to a joint public-private research and development program.

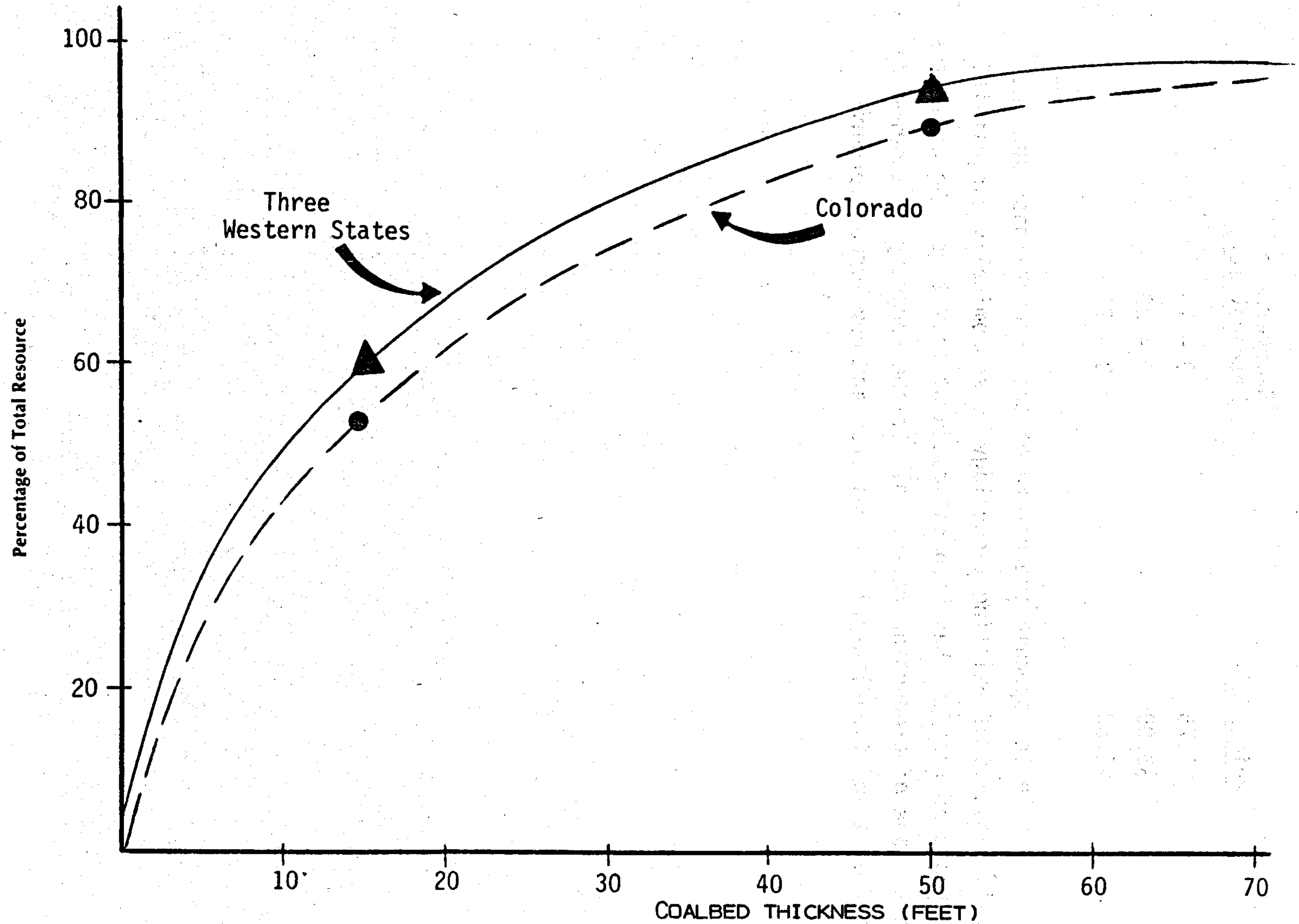
2. Methane Recovery from Unminable Coalbeds

The major target for recovering methane from unminable coal seams would be the thick, bituminous coal seams of Colorado and the other Western States. Exhibit 1-27 displays the estimated cumulative distribution of the thickness of these coal seams in the Western States.

An economic analysis of methane recovery from deep, unminable coal seams, using deviated wells, provided the following estimates of recoverable methane as a function of natural gas price:

Exhibit 1-27

Estimated Distribution of Total Bituminous Coal Resources by Coalbed Thickness for Colorado and Three Western States



SOURCE: Booz, Allen & Hamilton, ERDA's Underground Coal Gasification Program, Volume III - Resources, May, 1977.

Price/Mcf	Recoverable Methane (Tcf)
$1.75	0 - 10
$3.00	0 - 20
$4.50	0 - 25

Due to the speculative nature of the resource base and the uncertain capacity of existing technology to economically exploit it, only a range of recovery has been estimated at this time. No estimates have been made of production rates. All of the recovery is assumed to accrue from a joint public-private research and development program.

VIII. METHANE FROM GEOPRESSURED AQUIFERS

A. Background

Large water-bearing reservoirs, characterized by significantly higher temperatures and pressures than their depth alone would suggest, lie deep beneath the Gulf of Mexico and the coastal regions of Texas and Louisiana. These are referred to as geopressured aquifers. Under these conditions, considerable methane may be dissolved in the trapped water, particularly if the water is low in salinity. Should it be possible to produce the formation water, extract the methane, and dispose of the spent water in an economically and environmentally sound way, these reservoirs could contribute to the nation's gas supply.

The initial estimates of gas in place for these geopressured aquifers have been vast, ranging from 3,000 Tcf (B. R. Hise) to 50,000 Tcf (P. H. Jones). The USGS, in Circular 726, placed the estimate at 23,618 Tcf. These large gas-in-place figures have led to considerable speculation of a massive, economically recoverable future source of gas. Popular publications such as Fortune and the Wall Street Journal and publically known individuals such as Herman Kahn (Hudson Institute) have speculated that geopressured aquifers can provide gas for 1,000 years. More intensive interpretation of these initial estimates have placed the recoverable potential at 250 to 500 Tcf (M. H. Dorfman).

The essential question is not the total size of the resource, but the portion that may be technically and economically recoverable.

B. Methane Recovery from Geopressured Aquifers

While the basic technology for recovering methane from the geopressured aquifers is traditional and straightforward, only about 2 to 5 percent of the reservoir's water can be produced in 30 years or before exhausting the reservoir's drive mechanism. Thus, even under optimistic assumptions, less than five percent of the gas resource in place will flow to the surface at rates above an economic limit and be recoverable, as shown on Exhibit 1-28 for three Texas and Louisiana Gulf Coast reservoirs.

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

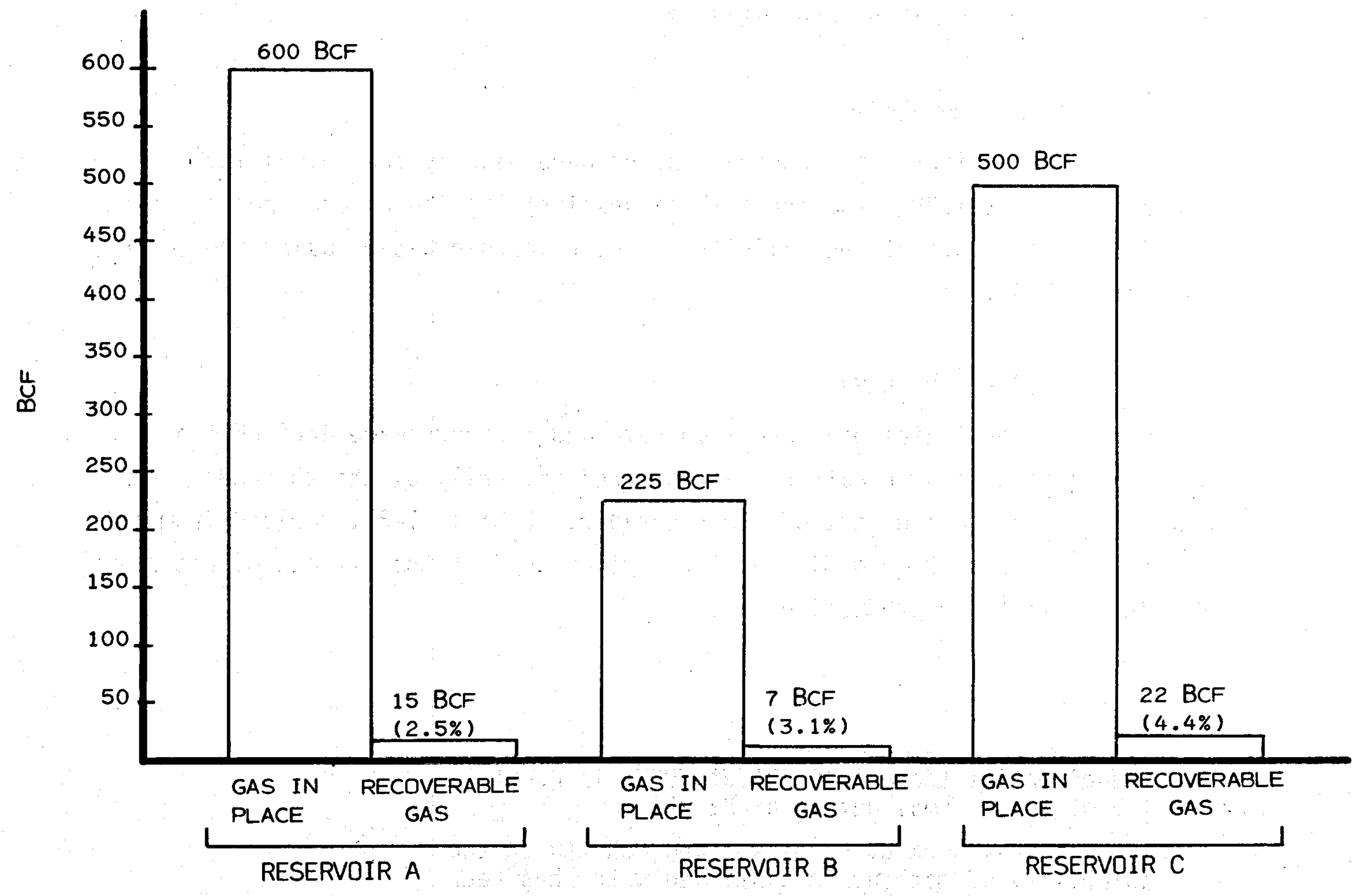
- That the rate of production of water containing methane (over and above that required to repay operating costs) be sufficient to repay the investment costs of the project.

These two factors, total methane content and production rate, are the two critical economic variables and provide a single means for representing the numerous geologic and reservoir characteristics that influence these variables.

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

Exhibit 1-28

Analysis of Technical Recoverv Efficiency from Geopressured Aquifers



SINGLE RESERVOIR AREA (SQUARE MILES)	60	42	20
PAY THICKNESS, FEET	300	200	500
PAY PERMEABILITY TO BRINE, MDS	20	125	100
PRESSURE, INITIAL, PSI	11,000	11,000	14,000
METHANE CONTENT, SCF/BBL	40	25	47
LOCATION	BRAZORIA FAIRWAY, TEXAS	LOUISIANA (W. MAURICE)	LOUISIANA (DEPTH RANGE, 18,000-19,000)

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^{o}F and thus relatively low potentials for thermal energy output.*

1. Methane Content

The estimates of methane content were made by the solubility curve in Exhibit 1-29 (assuming full saturation).** These were then adjusted based on an estimate of the salinity of the reservoir water, using the curves in Exhibit 1-30.***

2. Production Rates

The estimates of production rate and recovery were derived from basic production flow equations, as governed primarily by the thickness, permeability, and areal extent of the reservoir. Exhibit 1-31, derived from this model, provides a graphic display for a given area of the effects of net pay and permeability on production rate.

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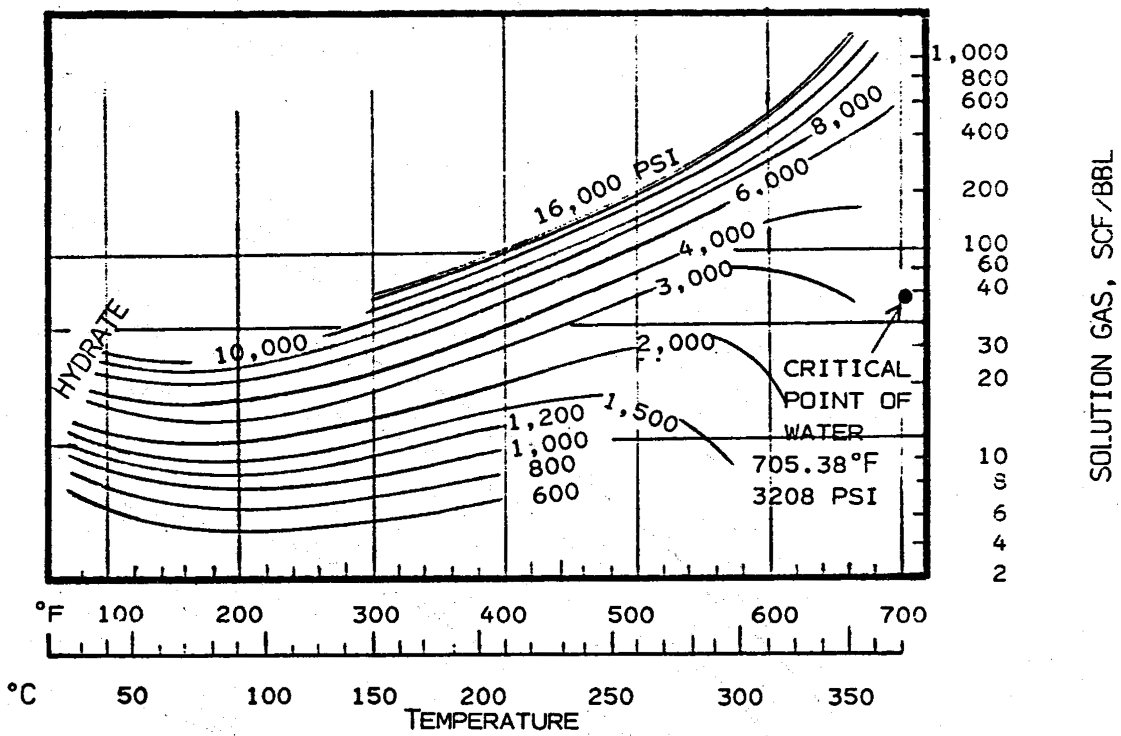
* The potential thermal output at 200^{o}F is about 1/5 of the thermal output at 325^{o}F.

** The original work by Culberson and McKetta on the solubility of methane in distilled water has been extended to higher pressures and temperatures by Sultanov, Skripka, and Namoit.

*** Standing and Dodson have provided means for estimating correction factors for saline water.

Exhibit 1-29

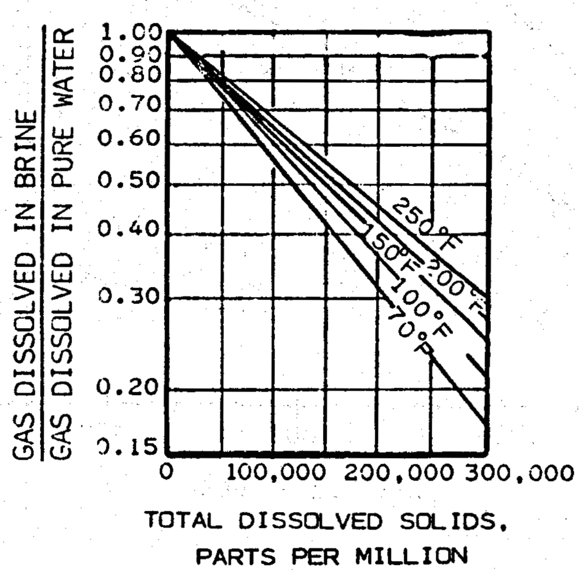
Solubility of Methane in Fresh Water



SOURCE: Sultanov, Skripka, and Namoit, 1972

Exhibit 1-30

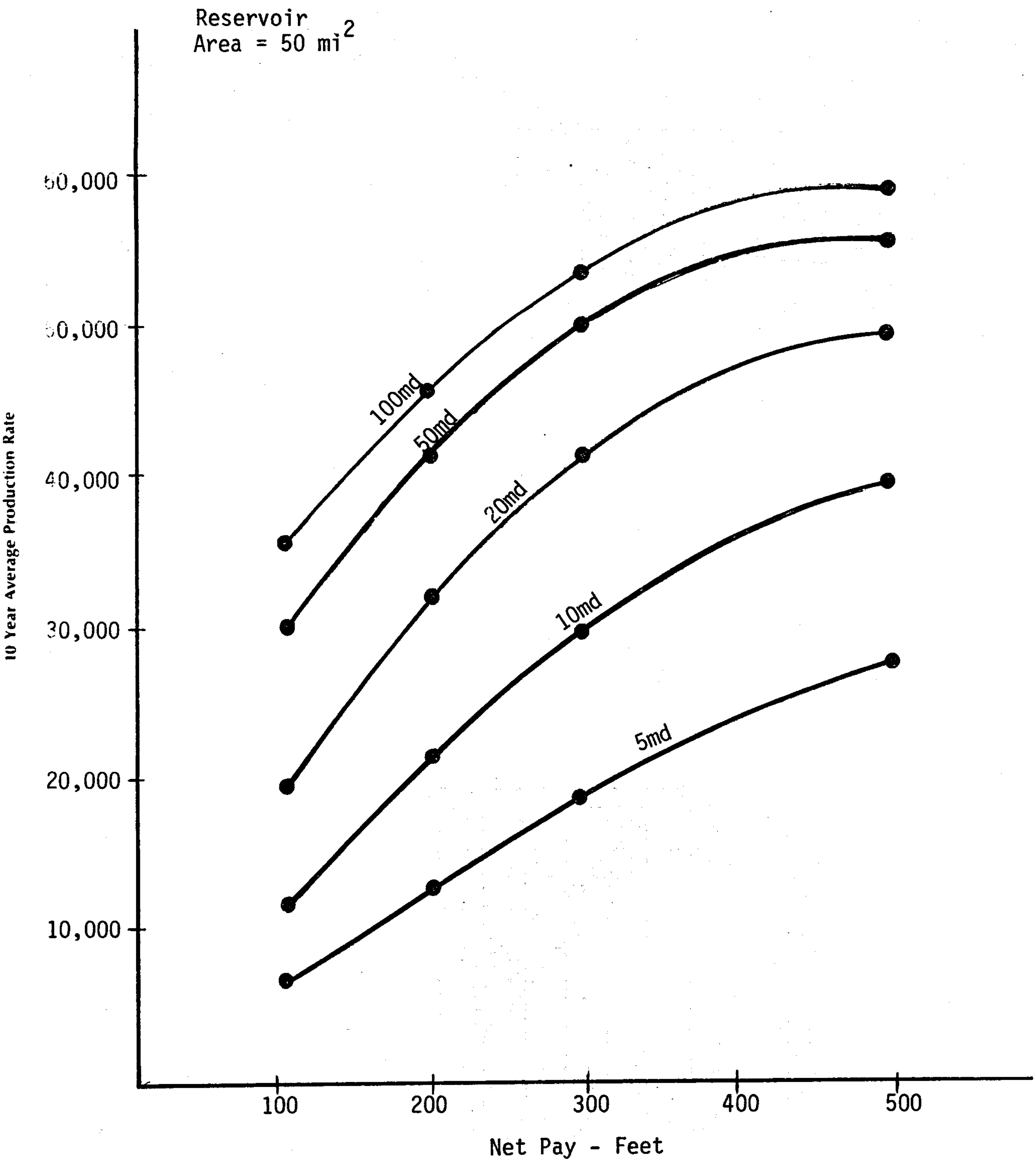
Effect of Salinity on Gas in Solution at Gas Saturation Point



SOURCE: Standing and Dodson

Exhibit 1-31

10 Year Average Production Rate as a Function of Net Pay, Permeability, and Area



3. Minimum Required Production Rate/Methane Content Combination to Cover Operating and Investment Costs

The analysis of operating and investment costs provides an overall minimum required combination of well production rate and methane content, as follows:

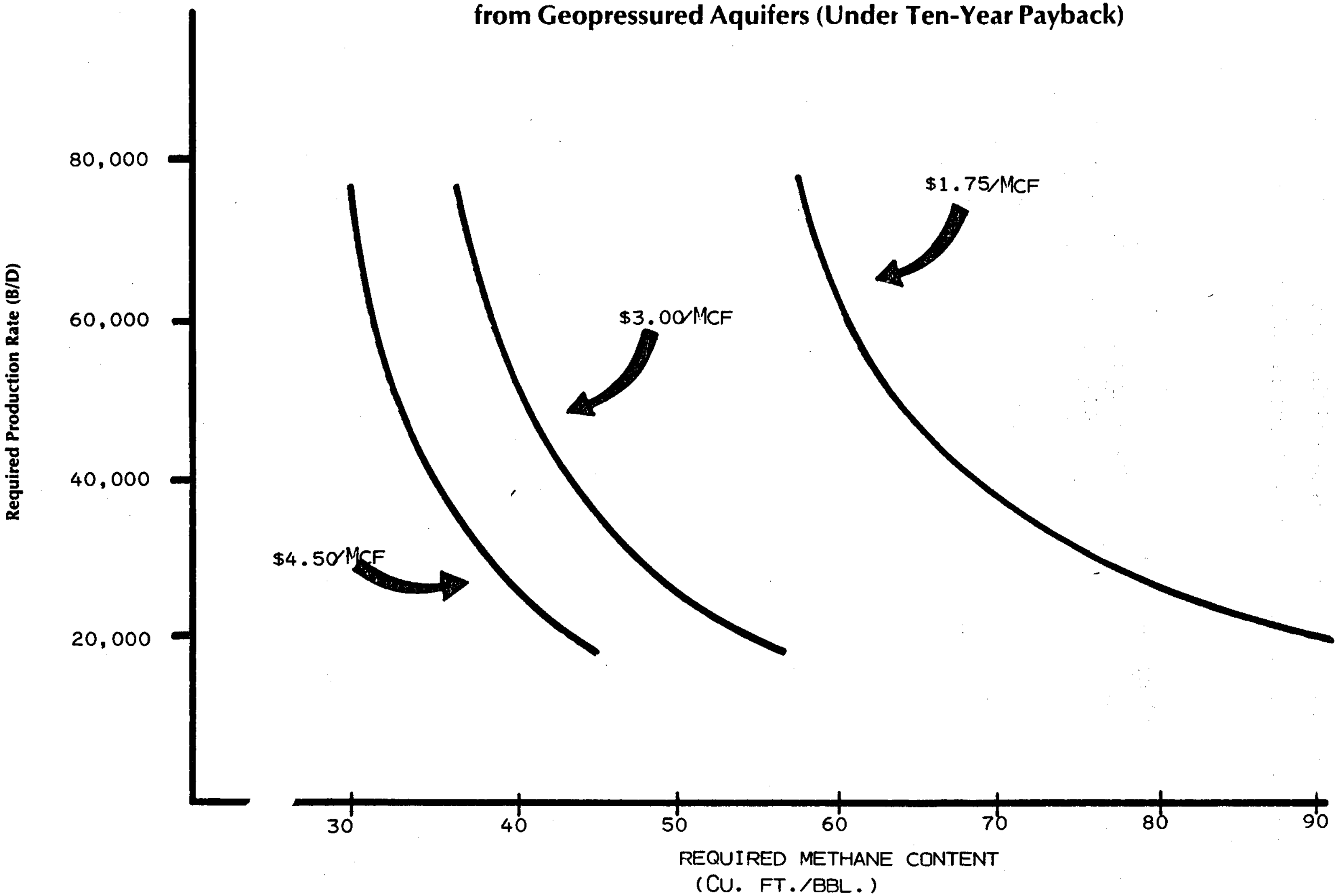
Price ($/Mcf)	Production Rate (B/D)	Methane Content (Cu. Ft./Bbl) to Pay Back: Operating Costs	Investment Costs (10 yr - 5 yr)	Total
$1.75	20,000	50	46-92	96-142
	40,000	50	23-46	73-96
	60,000	50	16-31	66-81
	80,000	50	12-23	62-73
$3.00	20,000	30	27-54	57-84
	40,000	30	14-27	44-57
	60,000	30	9-18	39-48
	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 1-32 illustrates the minimum required combination of production rate and methane content to provide a ten-year payback.*

* It is assumed that substantial additional resource characterization, technology development, and demonstration serve to reduce the risk to conventional levels, thereby permitting the use of the ten-year payback criterion.

Exhibit 1-32

Minimum Required Production Rate and Methane Content from Geopressured Aquifers (Under Ten-Year Payback)



C. Economic Potential of Methane from Geopressured Aquifers

The recovery of methane from geopressured aquifers would be directed to the Gulf Coast regions of Texas, Louisiana, and Mississippi. The target would be the Tertiary age (Frio and Wilcox) formations in Texas and the Miocene and Upper Cretaceous formations in Louisiana and Mississippi.

1. Geopressured 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/geopressured fairways in the Frio Formation (Tertiary) of the Texas Gulf Coast. The available geologic data and the analytic methods described above were used to estimate the methane content of the water and the average production rates for the five identified prospects, as follows:

	Estimated Methane Content (Cu. Ft./Bbl.)	Estimated Production Rate (Avg. Bbl/D; 10 Years)
• Hidalgo Fairway	45	7,000
• Armstrong Fairway	35	34,000
• Corpus Christi Fairway	40	9,000
• Matagorda Fairway	55	2,000
• Brazoria Fairway		
-- Austin Bayou	45	51,000
-- Other	40	41,000

When these five prospects were compared to the minimum economic conditions for the (low-risk) payback period of ten years, only the Austin Bayou prospect is economic at $3.00 per Mcf. The remainder of the Brazoria Fairway becomes economic at $4.50 per Mcf.

2. Geopressured Aquifers of the Louisiana Gulf Coast

Two major studies of the resource in the Louisiana area were used. They are reported separately, because they yield differing conclusions.

a. LSU Study

Eight large geopressured aquifers were located and defined by Hawkins of Louisiana State University, in the Louisiana Gulf Coast area.* The methane content for these eight areas are estimated as follows:

	Reservoir Properties			
Prospective Area	Temperature (°F)	Pressure (psi)	Dissolved Solids (ppm)	Estimated Methane Content (Cu.Ft./Bbl.)
• 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

* 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.

Under a minimum required methane content of 32-38 cubic feet per barrel (assuming the maximum 10 year production rate of 60,000 B/D), none of the eight prospective areas are economic at $3.00 or $4.50 per Mcf.

b. USGS Study

A second effort currently underway by USGS (Wallace) involves analysis of over 1,000 wells covering about 75,000 square miles from onshore and offshore 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, and the geopressured zone began 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:

Geopressured Interval (Ft.)	Temperature (^{o}F)	Pressure (psi)	Salinity (ppm)	Methane Content (Cu. Ft./Bbl.)	GIP Onshore (Tcf)
10,500-16,000	210-260	8,000 - 12,000	70,000- 110,000	16 - 31	695
16,000-17,000	270	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

Because little conclusive data are available on areal size or permeability of the south Louisiana geopressured aquifers, for economic and recovery purposes it was assumed that each interval could support a ten year production rate of 40,000 B/D.

An analysis of these deposits shows that the 18,000 feet and deeper interval is economic at $3.00 per Mcf and the interval deeper than 16,000 feet is economic at $4.50 per Mcf.

3. Summary Estimate of Economic Potential

Extrapolating from the analysis of the resource base provides the following estimates of economic potential from geopressured aquifers, shown below (in Tcf):

	Texas	Louisiana*
Gas In Place	60	800
Technically Recoverable Gas In Place	2	40
Economically Recoverable At:		
$1.75	-	-
$3.00	0.1	1.0
$4.50	0.4	5.0

* The resource data in Louisiana is classified as speculative.

Due to the very preliminary definition of these resources, no production rates have been projected.

Beyond the quantities estimated from available resource data, additional productive horizons may exist in Texas and in central Louisiana. Further, the research work on geopressured methane has intimated a second resource target that may be associated with geopressured aquifers -- free methane in excess of that in the saturated reservoir brines. Should either of these conditions be proved by further research, the economic potential of geopressured aquifers may substantially increase.

IX. THE PROPOSED RESEARCH STRATEGY IN ENHANCED GAS RECOVERY

A. Proposed R&D Plan

The overall objectives of the research plan are to define the unconventional gas resources, to advance the state of the technology to economically exploit these resources, and to optimize and accelerate the application of the emerging recovery technology.

The proposed five year program consists of 16 major programs across the four unconventional gas resource bases, as shown below:

Unconventional Resource Base	Title of the R&D Program	No. of Programs
1. Tight Gas Basins	• Resource Evaluation and Characterization	3
	• Develop Advanced Recovery Technology	4
	• Optimize Recovery Technology	2
	• Stimulate Accelerated Application	2
2. Devonian Shale	• Develop Deep, High Cost Formations	1
	• Test Potential of Dual Completions	1
	• Improve Recovery Efficiency	1
3. Methane from Coal	• Recover Methane in Association with Mining	1
	• Recover Methane from Unminable Coal Seams	1
4. Geopressured Aquifers	• Ascertain Reservoir Size, Methane Content, and Production Technology	1

B. R&D Costs

Unlocking the potential of these diverse unconventional sources of natural gas will require a concerted program of research, development, and demonstration. In addition to on-going industry outlays, nearly $370 million is required, over the next five years, for the joint Federal-industry research programs in enhanced gas recovery. DOE would provide $265 million and industry the remaining $105 million.

- The yearly costs for the 5-year DOE/Industry joint research program are as follows (in millions of constant 1977 dollars)

	Total Costs	DOE Share
Total 5-Year Costs (FY 79-FY 83)	$369.1	$265.5
Yearly Costs:		
FY 79	$ 59.7	$ 45.5
FY 80	80.7	60.4
FY 81	74.6	53.5
FY 82	87.0	56.3
FY 83	67.1	49.8

- Public R&D (the DOE share) funds the resource characterization, improved measurement, and technology transfer program elements; DOE and industry jointly fund the field-based R&D:

Program Elements	Tight Gas Reservoirs (Total/DOE)	Devonian Shale (Total/DOE)	Methane from Coal (Total/DOE)	Methane from Geopressured Aquifers (Total/DOE)	Total (Total/DOE)
Resource Characterization and Knowledge Base	$37.9/37.4	$6.5	$5.5	$2.7	$52.6/52.1
Improved Measurement Tools and Methods	15.2	2.5	2.0	3.0	22.7
Field Tests	188.1/98.0	27.1/19.1	36.5/31.5	30.0	281.7/178.6
Technology Transfer	8.0	2.0	1.6	0.5	12.1
TOTAL	$249.2/158.6	$38.1/30.1	$45.6/40.6	$36.2	$369.1/265.5

C. Production Benefits

Successful execution of the R&D program would lead to additional gas recovery and acceleration of its production.

Two measures were used to quantify the benefits:

- A long-term measure of additions* to ultimate recovery (at $3.00 per Mcf) over that due to Base Case technology.

- A near-term measure of additional* gas that can be produced between now and 1990 (at $3.00 per Mcf) due to Advanced technology.

The estimated additional recovery, under the Base Case, is shown below:

Unconventional Gas Target	Long-Term Measure Ultimate Addition to Recovery (@ $3.00/Mcf) (Tcf)	Near-Term Measure Cumulative Addition to Recovery: 1978-1990 (@ $3.00/Mcf) (Tcf)
• Tight Gas Sands	81	25
• Devonian Shale	8	2
• Methane from Coal Seams	2 - 22	N/A
• Methane from Geo-pressured Aquifers	1	N/A
TOTAL	92 - 112	27

* These are additional quantities, over the Base Case, that would accrue due to successful R&D leading to the Advanced Case.

X. SUMMARY

Under advanced recovery technology, unconventional sources of natural gas could make a substantial contribution to gas supplies between 1985 and 1990. These unconventional sources, already providing about 1 Tcf per year, could provide, under advanced technology and acceleration, from 3 to 4 Tcf in 1985, and from 6 to 8 Tcf in 1990 (at $1.75 and $3.00 per Mcf, respectively).

The largest total production from unconventional resources would accrue from a combination of increased economic incentives and advanced technology. At gas prices of $3.00 per Mcf, 200 to 220 Tcf of unconventional natural gas could be ultimately recovered with substantial quantities, nearly 50 Tcf, available between now and 1990.

Higher gas price combined with advanced technology will enable gas producers to develop the less productive parts of the Devonian shales in the Appalachian Basin, and will provide a threshold price for beginning production of methane from coal seams and geopressured aquifers. In the tight gas basins, it shifts a considerable portion of the near-conventional target to industry, relegating the more difficult targets to exploitation through advanced technology.

For an equivalent amount of energy, between now and 1990, the unconventional sources under advanced technology and up to $3.00 per Mcf** provide as low or lower cost to the public than any substitute energy sources.

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* A $3.00 per Mcf gas price would be equivalent to imported fuel oil, assuming a 20% premium differential.

** The study of enhanced gas recovery examined only three prices -- $1.75, $3.00, and $4.50 per Mcf -- and an optimum research program for a given price. It did not seek to establish the optimum price or optimum combination of public R&D and price.

However, even with these additions to supply, the projections are that gas supply remains below 1977 usage levels. Thus, additional gas supply programs such as coal gasification, electricity, and gas or LNG imports, though costly, are required to fill the gap and provide the nation with adequate energy supplies.

ATTACHMENT A

OVERALL APPROACH TO DEVELOPMENT OF THE EGR STRATEGIC PLAN

OVERALL APPROACH TO DEVELOPMENT OF THE EGR STRATEGIC PLAN

The EGR research strategies and estimates of their potential build directly on the problems -- as articulated by industry and supported by detailed, independent geological and engineering economics analysis -- that have constrained the development of the unconventional sources of natural gas. The R&D strategies call for vigorous Federal-industry collaboration to overcome these constraints, thereby enabling accelerated development and commercialization -- and substantial additions to the nation's gas supply.

This Attachment provides an overview of the process by which the Strategic Plan is being generated.*

I. PHASES IN THE OVERALL APPROACH

A. The Purpose of the Study

The Enhanced Gas Recovery Strategic Plan is to serve as the analytic foundation for selecting a rational, cost-effective R&D program for unconventional natural gas. Specifically, it is to support Federal policy-makers in selecting a portfolio of projects (strategies) that addresses the technical and geological problems that have deterred industry from developing these resources. Thus, the analysis has to include specific information on the following:

- Operational R&D objectives
- The technical feasibility of meeting these objectives

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* Volume III of this report contains methodological papers explaining the major analytic steps in detail.

- Activities, with their timing and costs, required to fulfill these objectives

- Production benefits attributable to meeting the R&D objectives.

This information will help Federal officials and the Working Group on Enhanced Gas Recovery select projects that will ultimately comprise the Strategy Plan.

B. Steps in the Planning Process

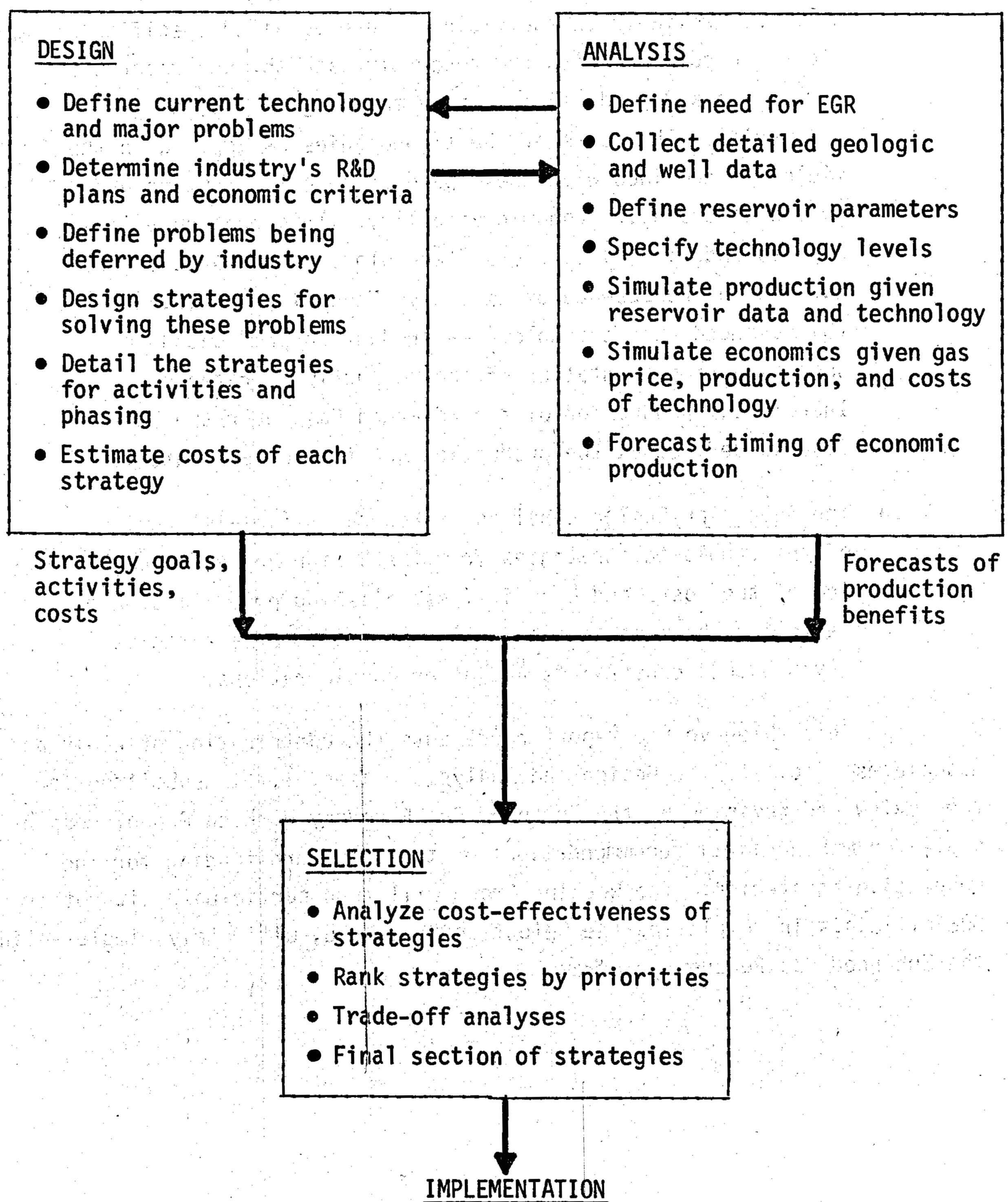
The overall planning process consists of three broad phases (Exhibit A-1):

- 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 are the basis for the Base Case; those that remain are candidates for Federal R&D strategies and a program of activities is suggested to solve these problems. The solutions to these problems form the basis for specifying the Advanced Case and the DOE R&D plan. The timing of the activities and the costs are part of the study.

- The Analysis Phase provides estimates of gas production from unconventional sources. These production forecasts stem from combining detailed geologic data, engineering modeling, and economic analysis.

EXHIBIT A-1

PHASES IN THE STRATEGIC PLANNING PROCESS



The broad definitions of Base and Advanced Cases developed in the Design Phase are translated into detailed 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. The costs of the technologies as applied in the field are combined with these production estimates and gas prices to evaluate economic viability. This procedure is applied under: (a) Base Case technology -- to forecast production in the absence of an active Federal R&D role; and (b) Advanced Case technology -- production predicated on successful implementation of the respective strategies. Incremental production of the Advanced Case over the Base Case is defined as the production benefits of a strategy.

- The Selection Design 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. The Working Group will then participate with other DOE officials in completing the Selection Phase and, ultimately, implementing the Enhanced Gas Recovery Program.

The chapters in Volume II of this report which discuss the various unconventional gas resources are each divided into two parts. The results of the Analysis Phase are reported in Part 1 of the respective resource chapters. This describes the resource and the major problems besetting its development, defines specific targets (portions of the total resource affected by similar problems), and forecasts the production expected under Base and Advanced technologies for a range of gas prices. The results of the Design Phase are detailed in Part 2 of each resource chapter. These descriptions of the candidate strategies define the central problems to be addressed for each target resource, the scope of the strategy, its R&D objectives, activities, manpower and field test activities, R&D costs, and associated production benefits.

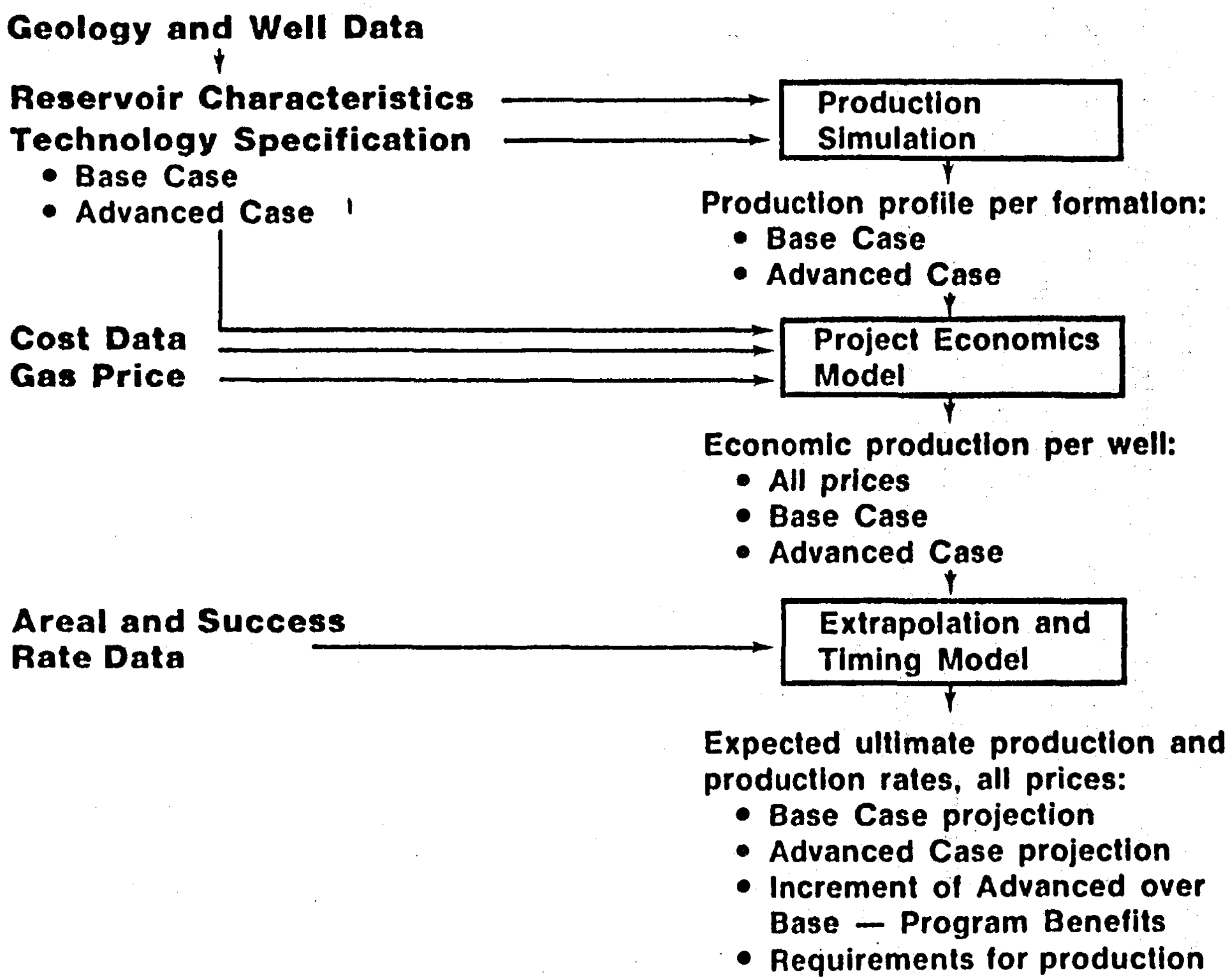
The subsequent Selection Phase is the province of Federal managers, so outside the scope of this report.

II. OVERVIEW OF THE ANALYSIS PHASE

Exhibit A-2 shows a simplified flow diagram of the EGR Analysis Phase. The Analysis Phase was designed to approximate, on a scale consistent with a planning model, the procedures followed by gas producers in evaluating prospective drilling opportunities. The analysis begins with the evaluation of geologic data and well records, proceeds to the estimation of production and evaluation of economic feasibility, and concludes with a field development schedule -- in brief, it follows a geology-engineering-economics approach. The principal features of this approach are described briefly below and in substantially greater detail in Volume III.

EXHIBIT A-2

Simplified Flow Diagram of the EGR Analysis



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 of the basins and provided to the analytic team for conversion into detailed analytic units.

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

- 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.

The object of this study is to focus analysis of incremental production from unconventional resources. Proved areas, therefore, were excluded from the study because this resource is part of the currently proved 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. This subdivision was necessary to allow for variations in the properties of individual formations in a vertical series and to reflect the absence of some formations from the "stack" in specific sub-areas. These interpretations were reviewed by geologists and engineers experienced in the respective basins. The resulting analytic units used by the study were as follows:

Resource	Analytic Units
Tight Gas Basins	622 reservoirs
Devonian Shale	34 areal units
Methane from Coal Seams	
-- with mining	Appalachian Region
-- unminable	All unminable coalbeds
Methane from Geopressured Aquifers	23 fairways and horizons

* 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 programming aimed at defining the reservoir parameters in these areas so they could be ranked in a way roughly similar to the probable and possible areas.

3. <u>Technology Specification</u>. 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 and verified through extensive surveying. For each resource, this 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). Eighty percent reliability was defined as the threshold level for replicable field applications. The costs of the remaining twenty percent were borne by the eighty percent that were successful.

4. <u>Production Simulation</u>. The detailed reservoir and geologic data of the analytic units were combined with the explicit specification of the technology 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 both 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 advances in technology, and for the thickness and intensity of natural fractures of the shales. The A&M reservoir simulator was used to provide supportive and validating analyses of the shales.

- Production from minable coalbeds was based on the rates of mining and methane capture. For unminable coalbeds, recovery estimates were made by a time-dependent analytic diffusion model based on the intensity of natural fractures and the methane content of the coal.

- 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 is the analysis of economic feasibility. A discounted net present value (NPV) cash flow model was used for the Tight Sands and Devonian Shale. A payback model was used for methane from coalbeds and geopressured aquifers. In all cases, the revenue stream was estimated by multiplying the net gas price (after royalty and production taxes) by the production rate as estimated above. 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 were basic 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 varied by location, depth, and technology. In all cases revenues were compared with costs using explicit financial criteria (NPV greater than zero at specified discount 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. It was assumed that all economic projects would be developed in a phased progression. For each basin, an areal 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 expected successful areas. Each area was then 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 development of these wells was then time-phased so that the rate of expansion represents an orderly progression of development across the basins. Probable areas were assumed to be drilled prior to possible areas. (Note that extrapolation is confined to the probable and possible areas of the basins; proved and speculative areas are excluded.) This final phase of the analysis provides for each strategy and price analyzed:

- Base Case ultimate recovery, annual production rates, and cumulative recovery.

- Advanced Case ultimate recovery, annual production rates, and cumulative recovery.

- Incremental benefits of the respective strategies (Advanced Case production minus Base Case production).

- Requirements for 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 of the unconventional resources using the best available geologic and reservoir data and production potential to estimate economic viability and pace of development.

III. OVERVIEW OF THE DESIGN PHASE

The methods of the Design Phase consisted primarily of intensive interaction with industry, academic, and government experts for each of the resources. The results were essentially qualitative in nature; their evaluation depends in large part on the accuracy of the problem definitions that emerged and the efficacy of the strategies for solving these problems. An independent study* 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.

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

This was complemented by 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.

The results of these consultations have their clearest expression in the Analytic Phase, where they were reduced to explicit, quantitative terms of economic recovery.

CHAPTER TWO

THE NEED AND ALTERNATIVES FOR INCREASING SUPPLIES OF NATURAL GAS

I. INTRODUCTION

Natural gas, the nation's second most utilized fuel source, provides about thirty percent of the country's energy requirements. It is a major component of home heating, industrial fuel and raw material, and electricity generation.

As the use of natural gas grew during the early 1970's, domestic capacity to meet this usage declined. The effects of this decline were felt first through periodic curtailments and finally by severe industrial disruption. In 1976/77, pipeline curtailments, one measurement of unmet demand, were 3.4 Tcf, a shortfall of about 15%.

Three aspects illustrate the current problem in domestic natural gas supply:

- Since 1970, additions to supply from new discoveries and extensions of known fields have replaced only 1 Tcf for every 2.5 Tcf consumed.

- Total proved reserves, therefore, have declined by 26% in the past seven years, 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.

- With 1976 production running at 19.7 Tcf, the ratio of proved reserves to production is at an all time low, less than 11 to 1. At current production rates and without new additions, the nation has less than eleven years' gas supply in terms of recoverable reserves -- about nine and a half years when Alaska is excluded.

While substitute fuel sources, such as oil and coal, can be used, a reduced gas supply: (a) increases the reliance on oil imports; (b) jeopardizes large fixed investments such as pipelines and home furnances; and (c) requires the use of fuels that are more costly to clean to meet environmental standards.

These trends portend a near-term crisis in domestic natural gas supply. This study of enhanced gas recovery -- the recovery of gas from difficult and unconventional sources -- was undertaken for the Department of Energy (DOE)* to define one option for meeting a portion of this crisis. It was launched in response to two questions:

- Is there a need for augmenting domestic supplies of natural gas?

- What is the economic potential of natural gas supplies from the geologically and technically challenging unconventional gas resources, namely:

  -- Tight gas sands

  -- Devonian shale

  -- Methane from coal seams

  -- Geopressured aquifers

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* During the course of the study, the Energy Research and Development Administration (ERDA) was incorporated into the Department of Energy (DOE).

II. THE NEED FOR ENHANCED GAS RECOVERY

Five programs are available to public policy-makers seeking to increase natural gas supply:

- Developing improved recovery technology and unlocking new, unconventional sources of gas.
- Increasing the economic incentives for gas production, through higher prices or more favorable taxes.
- Stimulating frontier exploration, through accelerated and innovative leasing policies.
- Developing secure, long-term sources of imported natural gas and LNG.
- Developing technology for generating synthetic gas by gasification of coal or heavy oil.

The decisions concerning the need for enhanced gas recovery will be made in light of the economic and long-term potential of supply from the alternative programs -- improved economics, frontier exploration, secure imports, and synthetic gas. Thus, decisions concerning enhanced gas recovery go to the heart of the basic issues in national energy policy as set forth in the Administration's National Energy Plan.

To outline the need for gas from unconventional sources, this chapter will provide, in summary form:

- An estimate of the domestic supply of conventional natural gas to the year 2000 under current economic conditions.

- Analyses of the major programs that could augment domestic gas supply.

A. Estimate of Gas Supply from Conventional Sources -- A Baseline for Comparison

The first step in developing policy for domestic natural gas is to estimate the supply available from conventional sources. Total domestic, conventional natural gas supply will be produced from three major sources:

- Proved reserves

- Growth in these proved reserves through development (extension) drilling

- New additions from exploration

Each of these conventional sources will be discussed individually and then combined into an overall estimate of available conventional domestic natural gas supply.

1. Proved Reserves

Our most secure national gas supply, proved reserves, must be separated into two geographical areas -- the contiguous states and Alaska.

The existing, proved reserves in the lower 48 states are 184 Tcf. These reserves will be depleted at a relatively predictable rate, with infill drilling and improved well life having only small effects on the established rate. The remaining portion of domestic gas reserves, the 31.9 Tcf of proved gas reserves in Alaska, requires a major pipeline whose costs dictate a gas price considerably in excess of current market prices.

2. Development Drilling

The initial estimates of proved reserves of a gas field do not remain static; rather they grow over time through additional development drilling. Recently, development drilling -- in known fields -- has served as the major source of new additions to domestic gas reserves.

- Eighty percent of the additions to reserves in the past seven years has come from development drilling (Exhibit 2-1).

- While development drilling has more than doubled in the past seven years, from 3,200 wells per year in 1970 to 7,400 wells in 1976 (Exhibit 2-2), annual productivity per well has declined from about 3 Bcf per well in 1970 to 1 Bcf per well in 1976 (Exhibit 2-3). Thus, new gas additions from development drilling are still below the 1970 rate.

- The area available for future development drilling is rapidly being exploited and is not being replaced due to low exploration success. Thus, after 1980, additional natural gas supplies from development drilling will begin to decline rapidly.

Exhibit 2-1

Additions to Domestic Natural Gas Supply 1970–1976 (Lower 48)

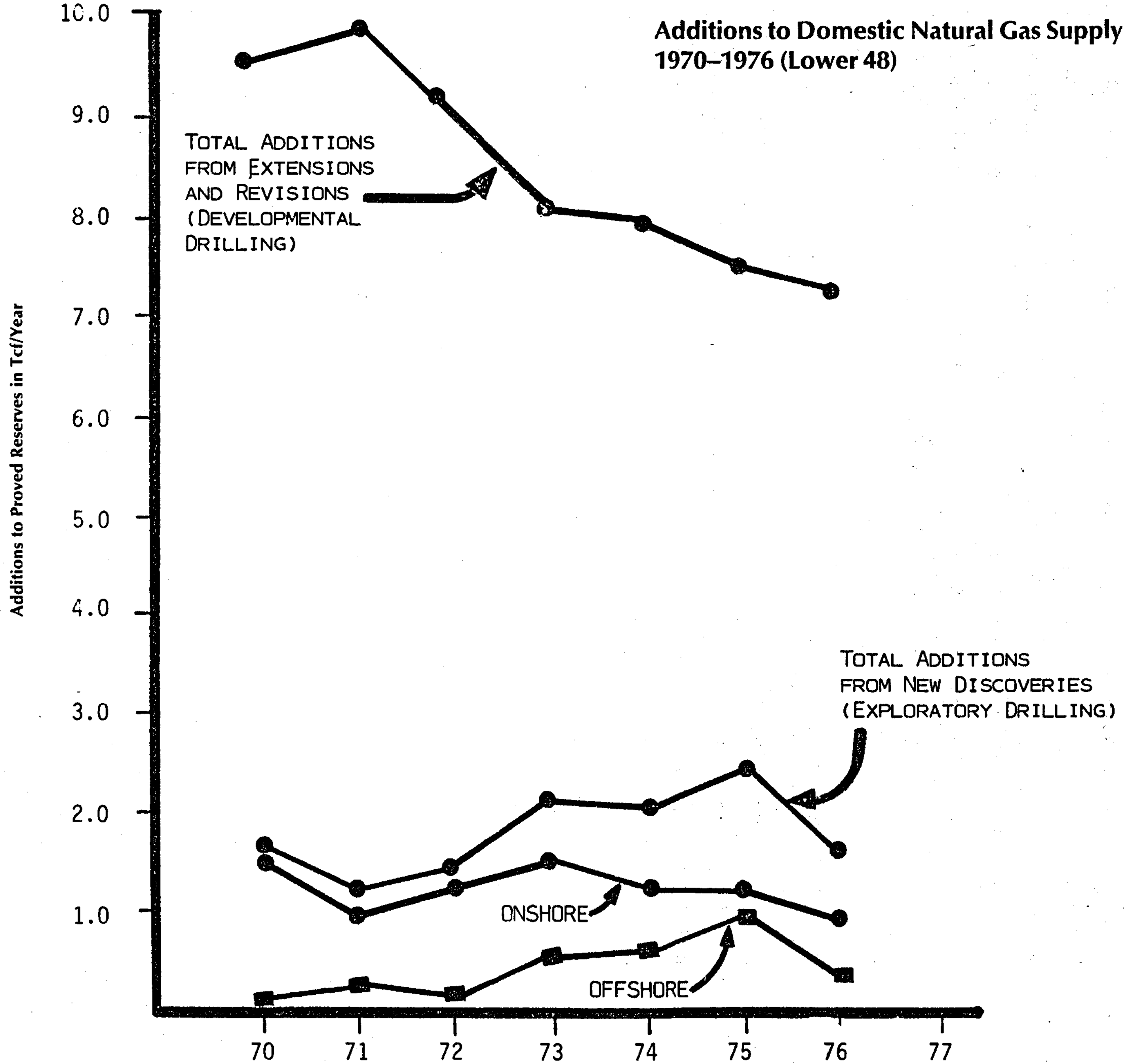
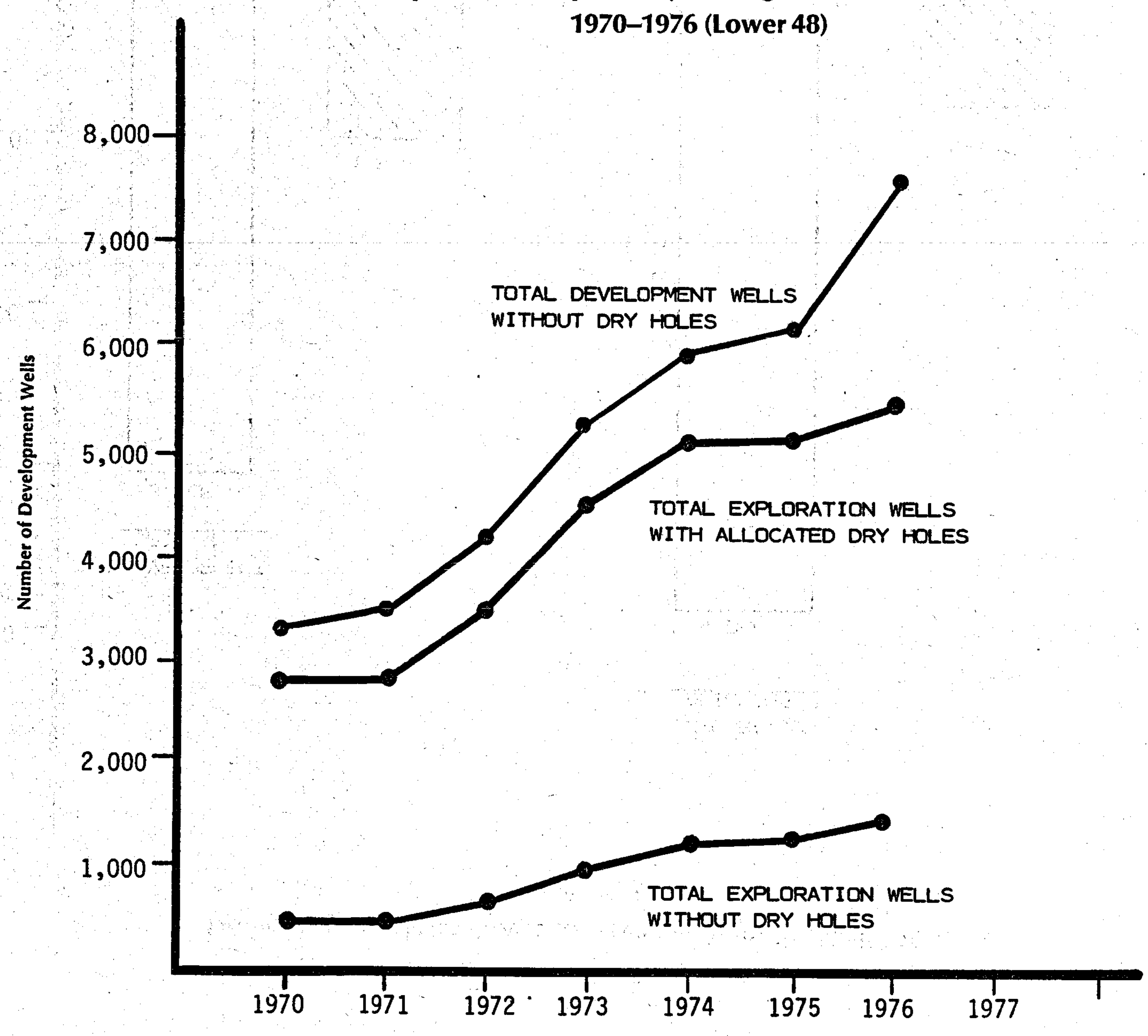


Exhibit 2-2

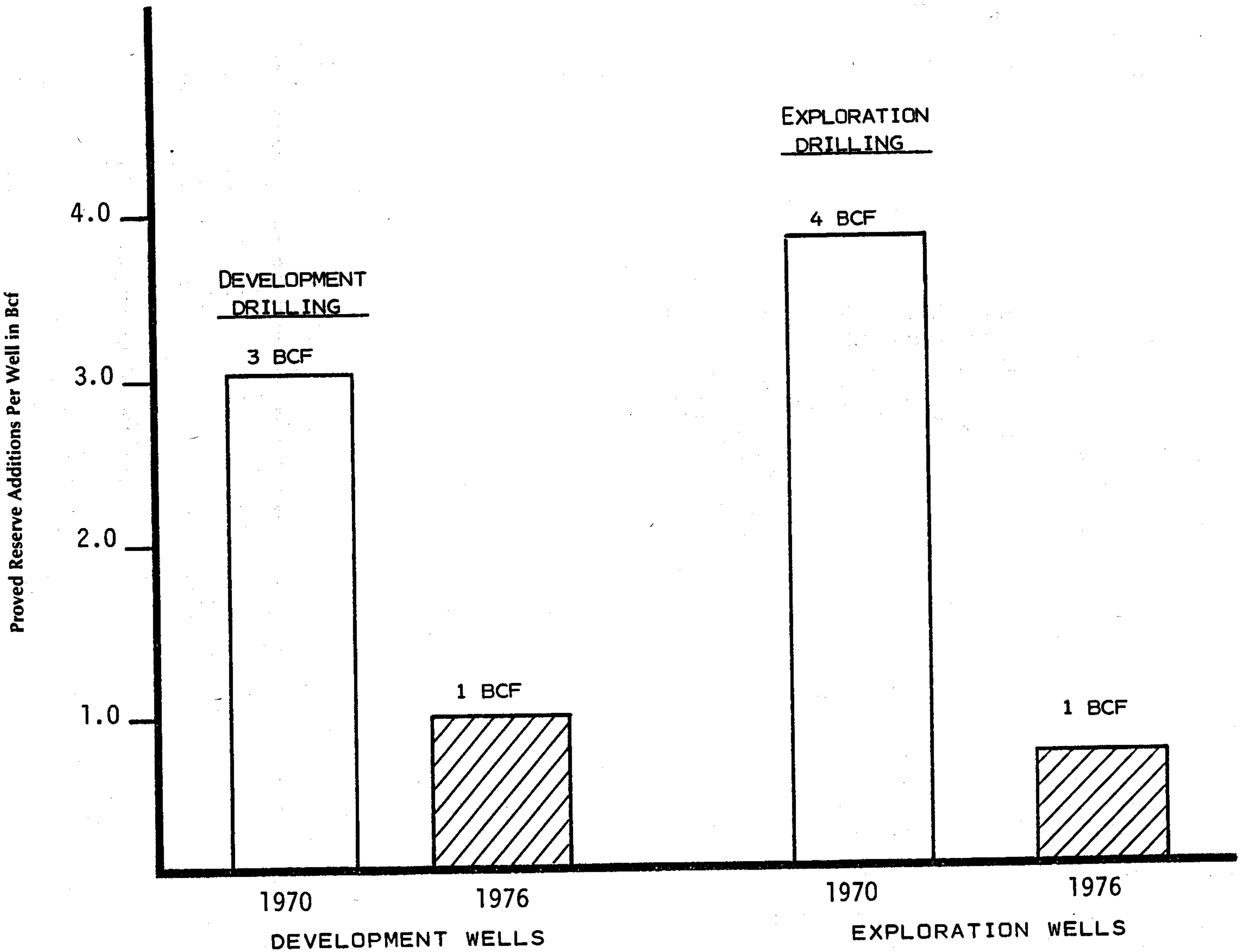
Development and Exploratory Drilling for Domestic Natural Gas 1970–1976 (Lower 48)



SOURCE: API, QUARTERLY REVIEW OF DRILLING STATISTICS, FOURTH QUARTER, 1970-1976

Exhibit 2-3

Domestic Natural Gas Proved Reserve Additions Per Well: 1970–1976
(Lower 48)



SOURCE: API, QUARTERLY REVIEW OF DRILLING STATISTICS, FOURTH QUARTER, 1970-1976

- A revised study of inferred reserves -- the future potential from development drilling in known fields (excluding Alaska) -- indicates that supplies from this source may have been severely overestimated. This analysis estimates the potential is nearly 50 Tcf lower than previously assumed -- 98 Tcf estimated by Brashear and Morra* versus 146 Tcf estimated by USGS.**

3. New Supply from Exploration

The final source of conventional gas supply is from the discovery of new gas fields and reservoirs. Currently a wide range of estimates exists as to the amount of new supply potentially available through exploration. No matter what the longer-term future holds, the near-term situation is limited, because:

- Current offshore leases are almost fully explored.
- Recent deep-well tests have had poor to mixed results.
- New finds in frontier areas will be slow to develop (five or more years) and expensive:
  - -- Alaskan gas is now estimated to cost $3.50 to $5.50 Mcf with transportation
  - -- The American Gas Association analysis shows that the drilling costs of a major portion of undiscovered gas reserves (the deep horizons) will be 6 to 10 times higher than current costs.

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* See Volume III, Enhanced Recovery of Unconventional Gas, Lewin and Associates, Inc.

** USGS Circular 725 reported 201 Tcf. However, an error of tabulation was made and has since been corrected to 146 Tcf.

From 1970-1976, in the lower 48 states, exploration added only a limited amount. Against annual natural gas usage in excess of 20 Tcf, exploration has added about 1.5 Tcf per year during the past seven years (Exhibit 2-1). Assuming that these additions ultimately grow by development drilling to 5.8 Tcf,* new discoveries are failing to replace consumption and the reserve will continue to decline.

A major part of the problem is that, during the past seven years, exploratory well productivity has severely declined. While the 1976 rate of exploration completions is three times the 1970 rate (shown previously in Exhibit 2-2), overall additions per well have gone from 4 Bcf per year in 1970 to 1 Bcf per well in 1976 (as shown previously in Exhibit 2-3). This is the same general trend as noted for development wells.

4. Projection of Gas Production from Proved Reserves, Development Drilling, and New Discoveries

The projection of gas supply from conventional sources includes estimates of production rates from currently proved reserves, from additions to those reserves due to development drilling, and new gas supply from exploration (including development drilling of the new discoveries).

Proved reserves for the lower 48, as of the end of 1976, were derived from API/AGA statistics. Growth in these reserves from development drilling were estimated from historical growth rates and years of discovery of known fields. New reserves from exploration were estimated based on the trend of the last seven years at 1.5 Tcf per year that ultimately grow to 5.8 Tcf during the life of the reserve (based on the study of inferred reserve growth).

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* Projected by the method of Brashear and Morra in Volume III.

Each of these conventional gas sources were declined, in the projection model, at the historic decline rate for proved reserves.

The projections that result from an analysis of these conventional sources show a continuing downturn in gas supply throughout the rest of this century (Exhibit 2-4):

- 19 Tcf in 1978
- 17 Tcf in 1980
- 13 Tcf in 1985
- 11 Tcf in 1990
- 8 Tcf in 2000

B. The Current Contribution of Unconventional Sources

Beyond conventional gas reserves, the unconventional sources of natural gas, particularly the more geologically favorable tight gas and Devonian shale basins, even now contribute to domestic production. These sources currently provide about 1 Tcf per year and could provide, under Base Case* technology assumptions, over 2 Tcf in 1990.

C. Total Domestic Natural Gas Supply

Combining production from the conventional and unconventional sources, the total gas supply from domestic sources would be as follows:

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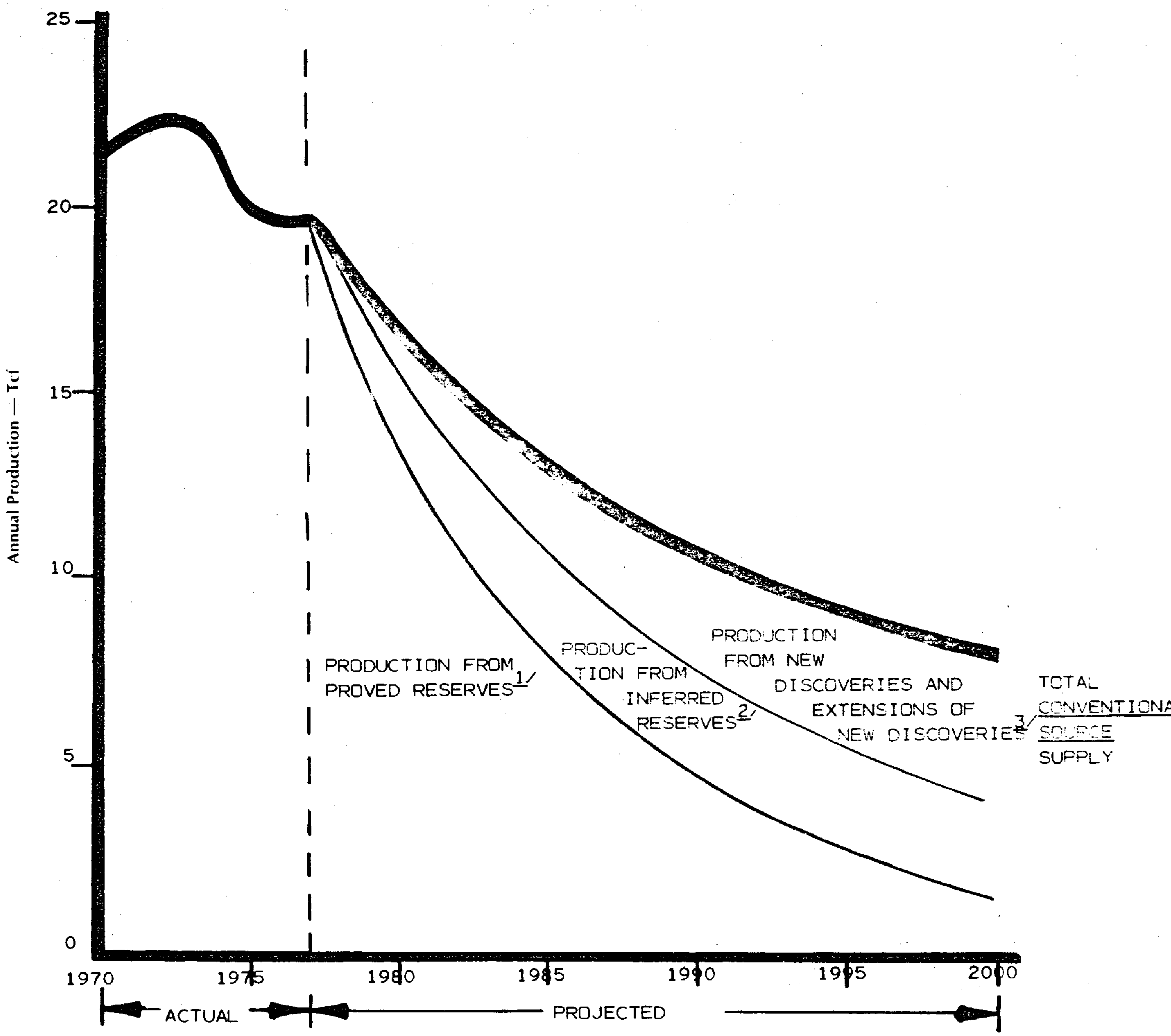
* The Base Case assumes industry as a whole would apply the technology that is currently the state of the art without a substantial Federal R&D role. The projection discussed assumes a gas price of $1.75 per Mcf.

Exhibit 2-4

Projected Production From Conventional Gas Reserves (at Gas Price of $1.75/Mcf)



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, <u>ANALYSIS OF THE TIMING AND TOTAL OF INFERRED RESERVES OF NATURAL GAS IN THE CONTIGUOUS UNITED STAES</u>, 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.

Total Domestic Supply From All Sources
@ $1.75 Per Mcf

Year	Conventional* Sources	Additional Base Case Unconventional Sources	Total Anticipated Domestic Supply
1980	17	<0.5	17
1985	13	1	14
1990	11	2	13
2000	8	3	11

Even with these additions from Base Case unconventional sources, by 1985 domestic natural gas supply will be 6 to 8 Tcf below recent usage and as much as 10 Tcf short by 1990.

Exhibit 2-5 provides a display of total anticipated domestic supply between now and the year 2000 under current economic and technological conditions. It is clear that still other options will need to be considered to avoid a serious natural gas shortfall.

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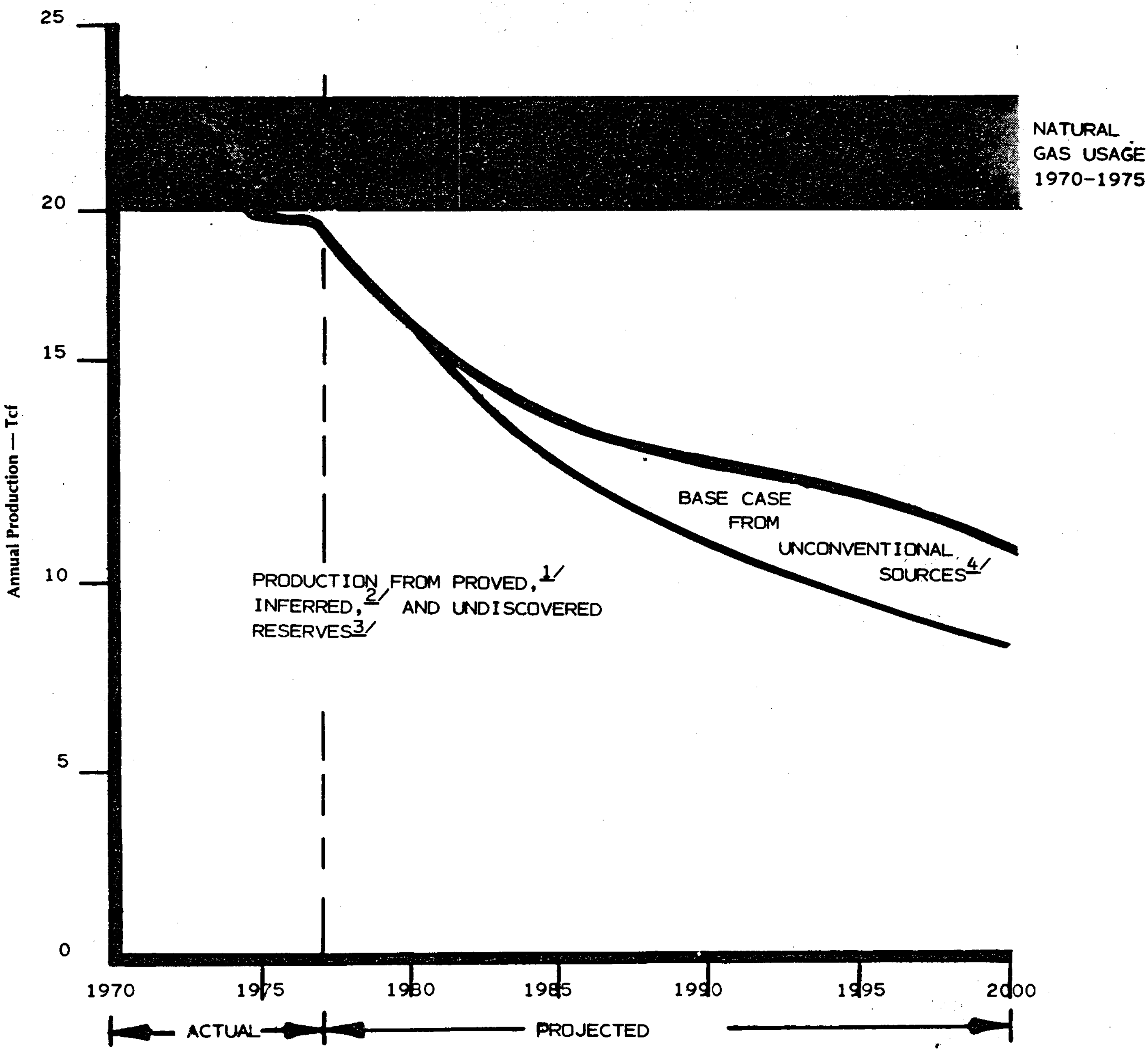
* The supply from conventional sources includes some unconventional gas production, calculated at 0.8 Tcf in 1975, and estimated at about 1 Tcf in 1977. The gas from unconventional sources estimated by this study is in addition to this already proved and being produced unconventional source of gas.

Exhibit 2-5

Total Domestic Gas Supply — Conventional and Unconventional Sources (at Gas Prices of $1.75/Mcf and Current Technology)



1/ BASED ON AGA/API/CPA, RESERVES OF CRUDE OIL, NATURAL GAS LIQUIDS AND NATURAL GAS IN THE UNITED STATES AND CANADA, DECEMBER 31, 1970 THROUGH 1976.

2/ BASED ON THE 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, REPORTED IN VOLUME III OF THIS REPORT.

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 RESPECTIVELY THROUGH DEVELOPMENTAL DRILLING.

4/ FROM THE 1978 STUDY OF ENHANCED GAS RECOVERY FROM UNCONVENTIONAL SOURCES BY LEWIN AND ASSOCIATES, INC.

III. OTHER PROGRAMS FOR DOMESTIC GAS SUPPLY

A. The Potential Effects of Improved Economics

Past estimates of the effect of price on stimulating additional natural gas supply have proven to be vastly in error. As recently as 1975, the Administration was projecting the 1977-1980 gas supply at more than 20 Tcf, with prices of $1.00 per Mcf and below. All of the gas supply models assumed direct, and simplistic, relationships between price and supply, with little consideration of the underlying conditions that govern supply -- geology, production technology, and threshold pricing levels:

- Geological constraints. The distribution of the gas resource, in which the bulk of the gas reserve is contained in large, low-cost fields and the remainder of the resource lies in increasingly small fields that are costly to produce, dictates that each additional increment in price will bring on a successively smaller increment of additional supply.*

- Production technology. As the traditional areas become fully drilled, the search for new gas supplies will turn to deeper horizons and to formations that require more expensive production technology. In these deeper and more difficult formations, drilling and completion can easily cost five to ten times more than in the shallower, more conventional gas formations characteristic of the past.

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* In economics this is referred to as decreasing marginal returns. In resource analysis this is inherent to depleting finite supplies and the apparent log-normal distribution of the sizes of all known fields.

- Threshold prices. The most essential price level is the threshold price for a given type or location of resource. This threshold price will bring on the initial, major portion of the supply; thereafter, additional price increases will have successively smaller returns.

The overall effect of combining the underlying geology, production technology, and analysis of threshold pricing leads to three principal conclusions:

1. Higher prices will have little effect on proved reserves.

The proved reserves are by definition producible under current economics. Higher prices could justify the installation of compressors and provide longer well life, but would add only limited additional supply.

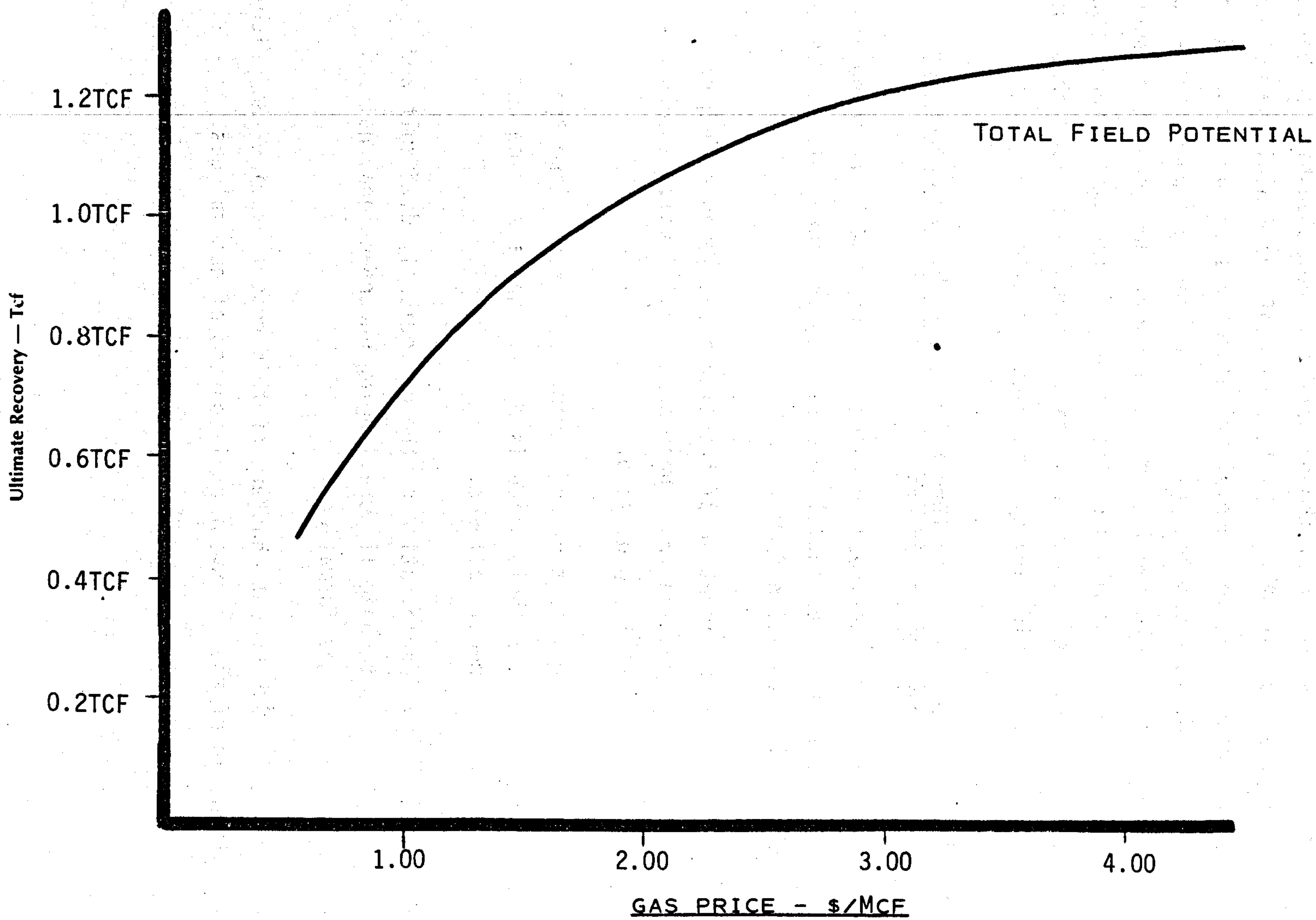
2. Higher prices will have only marginal effect on near-term development drilling in conventional gas formations.

Detailed geologic characteristics, well performance, and production cost data were collected on several hundred wells in one major gas basin. These data were used to analyze the potential impact of price on additional gas supplies from development drilling.

Using production and cost data from the basin, a "real-life" price/supply curve was developed for the sample basin (Exhibit 2-6). This shows that as price increases, successively smaller and smaller amounts are added to economically producible supply.

Exhibit 2-6

Cumulative Gas Supply As A Function of Price — Sample Basin



The impact of the price/supply relationship can be seen more clearly in Exhibit 2-7. The left side of the Exhibit shows the expotentially decreasing incremental price/supply step function; the right side of the Exhibit shows the primary reason for this phenomena -- price, after reaching threshold levels, enables economic development of successively less productive segments of the resource. The same general conclusions would be expected in any gas basin, although the exact shape of the price/supply curve would vary by geological setting.

3. <u>If they cross threshold levels, higher prices can have major effects</u>.

Given the need to reach for the more challenging and higher cost frontiers, it is essential to establish the threshold prices that will stimulate gas production from:

- Exploration of frontier areas, even though production from these areas will involve a substantial lag of time.

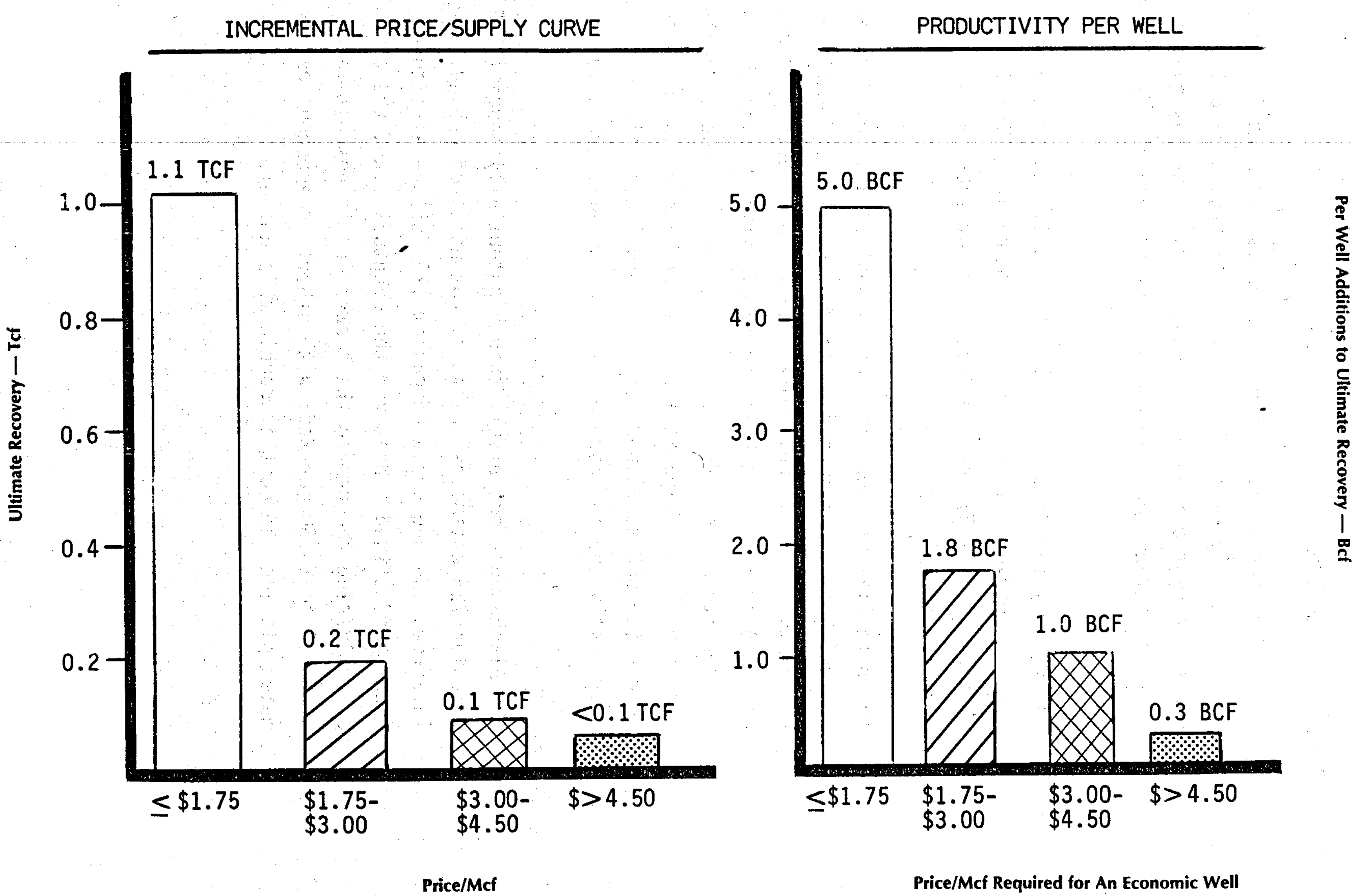
- Development of conventional areas where the threshold price is higher than the price currently allowed.

- Exploitation of the geologically difficult and technically challenging unconventional natural gas formations.

Subsequent chapters of this report examine the price/supply relationship of the unconventional sources of natural gas.

Exhibit 2-7

Incremental Gas Supply and Field Productivity As A Function of Price



B. Frontier Exploration

Three frontier areas have been posed as having major potential for additional gas supply -- the "lower 48" offshore, deep drilling, and Alaska. However, recent evidence has bequn to cast serious questions on the ultimate size of these undiscovered, frontier resources and their recovery costs.

- Analysis by the USGS shows that the estimates of undiscovered recoverable resources (estimated at 63 Tcf in USGS Circular 725) for the "lower 48" offshore areas were too optimistic.

- The potential of deep drilling in west Texas, New Mexico, and Oklahoma is estimated by the Potential Gas Committee at 140 to 190 Tcf. While drilling in the deeper portions of the Anadarko basin have led to significant discoveries, the results of deep drilling in the southern Rocky Mountain area have been disappointing. Exploration wells in these deeper (20,000 to 25,000 feet) gas provinces will be extremely costly and the pace of exploration will probably be slow.

- The Alaskan gas potential, though potentially large (USGS Circular 725 estimates the total potential of proved, inferred, and undiscovered gas at 123 Tcf) remains to be found and defined. Whatever the eventual size, the cost of delivering the gas to the "lower 48" is now estimated at $3.50 to $5.50 per Mcf, with other, independent estimates placing the cost at double this amount.

Imports of natural gas, the near-term alternative, will be costly:

- LNG imports from Algeria are being approved at $4.50 per Mcf.

- Imports from Canada and Mexico appear to be in the range of $2.50 to $3.00 per Mcf, and possibly higher.

Additional dependence on foreign sources, while potentially essential for averting near-term disruptions of supply, makes the nation increasingly vulnerable and adds to the trade deficit.

In the long-term the nation may have to rely on gas from coal, shale, or heavy, sulphurous crude oil. This option, however, will be expensive ($4.50 per Mcf or more), will require massive infusions of new capital (one billion dollars or more per plant), and will require substantial advancement in technology.

C. Imports and Synthetic Sources

The domestic supply of natural gas can be augmented in the near-term by imports and in the long-term by the gasification of coal, shale, or heavy sulphurous crudes.* However, these sources will be costly and entail political and technical risks.

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* The production of SNG (synthetic natural gas) from propane or butane is considered to be more of a change in form, for transportation and end-use purposes, than an addition to supply.

IV. CONCLUSIONS

Under current conditions, the prospects for shortfalls in natural gas supply are grave in the near future and continue for the rest of the century. The nation must face squarely the costs and efforts required to increase supplies from all sources -- new frontiers, imports, synthetic gas, and unconventional gas.

The promise of the first three sources is limited, at least in the foreseeable future. While higher prices may stimulate frontier exploration, gas production from this source will require substantial passage of time. Imports are costly, increase the nation's strategic and economic vulnerability, and worsen the balance of payments. Coal, shale, and heavy oil gasification are costly and rely on high capital-intensive technology that is still under development.

To avert shortfalls in natural gas supply, it may be essential to consider all of the available sources. This study provides information and a research strategy for increasing domestic gas supply through one of the more cost-effective of these sources -- unconventional natural gas.

CHAPTER THREE

TIGHT GAS BASINS

Part 1

I. THE PROBLEM AND THE POTENTIAL

A. Background

For more than a quarter century, large quantities of natural gas have been known to exist in tight (low permeability) formations where the gas flow is too low to support economic recovery under conventional technology. The basins containing these formations stretch westward from the Cotton Valley Trend in Louisiana, through Texas, to the Uinta Basin of Utah, and north through the Northern Great Plains Province, crossing the border into Canada. Declining natural gas production, higher gas prices, and the advent of new recovery technologies have rekindled interest in these resources.

Almost twenty years ago, this interest was the domain of nuclear scientists. They posed that underground nuclear explosions could rubbelize these formations and thus enable the gas to flow at commercial rates. Between 1967 and the early 1970's, three nuclear experiments were performed, with disappointing results. In response to low recovery, high costs, and potential environmental hazards, nuclear stimulation has been discarded.

In 1972, the Federal Power Commission convened several task forces to study the status and future potential of domestic gas supply.[1/] The task force on recovery technology identified massive hydraulic fracturing (MHF) as a promising alternative technology for developing these low permeability reservoirs.

While by 1972 small volume hydraulic fracturing* had become a well-known means of stimulating production from low permeability formations,

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* Hydraulic fracturing involves high-pressure injection of fluids into the wellbore to fracture reservoir formation rock (creating an enlarged pressure sink) and the use of proppants (usually sand) to keep the fractures open to the flow of gas.

the technology task force recommended that this approach be applied using volumes an order of magnitude larger than was conventional. Such massive fracturing was expected to stimulate production from basins and formations so impermeable as to be ignored up to that time. Using the limited geologic data available,* the task force estimated the potential from three such "tight gas basins"** -- the Piceance, the Greater Green River, and the Uinta -- at 600 Tcf gas in place,[2/] with 240 Tcf in defined areas and 360 Tcf in speculative areas. Overall, the task force estimated that between 30 and 50% of the gas in place, or 180 to 300 Tcf, could be recoverable,[3/] assuming a successful MHF technology and adequate prices.[4/]

As a consequence of this study, a joint government-industry test of MHF was conducted in the Piceance Basin in 1974. The results of this test, although less promising than anticipated, demonstrated improvements could be achieved in the rate of gas flow.[5/] Since that time the technology has advanced such that it is becoming standard practice in low permeability but otherwise more favorable geologic formations, such as in the Wattenberg Field (north of Denver),*** in several fields in the Sonora Basin in southwest Texas, and in the Cotton Valley Trend in east Texas and northern Louisiana.

Despite these promising developments, the potential of the Western Tight Gas Basins, the large land area that originally attracted attention, remain undeveloped and unproved. The challenges posed by the difficult

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* Additional geologic and reservoir data gathered since 1972 have provided a basis for making more precise resource and recovery estimates, as discussed subsequently in this chapter.

** These three basins are referred to below as the Western Tight Gas Basins.

*** The stimulus for developing the Wattenberg Field has been due to the technological foresight of AMOCO and the economic incentives provided by the gas transmission companies in the Denver Basin.

geological setting -- the deep, tight, lenticular gas pays -- have yet to be overcome. Even in the more geologically favorable basins -- in the less tight or blanket type deposits -- fundamental improvements in recovery technology need to be pursued. Finally, major opportunities exist for optimizing the recovery technology and accelerating its application for recovering additional gas supplies between now and 1990.

Overall, the low permeability formations included in the study cover 13 major basins. The major geological and technological problems that currently impede the development of these Tight Gas Basins and that need to be overcome by R&D are summarized below.

B. Geological Problems

While the most popular characterization of these basins is their "tightness", low permeability is only one of several geological problems that have limited commercial development for tight gas basins. All are marked by generally low quality net pays which are often highly discontinuous or lenticular.

1. Permeability

Low in situ gas permeability* is the defining characteristic of the tight formations. For this study, formations with in situ permeabilities of less than 1.0 millidarcy (md) were considered as tight gas sands. The formations discussed in this chapter range in permeability from 1.0 md down to 0.001 md (one microdarcy, or μd),** with the vast majority of the formations being

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* Permeability is the resistance of reservoir rock to the flow of gas under reservoir conditions of water saturation and confining pressure -- measured in millidarcies or microdarcies (one thousandth of a millidarcy).

** These are measured as in situ permeability. Under reservoir conditions, overburden pressure and high water saturations can reduce the relative gas permeability within the formation to values ranging down to six percent or less of the permeabilities measured in the laboratory.6/

below 0.05 md. (As the formation permeability drops below about 0.1 md, recovery efficiency becomes highly sensitive to small changes in permeability as shown by Elkins.[7/])

Permeability of the pay, however, appears to be an important impediment rather than the central problem. The Wattenberg Field (Denver Basin) with a broad, continuous net sand pay has permeabilities ranging from 5 to 50 microdarcies and is being commercially produced. By contrast, a Uinta Basin, Chevron well (No. 212) completed in the lower Mesaverde lenticular pay encountered permeabilities of 90 microdarcies,* almost twice as high as the better portions of the Wattenberg, but failed to produce at even one-half the Wattenberg rates. It appears that low permeability combines with the lenticular nature and low quality of the pay to pose the major challenge.

2. Lenticularity

The principal commercial successes in tight formations have been in relatively continuous, "blanket" type sands. The sands in many of the tight basins, however, are notably discontinuous -- the gas-bearing pays consisting of uncorrelatable lenses within sometimes massive gross sections. The effect is to limit well drainage area and to preclude recovery from sand lenses not contacted by the wellbore. To illustrate, a square mile (640 acres) with typical reservoir characteristics** would contain approximately 32 Bcf of gas in place. With lenticular, discontinuous pay (having lens dimensions typical of the Mesaverde of 20 feet by 400 feet by 6,000 feet),

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* Based on computer simulation history match of actual production data.

** Assuming following average characteristics: 100 feet of net pay, 10% porosity, 45% water saturation, and 9,000 feet of depth.

and current field development practices (one well per section), a wellbore would be in contact with only 3 Bcf, or 9% of the sand lenses in the section. Even if field spacing is reduced in half, two wells per section, these two wells would be in contact with only 6 Bcf, or about 18% of the gas-bearing sand lens.

To date, MHF technology has been successful in lenticular formations only where the individual lenses are large relative to the normal well drainage area or where the individual lenses are developed in conjunction with vertically adjacent blanket formations.

3. Pay Quality

In addition to low permeability and frequent lenticularity, the gas bearing portions of the tight basins are of low quality relative to conventional gas formations. First, although the gross sections can be extremely thick, ranging from two to over five thousand feet, the gas bearing portions of such segments -- the net pay -- may be only a few hundred feet. Further, the net pay may be dispersed in relatively small (tens of feet or less) strata interbedded with clays and shales. Second, the permeable sand segments often contain high levels of connate water that impede the gas flow in the fracture system.* Third, the porosities of the net pay are low, generally in the range of five to fifteen percent. Low porosity combined with relatively high water saturations of 40 to 70 percent reduce the gas-filled porosities from levels from less than 3% to seldom over 9%. Finally, the net pays in tight basins often contain clays that swell when contracted by drilling or fracturing fluids (unless these fluids contain chemicals to inhibit swelling).

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* The presence of water frequently confuses initial testing and interpretation of fractured wells. Water from both net pay and adjacent strata inhibits production, until removed. Except for extremely poor quality formations, the gas will ultimately push this water out of the well, but as long as three to six months may be required before the well's productivity can be accurately ascertained.

C. Technological Challenges and Goals

The geology and reservoir characteristics of the tight gas basins impose some absolute limits on the amount of commercial recovery. The limited gas in place in a given areal/vertical section, the lenticular, discontinuous sands, and the fundamental reservoir characteristics are immutable. The technological challenge is to exploit the limited opportunities that lie within these constraints.

Meeting this challenge will require that fracturing technology evolve toward four major goals:

- To stimulate all gas pay intervals exposed to the wellbore by using multiple fractures from the same well.
- To intersect, in lenticular formations, sand lenses not initially in contact with the wellbore.
- To maintain an effectively propped fracture, thus providing adequate fracture conductivity.
- To optimize the process and make economic the currently marginal and sub-marginal gas resources.

These technological goals appear to be within reach of a concerted research and development effort. However, achieving them will require substantial R&D investments in resource characterization, testing, and demonstration. Joint federal-industry collaboration could accelerate this R&D and demonstrate its commercial application.[8/]

D. Structure of the Analysis

The objectives of the analysis were to define the required research and development that would assist in commercializing the tight gas basins. The analysis followed six basic steps:*

1. Basic Data: Collect and analyze detailed geological and engineering data on each of the identified basins.

2. Base Case Technology: Define the major problems and constraints that limit full exploitation of these resources by industry; define the current and near-term (next 5 years) technology and its application without federal stimulus -- the Base Case.

3. Advanced Case Technology: Develop R&D strategies for overcoming current technical limitations and that would accelerate the development of the target basins -- the Advanced Case technology.

4. Economic Analysis. Simulate the production and economics of Base Case and Advanced Case technologies to establish the economic potential of the tight gas basins.

5. Sensitivity Analysis: Repeat the economic analysis under alternative gas prices and technology assumptions to assess price and technology sensitivity.

6. Cost-Effectiveness: Compare the costs of the R&D programs to their production benefits to establish cost-effectiveness.

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* Volume III contains a more detailed discussion of the methodology employed in each step.

E. The Potential of the Tight Gas Basins -- Overview

1. The Resource Targets

The thirteen tight basins included in the analysis differ geologically and in the technological problems they pose. To facilitate the analysis, the individual basins were grouped into five categories (called resource targets) having common geologic features:

- Western Tight Gas Basins -- the three basins that were the original focus on the FPC study are deep, generally very tight, and lenticular.

- Shallow Gas Basins -- the large land area of the Northern Great Plains Province, characterized by low productivity, is shallow and has a range of deposits that vary from blanket to lenticular.

- Other Tight, Lenticular Basins -- fully as tight as the Western Basins, these basins tend to be somewhat less deep and contain larger individual lenses.

- Tight, Blanket Sands -- deep and very tight, these basins are favored by highly continuous, blanket-type gas deposits.

- Other Low-Permeability Reservoirs -- these near-conventional formations have special development and engineering problems.

2. The Gas In Place

These five resource targets contain considerable gas in place -- over 400 Tcf* -- distributed as follows:

Target	Gas in Place (Tcf)
• Western Tight	176
• Shallow Gas	74
• Other Tight, Lenticular	51
• Tight, Blanket Sands	94
• Other Low-Permeability	14
TOTAL	409

3. Current Activity

Some development, in the more favorable formations and segments, is underway in each resource target. The largest amount of drilling has taken place in the Tight, Blanket sands, where the continuity of the gas pays improves recovery. It is estimated that nearly one trillion cubic feet of gas were produced from the tight gas basins in 1976. Continuing advances in the technology and improved economics will foster further development in the more favorable areas, as projected in the Base Case estimates.

4. Base Case Technology

Under Base Case technology -- current and near-term advances without Federal R&D supplementation -- the following outcomes are projected:

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* This estimate excludes gas in place in proved and speculative areas.

- The tight gas formations could provide from 70 to 110 Tcf of additional recovery, for gas prices of $1.75 to $4.50 per Mcf* (Exhibit 3-1).
- The annual production rate could range from about 2 to over 3 Tcf per year by 1990 (Exhibit 3-2).

The contribution of the individual resource targets is shown below:

Base Case, Recovery, and Production - Tight Gas Basins

	Ultimate Recovery		1990 Production Rate	
	@$1.75/Mcf	@$4.50/Mcf	@$1.75/Mcf	@$4.50/Mcf
• Western Tight	4	11	0.2	0.4
• Shallow Gas	21	22	0.6	0.6
• Other Tight, Lenticular	8	15	0.2	0.5
• Tight, Blanket	32	51	1.0	1.6
• Other Low-Permeability	5	8	0.2	0.3
TOTAL	70	107	2.2	3.5

* Price is stated in 1977 dollars and assumed maintained in constant dollars through the period of analysis; for example, a $1.75 price under 6 percent inflation would need to be $2.75 as expressed in 1985 dollars.

Exhibit 3-1

Base Case Ultimate Recovery from the Tight Gas Basins (at Three Prices)

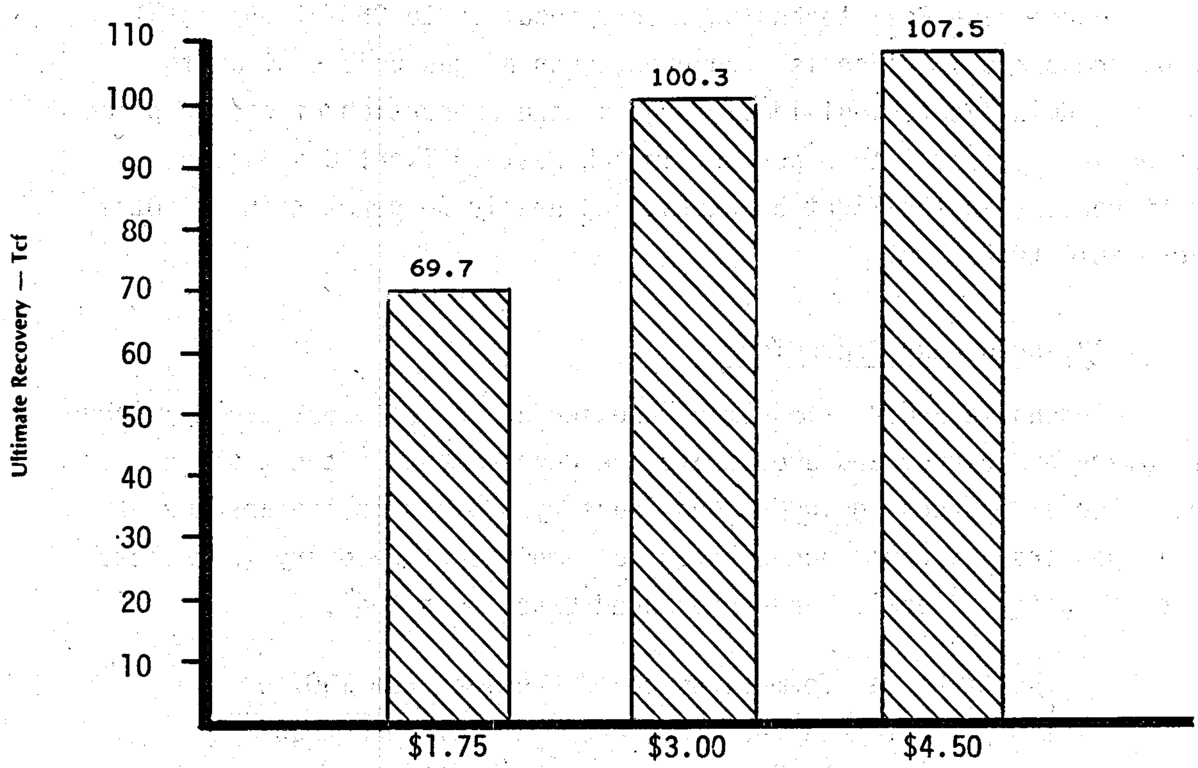
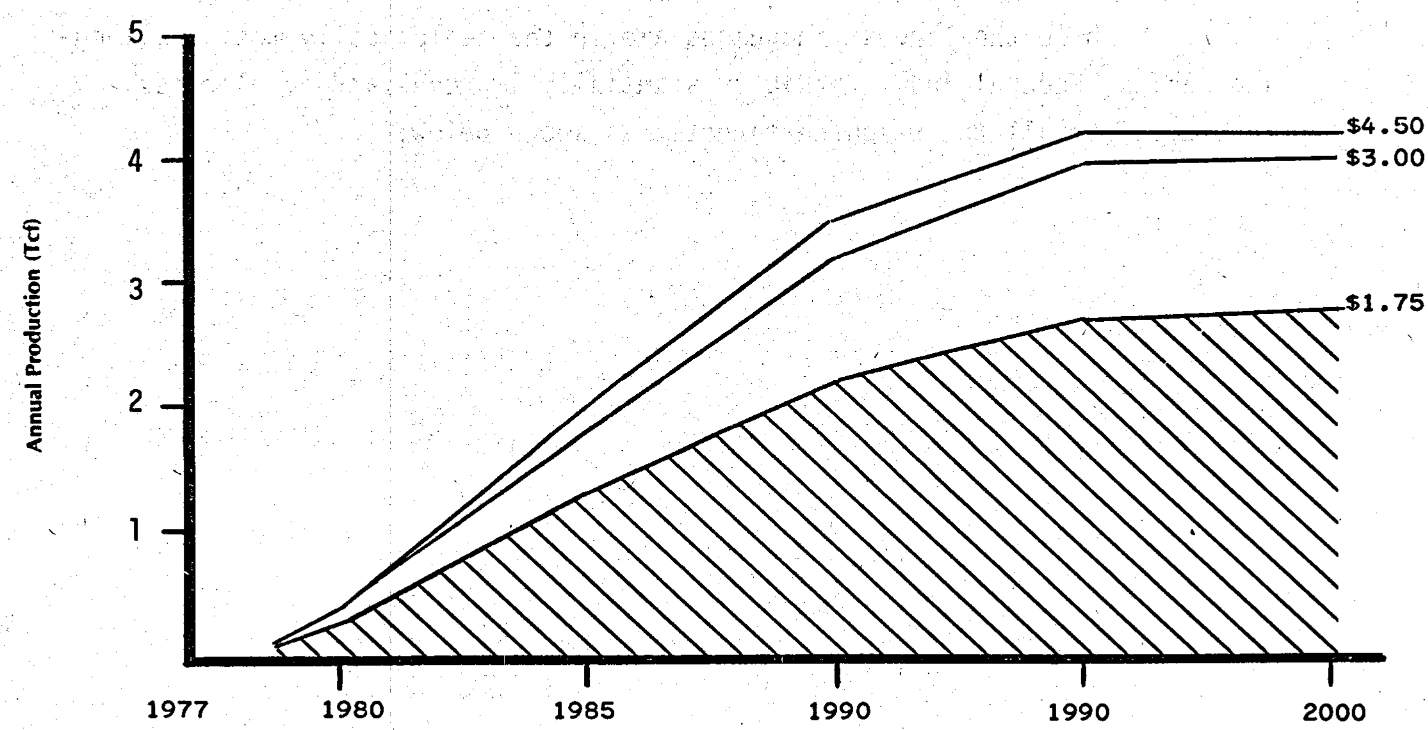


Exhibit 3-2

Base Case Annual Production from the Tight Gas Basins (at Three Prices)



Under Base Case technology, only about 15 to 25% of the total tight gas resource in place is recovered, even at gas prices of up to $4.50/Mcf. Relative to individual targets, the proportion of gas in place recovered varies from 2 to 6 percent in the Western Tight Gas Basins, 34 to 54 percent in the Tight Blankets, and nearly 60 percent in the Other Low-Permeability Basins.

5. Advanced Case Technology

Intensive Federal-industry research and development could improve the recovery efficiency and accelerate the development of the tight gas basins. These advances, going beyond industry's plans in the absence of Federal sponsorship, could add substantial amounts of recovery from these resource targets. Overall, under Advanced Case technology:

- The tight gas formations could provide from 150 to 190 Tcf ultimate recovery, about 80 Tcf more than under Base Case technology (Exhibit 3-3).

- The annual production rate by 1990 could range from 6 to nearly 8 Tcf per year, about 4 Tcf per year more than under the Base Case (Exhibit 3-4).

While the largest increases are in the geologically most challenging basins, Federal-industry R&D substantially improves and accelerates recovery from all the resource targets, as shown below:

Exhibit 3-3

Ultimate Recovery from the Tight Gas Basins (at Three Prices)

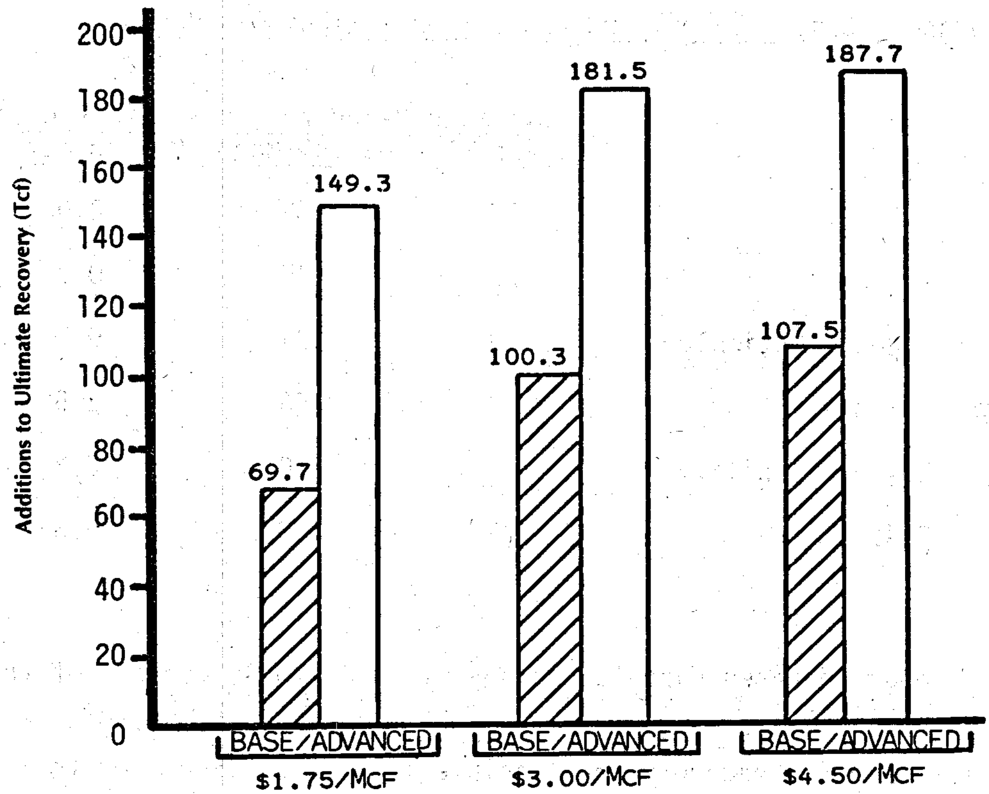
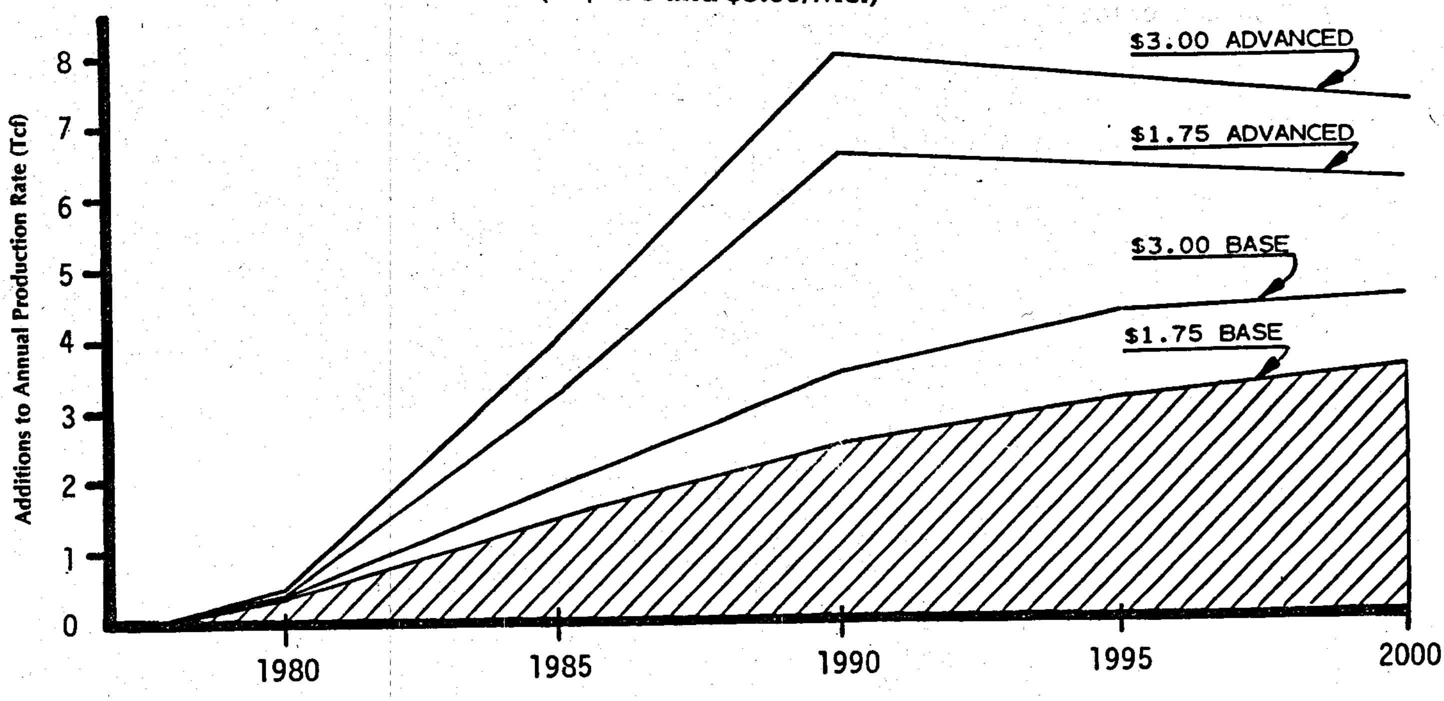


Exhibit 3-4

Annual Production from the Tight Gas Basins to the Year 2000 (at $1.75 and $3.00/Mcf)



Advanced Case Recovery and Production - Tight Gas Basins

	Ultimate Recovery		1990 Production Rate	
	@$1.75/Mcf	@$4.50/Mcf	@$1.75/Mcf	@$4.50/Mcf
• Western Tight	38	53	2.0	2.7
• Shallow Gas	23	35	0.8	1.0
• Other Tight, Lenticular	23	24	0.7	0.7
• Tight, Blanket	59	66	2.5	2.8
• Other Low-Permeability	6	10	0.3	0.5
TOTAL	149	188	6.3	7.7

Under Advanced Case technology, from 35 to 45 percent of the resource in place can be recovered, at prices of $1.75 to $4.50 per Mcf. Substantial gains in recovery are possible in all resource targets. For example, at $1.75 per Mcf, the recovery in the Tight, Blanket formations essentially doubles, from 32 Tcf in the Base Case to nearly 60 Tcf in the Advanced Case. In the more difficult targets, the proportion is still larger. For the Western Tight Gas Basins, the Advanced Case increases recovery from a base of 4 to 11 Tcf to a range of 38 to 53 Tcf, depending on gas price.

F. Summary

The largest total production from the tight gas basins would accrue from a combination* of higher gas prices** and advanced technology. At gas prices of about $3.00 per Mcf,*** 180 Tcf of natural gas could ultimately be recovered with substantial quantities, over 40 Tcf, available between now and 1990.

These findings are further discussed in the next four sections. Section II describes the extent of the resource base and its major characteristics. Section III discusses the state-of-the-art in massive hydraulic fracturing and the possible directions for its improvement through focused Federal-industry R&D. Section IV presents the overall results and discusses the price-sensitivity of Base Case and Advanced Case estimates. Section V provides an overview of the federal-industry R&D strategies. Part 2 of this chapter contains the detailed descriptions of the R&D strategies.

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* The study of enhanced gas recovery examined only three prices -- $1.75, $3.00, and $4.50 per Mcf -- and an optimum research program for a given price. It did not seek to establish the optimum price or optimum combination of public R&D and price.

** The term "price", used in the paper, serves to summarize any combination of economic incentives such as market price, tax provisions, public subsidies, etc., that can be expressed in "price to the public" equivalent terms.

*** A $3.00 per Mcf gas price would be equivalent to imported fuel oil assuming a 20% premium differential.

II. THE RESOURCE BASE

The tight gas resource base consists of twenty basins, grouped into five resource targets. The Federal Power Commission's analyses in the early 1970's focused attention on three -- the Greater Green River, the Piceance, and the Uinta -- referred to below as the Western Tight Gas Basins. Subsequent Federal-industry collaboration has focused on these, with the somewhat later addition of the shallow, tight gas basins in the Northern Great Plains Province. In addition to the four basins, sixteen additional basins[9/] have been identified as having permeabilities too low to permit economic recovery by existing, conventional technology. Of these twenty basins, thirteen were included in the present study; seven basins were eliminated from the analysis due to insufficient data (Exhibit 3-5).

A. Approach to Describing the Resource Base

Data on the tight gas resource base were collected by teams of reservoir engineers and geologists who had previously worked in these basins.* The highest data collection priority was assigned to the four basins in which joint Federal-industry research is underway.**

The analysis rests of detailed reservoir characteristics and well performance data sufficient to support reservoir engineering, and computer-based simulation of gas in place, production, and economics.

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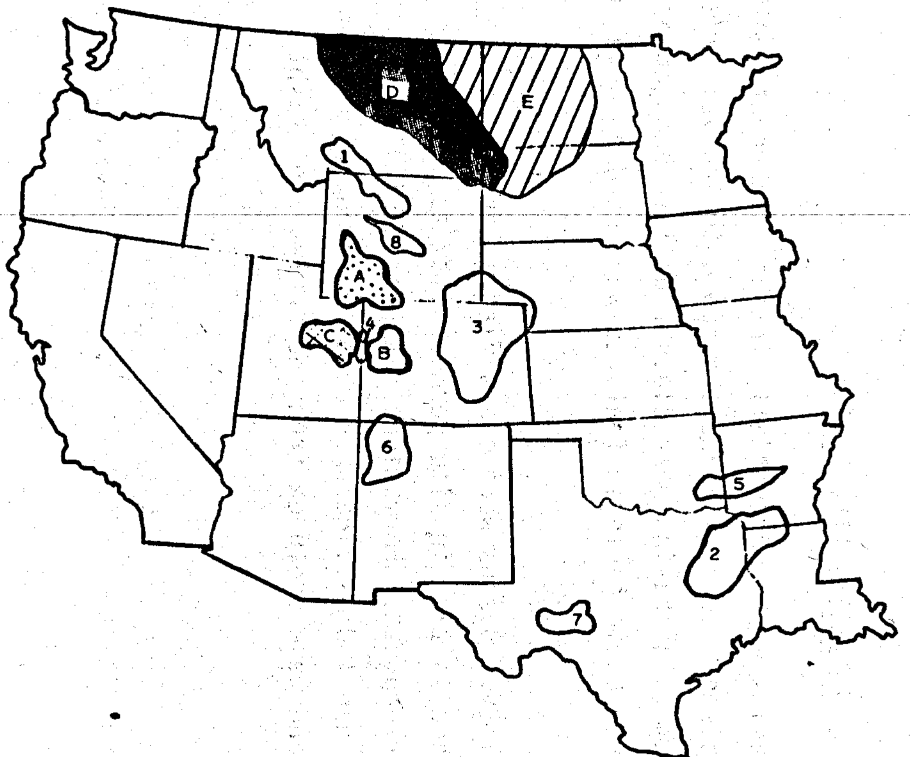
* Appreciation for data collection is expressed to the following organizations and individuals: Sandia, Inc.; CER Geonuclear, Inc.; C.K. Geoenergy, Inc.; Gruy Federal, Inc.; Mitchell Energy, Inc.; the Godsey-Earlougher Division of Williams Brothers Engineering, Inc.; the Bartlesville Energy Research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

** See Volume III for description of the data collection procedures.

Exhibit 3-5

Location of Major Tight Gas Basins



ERDA'S PRIMARY STUDY AREAS		GEOLOGICAL AREA
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	JURRASSIC
3.	DENVER BASIN	CRETACEOUS
4.	DOUGLAS CREEK ARCH	CRETACEOUS
5.	OUACHITA MOUNTAINS PROVINCE	MISSISSIPPIAN
6.	SAN JUAN BASIN	CRETACEOUS
7.	SONORA BASIN	PENNSYLVANIAN
8.	WIND RIVER BASIN	TERTIARY AND CRETACEOUS

OTHER LOW-PERMEABILITY AREAS NOT INCLUDED IN STUDY

a.	ANADARKO BASIN	PENNSYLVANIAN
b.	ARKOMA BASIN	PENNSYLVANIAN
c.	FORTH WORTH BASIN	PENNSYLVANIAN
d.	RATON BASIN	TERTIARY AND CRETACEOUS
e.	SNAKE RIVER DOWNWARP	TERTIARY AND CRETACEOUS
f.	WASATCH PLATEAU	CRETACEOUS
g.	WESTERN GULF BASIN	TERTIARY AND CRETACEOUS

SOURCE: U.S. ERDA, Western Gas Sands, Project Plan, 8/1/77

All available public data -- in published documents and in computer data banks -- pertaining to the tight gas basins and the target geologic ages were accumulated. These were supplemented by well-location maps and well test data from state and industry sources. Detailed analysis of logs, core data, outcrop studies, and production histories served to complete the basic data used in the analysis.

These data provided the basis for dividing each basin into homogeneous sub-basin areas. These reservoir characteristics and geologic interpretations were reviewed with local geologists and with gas production firms active in the basins. The disaggregated units were placed into a reservoir data file and formed the basic units of analysis for assessing technical and economic recovery. In all, 622 areal/vertical units (reservoirs) in 13 basins were defined and analyzed.

B. Classification of Low Permeability Basins

Tight gas basins vary substantially in their inherent geological and technological problems. To facilitate the economic analysis and the planning of R&D programs, the basins were classified into homogeneous resource targets. Three basic geologic features were used to develop the classification:

- 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 millidarcies were regarded as commerical and were excluded from the analysis of tight gas formations.* 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:

1. Western Tight Gas Basins -- the three basins, Greater Green River, Piceance, and Uinta that originally attracted the attention of the FPC task force.

2. Shallow Gas Deposits -- the shallow, low production formations of the Northern Great Plains Province and the Williston Basin.

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* Such formations are assumed to be included in the analysis of proved and inferred reserves presented in Chapter Two.

3. Other Tight, Lenticular Gas Sands -- Sonora, Douglas Creek Arch, and the Big Horn basins.

4. Tight, Blanket Gas Sands -- the Denver, San Juan, Wind River, Cotton Valley basins, and the Ouachita Mountain Province.

5. 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, Forth Worth, Raton, Snake River, Wasatch, and Western Gulf basins.

C. Current Industry Activity in the Target Basins

Nearly all the tight basins have more favorable areas or formations where substantial development has been or is underway. While data on proved reserves at the basin level are not available, production data are reported by various state agencies and provide a valuable index of current industry activity in tight gas sands. This historical development, as well as industry's tests in the more difficult formations, provide a useful baseline for assessing industry's future activity.

The production data shows that the tight gas formations already produce substantial amounts of gas. Exhibit 3-6 shows the number of wells and annual and cumulative production in the latest reported year (1974 or 1975) for the target basins. These figures apply only to non-associated gas production from the target formations.

Exhibit 3-6

Recent Production from the Tight Gas Basins

TARGET/BASIN	END OF YEAR	PRODUCING WELLS	ANNUAL (Bcf) PRODUCTION	CUMULATIVE (Bcf) PRODUCTION
WESTERN TIGHT GAS SANDS				
Greater Green River	1974	155	43	410
Piceance	1975	46	3	68
Uinta	1974	172	17	127
SUBTOTAL		373	63	605
SHALLOW GAS BASINS				
Williston and Northern Great Plains	1974	280	12	135
OTHER TIGHT, LENTICULAR				
Big Horn	1974	27	2	40
Douglas Creek	1975	127	14	126
Sonora	1975	1,254	108	462
SUBTOTAL		1,408	123	629
TIGHT, BLANKET GAS				
Cotton Valley Trend	1975	1,266	189	7,663
Denver	1975	640	51	113
Ouachita	1974	0	0	0
San Juan	1974	2,413	187	2,604
Wind River	1974	52	17	214
SUBTOTAL		4,371	444	10,594
OTHER LOW-PERMEABILITY RESERVOIRS				
Cotton Valley Sour	1975	174	105	577
TOTAL		6,606	747	12,540*

* Texas cumulative production from Oil Scouts 1974 Yearbook and Texas RRC Annual Production of Oil and Gas, 1975.

Of a total of over 700 Bcf in annual production from the target basins,* the Tight Blanket and Other, Low Permeability formations contributed over 70 percent. Their generally favorable geology would have suggested this outcome. Four of these basins, the Denver, San Juan, Sonora Basins, and Cotton Valley Trend are where fracturing technology has had the most extensive application. Together, these account for over 500 Bcf per year. The geologically and technologically most difficult areas, the Western Tight Gas Basins and the Shallow Basins, together contribute less than 100 Bcf per year despite their vast land areas and considerable gas in place.

The review of current industry activity suggests that breakthrough R&D is most essential in the Western Tight, Shallow and Other Tight, Lenticular Basins.

In the Tight, Blanket and Other, Low Permeability Basins, the R&D would be first directed toward stimulation technology and accelerated field development. As field development moves beyond the more favorable areas and formations, toward the less favorable margins of these basins, the technological problems will increase and will require the R&D breakthrough gained from the more difficult basins.

D. Scope and Areal Extent of the Resource Base

Exhibit 3-7 lists the thirteen basins and the formations within them that were analyzed. The discussion of the resource base and the

* These data are now 3 to 4 years old. Given the considerable drilling that has taken place in the tight gas basins since 1975, annual production in 1977 is estimated at about 1 Tcf.

Exhibit 3-7

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

analysis of its potential relate explicitly to these basins and formations.* The scope of the analysis is further limited to undeveloped areas of these basins, yet where exploration and gas shows indicate likely future potential. 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[10/] and the well classifications of the American Association of Petroleum Geologists.[11/] Four classes of acreage were defined for each basin:

1. Proved acreage -- within the defined perimeter of existing fields.

2. Probable acreage -- extensions of existing fields and obvious corridors between fields where the direction of recent drilling suggests the fields will ultimately merge.

3. Possible acreage -- areas outside proved or probable acreage where the subject formations have had gas "shows" or production but no multi-well fields have developed.

4. Speculative acreage -- areas in which drilling through the subject formations has yielded no show of gas and areas where no drilling has taken place.

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* 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 even within the basins analyzed may represent additional potential. The size of the potential of the basins and formations not analyzed cannot be assessed without substantial additional data collection, but the problems and constraints that affect their commercial development are highly likely to parallel those in the analyzed basins. 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 to the formations listed on Exhibit 3-7.

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 3-8 shows the anticipated productive area of each of the basins in the analysis.

Thus, the scope of the analysis includes only those areas (having adequate data and containing gas incremental to current proved reserves) that are anticipated to be developed given appropriate technology and economics.

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

Exhibit 3-8

Anticipated Areal Extent of Tight Gas Basins

TARGET/BASIN	PROBABLE AREA* Area(Mi²)	PROBABLE AREA* Weight (%)**	POSSIBLE AREA* Area(Mi²)	POSSIBLE AREA* Weight (%)**	TOTAL ANTICIPATED* AREA(Mi²)
WESTERN TIGHT					
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
SHALLOW GAS					
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
OTHER TIGHT LENTICULAR					
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
TIGHT BLANKET					
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
OTHER LOW-PERMEABILITY					
Cotton Valley (Sour)	569	78	642	29	1,211
TOTAL	10,538		26,813		37,351

* After application of anticipated success ratios
** Success ratios developed from American Association of Petroleum Geologists data

E. Reservoir Characteristics

The reservoir characteristics of the basins and formations included in the analysis are displayed in Exhibit 3-9. They suggest several conclusions. The first is that the geological problems described in the introductory section of the analysis are clearly demonstrated:

- The in situ gas permeabilities of the major formations rarely exceed 100 microdarcies (0.1 millidarcy). Outside of the shallow basins, the few higher permeabilities represent the relatively small, most favorable geographic areas.

- In the area where the net pay is greatest, the pay is also highly discontinuous, or lenticular.

- All the basins are marked by low gas-filled porosities (high water saturation with low porosities).

Given these conditions, it is not surprising that industry has only developed the most favorable portions of these basins and directed its activity inversely in relation to the severity of the geology.

The Western Tight Gas Basins, where there is little current activity, are beset by the most severe combination of geologic constraints -- lenticularity coupled with great depth, very low permeability, and low gas-filled porosities. The Tight Blanket Sands, in which there is substantial current activity, have blanket-type sands and somewhat better pay sections -- higher gas-filled porosity and lower clay content.

Exhibit 3-9

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. (μd)	GAS-FILLED POROSITY (%)	RESERVOIR PRESSURE (psi)	RESERVOIR TEMPERATURE (°F)
WESTERN TIGHT GAS SANDS										
1. Greater Green River	36	Ft. Union	5700-9000	500-2680	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	66-600	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
SHALLOW GAS BASINS										
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	10-900	5.4-7.1	670	85
		Greenhorn/Frontier	2000-2600	30-50	3-29	Blanket	17-2700	5.4-7.8	900-1130	100
OTHER TIGHT LENTICULAR GAS SANDS										
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
TIGHT BLANKET GAS FORMATIONS										
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
OTHER LOW PERMEABILITY GAS FORMATIONS										
1. Cotton Valley "Sour"	5	Bruckner-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

The single lenticular basin that has experienced appreciable development -- the Sonora Basin -- is favored by large lenses that approach the dimensions required to support economic productivity from a single well. Knutsen[12/] has estimated that a typical lens in the Tertiary and Mesaverde sections of the Western Basins might have areal dimensions of 400 feet wide by 6,000 feet long, or a total area of about 55 acres. The typical dimensions of a lens in the Sonora Basin might be about 1,300 feet by 3,800 feet, approximately 110 acres. Doubling of the expected lens size (and hence drainage area) mitigates the lenticularity constraint.* Thus, the severity of the lenticularity problem is largely a function of the geometry of the lenses and of the degree to which lenticularity is associated with other geologic problems. Basins with broad lenses would be nearly as commercially attractive as blanket sands, other factors being equal.

The data show that the Western Tight Gas Basins contain at least one blanket-type gas formation. The occurrence of a "stack" of sands or formations presents the opportunity for multiple MHF treatments, each of which need to cover only slightly more than marginal fracturing costs to justify economic development.

The final observation is that the reservoir parameters, even within given formations, vary significantly. The ranges shown represent the sections of the formations that are not "dry", but have at least shows of gas. Permeability varies by an order of magnitude or more.

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* As discussed later, the length to width ratio is also important in the effectiveness of the MHF treatment. Typically, this ratio is about 15:1 for the Western Basins, but only about 3:1 in the Sonora Basin.

Gas-filled porosity (porosity times gas saturation) varies by a factor of two or more. Net pay thickness varies by a factor of two to thirty.

Such variability can be observed even within the relatively narrow confines of adjacent townships of a proved field with a blanket formation, as have been shown in the Wattenberg Field (Denver Basin).[13/] Even greater variation can be expected in lenticular sands.*

These geological variabilities and uncertainties have deterred many producers from attempting commercial development. Federal-industry R&D involving improved measurement and resource characterization could reduce these uncertainties.

F. Expected Gas In Place

Exhibit 3-10 shows the expected gas in place for each of the basins and targets derived from combining the 622 analytic units (reservoirs). Together these units cover forty thousand square miles and contain over 400 Tcf in place. The Western Tight Gas Basins as a group have the largest amount of gas in place -- 176 Tcf, or 43% of the total. The Tight Blanket Formations are the next largest, at 94 Tcf, or 23% of the total.

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* At present, the quality of the pay in a particular area can only be known after drilling and testing the well. With the current limitations on the accuracy of available measurement, testing procedures, and devices as applied to very tight formations, even testing the well fails to remove all uncertainty. Producers in many cases must fully complete the well, including costly MHF stimulations, apply all available measurements and tests, and produce the well for considerable time to evaluate the reservoir characteristics in a particular segment of the basin. Even then, they can seldom generalize this evaluation to nearby areas.

Exhibit 3-10

Areal Extent and Gas in Place—Tight Gas Basins

TARGET/BASIN	ANALYTIC UNITS	TOTAL ANTICIPATED AREA (Mi^2)	EXPECTED GAS IN PLACE (Tcf)*
WESTERN TIGHT			
Green River	216	870	91
Piceance	75	855	36
Uinta	128	996	50
SUBTOTAL	419	2,720	176
SHALLOW GAS			
Northern Great Plains	68	17,560	53
Williston	40	6,520	21
SUBTOTAL	108	24,080	74
OTHER TIGHT, LENTICULAR			
Big Horn	5	761	24
Douglas Creek	10	369	3
Sonora	10	1,960	24
SUBTOTAL	25	3,090	51
TIGHT, BLANKET GAS			
Cotton Valley (Sweet)	20	5,127	53
Denver	15	2,591	19
Ouachita	15	113	5
San Juan	5	830	15
Wind River	10	465	3
SUBTOTAL	65	9,126	94
OTHER LOW-PERMEABILITY			
Cotton Valley (Sour)	5	1,211	14
TOTAL	622	40,227	409

* Totals may not add due to rounding

The gas in place estimates from this study contrasted with the FPC study conducted in 1972[14/] for the Western Tight Gas Basins.* (The other basins were not analyzed by the FPC task force.) The areas and gas in place estimates for the three Western Tight Gas Basins are shown in Exhibit 3-11. The total acreage included in the two analyses is comparable, but the present study places the gas in place estimate at less than 30 percent of the FPC's initial estimate. Two major factors account for this:

- Recent drilling and analysis shows that the net pay of the tight formations is substantially smaller than estimated by the FPC Task Force. The task force estimated net pays for the various formations ranging from 500 to 1000 feet. By contrast, as shown in Exhibit 3-9, recent drilling has found these formations to have yet pay thickness ranging from 200 to 500 feet, less than one half that initially estimated by the FPC.

- Recent well data shows that the gas saturations and porosities (gas-filled porosities) are lower than estimated in the FPC study. While direct comparison is not possible, the task force estimated only one formation with the gas-filled porosity less than 4.2%, while, as shown in Exhibit 3-9, the present study found many at levels lower than this.

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* Although the relationship between the categories used by the FPC study and the ones employed in the present study are not exact (and a direct translation from the FPC categories and the Probable and Possible categories used here cannot be made), the overall area studied is comparable. The FPC report classified the acreages into three categories: "Essentially proved because of good well control"; "Inferred to be productive from geological interpretation"; and "Has a geological basis for being productive but is untested and must be considered speculative".

Exhibit 3-11

Comparison of FPC 1972 Estimates to Present Study Estimates—Areal Extent and Gas in Place for Western Tight Gas Basins

	FPC*		Present Study	
	Area (Sq. Mi)	Gas In Place (Tcf)	Area (Sq. Mi)	Gas in Place (Tcf)
GREATER GREEN RIVER				
Category 1	140	37.1		
Category 2	500	108.4		
Category 3	500	94.5		
TOTAL	1,140	240.0	870	90.5
PICEANCE				
Category 1	550	103.2		
Category 2	650	103.9		
TOTAL	1,200	207.1	855	35.5
UINTA				
Category 1	300	101.6		
Category 2	200	47.5		
TOTAL	500	149.1	996	50.2
GRAND TOTAL	2,840	496.2	2,720	176.2

*FPC, National Gas Survey, 1973, Vol. II, p. 95.

Thus, this study's lower gas in place estimate arises from thinner net pays and lower gas-filled porosities.*

The expected gas in place estimates by themselves, however, can only suggest the size of the potential for recovery. The amount of this gas actually produced is a function of recovery technology and economics. The next section appraises the major technological issues in recovering gas from these basins.

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* The exclusion of speculative acreage from the present study caused the total areas analyzed in the Greater Green River and Piceance Basins to be considerably smaller in the present study than in the FPC study (76% and 71%, respectively), while additional drilling and research in the Uinta Basin between 1972 and 1977 have resulted in acreage increases to almost double that used in the FPC analysis. Thus, the total area considered by the two studies is comparable.

III. TECHNOLOGICAL CHALLENGES AND GOALS

A. Requirements for Commercialization

The geology and reservoir characteristics of the tight gas basins impose some absolute limits on the amount of commercial recovery. The limited gas in place in a given areal/vertical section, the lenticular, discontinuous sands, and the fundamental reservoir characteristics are immutable. The challenge is to improve gas recovery technology and adapt it to specific geologic settings.

Doing this successfully requires: (1) detailed understanding of the geology and reservoir characteristics of the tight gas basins; and (2) improved field development and well stimulation technology.

This section discusses the two tools available to the reservoir engineer -- geological measurement and stimulation technology -- and then examines the four key R&D problems that currently constrain the development of the tight gas basins.

B. The Available Tools

1. Measurement and Characterization of the Resource

Effective design of field development and well stimulation programs for low permeability basins requires a level of understanding of the resource vastly greater than for conventional basins. Especially pressing is the need for improved ability to differentiate net pay within huge gross sections, greater precision in evaluating the quality of the net pay, measurements of rock strength and stress characteristics, and understanding of the geometry and orientation of gas-bearing lenses in lenticular formations.

The importance of the resource characterization goal is directly related to the severity of the geological problems besetting each basin. In the most difficult basins, e.g., the Western Tight and the Shallow Basins, progress in resource characterization is a critical prerequisite to improving and applying the technology. In basins with more favorable geology, improved recovery technology becomes dominant, as demonstrated by the intelligently applied trial and error approach used in the Tight, Blanket Sands.*

2. Stimulation Technology

The objective of the gas recovery technology in tight gas basins is to create an effectively propped, vertical fracture that intersects the net pay for considerable distances (sometimes up to 1500-2500 feet) in each direction from the wellbore. This fracture is created by high pressure injection of fluids -- water, gels, foams, or combinations -- through the well perforations into the formation rock. The fracture fluid carries and deposits solid particles (the proppant) to keep the fracture from closing when the injection pressure decreases. The fracture creates an enlarged pressure sink to all exposed gas pays, possibly cutting across the less permeable horizontal bedding planes, and provides a relatively direct, high permeability channel to the wellbore.

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* In the Wattenberg field, for example, the major operator incrementally increased the size of the fractures used until larger fractures no longer improved well performance. Once this point was reached, the majority of the future stimulations were standardized at this fracture size.

The effectiveness of the fracture depends on the extent to which it intersects the gas-bearing sections and remains open to the gas flow. Exhibit 3-12 shows isometric and plan views of typical fractures and the flow path of gas from the matrix, to the fracture, and into the wellbore.

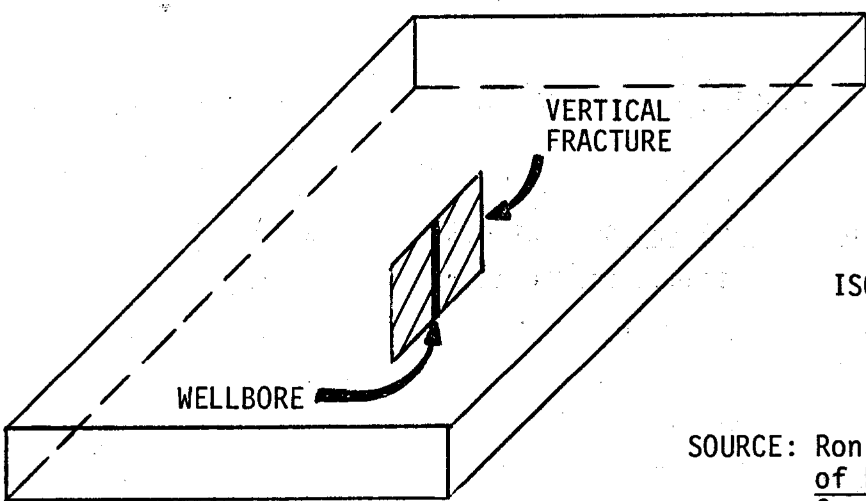
Three key variables need to be considered as part of stimulation technology:

- Fracture height and length. Effective MHF stimulation depends on the distance the fracture remains in gas-bearing strata. Economic stimulation depends on expending minimum funds in fracturing non-productive zones adjacent to the net pay. Fractures with excessive ratios of height to length or which tend to rise or fall out of the gas zone will be ineffective and uneconomic. Thus, improved ability to design the fracture treatments and control their height and shape are essential for full commercial application.

- Conductivity. Not only must the fracture expose the net pay, it must remain open to gas flow. The ability of the gas to flow depends on the permeability contrast between the rock matrix and the fracture. To the extent proppants crush, compact, or imbed in the fracture -- or fail to reach the full extent of the fracture -- this contrast is lost and the effectiveness of the fracture is reduced. Although generally not a problem in shallow formations, the greater overburden pressures of formations deeper than about 8,000 feet necessitate improved proppants and procedures for placing them in the fracture.

Exhibit 3-12

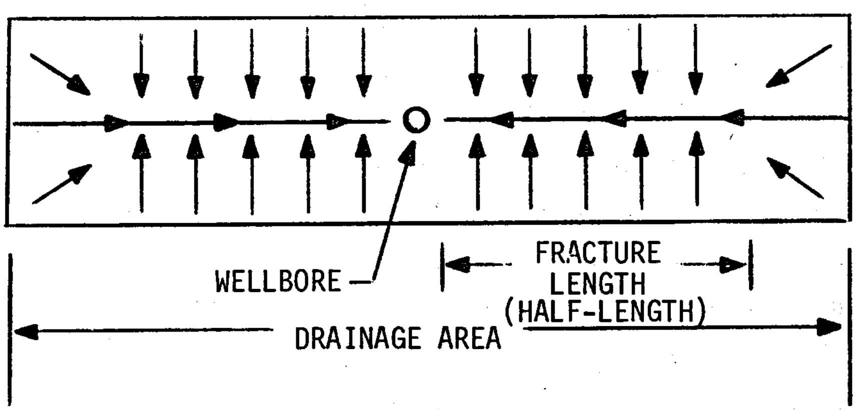
Isometric and Plan Views of Typical Fractures



ISOMETRIC VIEW

SOURCE: Ron G. Agarwall, Evaluation of Fracturing Results in Conventional and MHF Applications, SPE, February 28, 1977.

PLAN VIEW*



*Arrow denotes flow path.

SOURCE: Lloyd E. Elkins, "The Role of Massive Hydraulic Fracturing in Exploiting Very Tight Gas Deposits, "Natural Gas for Unconventional Geologic Sources, National Academy of Sciences, Washington, D. C. 1976.

- Multiple Fractures. Economic exploitation of many of the basins will require that several intervals of a massive gross section be fractured from the same well, particularly when a single interval or formation must share drilling and operating costs with other formations to be commercial. On-going field research has already advanced the technology to enable some such multiple completions, but as the number, size, depth, and vertical dispersion of the treatments increase, additional improvements in well completion equipment and stimulation techniques may be required.

The current stimulation tools are adequate for producing the near commercial "Other Low Permeability Basins" and the more favorable portions of the "Tight, Blanket Sands". In these two areas, the R&D program should focus on optimizing field development and well stimulation technologies to yield higher recovery efficiencies, to obtain economic recovery from the less favorable (now uneconomic) segments, and to accelerate the rate of development. In the basins with more severe geological problems, substantial improvements over current gas recovery technology are required.

The required technological improvements appear to be within reach of a concerted program of research, development, and demonstration. However, the large costs of such a program and the considerable uncertainties surrounding the resource base argue that producers or service companies, acting singly, may under-invest in the R&D required to advance the technology.[15/] A collaborative Federal-industry program appears to be required for fully commercializing these basins.

C. Analysis of the Technological Challenges

The requirements of commercializing the tight gas basins form the research and demonstration goals for enhanced gas recovery. To provide a plan for the immediate, first steps, the R&D must address four key questions:

- What are the exact reservoir properties of the tight gas basins?
- To what extent can the entire net pay in the massive gross intervals of the tight gas sands be stimulated and produced from the same wellbore?
- Is it possible in lenticular formations for massive hydraulic fractures to intersect sand lenses not initially in contact with the wellbore?
- What other significant improvement in tight gas recovery would make the resource commercial in the near-term?

The importance of these four basic questions is discussed below. The analysis uses an "exemplary" tight gas reservoir* and a single phase,

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* Reservoir characteristics of the Tight Gas Formations used in the sensitivity analyses:

Depth of Well	9,000 feet	Final Fracture Conductivity	300 md-ft
Net Pay Thickness	100 feet	Propping Agent	20-40 Mesh Sand
Fracture Height	400 feet	Producing Life	30 years
Drainage Area	160 and 320 acres	Fracture Gradient	0.7 psi/ft
Flowing Bottom Hole Pressure	1,000 psi	Porosity	10 percent
Reservoir Temperature	$200^{o}F$	Water Saturation	55 percent
Gas Gravity	0.6 (air=1.0)	Initial in situ permeability (to gas)	.001 to .10 md
Original Fracture Conductivity	2,400 md-ft	Initial Pressure	4,500 psi

finite difference reservoir simulator to ascertain the impact of research outcomes on economic exploitation of the resource.

1. What are the exact reservoir properties of these tight gas basins?

In the tight gas sands, the geology and reservoir properties dictate the limited technological interventions that can be applied. This makes it essential to know how these key properties affect economic recovery and in which range they become most restrictive. Briefly, assuming adequate gas pay thickness is available, the deposition of the pay, its permeability, and its gas filled porosity dominate all other properties.

a. Sand Deposition

The most dominant feature is the sand deposition, either blanket-type or lenticular, and if lenticular, the dimensions of the sand lenses. The following examples illustrate these concerns:

- Using the reservoir properties of the example formation (at 5 μd, 320 acre spacing, and a 1000-foot fracture), a blanket sand of 100 feet would produce about 8 Bcf per well, but a lenticular sand body (100 feet net and dimensions of 400 feet wide by 6000 feet long) would produce less than 2 Bcf per well; this is because the drainage area exposed to wellbore in a lenticular pay is less than 20% of that available to a wellbore in a blanket pay, as summarized below.

	Blanket Sand	Lenticular Sand
Single Well Drainage Area	320 acres	55 acres
Gas In Place		
-- Total per 320 acres	16 Bcf	16 Bcf
-- In contact with wellbore	16 Bcf	3 Bcf
30 Year Recovery Per Well	8 Bcf	<2 Bcf

- The critical dimension of the lenticular pay is its width rather than its length. The simulation analyses show that increasing lens width by 50% (to 600 feet) increases recovery by nearly 50%, but increasing lens length by 50% (to 9,000 feet) adds only about 5% to recovery in the economically most critical first ten years.

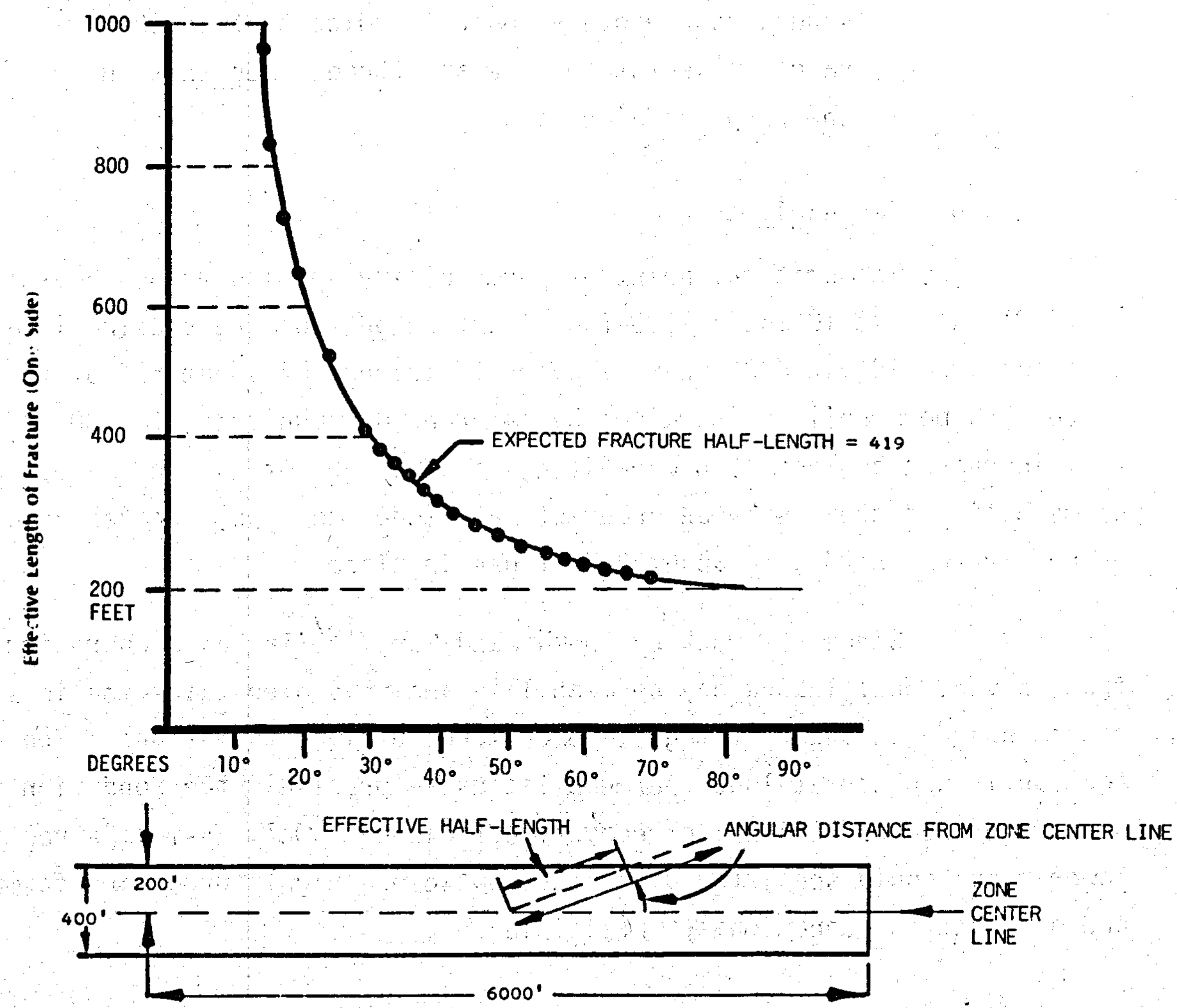
The second feature of sand deposition is the dominant orientation of the sand lens and the extent to which this parallels expected fracture azimuth. The impact of their relative orientations can be striking:

- If the relationship between the fracture orientation and the azimuth is random, a fracture designed for 1000 feet of penetration (half length) will remain in the example lens for only about 420 feet (Exhibit 3-13).

- When regional tectonic forces are essentially perpendicular to lens direction, effective fracture half-length is limited to 200 feet (one half of

Exhibit 3-13

Analysis of Effective Fracture Half-Length



the width of the lenses), and unless other lenses can be intersected, fractures designed larger than this are wasted.

- However, should the fracture azimuth parallel the sand lens, effective fracture length could reach the full 1,000 foot of design, and in tight (5 μd) sands, gas recovery would be twice that in the random orientation case and three times that in the perpendicular case.

b. Permeability

The critical point of permeability appears to be about 10 μd (or 0.01 md). At 10 μd, a 1000-foot fracture on 160 acre spacing in a blanket-type sand, would yield 30 year recovery efficiency of about 68% of the gas in place. As permeability increases by an order of magnitude, to 100 μd, recovery increases by less than one-fifth, to about 80% of gas in place. As permeability decreases by an order of magnitude, to 1 μd, recovery decreases by nearly two-thirds, to about 25% of gas in place.

Since the work by Thomas and Ward,[16/] it has been recognized that conventional laboratory permeability analysis overstates the in situ conditions by an order of magnitude or more in tight formations. The distortion is greater at lower permeabilities -- precisely the condition that shows the greatest effect on recovery efficiency. Only a small error in the lower range could spell the difference between a highly promising formation and one that is economically infeasible.

c. Gas Filled Porosity

The amount of gas filled porosity has direct and compounding effects: it is linearly related to gas in place and it directly effects recovery efficiency. Using the typical tight formation discussed earlier, recoveries were compared for gas filled porosities of 4.5 percent (total porosity of 10 percent with 55 percent water saturation) and 2 percent (total porosity of 8 percent with 75 percent water saturation). The effect of the lower gas filled porosity was to reduce total gas recovery in the lower-quality section to less than 20% of that achieved in the higher quality section, from 8 Bcf to about 1.5 Bcf per well.

Lower gas in place accounts for about one-half of the reduction and lower recovery efficiency compounds the problem. Thus, even slight overestimation of gas filled porosity* could render an apparently promising reservoir uneconomic.

2. To what extent can the entire net pay in the massive intervals of the tight gas sands be stimulated and produced from the same wellbore?

Many of the tight basins are characterized by massive sections containing numerous gas-bearing intervals or by the occurrence of numerous, discrete gas formations "stacked" one over another over a span of thousands of feet. Under existing practices, often less than one-third of the sand is completed and stimulated. In the Western Tight and Shallow Gas Sands, no single interval may be productive enough to be commercial on its own,

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* Moreover, since in the tight gas sands there appears to be a direct correlation between porosity and permeability, the effects of lower porosity in actual practice could be even more dramatic.

yet several in combination could be economic. This requires multiple massive fracturing treatments through a common wellbore. As the number, size, and vertical dispersion of the treatments grow, it may require:

- Improved casing, cementing, and well completion practices.
- Cost-effective means of stimulating multiple intervals without damaging the production string.
- Advanced stimulation techniques to maintain the massive induced fractures in their intended pay intervals.

Should multiple completions with numerous MHF prove to be technically ineffective, much of the potential of the Western Tight, Shallow Gas, and Other Tight, Lenticular formations would become economic only at the higher ($3.00-$4.50 per Mcf) gas prices.

Assuming that MHFs in multiple intervals can be successfully placed through the same wellbore, there still remains the challenge of stimulating as much of the quality gas pay in the formation as possible. The objective of the R&D program would be to stimulate 80% of the quality pay in the formation.

3. Is it possible in lenticular formations for a massive fracture to intersect sand lens not initially in contact with the wellbore?

While considerable argument can be marshalled on each side of the question, the field tests to date provide little evidence either way to this vital question.

A comparison of performance between 60 small fractures (100 to 300 feet) and 6 larger (500 to 1,000 feet) fractured showed only an insignificant improvement in anticipated gas recovery for the larger fractures. However, given the relatively small length and the low sand shale ratio (from 20 to 40 percent), the larger fractures had only limited probability of intersecting additional lenses.

If a fracture will not enter lenses other than those initially encountered by the wellbore, numerous small fractures appear to provide an optimum approach. However, should a large (1,500 to 2,000 foot) fracture be able to intersect additional lenses, the effect can be dramatic:

- At a rate of 1 additional lens (for each lens seen at the wellbore), the initial 10 year recovery would be about 70% higher than for the single lens; the larger fracture might add nearly 1 Bcf of additional recovery during this time, in the example formation.

- At the probalistic estimate of two additional lenses (for each lens seen at the wellbore) initial 10 year recovery would be more than double than for the single lens and might add 1.5 to 2 Bcf.

4. <u>What other significant improvements in tight gas recovery should be pursued for accelerating commercialization of the tight gas basins?</u>

Beyond the above research questions, numerous additional opportunities should be pursued for optimum, economic exploitation of these tight sands.* Of these, five stand out:

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* As in any scientific discipline, major advancements in measurement and reservoir analysis capability must parallel all technological advances.

- Designing the optimum size fracture with respect to any given set of geological conditions. Exhibit 3-14 shows that long fractures (1500 feet) are effective in low, 1 μd to 10 μd, blanket sands but contribute little to recovery efficiency over short fractures (500 feet) in the higher permeability sands (50 μd and higher).

- Ensuring adequate fracture conductivity, particularly through the use of higher sand concentrations and new proppant materials (e.g., bauxite).

- Engineering optimum fracture height, particularly in relation to the available net pay and desired length. Exhibit 3-15 shows the relationship of fracture height and length (when using a high quality fracture fluid) and how unnecessary height impedes effective fracture length at any given volume of fluid.

- In blanket sands, well placement, given fracture azimuth, determines the shape of the effective drainage area. At higher permeabilities, 0.1 md and greater, square drainage patterns with relatively short fractures were most efficient, while at low permeabilities rectangular patterns with long fractures are most efficiently drained (Exhibit 3-16).

- Establishing optimum field development in relation to sand deposit. Since only the lenses connected to the well (or to the fracture) can be drained, it may be

Exhibit 3-14

Recovery Efficiency as a Function of Fracture Length and Permeability (Assuming 30 Year Production Life)

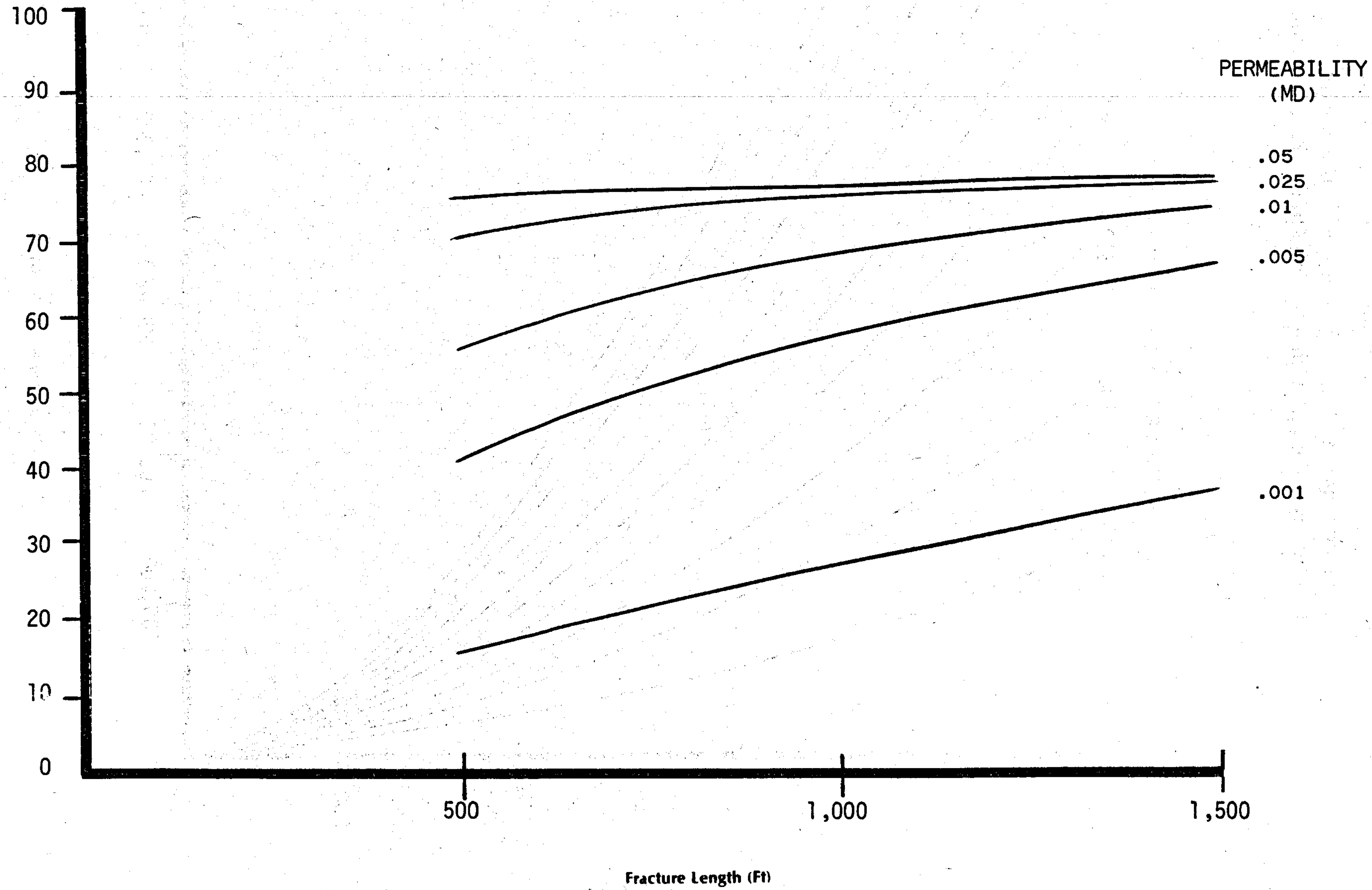


Exhibit 3-15

Relationship of Fracture Volume, Fracture Height, and Fracture Half-Length Using A High Quality Fracture Fluid . .

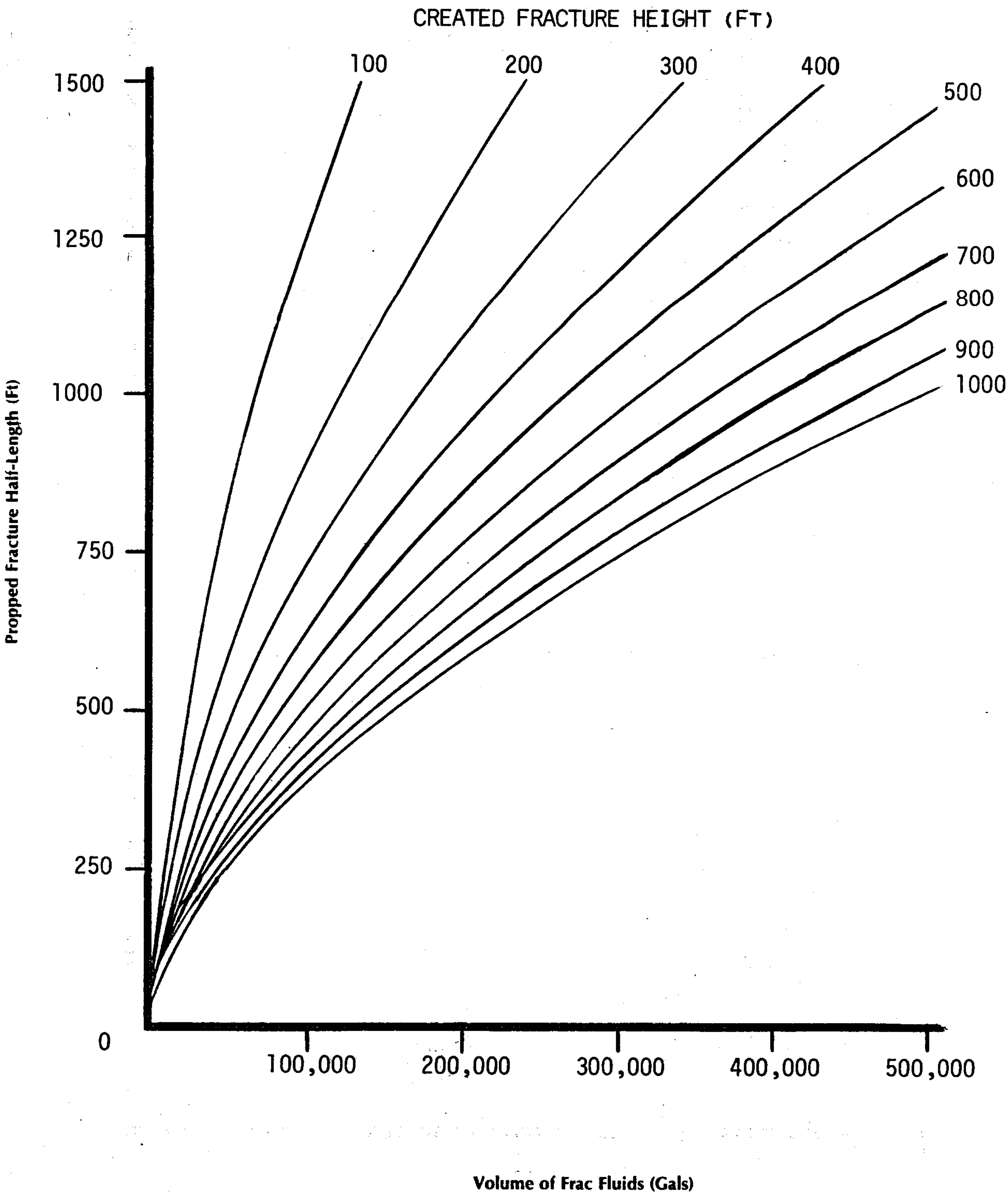
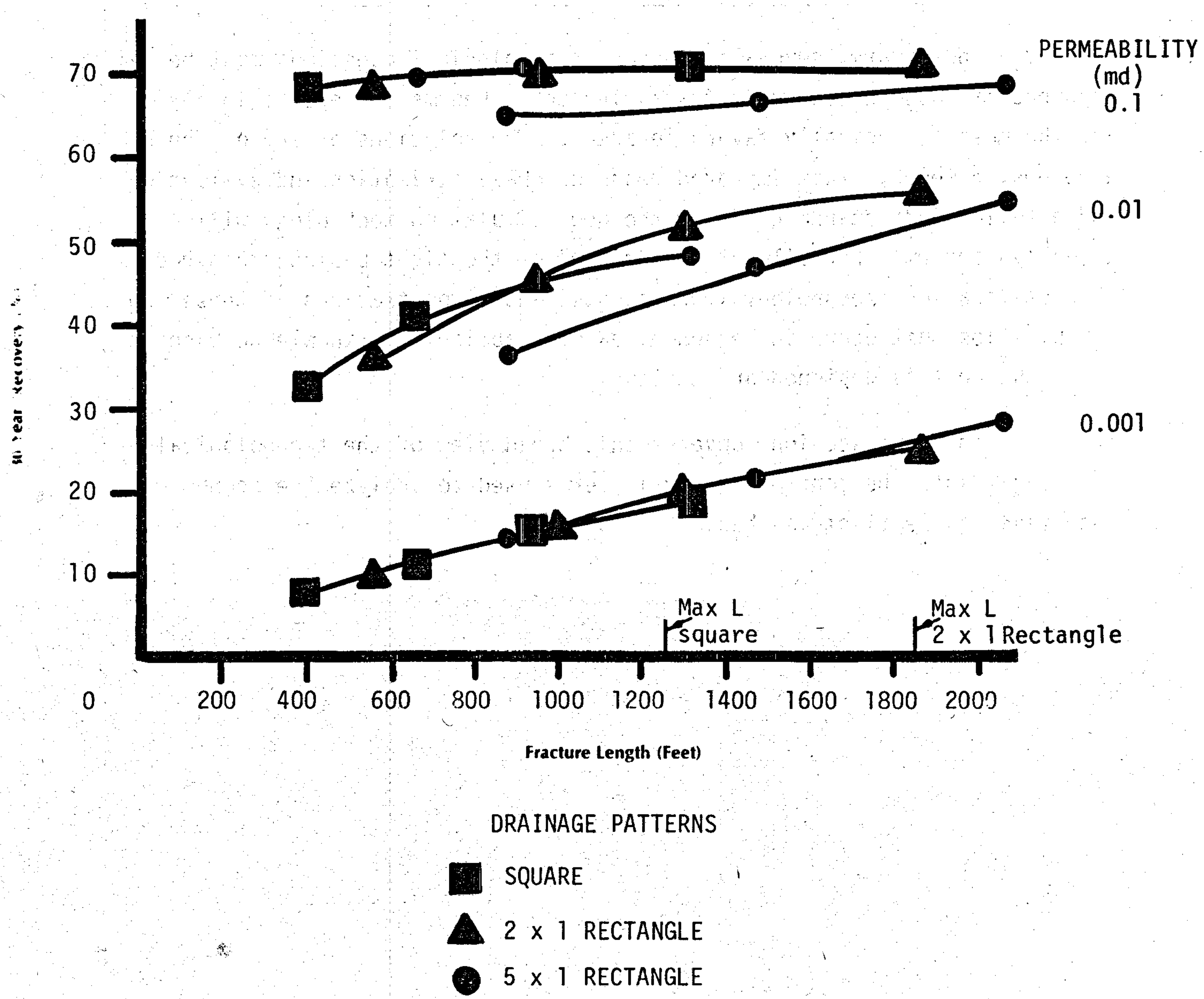


Exhibit 3-16

Simulated Twenty Year Recovery for Three Drainage Shapes



necessary to use substantially closer spacing in formations marked by long, thin lenses. Closer spacing, combined with multi-lens fractures, could be the key to recovering substantial portions of the gas in place in these basins.

D. Summary of the Technological Challenges and Questions

In summary, several important technological questions must be answered if massive hydraulic fracturing is to become commercial in any but the most geologically favorable areas. The solutions of any of these problems, however, await improved resource characterization and evaluation and a fuller understanding of how the new stimulation technology will actually perform. For all but the "cream" of the tight basins, resource characterization, technology improvements, and demonstrations of these new capabilities must occur in sequence, each establishing a knowledge base on which the next is designed and tested.

The next section converts this broad view of the technological challenges into the concrete analytic terms used to analyze the economic potential of the tight gas basins.

IV. THE POTENTIAL OF THE TIGHT GAS BASINS

A. Approach

The preceding sections have described the tight gas resource base and the level of technology required to exploit it. This section estimates the amount of gas that could be economically recoverable under alternative technological and economic assumptions. Three elements are essential for estimating this potential:

- Technology. Two sets of technological assumptions were projected:

  -- Base Case: the level of the technology expected to be attained by industry during the next five years without active federal involvement.

  -- Advanced Case: the level of the technology expected to be attained by virtue of active federal-industry collaboration.

- Gas Production. The analytic units in the resource base were developed and produced using a reservoir simulator and development model.

- Economics. Each analytic unit was evaluated using actual field development costs, return on capital requirements, and at three gas prices.

1. Base and Advanced Technology Cases

The Base Case reflects the current state of the art of MHF technology plus anticipated advances in the next five years. The assessment of current technology was based on on-going field tests and discussions with industry's leaders in massive fracturing. The conclusions drawn from these steps were consistent with the results of a survey of key financial and technical managers of 92 companies in all phases of the gas industry.[17/]

The Advanced Case represents evolutionary technological advances that hold reasonable promise of being achieved through focused R&D. The projection of technological advances draws on the theoretical analysis and laboratory tests of the leading gas recovery experts and on preliminary pilot tests by the most prominent MHF practitioners.

Exhibit 3-17 displays the major technological elements and how they differ between the Base and Advanced Cases. The salient parts of this Exhibit are summarized below.

- Resource Characterization. The Advanced Case assumes all formations are eligible for economic testing; the Base Case assumes industry's interest would be confined to areas and formations that have been demonstrated to have favorable geologic characteristics. The Advanced Case assumes lower dry hole rates stemming from accelerated resource definition and improved geologic an reservoir measurement technology.*

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* Numerous additional advances are achieved through the resource characterization efforts, but these are prerequisite to the other differences shown, e.g., ability to make and interpret measurements required for more effective and efficient field development and well stimulation, acceleration of development in less defined areas, and reduced risks. These differences are reflected in items listed under technology, economics, and development in Exhibit 3-17.

Exhibit 3-17

Summary of Major Differences Between the Base and Advanced Case—Tight Gas Basins

STRATEGY/ITEM	BASE CASE	ADVANCED CASE
• Eligible Formations	Limited to those demonstrated to be geologically favorable	All
• Dry Hole Rate		
- Lenticular	30%	20%
- Blanket	20%	10%
Technology		
• Fracture Height	4 x net pay limit 600 (200' minimum)	3 x net pay limit 400' (150' minimum)
• Fracture Length (one way)		
- Shallow gas sands	200'	500'
- Near-tight gas sands	500'	500'
- Tight gas sands	1000'	1500'
• Fracture Conductivity	Decreases with depths using current proppants and methods	(With improved proppants and methods maintaining adequate conductivity)
• Field Development		
- Lenticular	320 acres/well (2 wells/section)	107 acres/well (6 wells/section)
- Blanket	160 acres/well (4 wells/section)	160 acres/well (4 wells/section)
• Net Pay Contacted		
- Lenticular gas sands		
-- 320 acres drainage	17%	
-- 107 acres drainage	-	80%
- Blanket	100%	100%
Economics		
• Cost of Delivered Fracture	120%	100%
• Risks - reflected in discount rate of	26%	16%
Development		
• Start Year for Drilling		
- Probable Acres	1978	1981 (RD&D effect begins)
- Possible Acres	1987	1987
• Development Pace		
- Probable Acres	17 years to completion	13 years to completion
- Possible Acres	17 years to completion	15 years to completion

- Technology Advancement. The Advanced Case assumes improved ability to design and control the fractures and to increase their intersection of widely disseminated gas pay. In lenticular formations, spacing is reduced and fractures are assumed capable of intersecting net pay lenses not encountered at the wellbore. This combination of advances would increase the proportion of net pay in a section in contact with a wellbore from 17% to about 80%.

- Cost and Economic Criteria. In the Advanced Case, the fracture is assumed to achieve the engineered level of performance, up from 80% effectiveness in the Base Case. Improved capacity for predicting the technology, as demonstrated by successful pilot tests, would reduce industry's risk premium from the present 26% ROI* (after tax) to a more conventional level of 16% ROI (after tax).

- Acceleration. The Advanced Case assumes accelerated application of the technology and timing of field development. The initial technological advances are estimated to become effective in 1981.

The differences between the Base Case and the Advanced Case set the goals of the joint federal/industry program and are discussed at more length in Section V and in Part 2.

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* ROI = Return on Investment.

2. Simulated Expected Production

A single phase, finite difference reservoir simulator, was used to estimate gas production and recovery from the individual formations and areal units. It was developed at Texas A&M University by Drs. Steven A. Holditch and Richard Morse[18/] (described in further detail in Volume III) and was validated, during the study, against field data and other simulation models used in the production industry.

The grid pattern of the simulator consists of 300 cells (20 x 15) and uses a fine breakup near the wellbore and along the fracture and small time steps, as small as .001 days, to provide accurate simulation of the early transient flow periods. The model uses a direct solution technique -- alternating diagonal, matrix inversion -- for solving the equations that describe a fractured reservoir.

The reservoir simulator was modified to include two important phenomena that occur in tight gas reservoirs. First, the effects of non-Darcy flow on the well performance were incorporated using published correlations to simulate pressure gradients under non-Darcy flow conditions. The second modification was to simulate increasing closure pressure on fracture conductivity. If sand is used as a propping agent, fracture conductivity may decrease by an order of magnitude during the life of a well. Adjustments were made that explicitly account for proppant type, proppant concentration, the formation embedment pressure, the value of the least principal stress, and the flowing bottom hole pressure.

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* Gratitude is expressed to Dr. S. A. Holditch and his staff at Sovereign Engineering, Inc., for conducting the numerous analyses.

This model was used to simulate the performance of each formation and each areal unit in the resource base. Where more than one formation was vertically adjacent, and could be produced by multiple completions, the gas production was individually calculated and then combined.

3. Economics

A net present value (discounted cash flow) model was used to simulate the economics of production.* The unit of analysis was a well and its drainage area representing a specific areal unit. The areal units for which the discounted net cash flow exceeded zero were deemed economic and developed, according to the timing model.

State-level drilling and completion costs were drawn from the API/AGA Joint Association Survey of Costs.[19/] Well stimulation costs were provided by major service companies. Surface equipment and operating costs were developed from studies by Gruy Federal, Inc.[20/] Dry hole and exploration costs were functions of drilling and completion costs and the areas involved. Taxes, royalties, burden rates, and accounting procedures were drawn from actual applications in each region. All costs were varied as a function of depth and geographic region. Constant 1977 dollars were used throughout the analysis.

The analysis was conducted for three gas prices -- $1.75, $3.00, and $4.50 per Mcf. Where the well, representing a specific areal unit, was found to be economic, it was extrapolated to the full unit. Each area was assumed to be developed according to a fixed schedule. The better defined (Probable) areas were assumed to be developed first, followed by the less well defined (Possible) areas.

* See Volume III for additional detail.

B. Technically Recoverable Gas

Setting the price constraint aside and analyzing the formations under the Advanced Case technology provides an estimate of technically recoverable gas* -- a useful benchmark for subsequent analyses.

Exhibit 3-18 displays the technically recoverable gas from each of the five resource targets. Exhibit 3-19 shows the same information in graphical form:

- Overall, slightly less than half of the gas in place is technically recoverable in 30 years under Advanced Case technology.

- The 30 year recovery efficiencies differ substantially among the resource targets, ranging from 38 to 82 percent:

  -- The geologically more favorable targets -- the Tight Blanket and Other Low Permeability targets -- have technological recovery efficiencies of 70 to 80 percent.

  -- The geologically more difficult targets -- the Western Tight Gas Basins, the Shallow Basins, and the Other Tight, Lenticular Basins -- have technological recovery efficiencies of about one-half these levels, at 40 to 50 percent.

The technically recoverable gas provides a useful benchmark for assessing the benefits of lifting economic constraints and improving technological performance. For the Advanced Case, it represents a limit of what can be realistically expected.

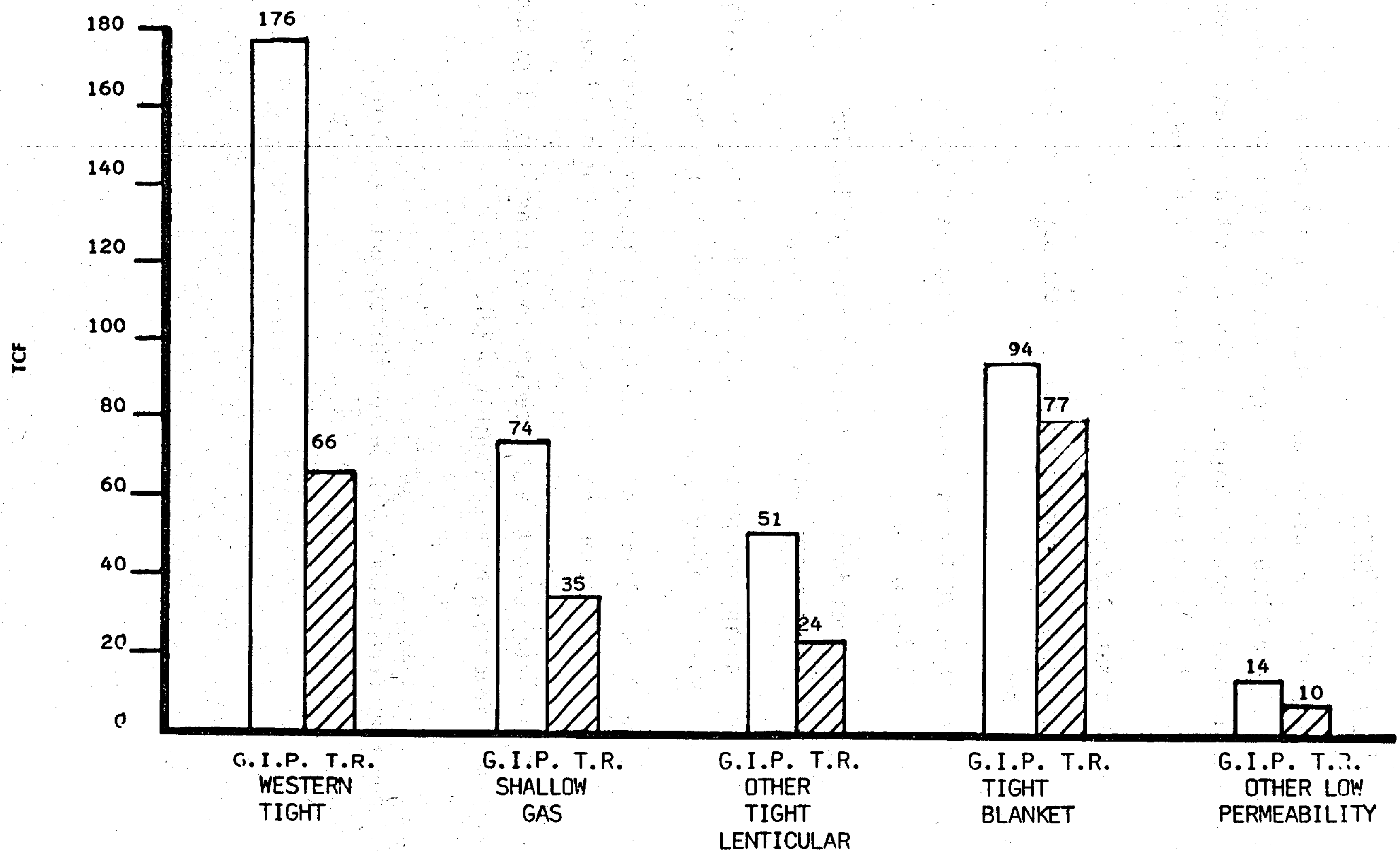
Exhibit 3-18

Gas in Place, Technically Recoverable Gas, and Technical Recovery Efficiency—Tight Gas Basins

TARGET/BASIN	GAS IN PLACE (Tcf)	TECHNICALLY RECOVERABLE (Tcf)	TECHNICAL RECOVERY EFFICIENCY (%)
WESTERN TIGHT			
Greater Green River	90.5	35.5	39.3
Piceance	35.5	12.1	34.1
Uinta	50.2	18.0	35.8
SUBTOTAL	176.2	65.6	37.2
SHALLOW GAS			
Northern Great Plains	53.4	18.4	34.4
Williston	20.9	16.5	79.2
SUBTOTAL	74.3	34.9	47.0
OTHER TIGHT, LENTICULAR			
Sonora	23.9	15.8	66.3
Douglas Creek	3.3	0.3	8.5
Big Horn	23.4	7.8	33.5
SUBTOTAL	50.6	23.9	47.2
TIGHT, BLANKET GAS			
Cotton Valley (Sweet)	67.1	49.7	74.1
Denver	18.5	13.0	70.5
Ouachita	4.9	1.4	28.6
San Juan	15.0	12.0	79.9
Wind River	2.7	1.0	36.5
SUBTOTAL	108.2	77.1	71.3
OTHER LOW PERMEABILITY RESERVOIRS			
Cotton Valley (Sour)	13.8	9.9	71.7
TOTAL	423.1	211.4	50.0

Exhibit 3-19

Comparison of Gas in Place and Technically Recoverable Gas—by Tight Gas Resource Target



C. The Base Case Estimates

Base Case production estimates, at the three gas prices of \$1.75, \$3.00, and \$4.50 per Mcf, represent the amount of recovery that can be anticipated from the tight gas basins without advanced technology and without a federally sponsored research and development program.

1. Ultimate Recovery

In terms of ultimate recovery,* the Base Case for the tight gas basins shows:

- About 70 Tcf is recoverable at a gas price of \$1.75 per Mcf.
- An additional 30 Tcf, for a total of 100 Tcf, can be recovered at \$3.00 per Mcf.
- Raising the price from \$3.00 to \$4.50 increases ultimate recovery by 8 Tcf, to a total of 108 Tcf.
- At \$3.00 and under Base Case technology, industry will recover about one-fourth of the gas in place.

Industry efforts are expected to be concentrated in the geologically more favorable basins (Exhibit 3-20).

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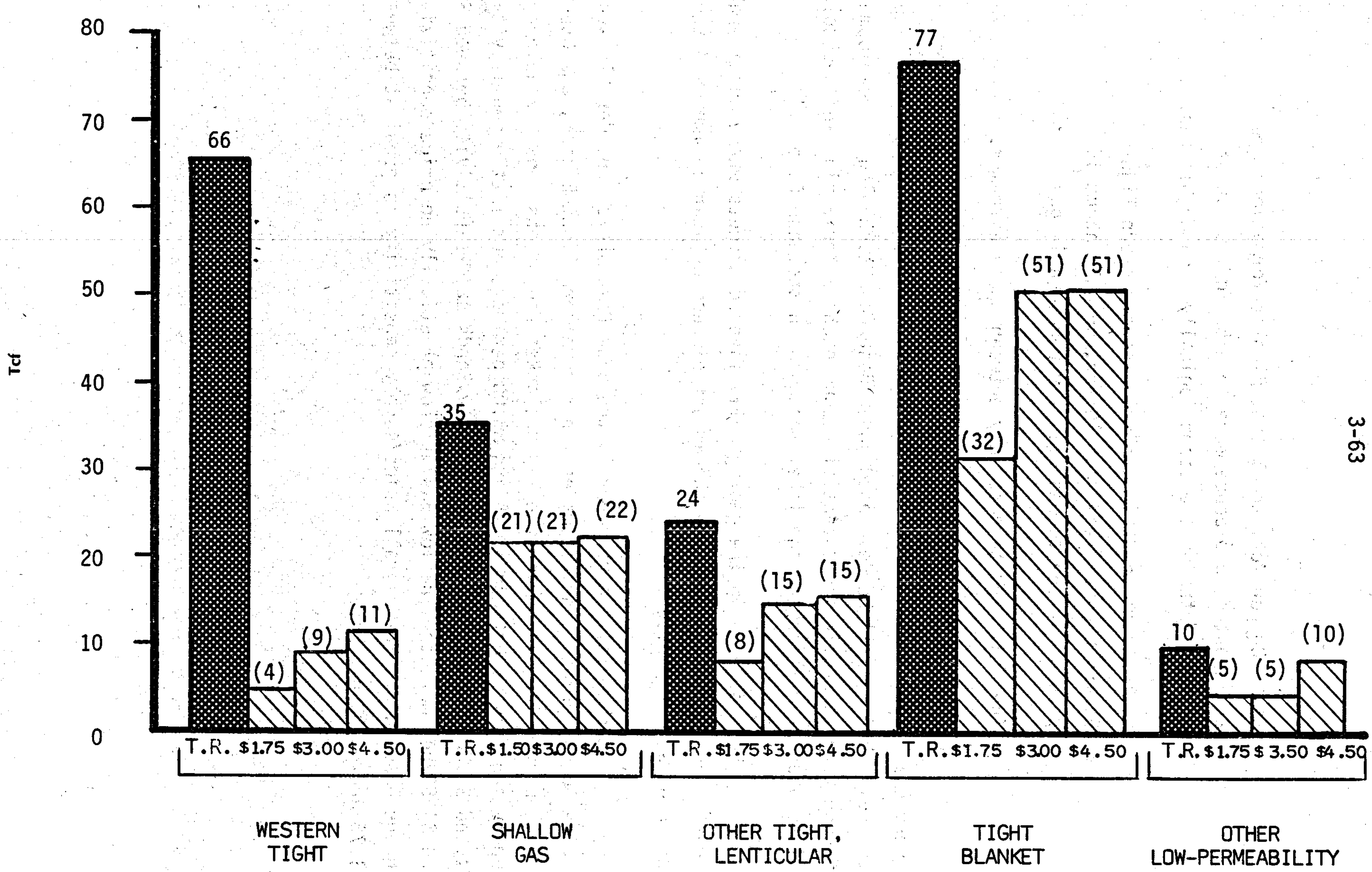
* Recoveries were estimated based on thirty-year well life.

Exhibit 3-20

Base Case Ultimate Recovery—by Tight Gas Resource Target



- At $3.00 per Mcf, the Tight, Blanket formations are anticipated to produce more than 50 Tcf, or about three-fourths of the technologically recoverable gas.
- By contrast, at this gas price, the Western Tight Basins produce less than 10 Tcf, or only about 14 percent of the technologically recoverable gas.
- The remaining targets vary between these extremes.

These results point up three important conclusions. First, only a very small portion of the ultimate potential of the geologically difficult, lenticular basins will be developed under Base Case technology. Development of such targets requires substantial resource characterization and technological advance -- well beyond the levels assumed in the Base Case.

Second, even in the geologically favored targets where considerable industry activity is projected, the amount of recovery can be improved through Advanced Case technology.

Third, ultimate recovery in the Base Case shows considerable sensitivity to gas price. The estimates for the Western Tight Basins, the Other Tight, Lenticular Sands, and the Tight Blanket Formations show sizeable price/supply sensitivity between $1.75 and $3.00 per Mcf, but little sensitivity beyond $3.00. The Other Low Permeability Sands show sensitivity between $3.00 and $4.50 per Mcf; the Shallow Basins show practically no price sensitivity in the Base Case. The overall price/supply sensitivity is greatest between $1.75 and $3.00 per Mcf.

2. Production Rate

While ultimate recovery is a valuable indicator from a total resource perspective, many of today's concerns center on: "How much additional gas can we produce in 1985 or 1990"?

Exhibits 3-21 and 3-22 show that the total Base Case production rate from the tight gas basins rises gradually from 1979 to a peak of 4.0 Tcf per year by 2000.*

- The Tight, Blanket basins provide over one-half of the total production rate -- nearly 1.6 Tcf per year in 1990 and 2.0 Tcf per year at their peak in 1995, at $3.00 per Mcf.

- The contribution of the other four targets becomes significant after 1990, equaling the contribution of the Tight, Blanket basins.

The cumulative recovery curve (at $3.00 per Mcf) shows that only about 20 Tcf of the 100 Tcf of ultimate recovery could be produced by 1990.** This argues that acceleration as well as increased recovery should be the goals of federally sponsored research and development.

3. Improving on the Base Case

While important quantities of gas can be recovered from the tight gas basins, even under Base Case technology and without a federally sponsored research and development program, the analysis of technical recovery efficiency and the status of the technology show that major improvements are feasible and should be pursued through advanced technology.

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* These estimates are incremental to current tight gas production from proved reserves.

** By 1995 and 2000, cumulative production is about 40 and 60 percent of the ultimate, respectively.

Exhibit 3-21

Base Case Annual Production to the Year 2000 (at $3.00/Mcf)— by Tight Gas Resource Target

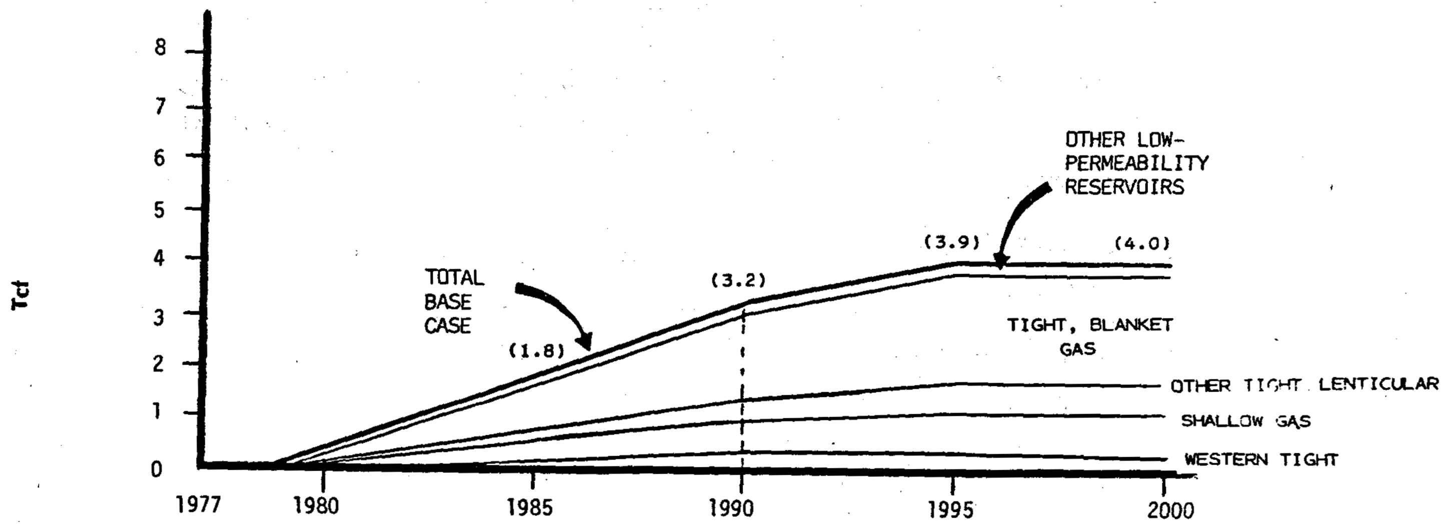
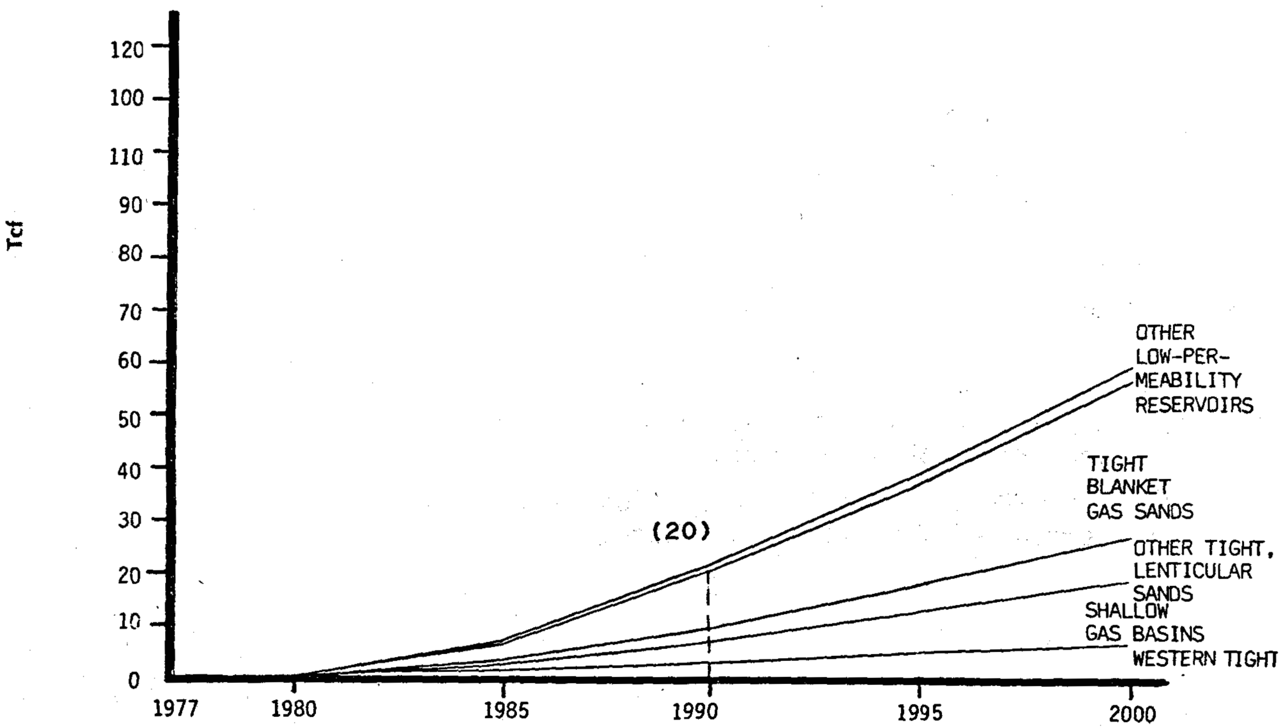


Exhibit 3-22

Base Case Cumulative Production to the Year 2000 (at $3.00/Mcf)— by Tight Gas Resource Target



D. The Advanced Case Estimates

The impact of the Advanced Case technology -- achieving the resource characterization and technology goals of the joint Federal-industry R&D strategies -- was analyzed at the same three prices. The difference between the Advanced Case and Base Case is the incremental production stimulated by a successful R&D program.

1. Ultimate Recovery

Under Advanced Case technology, almost 150 Tcf is projected to be ultimately recoverable at $1.75 per Mcf. Raising the gas price to $3.00 per Mcf for all the basins would yield another 32 Tcf, raising total recovery to above 180 Tcf (Exhibit 3-23). Further increasing the price to $4.50 per Mcf adds only about 6 Tcf.

Under Advanced Case technology and at $3.00 per Mcf, about 43 percent of the gas in place could be recovered. This contrasts with the Base Case where at the same price, about 24 percent of the gas in place is economically recoverable.

As shown in Exhibit 3-24, the increase in recovery is not proportional across all targets, although significant benefits are available from all:

- The largest benefits are those in the geologically difficult Western Tight Gas Basins. At $1.75 per Mcf, the Advanced Case ultimate recovery is almost

Exhibit 3-23

Ultimate Recovery from the Tight Gas Basins (at Three Prices)

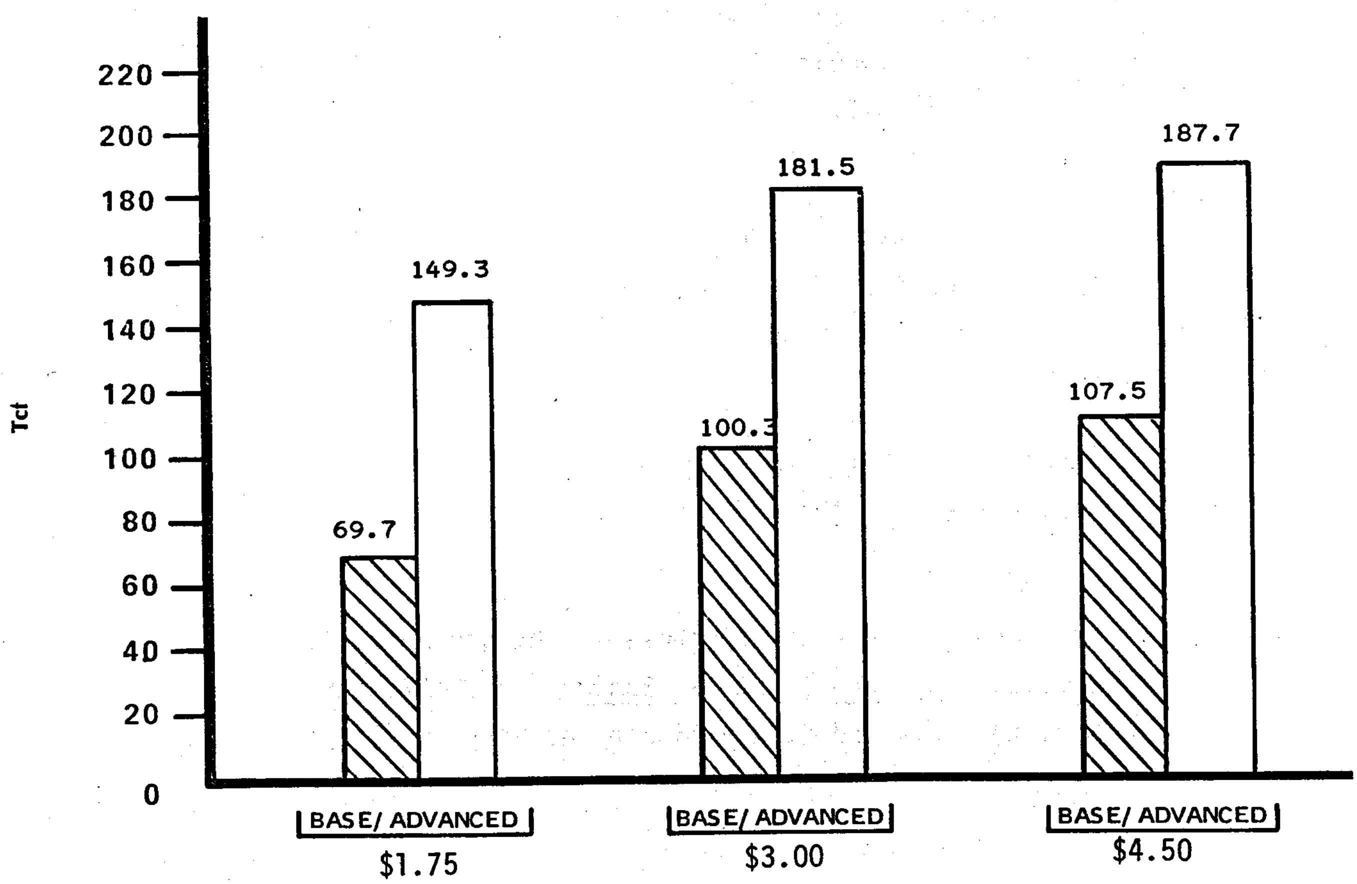
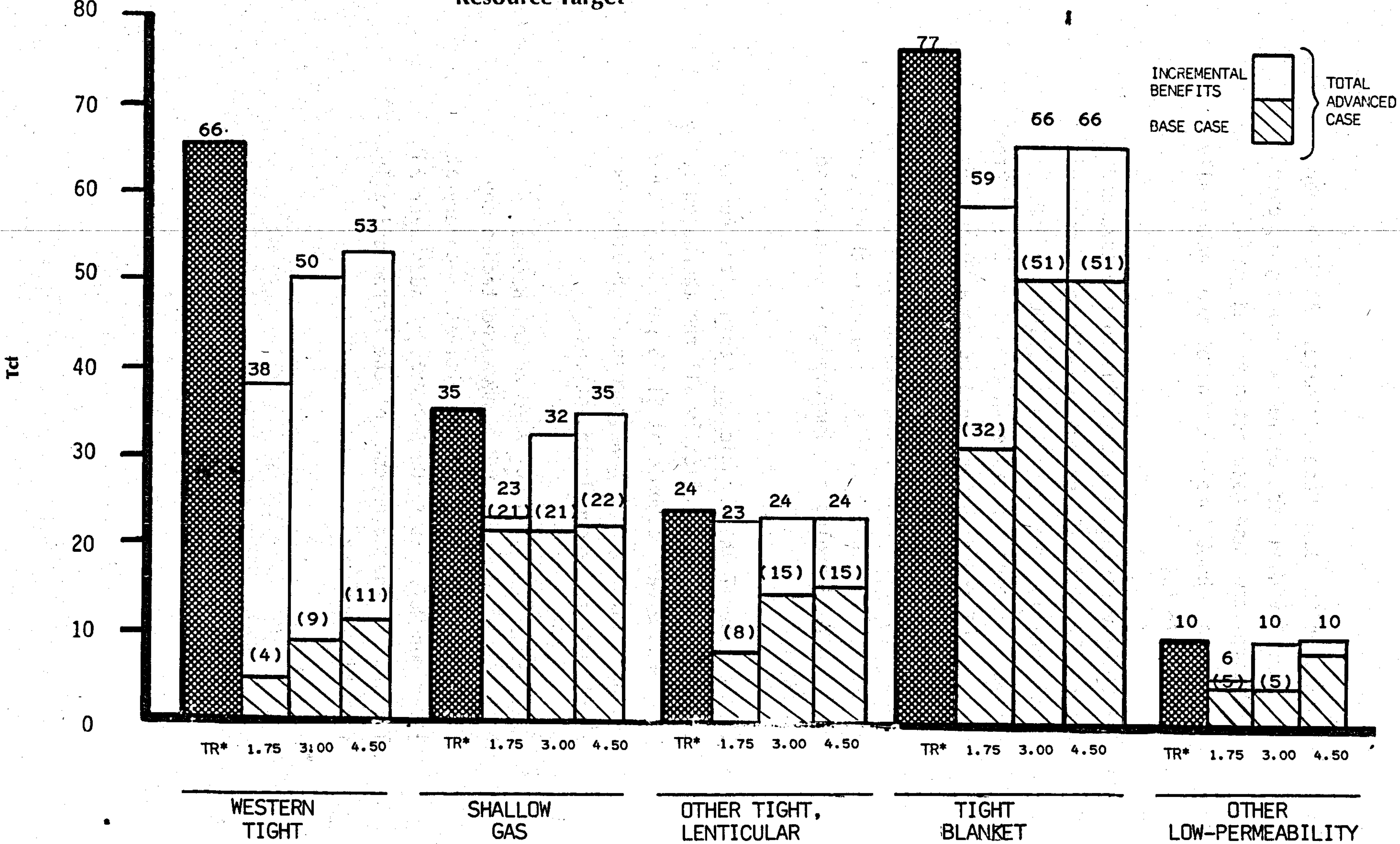


Exhibit 3-24

Ultimate Recovery from the Tight Gas Basins—by Tight Gas Resource Target



TR* – TECHNICALLY RECOVERABLE

nine times the Base Case estimate. At $3.00 per Mcf, the Advanced Case ultimate recovery is over five times the Base Case estimate and yields recovery of about three-fourths of the technically recoverable gas.

- For Shallow Basins, the gain due to the Advanced technology at $1.75 per Mcf is only about ten percent. Raising the gas price to $3.00 per Mcf, however, crosses the price threshold of the tighter portions of these basins, leading to a 50 percent increase in anticipated ultimate recovery and yielding almost 90 percent of the technologically recoverable gas. The Shallow Basins require both higher prices and technological improvements to increase production.

- In the Other Tight, Lenticular Basins, the Advanced technology makes practically all the technologically recoverable gas economic at $1.75 per Mcf. These basins pointedly show how improved technology can substitute for economic incentives.

- The Tight, Blanket Sands respond to changes in both price and technology. Advanced technology nearly doubles the projected ultimate recovery at $1.75 per Mcf. At $3.00 per Mcf, it adds over 25 Tcf and exceeds 85 percent of the technologically feasible recovery.

- The <u>Other Low Permeability Reservoirs</u> show a small increase for the Advanced Case at $1.75 per Mcf, but a doubling of the Base Case estimate at $3.00 per Mcf. Under the Advanced Case and at $3.00 per Mcf, nearly all the technologically recoverable gas would be produced. In these reservoirs, the price mechanism and R&D can be mutually supportive Federal strategies for increasing gas supply.

2. <u>Production Rate</u>

Exhibits 3-25 and 3-26 show the total annual and cumulative production from the Advanced Case as well as the increments over the Base Case, at $3.00 per Mcf.

Total production rises rapidly due to acceleration of field development and improved recovery. Annual production reaches a peak in 1990 at 7.7 Tcf per year and declines slightly after that time to 7.2 Tcf in 1995 and 6.8 in 2000. This peaking is due to the rapid development of the Western Tight and Tight, Blanket Sands. Annual production from the other targets continues to expand throughout the period to 2000.

- Under Advanced Technology at $3.00 per Mcf, the tight gas basins can make a significant contribution to the nation's overall demand for gas, providing 4 Tcf in 1985 and nearly 8 Tcf in 1990.

- The cumulative recovery curve (at $3.00 per Mcf) shows that 45 Tcf, or almost one-quarter of the ultimate recovery, can be produced by 1990.

Exhibit 3-25

Annual Production to the Year 2000 (at $3.00/Mcf)—by Tight Gas Resource Target

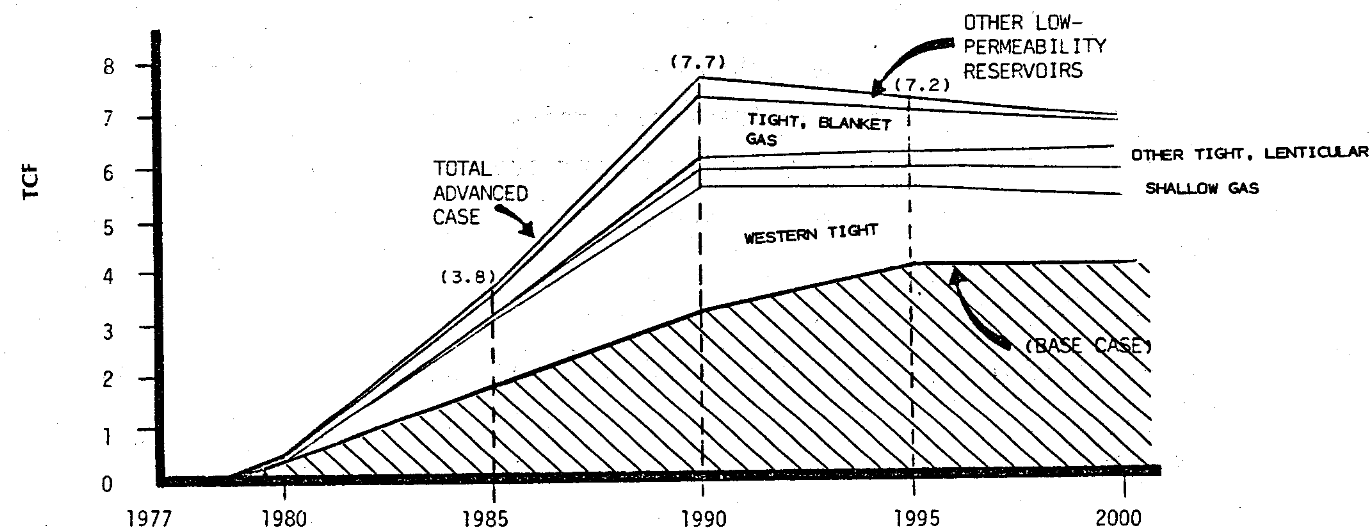
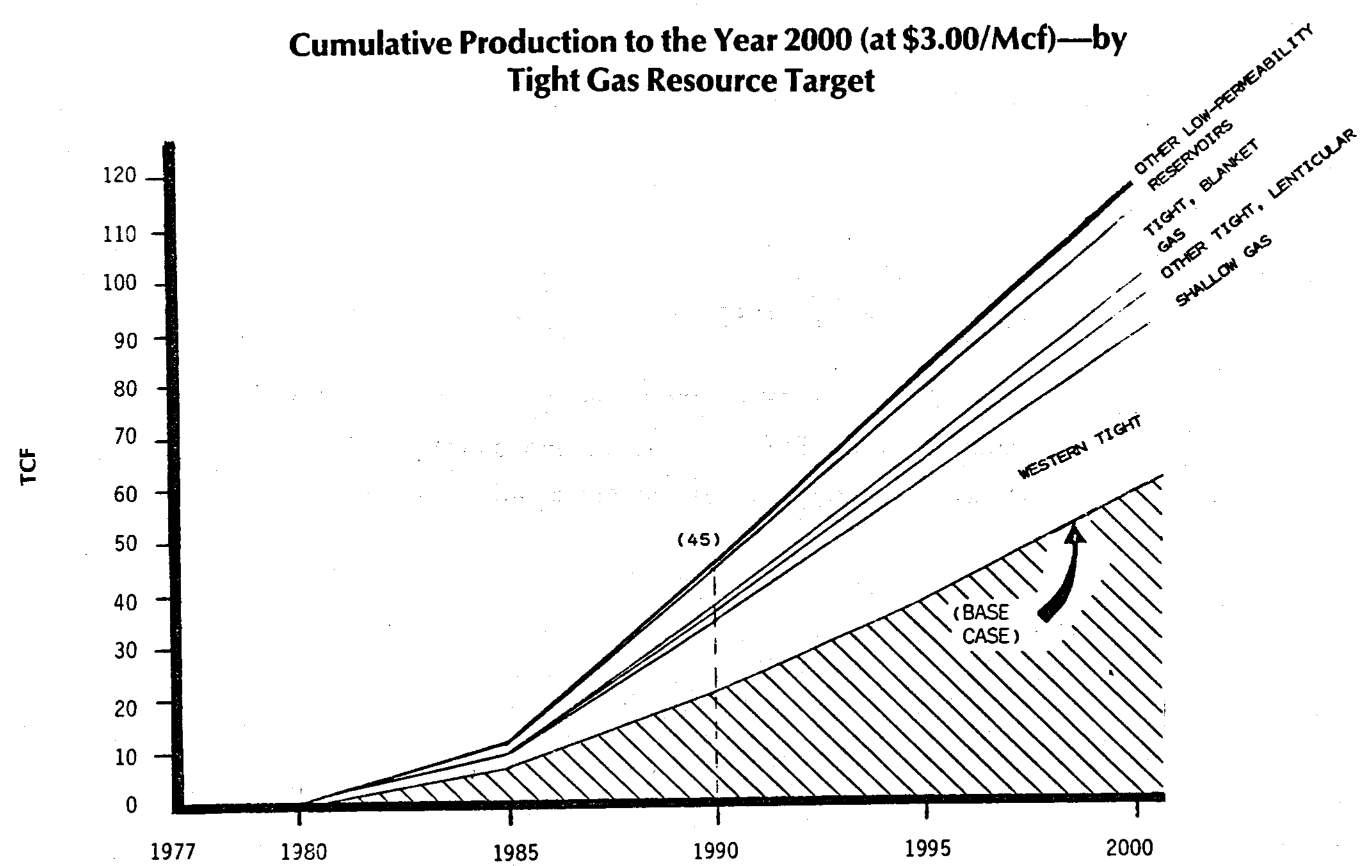


Exhibit 3-26

Cumulative Production to the Year 2000 (at $3.00/Mcf)—by Tight Gas Resource Target



E. Well Requirements

Exhibit 3-27 shows the number of new wells required in each resource target under Base and Advanced Technology at $1.75 and $3.00 per Mcf.

In 1976, approximately 7400 successful onshore gas development wells were drilled, excluding all exploratory wells, all oil wells, and all dry holes.

As the supply of natural gas falls behind the need, it is reasonable to assume that drilling capacity will expand. It has been estimated[21/] that the growth in onshore drilling capacity could be sustained at 10-15 percent between now and 1995. Since the drilling requirements in the tight gas basins would use only 10 to 20% of projected capacity, as shown below, well requirements should not pose a constraint on reaching the projected production levels.

Drilling Capacity Requirements of the Tight Gas Basins

Annual Drilling Growth Rates	Requirements as Percent of Total 1990	1995
8%	30	21
10%	23	14
15%	12	6

Exhibit 3-27

Drilling Requirements in 1990 and 1995–by Tight Gas Resource Target

	Number of New Wells - 1990				Number of New Wells - 1995			
	Base Case		Advanced Case		Base Case		Advanced Case	
	$1.75/Mcf	$3.00/Mcf	$1.75/Mcf	$3.00/Mcf	$1.75/Mcf	$3.00/Mcf	$1.75/Mcf	$3.00/Mcf
Western Tight Gas Sands	120	260	970	1350	60	150	510	590
Shallow Gas Basins	750	750	1290	3170	1210	1210	1300	4740
Other Tight, Lenticular Sands	290	450	700	700	320	510	830	830
Tight, Blanket Gas Sands	730	1120	1400	1720	630	900	880	1020
Other Low Permeability Reservoirs	60	60	80	120	30	30	30	40
TOTAL	1950	2650	4440	7070	2260	2800	3550	7230

F. The Relative Roles of Price and R&D

One of the strategy decisions facing Federal energy policymakers involves balancing economic incentives (prices and taxes) and sponsored research and development for augmenting domestic supplies of natural gas.

The study finds that future production from the tight gas basins is highly sensitive to economic incentives and to major advances -- but most sensitive to improved economics and technology used in combination.

- Gas prices up to $1.75 per Mcf provide enough economic incentives to stimulate the geologically more favorable portions of all the resource targets. Under Base Case technology, a total ultimate recovery of 70 Tcf and 1990 annual production of 2.7 Tcf are projected.

- Raising the price to $3.00 per Mcf permits development of additional areas, increasing ultimate recovery to 100 Tcf and 1990 production to 3.2 Tcf.

- Further increasing price -- up to $4.50 per Mcf -- has negligible effect on the estimates of production.

- Even at the lower level of economic incentives, $1.75 per Mcf, focused Federal-industry R&D adds substantial potential production; under Advanced Case technology the projections are:

  -- Ultimate recovery of nearly 150 Tcf

  -- Annual production in 1990 of 6.3 Tcf.

- Combining Advanced Case technology and improved economic incentives yields substantial additional recovery:

  -- At $3.00 per Mcf, Advanced Case ultimate recovery is estimated at over 180 Tcf, and 1990 annual production at 7.7 Tcf.

  -- At $4.50 per Mcf, however, the projections are only marginally higher than at the $3.00 per Mcf levels.

Maximizing production from the tight gas basins relies on both focused R&D and increased price. While estimating the exact levels of economic incentives that would accompany the R&D program was beyond the scope of the present study, the analysis suggests that the optimal price is between $1.75 and $3.00 per Mcf in 1977 dollars.

V. SUMMARY OF THE R&D STRATEGIES

The final section of Part 1 summarizes the major goals, benefits, costs, and cost-effectiveness of the research and development strategies for the tight gas basins.

A. Research and Development Goals

The assessments of the resource base and the current technology defined the problems and constraints that currently deter development of the tight gas basins. Overcoming these problems and constraints constitutes the goals of the R&D program. In summary, the strategic goals are:

1. Resource Characterization

- Resource Measurement - Develop accurate, reliable methods for collecting and analyzing reservoir and geologic data.

- Resource Evaluation - Conduct a series of reservoir measurements and production tests in the better defined (Probable) areas of the basins.

- Resource Definition - Obtain sufficient geologic data to define the resource in the less defined (Possible) areas of the basins, thus accelerating application of advanced well stimulation technology.

2. <u>Fracture Technology</u>

   - Fracture Length and Height - Create efficiently propped fractures out to 1500 feet from the wellbore, where desired; control fracture height to three times the net pay or 150 feet, whichever is greater.

   - Fracture Azimuth - Determine likely fracture azimuth to assist in spacing wells and contacting net pay.

   - Fracture Conductivity - Introduce improved proppants such that fracture conductivity is not a limiting condition.

   - Fracture Effectiveness - Improve effective fracture length and drainage area in lenticular formations by intersecting sand lenses not encountered by the wellbore.*

3. <u>Field Development Technology</u>

   - Effective Drainage Area - Encourage a reduction in spacing in highly lenticular sands to six wells per section.**

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* E.g., in thin, lenticular pays of the Mesaverde, achieving this goal would increase effective fracture length from 400 to 800 feet and increase drainage area from about 50 to about 80 acres.

** Under this spacing the wellbore would be in contact with about 50% of the pay, with no appreciable well to well interference. When this reduced well spacing is combined with the capacity to intersect sand lenses away from the wellbore, 80% of the gas in place would be in contact with the wellbore. (This contrasts with about 20% of the net pay in contact with the wellbore at current well spacing and fracture technology.)

- Multiple Completions - Improve well completion technology to enable numerous formations to be fractured and produced from the same wellbore.

4. Economics and Development

- Risk Reduction - Reduce the risk premium (the minimum required return on investment) by 10 percentage points -- to 16% from the current high risk level of 26%.

- Timing of Field Development - Accelerate the pace of field development in the Probable (defined) area and open for exploitation the Possible (less defined) area.

- Economic Analysis - Determine the appropriate price incentives required to develop each basin in a timely fashion.

5. Technology Transfer

- Transfer the resource definition, technology, and analysis to the gas production industry.

Ten R&D programs were defined to achieve these goals; four for the Western Tight Gas Basins, three for the Shallow Basins, and one each for the Other Tight, Lenticular Sands, Tight Blanket Gas Formations, and Other Low Permeability Reservoirs.

B. Costs of the R&D Program

Unlocking the potential of the tight gas basins will require a concerted program of research, development, and demonstration. In addition to on-going industry outlays, nearly $250 million is required, over the next five years, for the joint Federal-industry research programs in enhanced gas recovery. DOE would provide $160 million and industry the remaining $90 million.

- The yearly costs for the five-year DOE/Industry joint research program are as follows (in millions of constant 1977 dollars):

	Total Costs	DOE Share
Total 5-Year Costs (FY 79-FY 83)	$249.2	$158.6
Yearly Costs		
FY 79	40.6	27.8
FY 80	51.0	33.7
FY 81	51.4	33.3
FY 82	61.5	33.5
FY 83	44.7	30.3

- The total five-year DOE costs by resource target are as follows (in millions of constant 1977 dollars):

Resource Target	DOE Share
Western Tight Gas Basins	$102.5
Shallow Gas Basins	14.7
Other Tight Lenticular Basins	23.4
Tight, Blanket Sands	11.5
Other Low-Permeability Reservoirs	6.5
TOTAL	158.6

- Further detail is provided on Exhibit 3-28.

- The types and levels of effort that these budget outlays will support are as follows:

Activity Category	Level of Effort
Resource Characterization	379 person years
Improved Diagnostic Tools	167 person years
Field-Based Research, Development, and Demonstration	262 projects*
Technology and Information Transfer	35 person years

Additional detail in provided in Exhibit 3-29.

* Field-based R&D is a mix of resource characterization cores and wells, measurement calibration tests, technology improvement tests, and field demonstrations of improved technology.

Exhibit 3-28

Level of R&D Activities—Tight Gas Basins

Target/Program	Resource Characterization (Person-Years)	Improved Diagnostic Tools (Person-Years)	Field-Based RD&D (Cores/Wells)	Technology/ Information Transfer (Person-Years)
1. Western Tight Gas Sands				
1.1 Resource Characterization -- 3 Basins*	(145)*	(40)*	(90)*	(5)*
1.2 Greater Green River -- Full Program	68	31	44	5
1.3 Piceance -- Full Program	45	8	37	0
1.4 Uinta -- Full Program	67	31	44	5
SUBTOTAL	(180)	(70)	(125)	10
2. Shallow Gas Basins				
2.1 Tight, Shallow Gas Sands	25	10	31	5
2.2 Low Permeability, Shallow Gas Sands	11	7	20	3
2.3 Shallow, Near Conventional Gas Sands	13	8	24	5
SUBTOTAL	(49)	(25)	(75)	(13)
3. Other Tight, Lenticular Sands	65	37	12	12
4. Tight, Blanket Gas Sands	60	15	25	0
5. Other Low Permeability Reservoirs	25	20	25	0
TOTAL	(379)	(167)	(262)	(35)

*Person-years, cores, and wells also counted in the three basin-specific "full programs".

Exhibit 3-29

Costs of R&D Strategies—Tight Gas Basins

TARGET/PROGRAM	5 YEAR PROGRAM COSTS (IN MILLIONS) TOTAL	FEDERAL SHARE
1. WESTERN TIGHT GAS SANDS		
1.1 Resource Characterization -- 3 Basins*	(88.0)	(56.0)
1.2 Greater Green River -- Full Program	66.4	38.7
1.3 Piceance -- Full Program	44.3	25.2
1.4 Uinta -- Full Program	66.3	38.6
SUBTOTAL	(177.0)	(102.5)
2. SHALLOW GAS BASINS		
2.1 Tight, Shallow Gas Sands	9.3	7.0
2.2 Low-Permeability, Shallow Gas Sands	5.1	3.8
2.3 Shallow, Near-Conventional Gas Sands	4.4	3.8
SUBTOTAL	(18.8)	(14.6)
3. OTHER TIGHT, LENTICULAR SANDS	35.4	23.4
4. TIGHT, BLANKET GAS SANDS	11.5	11.5
5. OTHER LOW-PERMEABILITY RESERVOIRS	6.5	6.5
TOTAL	249.2	158.5

* Field-based R&D is a mix of resource characterization cores and wells, measurement calibration tests, technology improvement tests, and field demonstrations of improved technology.

C. Production Benefits

Successful execution of the R&D program would lead to additional gas recovery and acceleration of its production.

Two measures were used to quantify these benefits:

- A long-term measure of additions* to ultimate recovery (at $3.00 per Mcf) due to the DOE/ Industry R&D program.

- A near-term measure of additional* gas that can be produced between now and 1990 (at $3.00 per Mcf) due to the DOE/Industry R&D program.

The estimated additional recovery due to the joint DOE/Industry R&D is shown below, by resource target:

Resource Target	Long-Term Measure Ultimate Addition to Recovery (@$3.00/Mcf)	Near-Term Measure Cumulative Addition to Recover: 1978-1990 (@$3.00/Mcf)**
• Western Tight Gas Basins	41	14
• Shallow Gas Basins	11	2
• Other Tight, Lenticular Basins	9	1
• Tight, Blanket Sands	15	7
• Other Low-Permeability Reservoirs	5	2
TOTAL	81	25

Additional detail is provided on Exhibit 3-30.

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* These are additional quantities, over the Base Case, that would accrue due to successful R&D leading to the Advanced Case.

**Totals may not add due to rounding.

Exhibit 3-30

Incremental Benefits Due to Advanced Technology (at $3.00/Mcf)—by Tight Gas Resource Target

TARGET/PROGRAM	ULTIMATE RECOVERY (Tcf)	1990 PRODUCTION (Tcf/Year)	1990 CUMULATIVE RECOVERY (Tcf)
1. WESTERN TIGHT GAS SANDS			
1.1 Resource Characterization -- 3 Basins	(2.6)**	(0.1)**	(0.7)**
1.2 Greater Green River -- Full Program	16.7	0.9	5.3
1.3 Piceance -- Full Program	8.6	0.5	2.5
1.4 Uinta -- Full Program	15.5	1.0	6.0
SUBTOTAL	(40.8)	(2.3)	(13.7)
2. SHALLOW GAS BASINS			
2.1 Tight, Shallow Gas Sands	7.6	0.1	0.1
2.2 Low-Permeability, Shallow Gas Sands	1.3	0.05	0.05
2.3 Shallow, Near Conventional Gas Sands	2.3	0.3	1.6
SUBTOTAL	(11.0)	(0.4)	(1.8)
3. OTHER TIGHT, LENTICULAR SANDS	8.9	0.2	1.0
4. TIGHT, BLANKET GAS SANDS	15.2	1.2	6.8
5. OTHER LOW-PERMEABILITY RESERVOIRS	5.1	0.3	1.9
TOTAL	81.2	4.4	25.2

* Totals may not add due to rounding
** Program 1.1 benefits also included in the three basin-specific programs, so are not added into subtotals.

D. Cost-Effectiveness of the Research Program

An essential question facing officials responsible for allocating public funds is: "How cost-effective is the expenditure?". Using the two production benefit measures discussed above, the analysis indicates that the payoff from R&D in enhanced gas recovery is considerable and cost-effective:

- The long-term cost-effectiveness measure for the five resource targets combined is 510 Mcf per dollar of federal R&D.
- The near-term overall cost-effectiveness measure is 150 Mcf per dollar of federal R&D.

Individually, each of the resource targets also have favorable cost-effectiveness ratios:

Resource Gas Target	Long-Term Measure (Mcf/$)	Near-Term Measure (Mcf/$)
• Western Tight Gas Basins	400	130
• Shallow Gas Basins	150	120
• Other Tight Lenticular Basins	380	40
• Tight, Blanket Sands	1320	590
• Other Low-Permeability Reservoirs	780	290

As the five tight gas resource targets would be developed according to ten R&D program, Exhibit 3-31 shows the cost-effectiveness measures for the individual programs:

- Two of the programs, the Tight, Shallow Gas Sands and Tight, Blanket Sands, yield long-term, cost-effectiveness ratios greater than 1,000 Mcf per dollar.

- The lowest ratio for resource characterization (without technology improvement)* in the Western Tight Gas Basins returns 46 Mcf per dollar.

- The near-term cost-effectiveness ratios generally follow the long-term measures with the following modifications:

  -- Two segments of the Shallow Gas Basins show only limited near-term response

  -- The Tight, Blanket Sands become relatively more cost-effective in the near-term.

In selecting the R&D strategies, the decision-maker should consider the absolute size of the incremental benefits, the time at which these benefits are incurred, and the relative cost-effectiveness of expenditures of public funds. For the tight gas basins:

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* This strategy, however, is principally designed to prepare the prerequisite methods and information for the application of the improved technology. The full benefits of this strategy, then, are seen in the other three Western Tight Gas strategies. In these, the long-term benefits range from 341 to almost 436 Mcf per federal dollar, for a weighted average of 398.

Exhibit 3-31

Cost-Effectiveness of R&D—by Tight Gas Resource Target

TARGET/PROGRAM	LONG-TERM (Mcf/Dollar)	NEAR-TERM (Mcf/Dollar)
1. WESTERN TIGHT GAS SANDS		
1.1 Resource Characterization -- 3 Basins	(46)	(13)
1.2 Greater Green River -- Full Program	436	137
1.3 Piceance -- Full Program	341	99
1.4 Uinta -- Full Program	402	155
AVERAGE	(398)	(132)
2. SHALLOW GAS BASINS		
2.1 Tight, Shallow Gas Sands	1,086	14
2.2 Low Permeability, Shallow Gas Sands	342	-
2.3 Shallow, Near-Conventional Gas Sands	605	526
AVERAGE	(753)	(123)
3. OTHER TIGHT, LENTICULAR SANDS	380	43
4. TIGHT, BLANKET GAS SANDS	1,322	591
5. OTHER LOW-PERMEABILITY RESERVOIRS	785	292
OVERALL AVERAGE	512	159

- Advanced technology offers considerable production potential at the gas prices of \$1.75 and \$3.00 per Mcf.

- The technological improvements for the tight basins require evolution of existing technology rather than entirely new approaches, providing greater confidence that the estimated benefits can be achieved from the five-year plan.

- Under Advanced technology, the tight gas basins offer the potential of substantial near-term additions to domestic gas supply, annually totaling nearly 4 Tcf in 1985 and over 7 Tcf in 1990. Of these totals, about 2 Tcf per year in 1985 and 4 Tcf per year in 1990 would be the increments due to Advanced Case over Base Case technologies.

- Industry should be expected to contribute a substantial portion of the total research program costs. In addition to their own, in-house R&D efforts, it is estimated that industry would provide about \$90 million to the joint Federal-industry research efforts in the Tight Gas Basins.

The R&D strategies for developing the full potential of the tight gas basins are detailed in Part 2.

CHAPTER THREE

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CHAPTER THREE

TIGHT GAS BASINS

Part 2

I. RESEARCH AND DEVELOPMENT STRATEGY FOR THE WESTERN TIGHT GAS SANDS

The research and development strategy for the Western Tight Gas Basins is organized into four segments:

- Program 1.1: Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations of the Greater Green River, Piceance, and Uinta Basins.

- Program 1.2: Greater Green River Full Program: (a) Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations of the Greater Green River Basin; and (b) Technology Development: Develop Improved Well Stimulation Technology for Application in this Basin.

- Program 1.3: Piceance Full Program: (a) Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations of the Piceance Basin; and (b) Technology Development: Develop Improved Well Stimulation Technology for Application in this Basin.

- Program 1.4: Uinta Full Program: (a) Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations of the Uinta Basin; and (b) Technology Development: Develop Improved Well Stimulation Technology for Application in this Basin.

The resource characterization program has certain incremental benefits on its own, but it is also pre-requisite to successful technology development strategies. Program 1.1 can stand alone, but because technology development strategies presuppose resource evaluation and characterization, Programs 1.2, 1.3, and 1.4 each contain their essential share of Program 1.1. To the extent that Programs 1.2, 1.3, or 1.4 are selected, Program 1.1 can be reduced.

Program 1.1

TARGET: Western Tight Gas Reservoirs

R&D STARTEGY: Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations

1. Central Problem

The Western Tight Gas Reservoirs of the Tertiary and Upper Cretaceous age (often referred to as the Mesaverde) have been cited as a major target for increasing domestic gas supplies. Achieving this target appears to hinge on the essential question:

Is there sufficient gas in place, permeability, and pay continuity to justify the drilling, fracturing, and operation of wells?

The problem is geological, requiring rigorous reservoir study to understand and precisely measure what is here.

This R&D strategy -- to obtain Data on Basin and Reservoir Properties Essential to Producing Tight, Lenticular Formations -- addresses the geological, resource characterization question.

2. Scope of the Effort

The target for the resource characterization effort consists of the three Western Tight Gas Basins, namely the Uinta (Utah), Piceance (Colorado), and Greater Green River (Wyoming).

Within each basin the resource characterization effort would follow two paths:

- The first, and most immediate, target would be the formations immediately adjacent to (areally or vertically) the major basin areas and formation target(s) already being pursued by industry. Thus, the ERDA target would be other tight formations coterminous with the producing and extension areas of each Basin, as follows:

Basin	Industry Target Formation	ERDA Resource Characterization Target Formations
Greater Green River	Almond Marine Almond Alluvial/ Deltaic	Ericson Rock Springs/ Blair
Piceance	Corcoran/Cozette	Fort Union Other Mesaverde
Uinta	Wasatch	Neslen Farrer Castlegate

The resource characterization effort for this target area would be to collect the most essential reservoir properties (e.g., sand lens geometry, permeability, gas saturation, rock stresses and strength) that would enable industry to apply advanced fracturing technology to these formations.

- The second target would be the undeveloped areas of these basins where the geology appears favorable, and gas shows have been noted. The resource characterization effort for this second target area would begin with basic geological studies and resource appraisal leading toward the focused definitions of reservoir properties.

3. R&D Goals

- To define the key reservoir characteristics (e.g., in situ permeability, porosity, pay continuity, gas saturation) in the probable formations and segments of the basins.
- To determine the geometry and distribution sand lenses.
- To ascertain the rock properties of the gas bearing sand lenses and surrounding rocks and their effects on fracture azimuth, extension, and conductivity.
- To assess the economic feasibility of producing these formations under advanced stimulation technology.

4. R&D Activities

The R&D activities would consist of a sequence of tasks as follows:

- Task 1 - The initial task would be to organize groups of highly qualified persons experienced in geology and production engineering to review and interpret available geologic, test, and production data and agree on the locus of the resource characterization effort. This task should start in FY 78.

- Task 2 - Assemble and analyze available geologic test and production data in support of the information requirements of the groups convened in Task 1. This task provides staff and analytic support to these groups.

- Task 3 - Undertake an extensive coring, logging, and measurement program with new tools and techniques in the more favorable portion of these basins to establish or identify:

  -- gas permeability and its distribution

  -- varying characteristics of the lens within a single well target

  -- the rock properties governing fracture behavior

  -- other reservoir rock properties that significantly affect gas production.

  This third task would also serve to develop new tools and methods to calibrate the quantitative measurements from previous logging and core analysis and extend them to unknown horizons.

- Task 4 - Drill a selected number of wells in the thoroughly assessed areas in each basin and measure the nature, geometry, and distribution of the sand lenses. The central issue would be to determine the number of lenses -- including those not encountered by the wellbore -- that could be interconnected by a single fracture or series of fractures from a single well.

- Task 5 - Drill a considerable number of resource characterization wells in each basin. This second set of resource characterization wells would be distributed to identify and define the high potential target areas and formations within the "probable" areas of the basin.

- Task 6 - Incorporate these reservoir properties into available production/economics models to ascertain the required technological and economic conditions for producing these first order target formations.

- Task 7 - Conduct basic geological and measurement studies of the more speculative portions of the basins (defined as "possible" in Part 1). Should sufficient potential be identified, this would be followed by the detailed reservoir characterization studies listed above (Tasks 1 - 6).

- Task 8 - A continuing task would be to thoroughly document the resource characterization and economic/technology studies and disseminate these findings to industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The decreasing manpower requirements are based on the considerable base of knowledge that has already been accumulated and that needs to be expanded in key areas.

The number of cores/wells is based on the requirement to conduct one full (20 corehole) coring program in each of the three basins and to drill 10 resource evaluation and characterization wells in each basin.

Program 1.1

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Western Tight Gas Basins

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Technical Committee	(10)	5	5	5	5	5	25	(35)
• Basic Geological Studies	(10)	10	10	10	10	10	50	(60)
• Reservoir Properties Measurement	(10)	20	20	20			60	(70)
• Recoverv and Economic Studies	(2)	2	2	2	2	2	10	(12)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing		2	4	4	4	2	16	(16)
• Development		3	6	6	6	4	24	(24)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Cores		20	20	20			60	(60)
• Resource Characterization Wells		5	5	5	10	5	30	(30)
4. Technology Information Transfer (man-years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly cost budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items of costs in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The incremental cost of taking 1 foot of core is $100; 1,000 feet of core would be taken per well.
- The cost of drilling, coring, logging and testing a resource characterization well is $2,000,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays for 90% of the professional and support costs of the Technical Committee.
- ERDA pays for 100% of all other professional man-year costs.
- ERDA pays for 75% of the incremental cost of the coring program.
- ERDA pays for 50% of the resource evaluation and characterization wells.

EXHIBIT 2
TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins

RD&D Costs (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(1,000)	1,000	1,000	1,000	1,000	1,000	5,000	(6,000)
• Basic Geological Studies	(1,000)	1,000	1,000	1,000	1,000	1,000	5,000	(6,000)
• Reservoir Properties Measurement	(1,000)	2,000	2,000	2,000			6,000	(7,000)
• Recovery and Economic Studies	(200)	200	200	200	200	200	1,000	(1,200)
SUBTOTAL	(3,200)	4,200	4,200	4,200	2,200	2,200	17,000	(20,200)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		200	400	400	400	200	1,600	(1,600)
• Development		300	600	600	600	300	2,400	(2,400)
SUBTOTAL		500	1,000	1,000	1,000	500	4,000	(4,000)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		2,000	2,000	2,000			6,000	(6,000)
• Resource Characterization Wells		10,000	10,000	10,000	20,000	10,000	60,000	(60,000)
SUBTOTAL		12,000	12,000	12,000	20,000	10,000	66,000	(66,000)
4. Technology/Information Transfer								
		100	100	200	300	300	1,000	(1,000)
TOTAL COST	(3,200)	16,800	17,300	17,400	23,500	13,000	88,000	(91,200)

Program 1.1

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(900)	900	900	900	900	900	4,500	(5,400)
• Basic Geological Studies	(1,000)	1,000	1,000	1,000	1,000	1,000	5,000	(6,000)
• Reservoir Measurement	(1,000)	2,000	2,000	2,000			6,000	(7,000)
• Recovery and Economic Study	(200)	200	200	200	200	200	1,000	(1,200)
SUBTOTAL	(3,100)	4,100	4,100	4,100	2,100	2,100	16,500	(19,600)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		200	400	400	400	200	1,600	(1,600)
• Development		300	600	600	600	300	2,400	(2,400)
SUBTOTAL		500	1,000	1,000	1,000	500	4,000	(4,000)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		1,500	1,500	1,500			4,500	(4,500)
• Resource Characterization Wells		5,000	5,000	5,000	10,000	5,000	30,000	(30,000)
SUBTOTAL		6,500	6,500	6,500	10,000	5,000	34,500	(34,500)
4. Technology/Information Transfer								
		100	100	200	300	300	1,000	(1,000)
TOTAL ERDA COST:	(3,100)	11,200	11,700	11,800	13,400	7,900	56,000	(59,100)

7. Production Benefits

The expected benefits from a successful completion of the Resource Evaluation and Characterization Program in the Western Tight Gas Basins are threefold:

- The type of resource characterization defined in this program is an essential prerequisite to the technology development phase.

- It raises as targets for Base Case Technology formations not now being pursued by industry (formations that are above and below the formation(s) being currently pursued).

- It provides adequate geologic and resource definition information to incorporate the "possible" areas of the basins as targets for advanced technology.

The first order benefits of the program are presented in recovery and production rate terms, by key years, measured as the difference between the Base Case and the After Resource Appraisal Case.*

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* Since the Resource Characterization Program is an essential prerequisite to the Technology Development Program, the full value of this program will only be realized as Advanced Production and Stimulation Technology is successfully applied to these basins. (See the Production Benefits section of the Technology Development Programs for the individual basins included among the Western Tight Gas Reservoirs.)

The anticipated benefits from a successful completion of the resource evaluation and characterization program for the Western Tight Gas Reservoirs are estimated at $3.00/Mcf as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
• Ultimate Recovery	9.0	11.6	2.6
• Production Rate in:			
1985	0.2	0.3	0.1
1990	0.4	0.5	0.1
1995	0.4	0.5	0.1
2000	0.3	0.4	0.1
• Cumulative Production by:			
1985	0.8	1.0	0.2
1990	2.5	3.2	0.7
1995	4.4	5.6	1.2
2000	6.0	7.7	1.7

8. Benefits and Costs

The key cost-effectiveness measures are production in Mcf per dollar of ERDA expenditure. For resource evaluation and characterization of the Western Tight Gas Reservoirs, these ratios (at the $3.00/Mcf gas price) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	46
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	13

TARGET: Western Tight Gas Reservoirs - Greater Green River Basin

R&D STRATEGY: Part a: Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations

Part b: Technology Development: Develop Improved Well Stimulation Technology

1. Central Problem

Resource Problem (Part a)

The tight gas reservoirs of the Tertiary and Upper Cretaceous age (often referred to as the Mesaverde) in the Greater Green River Basin have been cited as a major target for increasing domestic gas supplies. Achieving this target appears to first hinge on the essential question:

Is there sufficient gas in place, permeability, and pay continuity to justify the drilling, fracturing and operation of wells?

The first problem is geological, requiring rigorous reservoir study to understand and precisely measure what is there.

The first part of this R&D strategy to Obtain Data on Basin and Reservoir Properties Essential to Producing Tight, Lenticular Formations addresses the geological, resource characterization question, has been described previously.

Technical Problem (Part b)

Should sufficiently favorable reservoir conditions be found, recovering the resource depends on the second essential question:

> *Can a sufficient number of the distinct gas bearing lens in which the gas is contained be intersected with a fracture to ensure economic flow?*

The second question is technological, requiring the definition of the conditions under which fractures can be made: a) to intersect and effectively drain a significant portion of the sand lens seen at the wellbore, and/or (b) to enter sand lens not initially contacted at the wellbore.

The second part of this R&D strategy to Develop Improved Well Stimulation Technology for intersecting multiple pay zones and sand lens from the same wellbore addresses this technological question.

Once the technology for intersecting multiple sand lens is achieved, numerous additional research efforts into fracture technology (e.g., proppant concentrations, fluid design, injection procedures) and well production practices (e.g., post-clean-up water production) will be undertaken to ultimately develop the resources of the Greater Green River Basin on an economical basis.

2. Scope of the Effort

The overall target for the technology development program are the tight, lenticular deposits of the Greater Green River Basin (Wyoming).

The specific target formations within this basin are the Upper Cretaceous and Tertiary age formations as follows:

Basin	Industry Target Formation	Target Formations for Advanced Technology
Greater Green River	• Almond (Marine) • Almond (Alluvial/ Deltaic)	• Fort Union • Erickson • Rock Springs/Blair

The development of the extension (probable) area of this basin would be dependent on the resource evaluation effort described in Program 1.1. The development of the possible areas of this basin will follow basic geologic studies and resource characterization efforts focused on ascertaining the potential size and economic feasibility of these less well-defined areas.

3. R&D Goals

- To achieve the goals of Program 1.1 -- Resource Evaluation and Characterization -- as they pertain to the Greater Green River Basin.
- To establish the conditions under which a fracture will traverse a significant portion of the sand lens contacted at the wellbore.
- To determine under what conditions the fracture will effectively intersect sand lens not initially contacted by the wellbore.

- To control the height of the fracture, where desired, such that the induced energy serves to proppagate fracture length rather than ineffectual fractual height.

- To use successfully numerous, massive hydraulic fractures from the same wellbore.

- To create and maintain effective fracture conductivity, particularly in the deeper formations.

- Assuming the above goals are met, the ultimate goal would be to determine the technology that will provide the most economic means for drilling, completing, fracturing, and operating gas wells in the Greater Green River Basin.

4. R&D Activities

The R&D activities in this strategy would follow two parallel, but closely related sequences. The first is the Resource Evaluation and Characterization sequence. This sequence is precisely the same as laid out in Program 1.1, except that it is specific to the Greater Green River Basin. To avoid redundancy, its individual tasks are not repeated here. The second sequence are those tasks that relate specifically to the Technology Development component of this strategy. These are enumerated below. Essential coordination of the two sequences of tasks would be ensured by a common project manager and by a common group of experienced experts overseeing and coordinating the efforts under the respective task sequences. The R&D activities related to Technology Development would consist of the sequence of tasks that follows:

- Task 1 - The initial task would be to assemble a group of highly qualified persons experienced in geology and production engineering. This group of experts would set forth the design specifications for the technological tests defined below. This task should start in FY 78.

- Task 2 - Identify wells that have been drilled (by industry) into the deeper Mesaverde segment of the basin but where for various reasons these deeper formations have not been produced. These wells, as well as the 20 resource characterization wells from the Resource Evaluation and Characterization sequence, would serve as the locus for the technical tests of advanced stimulation technology.

- Task 3 - Use moderate size fractures in selected high quality sand intervals and then produce the well long enough to establish the productive capacity and reservoir properties of the well and determine the effectiveness of a moderate size fracture for intersecting the pay.

- Task 4 - The next step would be to use a series of large fractures and improved proppants over large gross intervals (up to 600 feet each) to determine the capacity of massive hydraulic fracturing to intersect multiple pays and sand lens not encountered at the wellbore.

- Task 5 - Test and apply various well stimulation and completion practices to these wells to establish optimum practice.

- Task 6 - Repeat the third, fourth, and fifth steps above in sufficiently varied geologic settings to demonstrate the technical feasibility and define the geologic conditions that influence fracture effectiveness.

- Task 7 - Supporting these technical tests would be basic R&D for improving stimulation and well completion technology and applied R&D focused on improving recovery and economic models, calibrated to the specific conditions of the Tight Gas Formations.

- Task 8 - Running parallel to the technical tests of well stimulation and production practices would be a series of major confirmation projects designed to test the state of evolution in fracture technology as applied to tight, lenticular gas pays. These demonstration projects would entail the full range of laboratory testing and correlative interpretation before designing and applying the best of the "state-of-the-art" fracture treatments. Multiple fracture treatments would be applied to the entire Tertiary and Mesaverde interval. Thorough production testing would be required for each fractured interval before moving up the well to the next interval.

- Task 9 - A continuing task would be to thoroughly review, analyze, and document the results and disseminate these findings (with fullest possible detail) to the industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of resource characterization wells and technical tests to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements are based on the need to gather considerable basic geological, engineering, and economic information on the diverse tight gas formations of the areally large Greater Green River Basin.

The number of cores, wells, and tests are based on the need to conduct in the Green River Basin:

- A full 20-core measurement program.
- A 10-well resource evaluation program.
- Ten technical tests of advanced well stimulation.
- Four major advanced production technology demonstrations.

Program 1.2

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Western Tight Gas Basins-
Greater Green River Basin

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Technical Committee	(10)	4	4	4	4	4	20	(30)
• Basic Geological Studies	(5)	4	4	4	4	4	20	(25)
• Reservoir Properties Measurement	(5)	10	5	5			20	(25)
• Recovery and Economic Studies	(2)	2	1	2	1	2	8	(10)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing	(2)	2	3	3	3	2	13	(15)
• Development	(2)	3	4	4	4	3	18	(20)
3. Field-Based Research, Development, and Demonstration (core/wells)								
• Cores		10	5	5			20	(20)
• Resource Characterization Wells		5				5	10	(10)
• Technical Tests			5		5		10	(15)
• Technology Demonstration		2		2			4	(4)
4. Technology/Information Transfer (man-years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported man-year costs $100,000.
- The incremental cost of taking 1 foot of core is $100; 1,000 feet of core would be taken per well.
- The cost of drilling, coring, logging and testing a resource characterization well is $2,000,000.
- The incremental cost of a multiple, massive hydraulic fracture treatment is set at $1,000,000 per well.
- The full cost of each advanced production technology demonstration test is $6,000,000, including drilling, completion, multiple fracturing, testing and supportive planning, management, and analysis.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays for 90% of the professional and support costs of the Technical Committee.

EXHIBIT 2

TOTAL PROGRAM COSTS

Program 1.2

TARGET: Western Tight Gas Basins - Greater Green River Basin

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(1,000)	400	400	400	400	400	2,000	(3,000)
• Basic Geological Studies	(500)	400	400	400	400	400	2,000	(2,500)
• Reservoir Properties Measurement	(500)	1,000	500	500			2,000	(2,500)
• Recovery and Economic Studies	(200)	200	100	200	100	200	800	(1,000)
SUBTOTAL	(2,200)	2,000	1,400	1,500	900	1,000	6,800	(9,000)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(200)	200	300	300	300	200	1,300	(1,500)
• Development	(200)	300	400	400	400	300	1,800	(2,000)
SUBTOTAL	(400)	500	700	700	700	500	3,100	(3,500)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		1,000	500	500			2,000	(2,000)
• Resource Characterization Wells		10,000				10,000	20,000	(20,000)
• Technical Test			5,000		5,000		10,000	(10,000)
• Technology Demonstration		6,000	6,000	6,000	6,000		24,000	(24,000)
SUBTOTAL		17,000	11,300	6,500	11,000	10,000	56,000	(56,000)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL COST	(2,600)	19,600	13,700	18,800	12,700	11,600	66,400	(69,000)

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins - Greater Green River Basins

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(900)	360	360	360	360	360	1,800	(2,700)
• Basic Geological Studies	(500)	400	400	400	400	400	2,000	(2,500)
• Reservoir Measurement	(500)	1,000	500	500			2,000	(2,500)
• Recovery and Economic Study	(200)	200	100	200	100	200	800	(1,000)
SUBTOTAL	(2,100)	1,900	1,360	1,460	860	960	6,600	(8.700)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(200)	200	300	300	300	200	1,300	(1,500)
• Development	(200)	300	400	400	400	300	1,800	(2,000)
SUBTOTAL		500	700	700	700	500	3,100	(3,500)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		750	375	375			1,500	(1,500)
• Resource Characterization Wells		5,000				5,000	10,000	(10,000)
• Technical Tests			2,500		2,500		5,000	(5,000)
• Technology Demonstrations		3,000	3,000	3,000	3,000		12,000	(12,000)
SUBTOTAL		8,750	5,875	3,375	5,500	5,000	28,500	(28,500)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(2,500)	11,310	8,035	5,635	7,160	6,560	38,700	(41,200)

- ERDA pays for 75% of the incremental costs of the coring program.
- ERDA pays for 50% of the resource evaluation and characterization wells.
- ERDA pays 50% of the incremental costs of each stimulation stimulation treatment.
- ERDA pays 50% of the full costs of each production demonstration test.

7. Production Benefits

The anticipated production benefits from a successful completion of the full research and development program in Greater Green River are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D* (Tcf)
• Ultimate Recovery	6.3	22.9	16.7
• Production Rate in:			
1985	0.1	0.6	0.4
1990	0.2	1.2	0.9
1995	0.3	0.9	0.7
2000	0.2	0.8	0.6
• Cumulative Production by:			
1985	0.5	1.6	1.1
1990	1.5	6.8	5.3
1995	2.8	11.9	9.0
2000	4.0	16.1	12.1

*Totals may not add due to rounding

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Greater Green River Basin (at $3.00/Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	432
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	137

TARGET: Western Tight Gas Reservoirs - Piceance Basin

R&D STRATEGY: Part a: Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations

Part b: Technology Development: Develop Improved Well Stimulation Technology

1. Central Problem

Resource Problem (Part a)

The tight gas reservoirs of the Tertiary and Upper Cretaceous age (often referred to as the Mesaverde) in the Piceance Basin have been cited as a major target for increasing domestic gas supplies. Achieving this target appears to first hinge on the essential question:

Is there sufficient gas in place, permeability, and pay continuity to justify the drilling, fracturing and operation of wells?

The problem is geological, requiring rigorous reservoir study to understand and precisely measure what is there.

The first part of the R&D strategy, to Obtain Data on Basin and Reservoir Properties Essential to Producing Tight, Lenticular Formations, addresses the geological, resource characterization question.

Technical Problem (Part b)

Should sufficiently favorable reservoir conditions be found, recovering the resource depends on the second essential question:

> *Can a sufficient number of the distinct gas bearing lens in which the gas is contained be intersected with a fracture to ensure economic flow?*

The second question is technological, requiring the definition of the conditions under which fractures can be made: a) to intersect and effectively drain a significant portion of the sand lens seen at the wellbore, and/or (b) to enter sand lens not initially contacted at the wellbore.

The second part of this R&D strategy, to Develop Improved Well Stimulation Technology for intersecting multiple pay zones and sand lens from the same wellbore, addresses this technological question.

Once the technology for intersecting multiple sand lens is achieved, numerous additional research efforts into fracture technology (e.g., proppant concentrations, fluid design, injection procedures) and well production practices (e.g., post-clean-up water production) will be undertaken to ultimately develop the resources of the Piceance Basin on an economical basis.

2. Scope of the Effort

The overall target for the technology development program are the tight, lenticular deposits of the Piceance Basin.

The specific target formations within this basin are the Upper Cretaceous and Tertiary age formations as follows:

Basin	Industry Target Formation	Target Formations for Advanced Technology
Piceance	Corcoran/Cozette	Fort Union
		Other Mesaverde

The development of the extension (probable) area of this basin would be dependent on the resource evaluation effort described in Program 1.1. The development of the possible areas of this basin require basic geologic studies and resource characterization efforts focused on ascertaining the potential size and economic feasibility of these less well-defined areas.

3. R&D Goals

- To achieve the goals of Program 1.1 -- Resource Evaluation and Characterization -- as they pertain to the Piceance Basin.
- To establish the conditions under which a fracture will traverse a significant portion of the sand lens contacted at the wellbore.
- To determine under what conditions the fracture will effectively intersect sand lens not initially contacted by the wellbore.

- To use successfully numerous, massive hydraulic fractures from the same wellbore.
- To create and maintain effective fracture conductivity, particularly in the deeper formations.
- Assuming the above goals are met, the ultimate goal would be to determine the technology that will provide the most economical means for drilling, completing, fracturing, and operating gas wells in the Piceance Basin.

4. R&D Activities

The R&D activities in this strategy would follow two parallel, but closely related sequences. The first is the Resource Evaluation and Characterization sequence. This sequence is precisely the same as laid out in Program 1.1, except that it is specific to the Piceance Basin. To avoid redundancy, its individual tasks are not repeated here. The second sequence are those tasks that relate specifically to the Technology Development component of this strategy. These are enumerated below. Essential coordination of the two sequences of tasks would be ensured by a common project manager and by a common group of experienced experts overseeing and coordinating the efforts under the respective task sequences. The R&D activities related to Technology Development would consist of the sequence of tasks that follows:

- Task 1 - The initial task would be to set forth the design specifications for the technological tests defined below.

- Task 2 - Identify wells that have been drilled (by industry) into the deeper Mesaverde segment of the basin but where for various reasons these deeper formations have not been produced. These wells in addition to the 20 resource characterization wells from the Resource Evaluation and Characterization sequence would serve as the locus for the technical tests of advanced stimulation technology.

- Task 3 - Use moderate size fractures in selected high quality sand intervals and then produce the well long enough to establish the productive capacity and reservoir properties of the well and determine the effectiveness of a moderate size fracture for intersecting the pay.

- Task 4 - The next step would be to use a series of large fractures and improved proppants over large gross intervals (up to 600 feet each) to determine the capacity of massive hydraulic fracturing to intersect multiple pays and sand lens not encoutered at the wellbore.

- Task 5 - Test and apply various well stimulation and completion practices to these wells to establish optimum practice.

- Task 6 - Repeat the third, fourth, and fifth steps above in sufficiently varied geologic settings to demonstrate the technical feasibility and define the geologic conditions that influence fracture effectiveness.

- Task 7 - Running parallel to the technical tests of well stimulation and production practices would be a series of major confirmation projects designed to test the state of evolution in fracture technology as applied to tight, lenticular gas pays. These demonstration projects would entail the full range of laboratory testing and correlative interpretation before designing and applying the best of the "state-of-the-art" fracture treatments. Multiple fracture treatments would be applied to the entire Tertiary and Mesaverde interval. Thorough production testing would be required for each fractured interval before moving up the well to the next interval. Each would be documented in detail and disseminated to industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores, resource characterization wells, and tests to carry out the above research, development and demonstration activities are provided on Exhibit 1.

The lower manpower requirements are based on considerable past activity in the basin and the need to still gather key reservoir properties. Program 1.3 in the Piceance Basin would rely heavily on work sponsored by the other tight gas basins in improved diagnostic tools and methods.

The number of cores, wells, and tests are based on the need to conduct, in the Piceance Basin:

- A full 20 core measurement program.
- A 10 well resource characterization well.
- Five technical tests of advanced well stimulation.
- Two major advanced production technology demonstrations.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Western Tight Gas Basins - Piceance Basin

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Technical Committee		2	2	2	2	2	10	(10)
• Basic Geological Studies		2	2	2	2	2	10	(10)
• Reservoir Properties Measurement				10	10		20	(20)
• Recovery and Economic Studies	(1)	1	1	1	1	1	5	(6)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing	(1)							(1)
• Development	(2)	1	2	2	2	1	8	(10)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Cores		5	5	10			20	(20)
• Resource Characterization Wells				5	5		10	(10)
• Technical Tests						5	5	(5)
• Technology Demonstration						2	2	(2)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The incremental cost of taking 1 foot of core is $100; 1,000 feet of core would be taken per well.
- The cost of drilling, coring, logging, and testing a resource characterization well is $2,000,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays for 90% of the professional and support costs of the Technical Committee.
- ERDA pays for 100% of all other professional man-year costs.
- ERDA pays for 75% of the incremental cost of the coring program.
- ERDA pays for 50% of the resource evaluation and characterization wells.

EXHIBIT 2
TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins - Piceance Basin

RD&D Costs (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee		200	200	200	200	200	1,000	(1,000)
• Basic Geological Studies		200	200	200	200	200	1,000	(1,000)
• Reservoir Properties Measurement			1,000	1,000			2,000	(2,000)
• Recovery and Economic Studies	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(100)	500	1,500	1,500	500	500	4,500	(4,600)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(100)							(100)
• Development	(200)	100	200	200	200	100	800	(1,000)
SUBTOTAL	(300)	100	200	200	200	100	800	(1,100)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		500	500	1,000			2,000	(2,000)
• Resource Characterization Wells				10,000	10,000		20,000	(20,000)
• Technical Tests						5,000	5,000	(5,000)
• Technology Demonstration		___	___	___	6,000	6,000	12,000	(12,000)
SUBTOTAL		500	500	11,000	16,000	11,000	39,000	(39,000)
TOTAL COST	(400)	1,100	2,200	12,700	16,700	11,600	44,300	(44,700)

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins - Piceance Basin

RD&D Costs (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee		180	180	180	180	180	900	(900)
• Basic Geological Studies		200	200	200	200	200	1,000	(1,000)
• Reservoir Measurement			1,000	1,000			2,000	(2,000)
• Recovery and Economic Study	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(100)	480	1,480	1,480	480	480	4,400	(4,500)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(100)							(100)
• Development	(200)	100	200	200	200	100	800	(1,000)
SUBTOTAL	(300)	100	200	200	200	100	800	(1,100)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		375	375	750			1,500	(1,500)
• Resource Characterization Wells				5,000	5,000		10,000	(10,000)
• Technical Tests						2,500	2,500	(2,500)
• Technology Demonstration						6,000	6,000	(6,000)
SUBTOTAL		375	375	5,750	5,000	8,500	20,000	(20,000)
TOTAL ERDA COST:	(400)	955	2,055	7,430	5,680	9,080	25,200	(25,600)

7. Production Benefits

The anticipated production benefits from a successful completion of the full research and development program in the Piceance Basin are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D* (Tcf)
• Ultimate Recovery	0.7	9.3	8.6
• Production Rate in:			
1985	**	0.2	0.2
1990	**	0.5	0.5
1995	**	0.3	0.3
2000	**	0.3	0.3
• Cumulative Production by:			
1985	0.1	0.6	0.5
1990	0.2	2.7	2.5
1995	0.4	4.7	4.3
2000	0.5	6.3	5.8

* Totals may not add due to rounding

** Less than 0.05 Tcf per year

8. Benefits and Costs

The key cost-effectiveness measures (incremental production dollar of ERDA cost) for the Piceance Basin (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	341
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	99

TARGET: Western Tight Gas Reservoirs - Uinta Basin

R&D STRATEGY: Part a: Resource Evaluation and Characterization: Obtain Data on Basin and Reservoir Properties Essential for Producing Tight, Lenticular Formations

Part b: Technology Development: Develop Improved Well Stimulation Technology

1. Central Problem

Resource Problem (Part a)

The tight gas reservoirs of the Tertiary and Upper Cretaceous age (often referred to as the Mesaverde) in the Uintah Basin have been cited as a major target for increasing domestic gas supplies. Achieving this target appears to first hinge on the essential question:

Is there sufficient gas in place, permeability, and pay continuity to justify the drilling, fracturing and operation of wells?

The problem is geological, requiring rigorous reservoir study to understand and precisely measure what is there.

The first part of this R&D strategy, to Obtain Data on Basin and Reservoir Properties Essential to Producing Tight, Lenticular Formations, addresses the geological, resource characterization question.

Technical Problem (Part b)

Should sufficiently favorable reservoir conditions be found, recovering the resource depends on the second essential question:

> *Can a sufficient number of the distinct gas bearing lens in which the gas is contained be intersected with a fracture to ensure economic flow?*

The second question is technological, requiring the definition of the conditions under which fractures can be made: (a) to intersect and effectively drain a significant portion of the sand lens seen at the wellbore, and/or (b) to enter sand lens not initially contacted at the wellbore.

The second part of this R&D strategy, to Develop Improved Well Stimulation Technology for intersecting multiple pay zones and sand lens from the same wellbore, addresses this technological question.

Once the technology for intersecting multiple sand lens is achieved, numerous additional research efforts into fracture technology (e.g., proppant concentrations, fluid design, injection procedures) and well production practices (e.g., post-clean-up water production) will be undertaken to ultimately develop the resources of the Uinta Basin on an economical basis.

2. Scope of the Effort

The overall target for the technology development program are the tight, lenticular deposits of the Uinta Basin.

The specific target formations within this basin are the Upper Cretaceous and Tertiary age formations as follows:

Basin	Industry Target Formation	Target Formations for Advanced Technology
Uinta	Wasatch	Neslen Farrer Castlegate

The development of the extension (probable) area of this basin would be dependent on the resource evaluation effort described in Program 1.1. The development of the possible areas of this basin require basic geologic studies and resource characterization efforts focused on ascertaining the potential size and economic feasibility of these less well-defined areas.

3. R&D Goals

- To achieve the goals of Program 1.1 -- Resource Evaluation and Characterization -- as they pertain to the Uinta Basin.

- To establish the conditions under which a fracture will traverse a significant portion of the sand lens contacted at the wellbore.

- To determine under what conditions the fracture will effectively intersect sand lens not initially contacted by the wellbore.

- To control the height of the fracture, where desired, such that the induced energy serves to proppagate fracture length rather than ineffectual fractural height.

- To use successfully numerous, massive hydraulic fractures from the same wellbore.
- To create and maintain effective fracture conductivity, particularly in the deeper formations.
- Assuming the above goals are met, the ultimate goal would be to determine the technology that will provide the most economical means for drilling, completing, fracturing, and operating gas wells in the Uinta Basin.

4. R&D Activities

The R&D activities in this strategy would follow two parallel, but closely related sequences. The first is the Resource Evaluation and Characterization sequence. This sequence is precisely the same as laid out in Program 1.1, except that it is specific to the Uinta Basin. To avoid redundancy, its individual tasks are not repeated here. The second sequence are those tasks that relate specifically to the Technology Development component of this strategy. These are enumerated below. Essential coordination of the two sequences of tasks would be ensured by a common project manager and by a common group of experienced experts overseeing and coordinating the efforts under the respective task sequences. The R&D activities related to Technology Development would consist of the sequence of tasks that follows:

- Task 1 - The initial task would be to set forth the design specifications for the technological tests defined below.

- Task 2 - Identify wells that have been drilled (by industry) into the deeper Mesaverde segment of the basin but where for various reasons these deeper formations have not been produced. These wells in addition to the 20 resource characterization wells from the Resource Evaluation and Characterization sequence would serve as the locus for the technical tests of advanced stimulation technology.

- Task 3 - Use moderate size fractures in selected high quality sand intervals and then produce the well long enough to establish the productive capacity and reservoir properties of the well and determine the effectiveness of a moderate size fracture for intersecting the pay.

- Task 4 - The next step would be to use a series of large fractures and improved proppants over large gross intervals (up to 600 feet each) to determine the capacity of massive hydraulic fracturing to intersect multiple pays and sand lens not encoutered at the wellbore.

- Task 5 - Test and apply various well stimulation and completion practices to these wells to establish optimum practice.

- Task 6 - Repeat the third, fourth, and fifth steps above in sufficiently varied geologic settings to demonstrate the technical feasibility and define the geologic conditions that influence fracture effectiveness.

- Task 7 - Supporting these technical tests would be basic R&D for improving stimulation and well completion technology and applied R&D focused on improving recovery and economic models, calibrated to the specific conditions of the Tight Gas Formations.

- Task 8 - Running parallel to the technical tests of well stimulation and production practices would be a series of major confirmation projects designed to test the state of evolution in fracture technology as applied to tight, lenticular gas pays. These demonstration projects would entail the full range of laboratory testing and correlative interpretation before designing and applying the best of the "state-of-the-art" fracture treatments. Multiple fracture treatments would be applied to the entire Tertiary and Mesaverde interval. Thorough production testing would be required for each fractured interval before moving up the well to the next interval.

- Task 9 - A continuing task would be to thoroughly review, analyze, and document the results and disseminate these findings (with fullest possible detail) to the industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of core resource characterization wells and technical tests to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements are based on the considerable base of knowledge that is being accumulated in the Uinta Basin and that needs to be expanded in key areas.

The number of cores, wells, and tests are based on the need to conduct in the Uinta Basin:

- A full 20 core measurement program.
- A 10 well resource evaluation program.
- Ten technical tests of advanced well stimulation.
- Four major advanced production technology demonstrations.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Western Tight Gas Basins
Unita Basin

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Technical Committee	(10)	4	4	4	4	4	20	(30)
• Basic Geological Studies	(5)	4	4	4	4	4	20	(25)
• Reservoir Properties Measurement	(5)	10	5	5			20	(25)
• Recovery and Economic Studies	(1)	1	2	1	2	1	7	(8)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing	(1)	2	3	3	3	2	13	(15)
• Development	(2)	3	4	4	4	3	18	(20)
3. Field-Based Research, Development, and Demonstration (core/wells)								
• Cores		5	10	5			20	(20)
• Resource Characterization Wells			5		5		10	(10)
• Technical Tests				5		5	10	(15)
• Technology Demonstration		2		2			4	(4)
4. Technology/Information Transfer (man-years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported man-year costs $100,000.
- The incremental cost of taking 1 foot of core is $100; 1,000 feet of core would be taken per well.
- The cost of drilling, coring, logging and testing a resource characterization well is $2,000,000.
- The incremental cost of a multiple, massive hydraulic fracture treatment is set at $1,000,000 per well.
- The full cost of each advanced production technology demonstration test is $6,000,000, including drilling, completion, multiple fracturing, testing and supportive planning, management, and analysis.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays for 90% of the professional and support costs of the Technical Committee.

Program 1.4

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins
Uinta Basin

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(1,000)	400	400	400	400	400	2,000	(3,000)
• Basic Geological Studies	(500)	400	400	400	400	400	2,000	(2,500)
• Reservoir Properties Measurement	(500)	1,000	500	500			2,000	(2,500)
• Recovery and Economic Studies	(100)	100	200	100	200	100	700	(800)
SUBTOTAL	(2,100)	1,900	1,500	1,400	1,000	900	6,700	(8,800)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(100)	200	300	300	300	200	1,300	(1,400)
• Development	(200)	300	400	400	400	300	1,800	(2,000)
SUBTOTAL	(300)	500	700	700	700	500	3,100	(3,400)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		500	1,000	500			2,000	(2,000)
• Resource Characterization Wells			10,000		10,000		20,000	(20,000)
• Technical Test				5,000		5,000	10,000	(10,000)
• Technology Demonstration		6,000	6,000	4,000	4,000	4,000	24,000	(24,000)
SUBTOTAL		6,500	17,000	9,500	14,000	9,000	56,000	(56,000)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL COST	(2,400)	9,000	19,300	11,700	15,800	10,500	66,300	(68,700)

Program 1.4

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Western Tight Gas Basins
Uinta Basin

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Technical Committee	(900)	360	360	360	360	360	1,800	(2,700)
• Basic Geological Studies	(500)	400	400	400	400	400	2,000	(2,500)
• Reservoir Measurement	(500)	1,000	500	500			2,000	(2,500)
• Recovery and Economic Study	(100)	100	200	100	200	100	700	(800)
SUBTOTAL	(2,000)	1,860	1,460	1,360	960	860	6,500	(8,500)
2. Improved Diagnostic Tools and Methods								
• Lab Testing	(100)	200	300	300	300	200	1,300	(1,400)
• Development	(200)	300	400	400	400	300	1,800	(2,000)
SUBTOTAL	(300)	500	700	700	700	500	3,100	(3,400)
3. Field-Based Research, Development, and Demonstration								
• Cores (incremental costs)		375	750	375			1,500	(1,500)
• Resource Characterization Wells			5,000		5,000		10,000	(10,000)
• Technical Tests				2,500		2,500	5,000	(5,000)
• Technology Demonstrations		3,000	3,000	2,000	2,000	2,000	12,000	(12,000)
SUBTOTAL		3,375	8,750	4,875	7,000	4,500	28,500	(28,500)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(2,300)	5,835	11,010	7,035	8,760	5,960	38,600	(40,900)

- ERDA pays for 100% of all other professional man-year costs.
- ERDA pays for 75% of the incremental costs of the coring program.
- ERDA pays for 50% of the resource evaluation and characterization wells.

7. Production Benefits

The anticipated production benefits from a successful research and development program in the Uinta Basin are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	△Due to R&D* (Tcf)
• Ultimate Recovery	2.1	17.6	15.5
• Production Rate in:			
1985	0.1	0.6	0.5
1990	0.1	1.1	1.0
1995	0.1	0.7	0.6
2000	0.1	0.5	0.4
• Cumulative Production by:			
1985	0.3	1.7	1.4
1990	0.7	6.7	6.0
1995	1.2	10.6	9.4
2000	1.5	13.5	12.0

* Totals may not add due to rounding

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Uinta Basin (at $3.00/Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	402
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	155

II. RESEARCH AND DEVELOPMENT STRATEGY FOR SHALLOW GAS DEPOSITS

The research and development strategy for the Shallow Gas Deposits is organized into three sections:

- Program 2.1: Characterize the Resource and Develop Advanced Technology in the Tight, Shallow Gas Basins
- Program 2.2: Assess the Potential of Producing Low Permeability, Shallow Gas Deposits With Improved Technology
- Program 2.3: Optimize Recovery and Development in Shallow, Near-Conventional Gas Sands

The strategies in this section are organized around distinct geological targets, so each contains appropriate resource characterization and technology development tasks.

TARGET: Tight, Shallow Gas Basins

R&D STRATEGY: Characterize the Resource and Develop Advanced Technology

1. Central Problem

Producing formation with very low permeabilities and pressures, particularly when the pay is contained in laminar sequences of sand and shale, requires that the sands be intersected with vertical fractures. Under conventional, unstimulated well completion, only 4 to 8 percent of the gas-in-place is recovered due to the very low pressures and permeabilities of these tight, shallow sands. Inducing fractures generally improves this recovery efficiency. Fractures in the horizontal plane will raise recovery to 10 to 25 percent of the original gas. Vertical fractures can increase the recovery efficiency to 40 to 60 percent. However, creating vertical fractures is currently hampered by geological and technological problems.

The geological problems include:

- Inability to measure accurately the in situ characteristics of the gas reservoir.
- Lack of understanding of the rock stress and strength factors that influence the plane (vertical versus horizontal) of the fracture's extension.
- Lack of understanding of the origin and migration of the gas.

- Absence of extensive studies of the areal extent, gross and net pay in the basins.

The principal technological difficulties are:

- Designing the stimulation treatment to control the plane of fracture extension.
- Increasing control of the fracture height so as to avoid encountering aquifers.

2. Scope of the Effort

The scope of the tight, shallow gas targets consists of the low permeability, Upper Cretaceous formations of the Northern Great Plains Province and Williston Basin in Montana.

Specifically, the target includes:

- The Judith River and Eagle formations in central Montana.
- The Bowdoin and Phillips formation in northern Montana.
- The Phillips formation in northcentral Montana.

3. R&D Goals

The research goals for this target are to accelerate development of the basins and improve the recovery efficiency of the resource's exploitation.

Specifically, the program is to:

- Improve in situ measurement capability to define the principal gas zones.
- Quantify the in-place rock stresses and strength factors that may cause the fractures to become horizontal.
- Define the generation, migration, and trapping of the gas.
- Define the extent of the quality gas potential in the province.
- Develop the ability to control the plane and height of the fracture.

4. R&D Activities

The activities required to reach the research goals listed above consist of the following:

- Task 1 - Develop logging systems capable of quantifying water and gas saturation, porosity and permeability in the alternating sand, siltstone, and shale sequences in these basins; calibrate log data against in situ measurements of permeability (to water and gas) obtained from production tests in selected pay intervals and against core measurements under simulated reservoir overburden pressure.

- Task 2 - Conduct laboratory and field research to improve control of the plane and height of the fracture.
- Task 3 - Conduct long term production tests to establish the amount of gas in place in contact with the wellbore, through natural permeability and fracture systems and intersected by the induced fracture; use this point analysis data for establishing improved spacing, well completion, and fracturing design for increasing recovery efficiency.
- Task 4 - Initiate basic geological/resource appraisal studies to establish formation boundaries, permeability barriers, and gas in place.
- Task 5 - Drill a selected number of resource characterization wells to establish the size of the gas potential in the more speculative portions of the basin.
- Task 6 - Conduct recovery and economic studies to refine and establish the potential of the sands of this target; review other basins to ascertain whether they should be added to this program's target.
- Task 7 - A continuing task would be to thoroughly review, analyze, and document the results of the above tasks and to disseminate the results (with fullest possible detail) to industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements are based on the need to gather considerable basic geologic and reservoir data in key areas.

The number of resource characterization wells, technical tests, and demonstration tests are based on:

- Placing a total of 15 resource evaluation and characterization wells in the basin, with 5 wells in each of the three tight formations of the basin.
- Conducting 10 demonstration tests, 2 per formation.
- Conducting 6 demonstration tests, 2 per major area.

Program 2.1

TARGET: Tight, Shallow Gas Sands

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

R&D ACTIVITIES (Physical Units) Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(2)	2	2	2	2	2	10	(12)
• Reservoir Properties Management	(2)	2	2	2	2	2	10	(12)
• Recovery and Economic Studies	(1)	1	1	1	1	1	5	(6)
2. Improved Diagnostic Tools and Methods (man-years)		2	2	2	2	2	10	(10)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Resource Characterization Wells		3	3	3	3	3	15	(15)
• Technical Tests		2	2	2	2	2	10	(10)
• Demonstration Tests			1	2	2	1	6	(6)
4. Technology/Information Transfer (man-years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of drilling, coring, logging, and testing a resource characterization well is $100,000.
- The cost of conducting an advanced fracturing and well completion test is $200,000.
- The cost of a demonstration test is $300,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 75% of the costs of the resource characterization wells.
- ERDA pays 50% of the costs of the technology and demonstration tests.

Program 2.1

EXHIBIT 2

TARGET: Tight, Shallow Gas Sands

TOTAL PROGRAM COSTS

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(200)	200	200	200	200	200	1,000	(1,200)
• Reservoir Properties Measurement	(200)	200	200	200	200	200	1,000	(1,200)
• Recovery and Economic Studies	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(500)	500	500	500	500	500	2,500	(3,000)
2. Improved Diagnostic Tools and Methods								
• Development								
		200	200	200	200	200	1,000	(1,000)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Wells		300	300	300	300	300	1,500	(1,500)
• Technical Tests		400	400	400	400	400	2,000	(2,000)
• Demonstration Tests		—	300	600	600	300	1,800	(1,800)
SUBTOTAL		700	1,000	1,300	1,300	1,000	5,300	(5,300)
4. Technology/Information Transfer								
		100	100	100	100	100	500	(500)
TOTAL COST	(500)	1,500	1,800	2,100	2,100	1,800	9,300	(9,800)

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Tight, Shallow Gas Sands

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(200)	200	200	200	200	200	1,000	(1,200)
• Reservoir Properties Measurement	(200)	200	200	200	200	200	1,000	(1,200)
• Recovery and Economic Studies	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(500)	500	500	500	500	500	2,500	(3,000)
2. Improved Diagnostic Tools and Methods								
• Development		200	200	200	200	200	1,000	(1,000)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Wells		225	225	225	225	225	1,125	(1,125)
• Technical Tests		200	200	200	200	200	1,000	(1,000)
• Demonstration Tests		—	150	300	300	150	900	(900)
SUBTOTAL		424	575	725	725	575	3,025	(3,125)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(500)	1,225	1,375	1,525	1,525	1,375	7,025	(7,525)

7. Production Benefits

The anticipated benefits from a successful completion of the research and development program in the Shallow Tight Gas Sands are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	△Due to R&D (Tcf)
• Ultimate Recovery	0	7.6	7.6
• Production Rate in:			
1985	0	*	*
1990	0	0.1	0.1
1995	0	0.2	0.2
2000	0	0.3	0.3
• Cumulative Production by:			
1985	0	0	0
1990	0	0.1	0.1
1995	0	0.9	0.9
2000	0	2.5	2.5

*Less than 0.05 Tcf

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Shallow Tight Gas Sands (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	1082
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	14

TARGET: Low Permeability, Shallow Gas Sands

R&D STRATEGY: Assess the Potential of Producing These Deposits With Improved Technology

1. Central Problem

The major problems to be overcome in the low permeability shallow gas sands are twofold:

- To discover the location of the more productive portions of the basin.
- To recover as much of the gas in place as economically feasible.

Locating the better quality pay and higher productive portions of the basin poses the first challenge. Finding the gas can be done, in part, through traditional exploratory efforts, however, several special problems stand in the way:

- The depositional history of the area is such that there is gas in place over considerable portions of the area; though in low concentrations (i.e., with low gas filled porosity); it may require the identification of special structural features such as structural highs and natural fractures for enough gas to be accumulated in any given area.
- The pay in much of the area is thin, averaging from 5-20 feet; further, given the minerology of the formation and current well drilling and completion practices, identifying

the producible pay poses considerable challenges to traditional logging techniques.

Recovering as much of the gas in place as technically possible, the second challenge, rests on the successful application of improved recovery technology:

- It appears that current production may only recover 40-60 percent of the potentially recoverable gas in place.

- The gas sands appear to be sequentially layered, with considerable shale sequences and with limited communication from well to well; for efficient drainage, a fracture will need to intersect (vertically) a series of these layered sands, including those not in communication with the wellbore.

- The pay is of low permeability, on the order of 1 md and less; this combined with the low bottom hole pressures (500-1500 psi) can lead to low production rates and early abandonment.

2. Scope of the Effort

The scope of the low permeability, shallow gas target consist of the Upper Cretaceous formations of the Northern Great Plains and Williston Basin in Montana. (The area for this investigation was limited to Montana, although the full target may, upon further study, extend to the Dakotas and to northern Wyoming; the formations were limited to the traditional sandstones and did not include the shales or marles that may, upon further definition, prove to be commercially gas bearing.)

Specifically, the target consists of Judith River and Eagle formations over a 27,000 square mile area in eastern Montana, as bounded on the South and East by formation boundaries and pinchouts.

3. R&D Goals

The research goals for this target are to identify the location of the deposits and to economically produce them through improved technology. Specifically, the program is to:

- Find and define the economically producible portion of this possible shallow gas resource and accelerate its development.
- Develop improved means for identifying the producible gas bearing pays in the full Upper Cretaceous interval.
- Improve well drilling and completions such that formation damage is reduced as much as possible.
- Establish the optimum field development, well stimulation technology and production practices to improve gas recovery to about 80 percent of the technically recoverable gas in place.

- Improve production rates and connect as much of the gas pay to one well as possible.

4. R&D Activities

The activities required to reach the R&D goals listed above consist of the following:

- Task 1 - Initiate basic geological/resource appraisal studies to establish formation boundaries, permeability pinch-outs, and gas in place.

- Task 2 - Develop reservoir evaluation procedures capable of quantifying water and gas saturation, porosity and permeability in the alternating sand, siltstone, and shale sequences typified by the Upper Cretaceous interval; calibrate log data against in situ measurements of permeability (to water and gas) obtained from production tests in selected pay intervals and against core measurements under simulated reservoir overburden pressure.

- Task 3 - Examine the use of alternative well drilling approaches (e.g., air drilling) to reduce formation damage.

- Task 4 - Establish the amount of gas in place in contact with the wellbore, through natural permeability and fracture systems, and the amount intersected by induced fractures; use this post-analysis data for establishing improved spacing, well completion, and fracturing design for increasing recovery efficiency.

- Task 5 - Test alternative means for intersecting the layered pay sands, including testing differing size fractures and the effectiveness of horizontal versus vertical fractures.

- Task 6 - Collect, analyze, and disseminate the results of the foregoing tasks, in fullest possible detail, to industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The level of manpower in resource characterization and diagnostic testing over the life of the program in that area is now poorly defined, with few wells over the large 27,000 square mile area.

The ten resource characterization and ten technology test wells are required because of the large areal extent of the basin and the considerable variation in reservoir properties anticipated over the basin.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Low-Permeability, Shallow Gas Sands

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(1)	1	1	1	1	1	5	(6)
• Reservoir Properties Measurement			1	1	1	1	4	(4)
• Recovery and Economic Studies			1	1			2	(2)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing		1	1	1			3	(3)
• Development			1	1	1	1	4	(4)
3. Field-Based Research, Development and Demonstration (cores/wells)								
• Resource Characterization Wells		2	2	2	2	2	10	(10)
• Technology Test Wells		2	2	2	2	2	10	(10)
4. Technology Information Transfer (man-years)				1	1	1	3	(3)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of drilling, coring, logging, and testing a resource characterization well is $100,000.
- The cost of conducting an advanced fracturing and well completion test is $200,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 75% of the costs of the resource characterization wells.
- ERDA pays 50% of the costs of the technology and demonstration tests.

EXHIBIT 2

TOTAL PROGRAM COSTS

Program 2.2

TARGET: Low Permeability, Shallow Gas Sands

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Properties Measurement			100	100	100	100	400	(400)
• Recovery and Economic Studies			100	100			200	(200)
SUBTOTAL	(100)	100	300	300	200	200	1,100	(1,200)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		100	100	100			300	(300)
• Development			100	100	100	100	400	(400)
SUBTOTAL		100	200	200	100	100	700	(700)
3. Field-Based Research, Development and Demonstration								
• Resource Characterization Wells		200	200	200	200	200	1,000	(1,000)
• Technology Test Wells		400	400	400	400	400	2,000	(2,000)
SUBTOTAL		600	600	600	600	600	3,000	(3,000)
4. Technology Information Transfer								
				100	100	100	300	(300)
TOTAL COST	(100)	800	1,100	1,200	1,000	1,000	5,100	(5,200)

Program 2.2

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Low Permeability, Shallow Gas Sands

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Measurement			100	100	100	100	400	(400)
• Recovery and Economic Study			100	100			200	(200)
SUBTOTAL	(100)	100	300	300	200	200	1,100	(1,200)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		100	100	100			300	(300)
• Development			100	100	100	100	400	(400)
SUBTOTAL		100	200	200	100	100	700	(700)
3. Field-Based Research, Development and Demonstration								
• Resource Characterization Wells		150	150	150	150	150	750	(750)
• Technology Test Wells		200	200	200	200	200	1,000	(1,000)
SUBTOTAL		350	350	350	350	350	1,700	(1,700)
4. Technology/Information Transfer								
				100	100	100	300	(300)
TOTAL ERDA COST:	(100)	550	750	950	750	750	3,750	(3,850)

7. Production Benefits

The anticipated production benefits from a successful research and development program in the low permeability, shallow gas sands are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	$\triangle$ Due to R&D* (Tcf)
• Ultimate Recovery	11.5	12.8	1.3
• Production Rate in:			
1985	-	-	-
1990	0.1	0.1	-
1995	0.4	0.6	0.2
2000	0.6	0.7	0.1
• Cumulative Production by:			
1985	-	-	-
1990	0.2	0.2	-
1995	1.5	2.1	0.6
2000	4.4	5.7	1.3

* Totals may not add due to rounding

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Low-Permeability, Shallow Gas Sands (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long-Term Measure: Ultimate Recovery/ERDA 5-Year Costs	342
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	-

TARGET: Shallow, Near-Conventional Gas Sands

R&D STRATEGY: Optimize Recovery and Development

1. Central Problem

The major problem to be solved in the shallow, near conventional shallow gas reservoirs is to ensure that: (a) as much of the resource is developed as possible; (b) that appropriate market access and economics are available to producers; and (c) the nation has as firm an estimate of the ultimate size and potential pace of development of these deposits.

In producing as much of the resource as possible the problems appear to center on:

- Identifying the full extent of the producible pay in the gross interval. Given the minerology and existing well completion practices, traditional well logging techniques may not be identifying the lower quality but potentially producible gas bearing pays.

- Existing well spacing and well completion and production practices may be leaving from 10 to 30 percent of the gas in place unproduced; improved fracturing techniques, closer well spacing, and use of compressors could serve to economically recover much of the gas now left in the ground.

The second problem of economics and access to market requires that appropriate gas prices be established and that pipelines be built to enable the gas to reach markets in short supply.

The problems of economics and access to market are integral to the third issue -- ascertaining the size and production potential of this resource target. It may be that the demand/supply analysis for these shallow gas deposits must be examined from a national rather than a regional demand perspective to assure that this potential resource base is produced as judiciously as possible in response to national gas needs.

2. Scope of the Effort

The scope of this shallow gas program consists of the Upper Cretaceous formations of the Northern Great Plains and the Williston Basins in Montana. The three specific targets are:

- Extension development of the Judith River and Eagle formations of the Tiger Ridge area of northwestern Montana.
- Extension development of the Bowdoin and Phillips formations of the Bowdoin Dome area of northcentral Montana.
- Exploratory development of the Frontier formations in central Montana.

3. R&D Goals

The research goals for this target are to accelerate the economic exploitation of this shallow gas resource by the independent producers prevalent in this geographic area. Specifically, the program is to:

- Develop means for identifying all potentially economically producible pay intervals.
- Establish the optimum development practices, including the optimum use of small fracturing, compression, and well completion practices.
- Establish the ultimate size of the development and exploratory resource.
- Ensure adequate economics and access to market.
- Accelerate the time within which this resource target would be produced.

4. R&D Activities

The activities required to reach the research goals listed above consist of the following:

- Task 1 - Develop well evaluation procedures capable of quantifying water and gas saturation, porosity, and permeability in the alternating sand, siltstone, and shale sequences typified by the Upper Cretaceous interval; calibrate log data against in situ measurements of permeability (to water and gas) obtained from production tests in selected pay intervals and against core measurements under simulated reservoir overburden pressure.

- Task 2 - Conduct long term production tests to establish the amount of gas in place in contact with the wellbore, through natural permeability and fracture systems, and intersected by the induced fracture; use this post analysis data for establishing improved spacing, well completion, and fracturing design for increasing recovery efficiency.

- Task 3 - Initiate basic geological/resource appraisal studies to establish formation boundaries, permeability barriers, and gas in place.

- Task 4 - Conduct economic, market demand, and transportation studies, examining the potential of these resources from a national gas demand view.

- Task 5 - Drill a selected number of resource characterization wells to establish the size of the gas potential in the more speculative portions of the basin.

- Task 6 - Transfer the results of the above analyses to public and private officials in enough detail to guide overall development of the resource.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research development and demonstration activities are shown in Exhibit 1.

The resource characterization manpower requirements are based on the considerable base of knowledge that has already been accumulated and that needs to be expanded to support the extension drilling required to develop this area.

The twelve resource characterization wells and the twelve production tests are based on the need to introduce at least one well and one test into each of the potential gas bearing formations in the three distinct areas of this target.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Shallow, Near Conventional Gas Sands

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(1)	1	1	1	1	1	5	(6)
• Reservoir Properties Measurement			1	1	1	1	4	(4)
• Economic and Market Studies		1	1	1	1		4	(4)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Testing		1	1	1	1		4	(4)
• Development			1	1	1	1	4	(4)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Resource Characterization Wells		3	3	2	2	2	12	(12)
• Production Tests		4		4		4	12	(12)
4. Technology/Information Transfer (man-years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The incremental costs of conducting a long term production test is $50,000.
- The cost of drilling, coring, logging, and testing a resource characterization well is $100,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 75% of the costs of the resource characterization wells.

Program 2.3

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Shallow, Near-Conventional Gas Sands

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Properties Measurement			100	100	100	100	400	(400)
• Recovery and Economic Studies		100	100	100	100		400	(400)
SUBTOTAL	(100)	200	300	300	200	200	1,300	(1,400)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		100	100	100	100		400	(400)
• Development			100	100	100	100	400	(400)
SUBTOTAL		100	200	200	200	100	800	(800)
3. Field-Based Research, Development and Demonstration								
• Resource Characterization Wells		300	300	200	200	200	1,200	(1,200)
• Production Tests		200		200		200	600	(600)
SUBTOTAL		500	300	400	200	400	1,800	(1,800)
4. Technology Information Transfer								
		100	100	100	100	100	500	(500)
TOTAL COST	(100)	900	900	1,000	800	800	4,400	(4,500)

Program 2.3

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Shallow, Near-Conventional Gas Sands

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Measurement			100	100	100	100	400	(400)
Recovery and Economic Study		100	100	100	100		400	(400)
SUBTOTAL	(100)	200	300	300	300	200	1,300	(1,400)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		100	100	100	100		400	(400)
• Development			100	100	100	100	400	(400)
SUBTOTAL		100	200	200	200	100	800	(800)
3. Field-Based Research, Development and Demonstration								
• Resource Characterization Wells		225	225	150	150	150	900	(900)
• Production Tests		100		100		100	300	(300)
SUBTOTAL		325	225	250	150	250	1,200	(1,200)
4. Technology/Information Transfer								
		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(100)	725	825	850	750	650	3,800	(3,900)

7. Production Benefits

The anticipated production benefits from a successful research and development program in the Shallow, Near Conventional Gas Sands are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D* (Tcf)
1. Ultimate Recovery	9.8	12.1	2.3
2. Production Rate In			
1985	0.4	0.5	0.1
1990	0.5	0.8	0.3
1995	0.4	0.4	-
2000	0.3	0.3	-
3. Cumulative Production By			
1985	1.4	1.6	0.2
1990	4.0	5.6	1.6
1995	6.1	8.1	2.0
2000	7.6	9.9	2.3

* Totals may not add due to rounding.

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Shallow, Near-Conventional Gas Sands (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	605
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	421

III. RESEARCH AND DEVELOPMENT PROGRAM FOR OTHER TIGHT LENTICULAR GAS SANDS

The research and development program for the Other Tight Lenticular Gas Sands consists of one strategy:

- Develop Improved Well Completion Technology Along With the Means for Intersecting Multiple Sand Lens

This strategy contains resource characterization as well as technology development tasks.

TARGET: Other Tight Lenticular Gas Sands

R&D STRATEGY: Develop Improved Well Completion Technology Along With the Means for Intersecting Multiple Sand Lens

1. Central Problem

Beyond the three Western Tight Gas Basins, the United States has several other basins with low permeability and lenticular gas pays, including the Sonora, Big Horn, the Douglas Creek Arch, and the tighter marginal areas of the "near tight" lenticular basins. The problems here are not as formidable as those found in the Western Basins. The quality of the pay is more readily identified and is generally better than in the Western basins. Moreoever, the lenses tend to be somewhat larger. These basins, however, face other unique challenges, particularly in well completion and control of fracture extensions.

Thus, while the better portions of several of these other tight, lenticular basins are being developed by industry with existing technology, development in the marginal portions has been slow, erratic and generally uneconomic.

It appears that, like the Western basins, the chief feature requirement for achieving successful completion is to connect the fracture with both the sand intersected by the wellbore and with other lenses in interwell areas. In the better section of these basins the recovery from sands observed at the well may be adequate for an economic return, but does not deplete all the sands that are in the range of the producing well. Moreover, there are considerable portions of these basins in which a well penetrating a single sand or lens is not profitable. In order to secure additional recovery and the economic development of such marginal portions of these basins, the following principal achievements are expected:

- The fracture intersects several or the full complement of gas sand lenses in the drainage area.
- The efficiency of the fracture process is improved so that more of the effective fracture length remains in the net pay.
- The effectiveness of the fracturing technology is improved sufficiently to insure optimum drainage and thus higher production from lenses that now can be intersected.

As one or more of these conditions begin to be achieved, ERDA will make a valuable contribution toward solving the technical and economic problems that impede development within these basins.

2. Scope of the Effort

The specific targets that have been identified and are included in this analysis of the program in the other tight lenticular gas sands are three basins, the Canyon sand of the Sonora Basin in western Texas, the Mesa Verde section of the Big Horn Basin, and the Mancos and Dakota formations of the Douglas Creek Arch in western Colorado.

3. R&D Goals

- To establish the specific geologic and reservoir properties in the other tight, lenticular gas basins, particularly the shape and dimensions of the sand lenses and their interconnection.

- To ascertain under what rock stress and strength conditions: (a) a fracture will only intersect (traverse through) the sand lenses intersected by the wellbore; or (b) will intersect other sand lens removed from the wellbore.

- To determine the fracture azimuth and optimal development pattern for the basins.

- To develop and demonstrate the optimal fracture fluids and propping agents for each basin and to improve the ability to control the fracture.

4. R&D Activities

The research and development activities required to reach the above goals consist of the following steps:

- Task 1 - Conduct geologic and reservoir studies to identify the size, dimension, and continuity of the gas bearing sand lenses.

- Task 2 - Use core and logging studies and occasional formation breakdown tests to determine fracturing characteristics of the formation and adjacent beds.

- Task 3 - Conduct basic and applied research in improving fracture technology, including means for:
  - -- improving fracture fluid compatibility
  - -- determining fracture azimuth
  - -- controlling vertical height of fractures
  - -- improving fracture conductivity.
- Task 4 - Conduct MHF, technical tests on selected wells to determine optimum frac size and production characteristics of the stimulated well. It is anticipated that these tests will consist of using existing or new wells of opportunity rather than drilling new wells.
- Task 5 - Conduct demonstrations tests in each basin to apply best available well completion and fracture technology to the specific geological settings.
- Task 6 - Document the above activities and disseminate the findings to industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of technical and demonstration tests required to carry out the above tasks are shown in Exhibit 1.

Six technical tests and six deomonstration tests are anticipated. Depending on the outcome of the geological and applied R&D, these would tentatively be allocated three of each type test to the Sonora Basin, two of each to the Big Horn Basin, and one of each to the Douglas Creek Arch.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Other Tight Lenticular Basins

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Reservoir Properties Measurement		5	5	5	5	5	25	(25)
• Recovery and Economic Studies		3	3	3	3	3	15	(15)
• Geological and Rock Mechanics Studies		5	5	5	5	5	25	(25)
2. Improved Diagnostic Tools and Methods (man-years)								
• Testing Fracture Technology		2	4	4	4	3	17	(17)
• Development of Measurement Technology		4	4	4	4	4	20	(20)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Technical Tests		1	2	2	1		6	(6)
• Demonstration Tests			1	2	2	1	6	(6)
4. Technology/Information Transfer (man-years)			3	3	3	3	12	(12)

6. R&D Costs

The R&D activities listed on Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported man-year costs $100,000.
- The incremental cost of a multiple, massive hydraulic fracture treatment for technical tests is set at $1,000,000 per well.
- The full cost of each advanced production technology demonstration test is $3,000,000, including drilling, completion, multiple fracturing, testing and supportive planning, management, and analysis.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional and support man-year costs of the Technical Committee.
- ERDA pays 50% of the incremental costs of each stimulation treatment.
- ERDA pays 50% of the full costs of each production demonstration test.

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Other Tight Lenticular Basins

RD&D Costs (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Reservoir Properties Measurement		500	500	500	500	500	2,500	(2,500)
• Recovery and Economic Studies		300	300	300	300	300	1,500	(1,500)
• Geological and Rock Mechanics Studies		500	500	500	500	500	2,500	(2,500)
SUBTOTAL		1,300	1,300	1,300	1,300	1,300	6,500	(6,500)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		200	400	400	400	300	1,700	(1,700)
• Development		400	400	400	400	400	2,000	(2,000)
SUBTOTAL		600	800	800	800	700	3,700	(3,700)
3. Field-Based Research, Development, and Demonstration								
• Technical Tests		1,000	2,000	2,000	1,000		6,000	(6,000)
• Demonstration Tests			3,000	6,000	6,000	3,000	18,000	(18,000)
SUBTOTAL		1,000	5,000	8,000	7,000	3,000	24,000	(24,000)
4. Technology/Information Transfer			300	300	300	300	1,200	(1,200)
TOTAL COST		2,900	7,400	10,400	9,400	5,300	35,400	(35,400)

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Other Tight Lenticular Basins

RD&D Costs (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Reservoir Properties Measurement		500	500	500	500	500	2,500	(2,500)
• Recovery and Economic Studies		300	300	300	300	300	1,500	(1,500)
• Geological and Rock Mechanics Studies		500	500	500	500	500	2,500	(2,500)
SUBTOTAL		1,300	1,300	1,300	1,300	1,300	6,500	(6,500)
2. Improved Diagnostic Tools and Methods								
• Lab Testing		200	400	400	400	300	1,700	(1,700)
• Development		400	400	400	400	400	2,000	(2,000)
SUBTOTAL		600	800	800	800	700	3,700	(3,700)
3. Field-Based Research, Development, and Demonstration								
• Technical Tests		500	1,000	1,000	500		3,000	(3,500)
• Demonstration Tests		—	1,500	3,000	3,000	1,500	9,000	(9,000)
SUBTOTAL		500	2,500	4,000	3,500	1,500	12,000	(12,000)
4. Technology/Information Transfer			300	300	300	300	1,200	(1,200)
TOTAL ERDA COST:		2,400	4,900	6,400	5,900	3,800	23,400	(23,400)

7. Production Benefits

The anticipated production benefits from a successful completion of the research and development program for other Tight Lenticular Gas Sands are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
• Ultimate Recovery	14.7	23.7	8.9
• Annual Production Rate In			
1985	0.2	0.3	*
1990	0.4	0.7	0.2
1995	0.6	0.9	0.3
2000	0.6	1.0	0.4
• Cumulative Production By			
1985	0.8	1.0	0.2
1990	2.7	3.7	1.0
1995	5.4	7.8	2.4
2000	8.5	12.8	4.3

* Less than 0.05 Tcf

8. Benefits and Costs

The key cost-effectiveness resources (incremental production dollars of ERDA cost) for the Other Tight Lenticular Gas Sands (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-year Costs	380
• Short Term Measure: 1990 Cumulative Production/ERDA 5-year Costs	43

IV. RESEARCH AND DEVELOPMENT STRATEGY FOR THE TIGHT, BLANKET GAS SANDS

The research and development strategy for the Tight, Blanket Gas Sands consists of one program:

- Develop Optimum Recovery Strategies to Fully Exploit the Available Resource

The above R&D strategy contains resource characterization as well as technology development tasks.

TARGET: Tight, Blanket Gas Sands

R&D STRATEGY: Develop Optimum Recovery Strategies to Fully Exploit the Available Resource

1. Central Problem

A significant portion of the identified, but as of yet undeveloped domestic gas resource, is in the tight, blanket-type gas basins.

Until recent advances in technology and increases in price, much of this resource was considered unrecoverable. Currently, development is being pursued by the industry in many of these basins, although the high risk nature of the technology serves as a severe constraint on the pace of application. In addition, although a small number of the operators have experimented with different fracture and field development designs, much of the current development follows a trial and error approach. There is presently an opportunity to accelerate the pace of drilling and to systematically test for the optimum development pattern and stimulation technology.

More specifically, three problems should be addressed:

- Vertical control. Under certain rock stress and depositional conditions, the massive fractures needed to exploit the resource will tend to leave the net gas pay after extending laterally for a relatively short distance, either rising or falling, so that the effective fracture length is only that distance actually in the pay. Improved vertical control will permit both more economic production (because smaller fluid volumes for a given fracture length would be required) and greater recovery (because of the greater effective fracture length).

- Well spacing. Full understanding of the regional stress patterns that determine the azimuth of the fractures would facilitate optimal well-spacing patterns and minimize the chance of interference in the drainage areas of each well.
- Optimizing the stimulation design. Each basin has somewhat differing characteristics that will call for tailoring of the fracturing fluids, proppant selection, and the size of the fracture for maximum economic recovery. A program of systematic variation of these factors could help the operators determine the optimal stimulation design.

2. Scope of the Effort

The basins and formations included in this target are the following:

- Cotton Valley Trend -- the Sand Trend through East Texas, Southern Arkansas, and Northern Louisiana and the Gilmer limestone in East Texas.
- Ouachita Mountains Province -- the massive Missippian section in Central Arkansas and Eastern Oklahoma.

- Denver Basin -- the Sussex, Niobrara, and Dakota formations in Eastern Colorado.

- San Juan Basin -- the Dakota formation in Southwestern Colorado and Northwestern New Mexico.

- Raton Basin -- the Dakota formation in Southern Colorado and Northeastern New Mexico.

3. <u>R&D Goals</u>

- To verify the initial appraisals of sand pay geology and geometry that have led these basins to be designated as blanket-pay type basins. This includes confirming quantitative accuracy of logging and core analysis techniques developed in other tight gas programs.

- Measure stress and strength of sand and shale sequences to ascertain fracture extension limitations.

- To ascertain the optimum field development and fracture design for each basin.

- To transfer information on the optimum field development and fracture design criteria to industry.

4. R&D Activities

The research and development steps would be as follows:

- Task 1 - Conduct a focused resource appraisal effort in probable and possible areas toward identifying the pay sand geometry, continuity, and permeability.
- Task 2 - Examine additional basins to ascertain the extent to which these should be added to this target, using core and logging studies and occasional formation breakdown tests to determine case of fracture extension lateral vs. vertical.
- Task 3 - Obtain data and help defray measurement costs on reviews of alternative field development and fracture design experiments to ascertain optimum recovery and economics for each tight, blanket pay gas basin.
- Task 4 - Analyze the results of these experiments, as well as all other industry efforts in these basins.
- Task 5 - Transfer the "best practices" technology to industry.

5. Manpower and Field Test Requirements

The levels of manpower required to carry out the above research, development, and demonstration activities are provided on Exhibit 1. Note that no ERDA-sponsored technical or demonstration tests are included. The strategy is to "buy-in" on selected wells of opportunity by supporting higher levels of measurement, data analysis, and reporting that operators would normally not perform.

The decreasing manpower requirements are based on the considerable base of knowledge that has already been accumulated but still requires detailed analysis as well as the need to gather additional data on pay geometry and rock mechanics.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Tight, Blanket Gas Sands

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal (man-years)								
• Appraise sand pay geometry	(5)	5	5	5	5		20	(25)
• Analyze and simulate field test results		5	5	5	5	5	25	(25)
• Geology/rock mechanics - field and laboratory		5	5	5			15	(15)
2. Field-Based Research, Development and Demonstration (wells)								
• Obtain experimental demonstration data		3	3	3	3	3	15	(15)
3. Technology/Information Transfer (man-years)		5	5	5	5	5	25	(25)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly cost budgets in Exhibit 2 (Total Program and ERDA Costs).

The line items in the budget are based on the following assumptions:

- One fully supported man-year costs $100,000.
- The incremental cost of experimental/demonstration data is $200,000 per pilot test.

The assumption is that ERDA will pay the full costs of this program in that all the activities are incremental to ongoing activities by industry.

EXHIBIT 2

TOTAL AND ERDA PROGRAM COSTS

TARGET: Tight Blanket Gas Sands

R&D ACTIVITIES (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
• Appraise sand pay geometry	(500)	500	500	500	500		2,000	(2,500)
• Analyze and simulate field test results		500	500	500	500	500	2,500	(2,500)
• Geology/rock mechanics - field and laboratory	___	500	500	500	___	___	1,500	(1,500)
SUBTOTAL	(500)	1,500	1,500	1,500	1,000	500	6,000	(6,500)
2. Field-Based Research, Development and Demonstration								
• Obtain experimental demonstration data		600	600	600	600	600	3,000	(3,000)
3. Technology/Information Transfer								
		500	500	500	500	500	2,500	(2,500)
TOTAL AND ERDA COST	(500)	2,600	2,600	2,600	2,100	1,600	11,500	(12,000)

7. Production Benefits

The anticipated benefits from a successful research and demonstration program in Tight, Blanket Gas Sands are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
1. Ultimate Recovery	50.6	65.8	15.2
2. Production Rate In			
1985	0.9	1.3	0.4
1990	1.6	2.8	1.2
1995	2.0	2.8	0.8
2000	2.0	2.5	0.5
3. Cumulative Production By			
1985	3.0	4.7	1.7
1990	9.8	16.6	6.8
1995	19.2	30.7	11.5
2000	29.6	44.4	14.8

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the Tight, Blanket Gas Formations (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	1322
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	591

V. RESEARCH AND DEVELOPMENT STRATEGY FOR THE OTHER LOW PERMEABILITY GAS DEPOSITS

The research and development strategy for the Other Low Permeability Gas Deposits consists of one program:

- Assist Operators Define Reservoirs and Use Optimum Fracturing Technology

The above R&D strategy contains resource characterization as well as technology development tasks.

TARGET: Other Low Permeability Gas Deposits

R&D STRATEGY: Assist Operators Define Reservoirs and Use Optimum Fracturing Technology

1. Central Problem

Beyond the gas supplies that are expected to be added by new exploration and the development of existing conventional gas reservoirs, reservoirs with permeabilities of 0.05 md to 1 md, falling outside the definition of tight gas formations, provide a high probability, near-term potential for augmenting domestic gas supplies.

Because these near-tight reservoirs are so close to conventional gas reservoirs and can be produced with essentially available technology, the target here is mainly one of acceleration, risk (and cost) reduction, and technology transfer to stimulate the expeditious development of this resource. A full and thorough understanding of geology and geometry of the sand deposition may be the single most important contribution in this area.

After researching the full results from geologic studies, risk reduction, and technology transfer, there may still be considerable areal portions of these reservoirs uneconomic to produce unless these are provided prices comparable to those being considered for the tight-gas and the unconventional sources. Thus, the remaining problem to be solved would be for ERDA to study the costs and economic requirements of these basins and to quantify the resulting gas supply that could be added due to increased price.

2. Scope of the Effort

The Bruckner-Smackover limestone of the Cotton Valley Trend was the only formation in this category analyzed, although additional similar circumstances are present in the formations of several other major basins that were outside the scope of the present study.

3. R&D Goals

- Obtain a full definition of the geology and geometry of the gas pay.
- Improve reservoir measurements and modeling to make the exploitation of this resource as conventional a recovery program as possible.
- Determine what additional basins contain significant target gas formations in the 0.05 - 1. md range; analyze their problems and potentials for possible inclusion into this program.
- Accelerate the pace of development within these basins by transferring technology to operators that might require it.
- Ascertain the costs, recoveries, and price-supply curves for each low permeability gas basin and seek adequate economics to fully exploit these resources.

4. R&D Activities

The research and development activities required to reach the above goals include the following steps:

- Task 1 - Assess the extent to which other basins and formations present problems of low permeability (but not "tight") gas deposits. Prepare preliminary analyses of the potential of such basins to ascertain whether they should be incorporated into this target (or others).

- Task 2 - Demonstrate the capacity of the existing (modified where required) gas reservoir models to accurately predict pre- and post-fracture production performance.

- Task 3 - Where necessary, conduct geologic studies of the identified low permeability basins, particularly to ascertain the sand pay geometry and continuity.

- Task 4 - Where necessary, support the accumulation of a data base required by the preceding activities.

- Task 5 - Transfer the measurement and performance prediction tools to operators that might require them.

- Task 6 - Conduct thorough reservoir performance and cost studies to establish the price-supply relationships in each basin.

- Task 7 - Should a significant potential be found to be held back due to inadequate price, assist the Department of Energy seek appropriate price relief for these basins or have the qualifying basins be included under price rules applicable to "tight-gas" and other unconventional sources.

5. Manpower and Field Test Requirements

The levels of manpower required to carry out the above research, development, and demonstration activities are provided in Exhibit 1.

Manpower requirements are based on the considerable base of knowledge that is being accumulated in the tighter gas basins that needs to be expanded in key areas. Note that no field tests are required, but substantial effort is devoted to analysis and technology transfer.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

Target: Other Low Permeability Gas Deposits

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(4)	5	5				10	(14)
• Performance Calibration	(4)	4	4				8	(12)
• Recovery and Economic Studies	(3)	5	2				7	(10)
2. Improved Diagnostic Tools and Methods (man-years)	(3)	5	5	5	5		20	(23)
3. Technology/Information Transfer (man-years)	(2)	3	4	4	4	5	25	(27)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total and ERDA Program Costs).

The line items of costs in the budget are based on the assumption that one fully supported man-year costs $100,000. It was further assumed that ERDA would bear all this strategy's costs because of the nature of the tasks.

EXHIBIT 2

TOTAL AND ERDA PROGRAM COSTS

TARGET: Other Low Permeability Gas Deposits

RD&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Resource and Economic Studies	(300)	500	200	-	-	-	700	(1,000)
• Geological Studies	(400)	500	500	-	-	-	1,000	(1,400)
• Data Base for Performance Calibration	(400)	400	400	-	-	-	800	(1,200)
SUBTOTAL	(1,100)	1,400	1,100				2,500	(3,600)
2. Improved Diagnostic Tools and Methods	(300)	500	500	500	500	-	2,000	(2,300)
3. Technology Transfer	(200)	300	400	400	400	500	2,000	(2,200)
TOTAL AND ERDA COST:	(1,600)	2,200	2,000	900	900	500	6,500	(8,100)

7. Production Benefits

The anticipated production benefits from a successful research and development program in the other low permeability gas deposits are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D* (Tcf)
• Ultimate Recovery	4.6	9.7	5.1
• Production Rate in:			
1985	0.1	0.2	0.1
1990	0.2	0.5	0.3
1995	0.2	0.4	0.2
2000	0.2	0.3	0.1
• Cumulative Production by:			
1985	0.3	0.7	0.4
1990	1.0	2.9	1.9
1995	2.0	5.2	3.2
2000	2.8	6.9	4.1

*Totals may not add due to rounding

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA expenditure) for the other low permeability gas deposits (at $3.00/Mcf) are:

Cost-effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	785
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	292

CHAPTER FOUR

DEVONIAN SHALE

Part 1

I. INTRODUCTION

Considerable analysis has centered on the potential of gas from the Devonian shales, one of the least defined domestic gas producing regions. Reserve estimates from 3 to 300 Tcf have been advanced. This study was undertaken to narrow this wide range of estimates by ascertaining the economic potential of gas from the Devonian shales. Specifically, this study is to:

- Estimate the economic potential of the Devonian shales based on empirical data on the geology, reservoir performance, and costs.

- Set forth a research strategy that would most cost-effectively assure (or further define) this potential.

The focus of the study is on the Appalachian Basin, where gas production of Devonian shales occurs in West Virginia, Kentucky, and Ohio, and potentially in Pennsylvania and New York.*

Part 1 of this chapter provides background on the nature and the economic potential of the Devonian shale resource base. Part 2 provides a detailed description of the R&D program.

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* Further data gathering and analysis would be required to identify the potential of the Michigan, Illinois, Indiana, Tennessee, and other states with Devonian age shale deposits.

II. DRILLING AND STIMULATION OF DEVONIAN SHALE GAS

Gas production from the Devonian shales, particularly from formations in northern Ohio (the Lake Erie district) and from eastern Kentucky (Big Sandy Field) has existed since the late nineteenth century. Recently, however, in response to growing concern about natural gas shortages and their potentially devastating effect on the Appalachian economy, the Devonian shales have received renewed interest. Over 100,000 square miles[1/] are underlaid by these shales and considerable resource definition and technical development is underway to determine what portion of this resource base could be economically produced.

A. Historical Production of Devonian Shale Gas

Historically, West Virginia and Kentucky have provided the bulk of the Devonian shale gas production. Based on API and AGA data gathered in 1976, 3.9 Tcf of gas have already been produced or are currently booked in proved reserves from the Devonian shales.[2/]

State	Cumulative Production (Tcf)	Proved Reserves (Tcf)	1976 Estimate of Ultimate Recovery (Tcf)
West Virginia	1.0	0.6	1.6
Kentucky	1.7	0.5	2.2
Ohio	*	*	0.1
TOTAL	2.7	1.1	3.9

In 1976, these states produced an estimated 0.1 Tcf of natural gas from the Devonian shales.

* Less than 0.5 Tcf.

B. Trends in Development Drilling

As of December 1974, there were about 9,500 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 4-1 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.

While the detailed drilling data have not been compiled, it appears that about 200 new shale wells are being drilled per year in these three states. At an average of 150-acre spacing and an ultimate recovery of 300 MMcf per well, about 50 square miles are being developed and about 60 Bcf of new reserves may be being added per year.

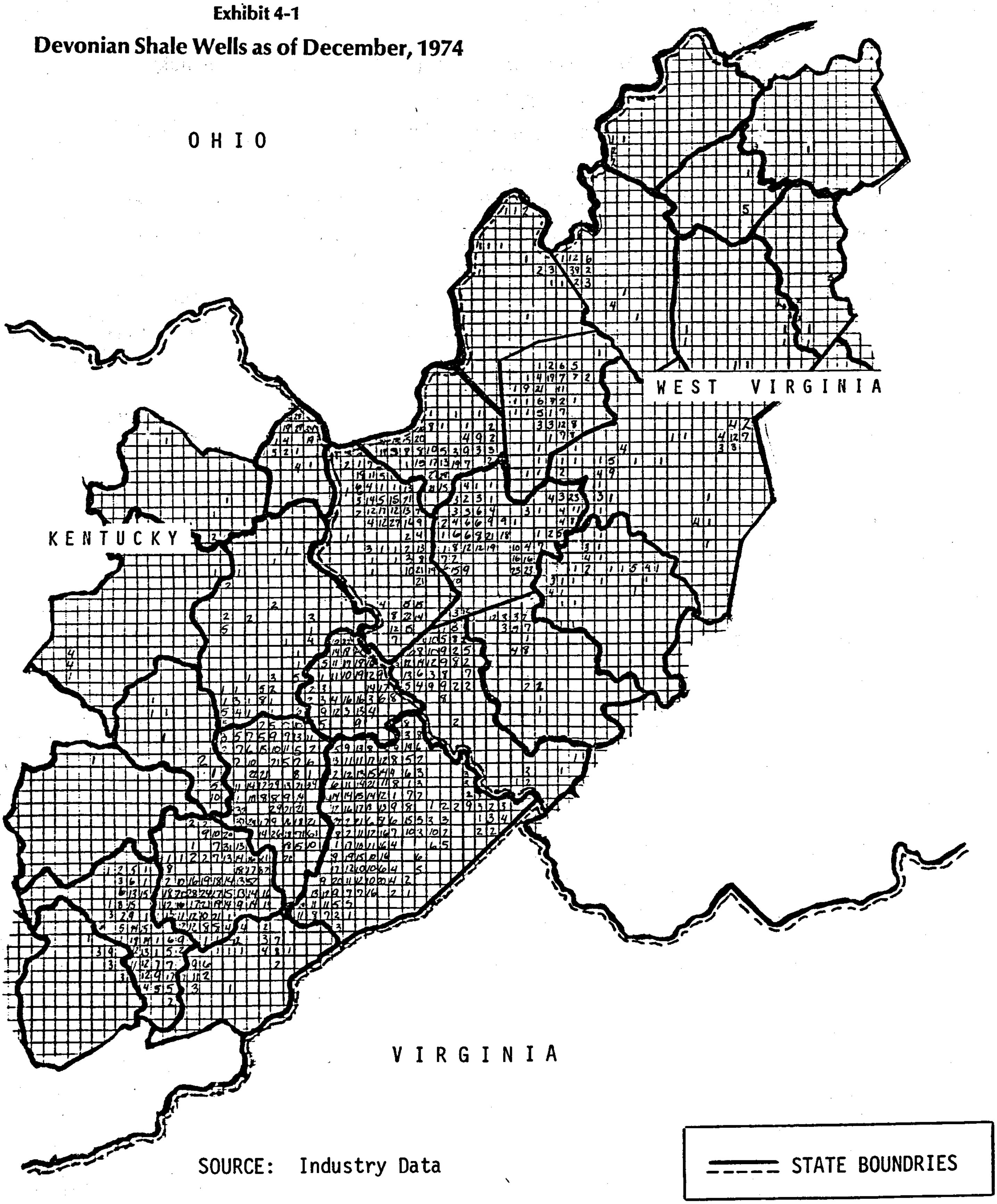
With yearly production from the proved reserves of 100 Bcf, the new additions of 60 Bcf in the recent years are not keeping pace; the total reserve is declining.

About two-thirds of the land in the four counties comprising the center of the Big Sandy Field appears fully developed -- as the primary producing area becomes depleted, new production must come from:

- Extension drilling around the borders of the currently developed areas.

Exhibit 4-1

Devonian Shale Wells as of December, 1974



SOURCE: Industry Data

- Stepout and exploratory drilling into new areas
- Improved recovery efficiencies from drilled and undrilled areas.

C. Stimulation Practices

1. Shooting

Traditionally, the Devonian shale wells have been stimulated by "shooting" with explosives. Analysis of work done by Hunter and Young[3/] in the 1950's show the increase in initial gas production due to shooting (Exhibit 4-2). These increases 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 creates any substantial additional fracturing.*

2. 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 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 released.

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

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* 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.

Exhibit 4-2

Average Initial Open Flows Before and After Shooting

County	IOF* Before Shot (Mcf/D)	IOF After Shot (Mcf/D)	Ratio of After/Before	Number of Wells
Floyd	72	368	5:1	1107
Martin	48	292	6:1	441
Knott	68	272	4:1	654
Pike	52	211	4:1	892
Magoffin	30	184	6:1	53
Johnson	28	103	4:1	52

*Initial Open Flow

SOURCE: Hunter and Young

The successful use of small hydraulic fracturing in eastern Kentucky may accelerate adoption of this technique by operators in other regions of Appalachia. Analysis based on work done by Ray[4/] shows that hydraulic fracturing may increase recovery over shooting by 16 to 24 MMcf (cumulative) over the first five years (Exhibit 4-3), or from 17 to 46 percent. The larger improvements generally occur in wells with <u>lower</u> production.

More production experience, however, is required to account for these increases in production in the early years. They could reflect either of at least two conditions:

- 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 ultimate 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. Two major reasons for this are:

- Shooting costs less than a small fracture.

Exhibit 4-3

Comparison of Five-Year Cumulative Production of Wells Stimulated by Fracturing and Shooting

	IOF 100-200 Mcf/D				IOF 200-300Mcf/D			
Year	Fractured Mmcf	Shot Mmcf	Increase Due to Frac Mmcf	% Change	Fractured Mmcf	Shot Mmcf	Increase 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: E. O. Ray

- The return from incremental production due to fracturing appears economic only at gas prices higher than have traditionally been obtained in the Appalachian area.

However, confidence in fracturing outcomes coupled with higher gas prices is encouraging the use of fracturing techniques. It is likely that small, multiple hydraulic fracturing will become the state of the art in the next five years.

3. New Stimulation and Recovery Technologies

The desire not only to maintain but to increase productive capacity has encouraged development of other stimulation technologies. Those currently being tested for effectiveness in the Devonian shales include massive hydraulic fracturing, cryogenic or gas fracturing, intensive explosives, and deviated well drilling. While data on the effectiveness of these approaches are currently being evaluated, the apparently high recovery efficiencies* of Devonian shale wells indicate that these new approaches may serve to accelerate production rather than add to ultimate recovery.

D. Preview of the Potential Recovery

Since the turn of the century, the gas industry has explored and produced the Devonian shale of the Appalachian Basin. As the more favorable portions of the Basin become developed, new additions to Devonian shale production will need to come from the less defined and potentially less favorable portions of the Basin. The analysis presented in the following sections shows that improved definition of fracture intensity, innovative production technology (e.g., using multiple completions), techniques for improving recovery efficiency, and higher gas prices could significantly increase the economic potential of the Devonian shale.

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* Reservoir simulation of Devonian shale gas reservoirs shows recovery efficiencies of 45 to 60% for shot wells and 55 to 65% for fractured wells, assuming the produced gas stems from fracture porosity.

1. Additions to Gas Reserves

As noted, current proved reserves amount to slightly more than 1 Tcf. In addition to these reserves:

- Industry, over the next 30 years, is expected to develop 2 to 10 Tcf additional gas reserves at prices ranging from $1.75 to $4.50 per Mcf.

- With active Federal participation in research and development, the total reserve additions are expected to rise to 4 Tcf at a gas price of $1.75 per Mcf.

- Combining R&D with an increase in price could increase the ultimate recovery from the Devonian shales to a range of 16 to 25 Mcf, at gas prices of $3.00 to $4.50 per Mcf.

These results are shown on Exhibit 4-4.

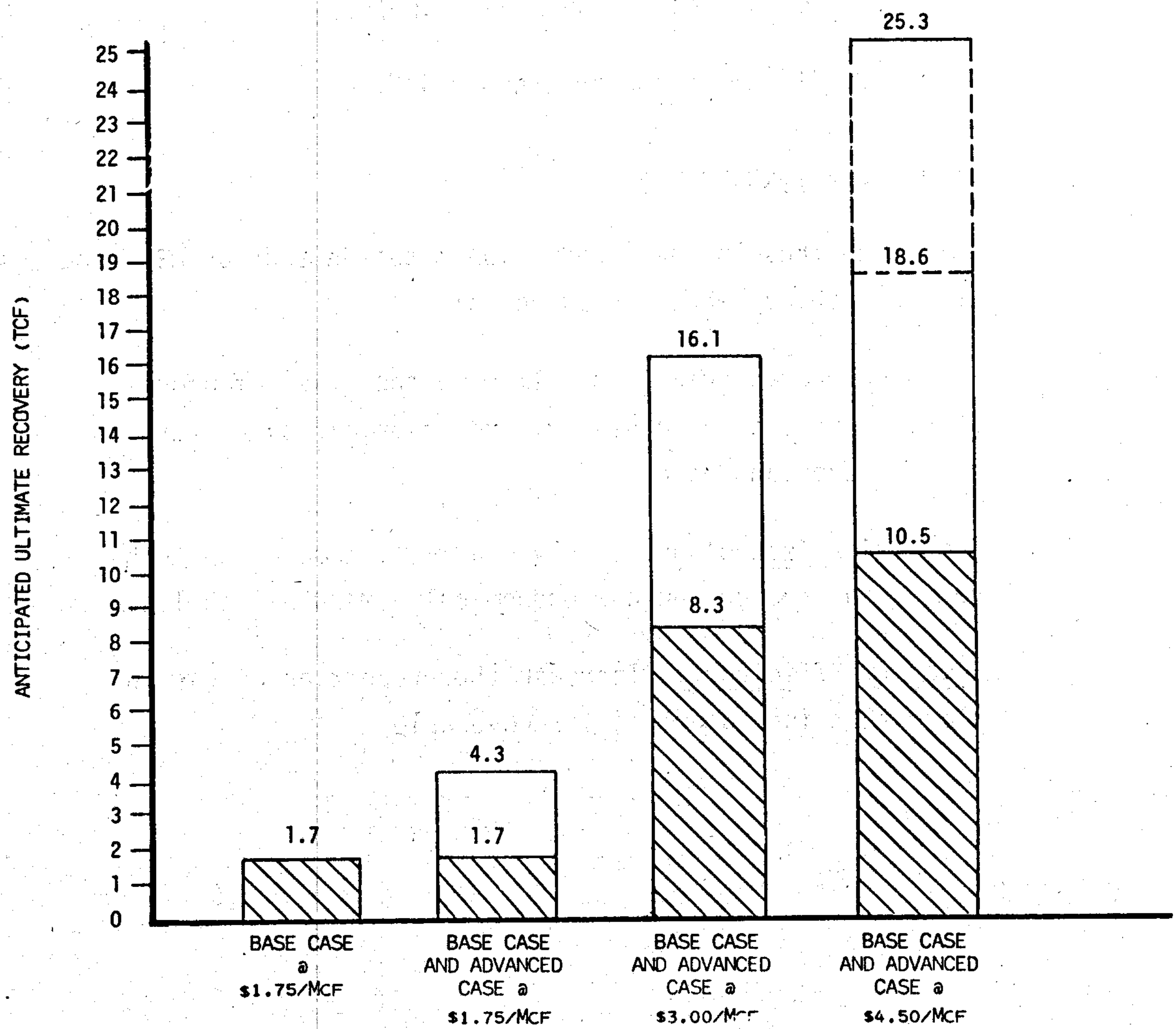
2. Addition to Production

Similarly, the amount of yearly production is directly influenced by technology and price:

- At current technology and prices, gas production from the Devonian shales would essentially remain flat, at about 0.1 Tcf per year.

Exhibit 4-4

Economic Potential of the Devonian Shales of the Appalachian Basin Under Base Case and Advanced Technology Case Assumptions



- Introducing R&D, at the same price level, would raise the yearly production level to 0.2 Tcf.

- Introducing R&D in combination with a higher price of $3.00 per Mcf could increase the 1990 production rate to 0.6 Tcf.

- By 1990, under a $3.00/Mcf and advanced technology case, the Appalachian shales could add, in cumulative, over 3 Tcf to the nation's gas supply.

These results are shown on Exhibit 4-5.

E. Research and Development Goals

Attaining these higher production rates depends on R&D programs that successfully achieve three broad goals:

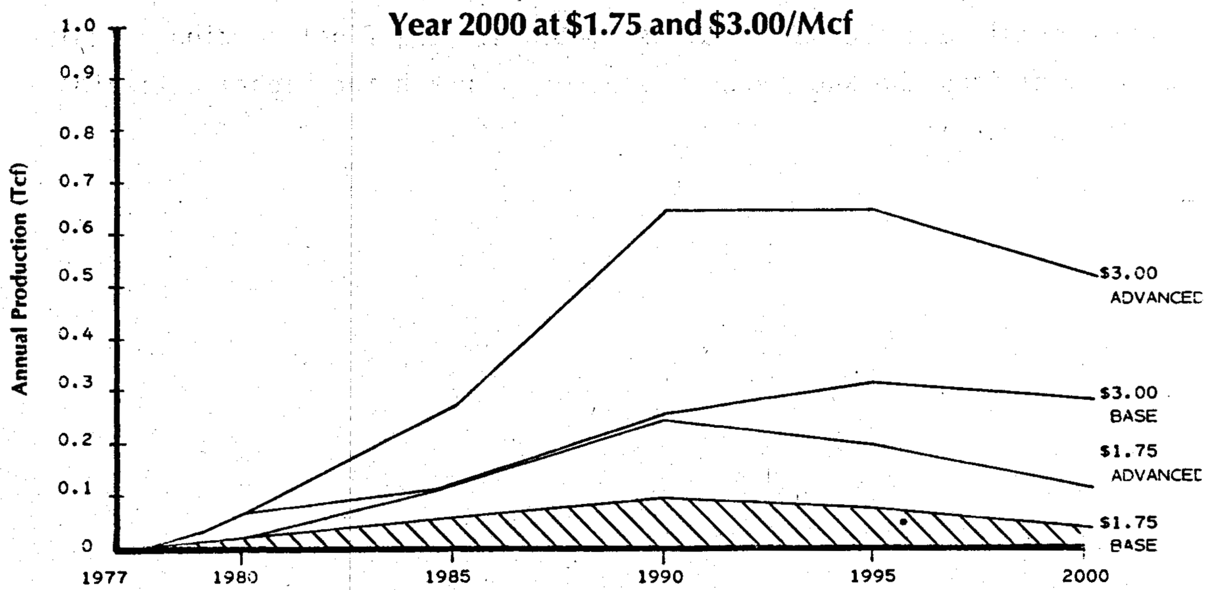
1. Resource Characterization. Improve the level of understanding of the basic geology and reservoir parameters of the Devonian shale.

2. Production Technology. Apply dual well completion technology to produce the now economically marginal shales.

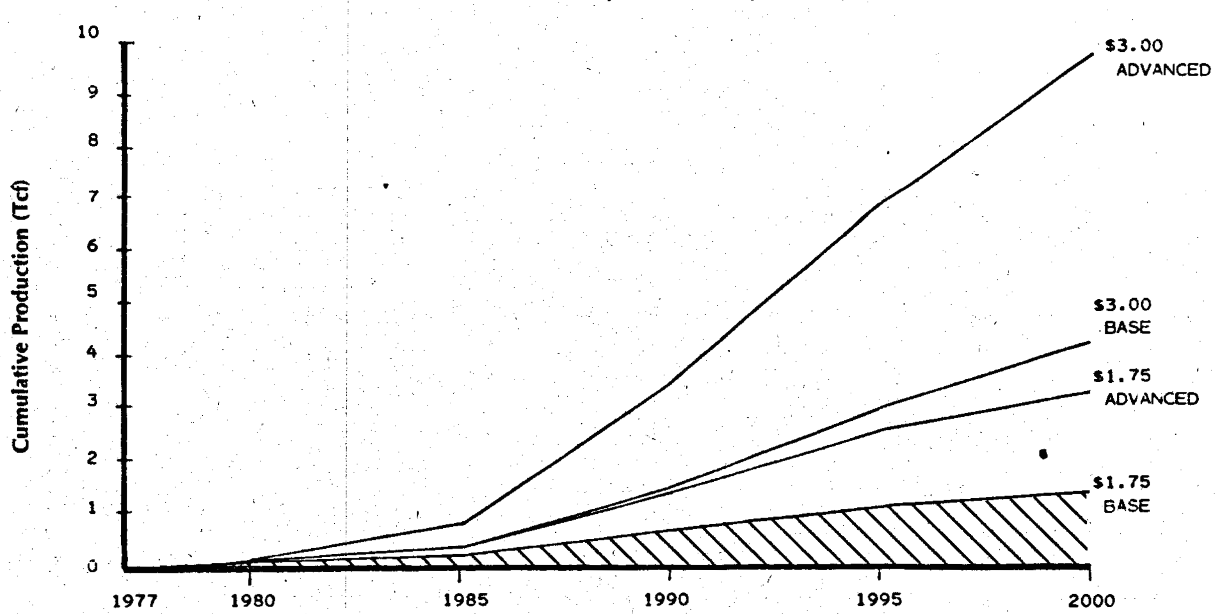
3. Recovery Efficiency. Increase the proportion of gas in place that is economically recoverable.

Exhibit 4-5

Annual Production from the Devonian Shale to the Year 2000 at $1.75 and $3.00/Mcf



Cumulative Production from the Devonian Shale to the Year 2000 at $1.75 and $3.00/Mcf



Section III elaborates on the nature of the resource and the challenges to characterizing it. Section IV addresses means for improving recovery efficiencies. Section V projects production under alternative economic and technological assumptions. The final section of this part summarizes the R&D program required to reach the higher estimates of the potential.

III. THE RESOURCE BASE

A. Essential Questions

The natural gas industry has conducted extensive exploratory and developmental drilling in the Appalachian Basin. In addition to the 9500 wells producing from the Devonian shale, 30 thousand wells have penetrated these brown/black shales in search of higher quality gas reservoirs in deeper sand, silt, and limestone formations.* This amount of drilling strongly argues that the more favorable portions of the shale may have been identified and the fact that new discoveries are on the decline** further argues that the most favorable areas may have already been developed.

To the extent these arguments hold, future discoveries are likely to come from the less productive portions of the basin. Locating economically producible gas from these less productive and technically challenging areas will require more detailed understanding of the resource than has heretofore been required.

Despite the number of wells drilled into or through the shale sequence, substantial uncertainty remains concerning its basic geology, areal extent, and reservoir properties.*** The following questions appear to be central:

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* E.g., the Oriskany, "Big Six", Medina, and Clinton formations.

** 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 1976.5/

*** DOE is currently supporting fundamental inquiries into many of these areas.

- What is the nature of the gas in the Devonian shales and what unique geological features -- e.g., origin of the gas, tectonic activity, stratigraphy, and depositional characteristics -- are essential to locate the gas and to assure its economic recovery?

- What is the likely areal extent of economically producible Devonian shale; how should this overall area be subdivided to form discrete, analytic units, each with individual geologic properties that govern economic performance?

- What is the estimated productive capacity within these analytic units?

This section discusses these questions and sets forth a definition of the resource base for estimating the economic potential of the Devonian shales of Appalachia.

B. Basic Geology

In brief, a combination of fortuitous geologic events has formed the gas in the Devonian shales.

1. Depositional History

The Appalachian Basin was at one time a large geosyncline covered by an epicontinental sea. Erosion of the Appalachian mountains (Taconic Range) created large sedimentary deposits during the late Silurian and early Devonian times. Organic matter developed during quiescent marine conditions and was subsequently overlain by massive deposition of argillaceous sediments. In later geological periods the sedimentary deposits were compressed, fractured, and exposed to fluid entry, verified by the frequent appearance of mineral filled fractures.

2. Origin of the Gas

The source of the gas in the Devonian shale appears to be the kerogen content found in the shale itself. This co-existence of the source bed and the reservoir makes the Devonian shales unique as well as posing a challenge to its recovery.

In general, the organic content of the major target formations, the "Brown Shale" of the Upper Devonian, ranges from 2.5 to 4.0% by weight, but exhibits considerable variations throughout the formation. For example, within one 350 foot core interval, the organic carbon content averages from 0.2 to 12%.[6/] The source material of the gas appears to be both marine and terrestial (woody-coaly) kerogen.

However, the presence of organic material in the source rock does not guarantee producible quantities of hydrocarbons. The organic material must have undergone sufficient metamorphosis to be converted to methane, and there had to be a sufficiently permeable porosity trap in which the gas could accumulate. Without enough permeability and porosity, methane and other hydrocarbons would remain "locked" into the source rock. A system of fracture porosity can well serve as the trap for desorbed and released solution gas.

It is probable that an equilibrium is reached between the pressure of the gas in the fracture, porosity, and the amount of gas adsorbed or held in solution. When the reservoir pressure is reduced through depletion, solution gas may again begin to migrate into the fractures. However, the rate of depletion, given the low organic concentration as well as the limited surface area, is slow and appears to contribute little if at all to recovery during the first 30 years of well life.*

3. Tectonic Activity

The faults and structural deformations which occurred during the active tectonic history of the Appalachian Basin appear to have induced the fracture porosity that now constitutes the Devonian shale gas reservoir.

Geologic study has identified some of these dominant fault systems, including one of the earliest basement faults, the Rome Trough. Exhibit 4-6 identifies the extent of the Trough and the relation to producing fields. Exhibit 4-7 shows the extensiveness of identified surface deformations within the Basin and their relation to producing fields. It also shows the abundance of smaller structural features which do not lie on the dominant northeast/southwest Basin trend in and around the Big Sandy Field. Except for the faults among the Allegheny Front, these features are post-Devonian and thus created the reservoir for the Devonian shale gas.

4. Stratigraphy

Stratigraphically the Devonian period is divided into three geological groupings. A summary is presented below beginning with the lowest formation.

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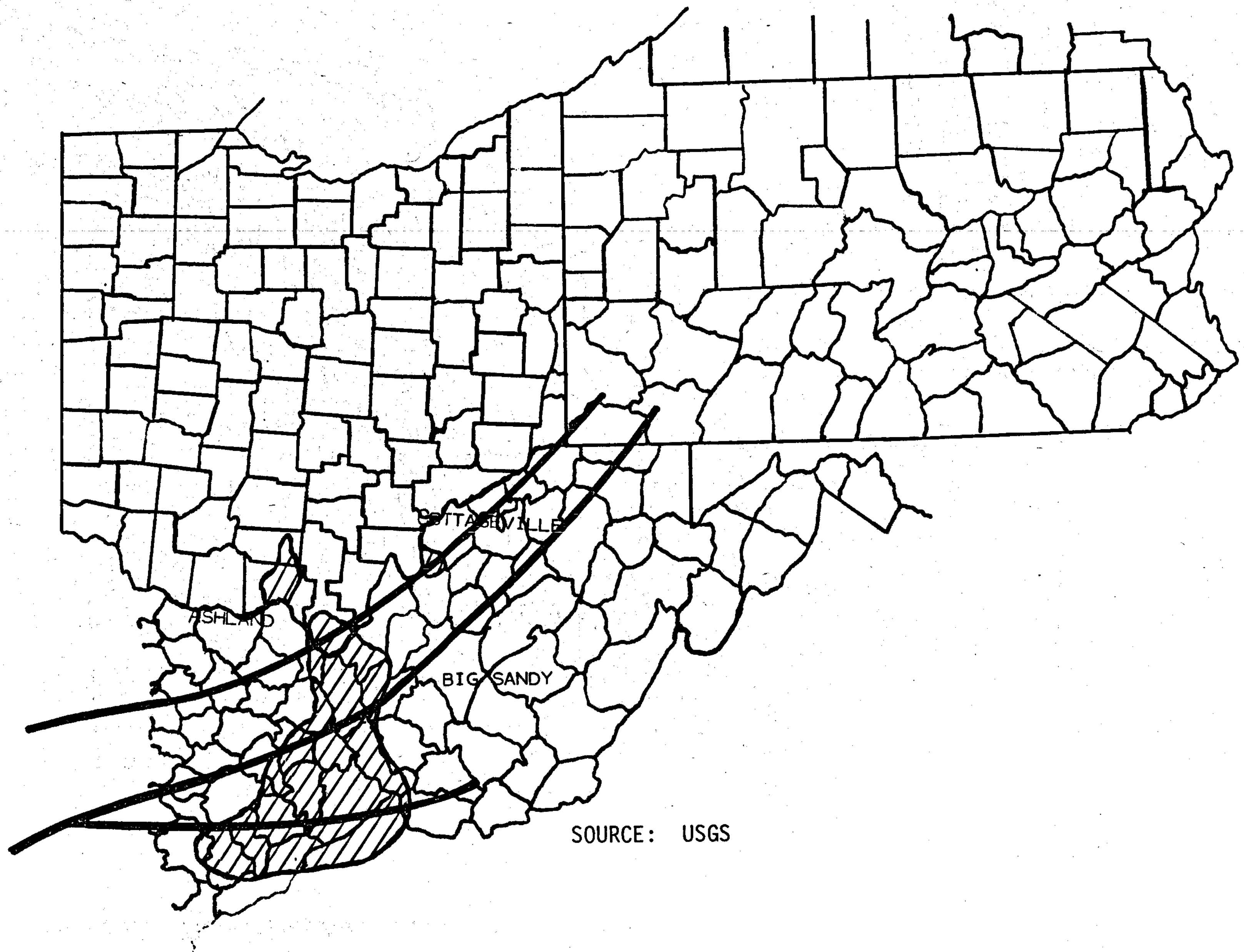
* In reservoir modeling the Devonian shales, the total thirty years of gas recovery could be accounted for by free gas in the fracture porosity.

Exhibit 4-6

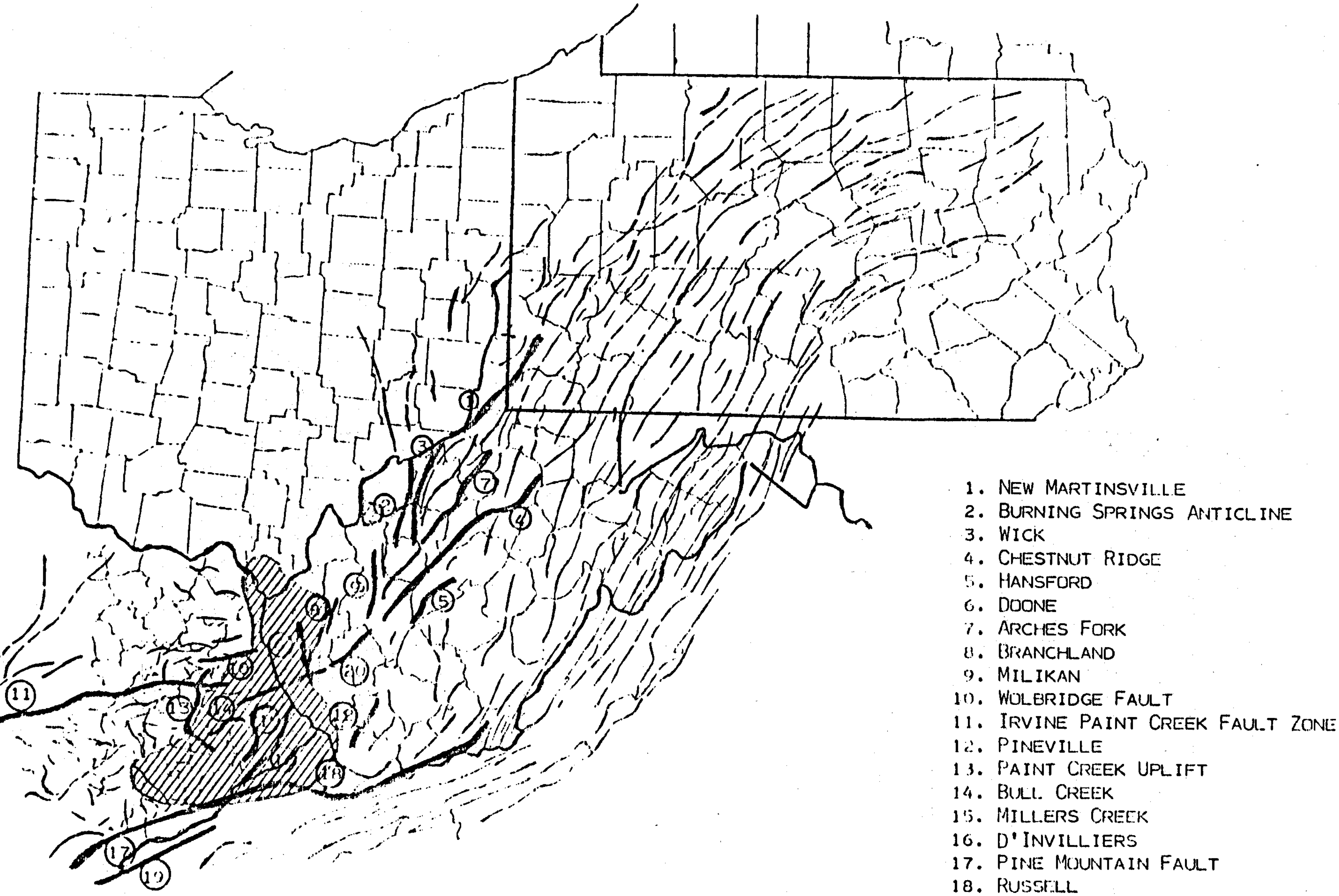
Extent of the Rome Trough



SOURCE: USGS

Exhibit 4-7

Structural Features of the Appalachian Basin



1. NEW MARTINSVILLE
2. BURNING SPRINGS ANTICLINE
3. WICK
4. CHESTNUT RIDGE
5. HANSFORD
6. DOONE
7. ARCHES FORK
8. BRANCHLAND
9. MILIKAN
10. WOLBRIDGE FAULT
11. IRVINE PAINT CREEK FAULT ZONE
12. PINEVILLE
13. PAINT CREEK UPLIFT
14. BULL CREEK
15. MILLERS CREEK
16. D'INVILLIERS
17. PINE MOUNTAIN FAULT
18. RUSSELL
19. POWELL VALLEY ANTICLINE
20. WARFIELD ANTICLINE

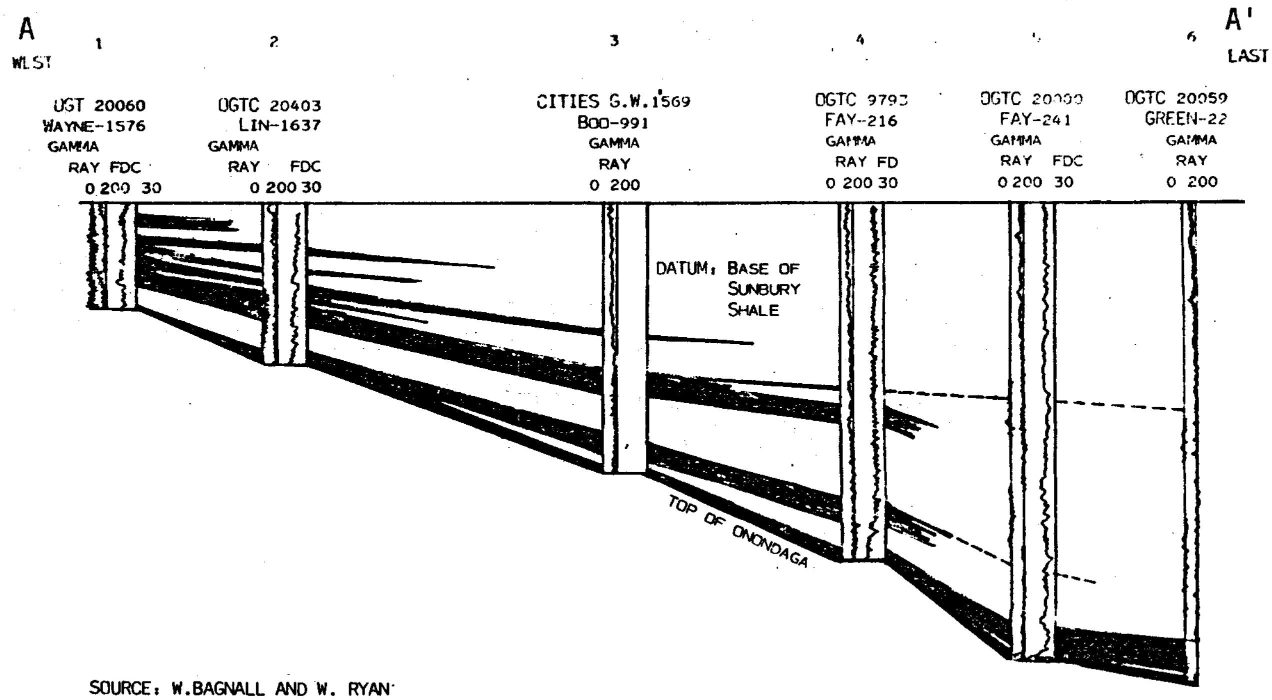
- Lower Devonian. The Lower Devonian consists mostly of sandstone and limestone, with some interbedded shales. The Oriskany sands and to a lesser extent the Helderberg limestone are the major gas producing zones.

- Middle Devonian. The first significant appearance of brown/black shales in the Devonian period occurs with the Middle Devonian Marcellus shales. However, while gas shows have been found in this section of the shale in northwestern West Virginia, parts of Ohio and Kentucky, little is known for certain about the productive capability.

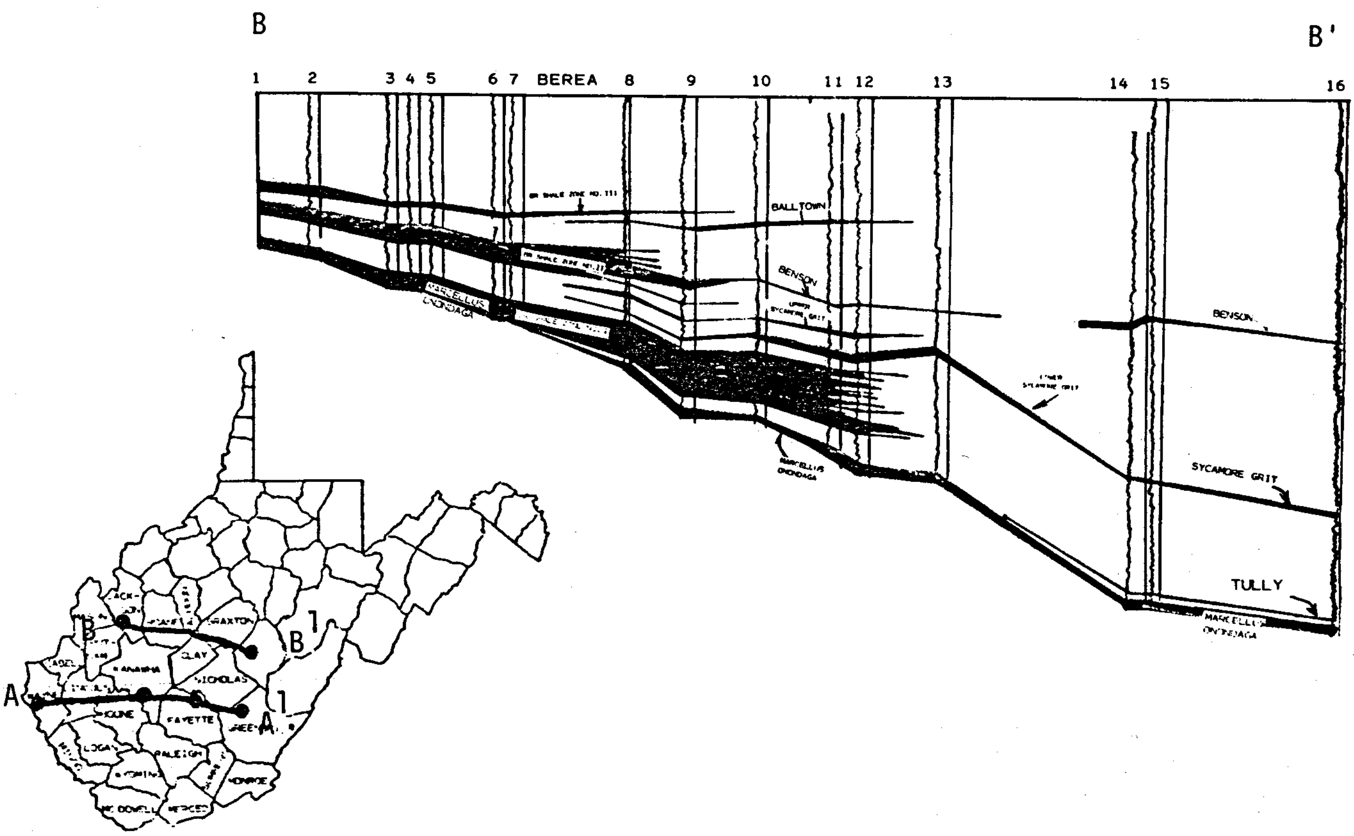
- The Upper Devonian. Often referred to as the "brown shales" or as the Ohio shales, the Upper Devonian has been the major Devonian shale gas producing zone, especially in the Big Sandy Field of eastern Kentucky and the Cottageville Field in central West Virginia. Exhibit 4-8 provides a cross-section of the Upper Devonian "brown shale" and gives an indication of the stratigraphy of the area. This stratigraphy influenced the characterization of the analytic units.

Exhibit 4-8

Generalized Cross-Section of the Devonian Shale in Southern West Virginia



SOURCE: W.BAGNALL AND W. RYAN



SOURCE: CONSOLIDATED GAS COMPANY
GEOLOGY: E.B. NUCKOLS

C. Areal Extent

1. Overall Area

The Appalachian Basin covers approximately 210,000 square miles and includes all or parts of ten states.[7] Approximately 100,000 square miles of the area has a low probability of being productive and has been excluded from this study (Exhibit 4-9) for the following reasons:

- Area A - The eastern portions of the Basin between the Allegheny and Blue Ridge Fronts (45,000 square miles). The brown/black Upper Devonian shales outcrop and the deeper Middle Devonian shales have been metamorphosed to such an extent that existing gas deposits are improbable.

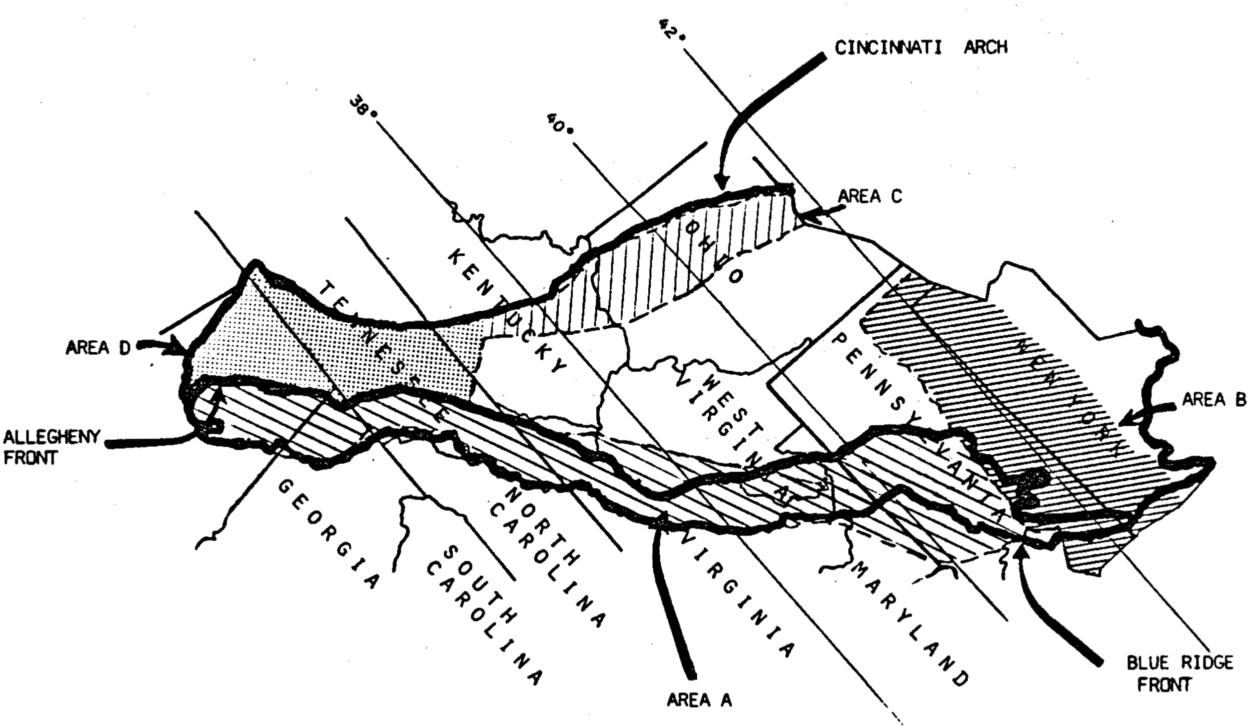
- Area B - The northern area of the Basin from Upper Erie across the State of New York and northeastern Pennsylvania (19,000 square miles). Like the eastern portion of the Basin, the shales have likely been metamorphosed to the extent of losing volatile hydrocarbons.

- Area C - The western flank of the Basin between the outcrops of Devonian brown/black shale and the Cincinnati Arch (15,000 square miles). The Devonian shales have played out and cannot be found from cross-sections.

- Area D - The southern portion of the Basin between the Allegheny Front and Cincinnati Arch from eastern Kentucky to Alabama (20,500 square miles). The shales are thin, averaging 25-50 feet in thickness, and represent a submarginal resource.

Exhibit 4-9

Geological Distribution of the Devonian Shales of the Appalachian Basin



SOURCE: DeWitt, Wallace and Perry

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.

An additional 48,000 square miles on the periphery of the examined acreage were classified as speculative, as they had no known productive wells, and were excluded from the analysis.

The remaining 62,000 square miles of the potential shales gas region of the Appalachian Basin were studied in detail. Of this, 5,000 square miles have already been drilled or found dry -- leaving 57,000 square miles as the future target.

This assessment of the total 210,000 square mile area is summarized below.

Definition of the Area	Areal Extent	Treatment by Study
• Areas A, B, C and D	100,000	Excluded because geology indicated the shale is thin or absent or the likelihood of gas is low
• Speculative	48,000	Insufficient data is available to define the economic potential of the area* -- excluded from this study
• Probable/Possible	57,000	Included in the study as the source of additional gas or potential gas
• Proved/Developed or Found Dry	5,000	Gas potential already included in proved reserves or past production

* By definition, speculative resources were excluded from analysis.

2. Analytic Areas

The 62,000 square miles of drilled and future potential area was divided into twelve analytic areas (Exhibit 4-10). Their principal characteristics are as follows:

- 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

- Area II - Eastern Kentucky, southwestern periphery of the Big Sandy Field; 2089 square miles, of which 1609 square miles are undrilled.

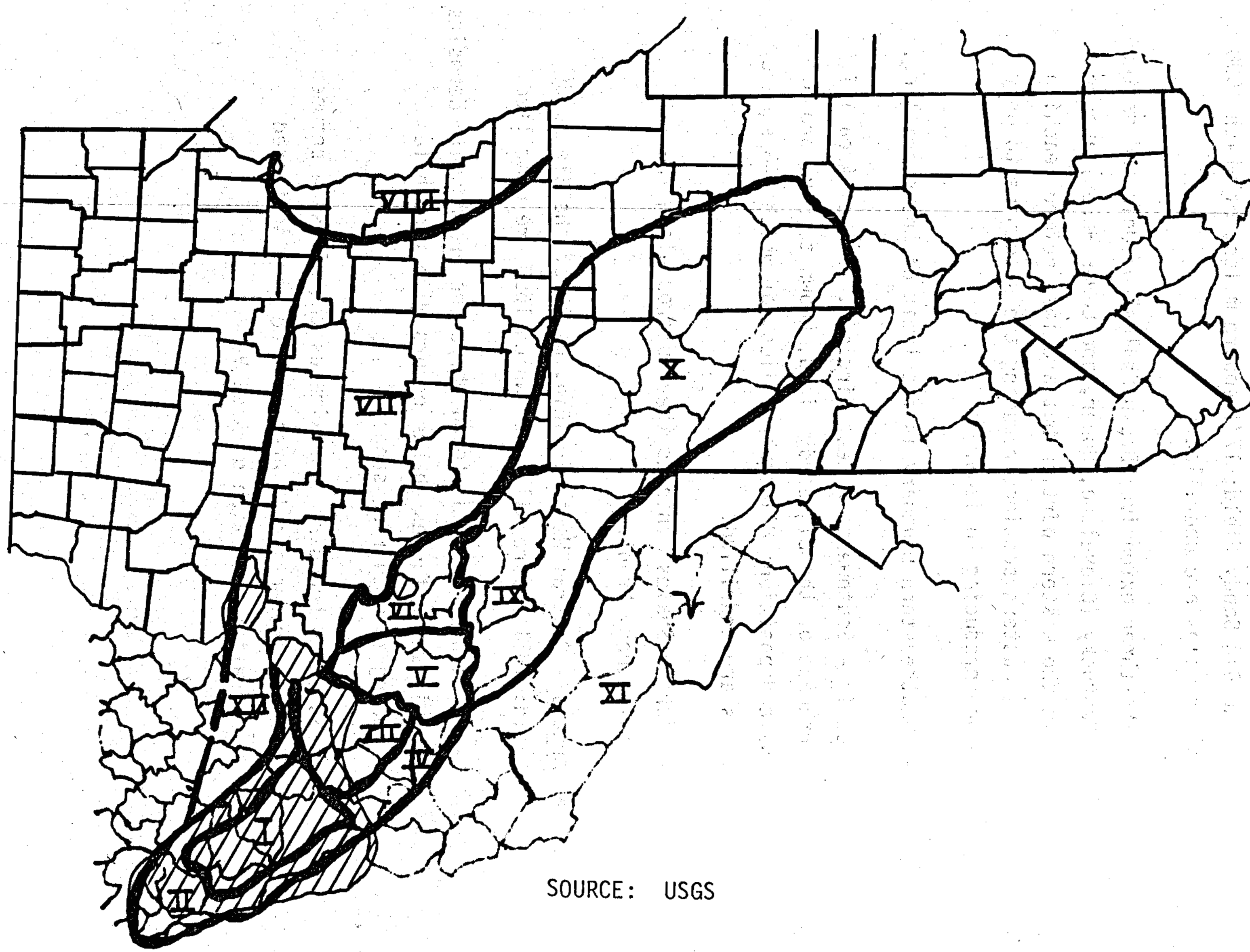
  -- "Brown Shales" in northern area merge into the oil producing zones without significant gas shows.

  -- Southern "Brown Shales" approach the outcrop area and are beginning to thin into less than 100-foot intervals.

  -- The Pine Mountain Overthrust in the southeastern region serves as a boundary for development drilling.

Exhibit 4-10

Areal Extent of Study
(Shaded Areas — Big Sandy, Ashland, and Cottageville Fields)



SOURCE: USGS

- 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) appear in the western portion but are lost 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, 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 known production in Area III and very scattered sporatic production of Area V.

-- 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; 3,090 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.

Each of the analytic areas was assigned a unique set of production curves, developed from empirical data on shot well performance, which were increased to represent incremental additional production from fracturing. The 30 year recovery curve was applied to the central part of each area and reduced in the periphary areas to represent field playout.

Exhibit 4-11 summarizes the location, the total, and the undrilled acreage in each analytic area.

Exhibit 4-11

Areal Extent of Analytic Units

Analytic Area	Location	Acres in Square Miles Total	Acres in Square Miles Undrilled
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	S.E. Extension	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
XIII	N.E. Kentucky	2,634	-
	TOTAL	62,183	56,651

D. Estimates of the Resource and Its Productive Capacity

1. Traditional Methods of Resource Analysis

The traditional means for estimating the original size and productive capacity of a gas field is to first collect the key volumetric data (e.g., porosity, net pay, areal extent, etc.) that provide an estimate of the size of the resource in place; second, to analyze core and well test data to develop the properties that govern rates of gas flow (e.g., permeability, pressure, etc.); and third, to apply reservoir engineering analysis to estimate production and ultimate recovery.

Given the limited data on the resource and particularly where the producible resource is the free gas in the fracture porosity, such a traditional approach is not yet possible for the Devonian shales.* However, some data has been gathered on certain of the key parameters and provide a departure point for further inquiries through reservoir simulation and history matching.

2. Porosity and Permeability Data from Core and Pressure Build-Up Analysis

Recently the Morgantown Energy Research Center measured the permeability and porosity on a Lincoln County well core under confining pressure approximating that of the reservoir. The cores had an effective permeability of less than 0.1 md and a porosity of less than 1%.

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* Past estimates using volumetrics or cannister off-gas analysis fail to define the dominant feature that governs production in the Devonian shales -- the natural fracture system.

A pressure build-up analysis, the first known to be run in the Devonian shale gas reservoir, indicated an effective permeability between 0.009 and 0.18 mds and a gas filled porosity between 0.8% and 1.9%. Although the permeability value derived from this analysis is that of the particular cores for the subject well, these observations are of considerable value in indicating the nature of the reservoir parameters for the particular area being studied.

3. Estimating Reservoir Data from History Matching

A standard procedure in reservoir engineering is to estimate reservoir parameters that govern production by matching the historical performance of the wells with the theoretical response of a hypothetical reservoir with assumed reservoir parameters -- history-matching.

a. The Essential Parameters

In order to predict the performance of such a gas reservoir using history matching, the following parameters must be known: 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.

b. The Analytic Approach

The preliminary analysis** of the shales was done using an isotropic, linear flow, reservoir simulation model modified to accept

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* For purpose of the analysis, it is assumed that the drainage area is 150 acres, the net thickness 500 feet, and the initial pressure and temperature 500 psi and 100^{o}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 Holditch and Moore at Texas A&M.

homogeneous and non-homogeneous flow. There is some thought that a fractured reservoir might be anisotropic, but no hard empirical evidence for this was found. Therefore, the reservoir analysis was not unduly complicated by including anisotropy.

(1) <u>Homogeneous Model</u>. The assumption was made that the Devonian shale reservoir comprises a network of fine, isotropic fractures through which the gas flows to the producing well. The flow through such a network is conceived to be approximating that for the radial flow of fluids through a uniformly distributed interstitial porosity such as that of a sandstone. It is then 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 boundary pressure being virtually unaffected despite the length of time during which the well has been producing. Therefore, the analysis can be made 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 arithemetic 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.

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* The analytic equation used in the reservoir simulator differ from the Hurst and vanEverdinger solution by making an adjustment to account for the compressibility drive effects prevalent in low pressure formations.

(2) Non-homogeneous Model. As a test of the analytic approach, a second set of reservoir geometrics was introduced -- a non-homogeneous reservoir consisting of a system of natural, horizontal fractures having radius of 15 to 50 feet spaced throughout the pay interval.

c. The History Matching

Three typical Devonian wells (a high, medium, and low), each having 30 years of production (shown on Exhibit 4-12) were history matched using the two reservoir geometrics.

The analytic approach provided an extremely close history match to long term production and potentially a unique solution.*

A history match of long term production data can be realistically divided into two parts. The early time data (0-5 years) is dominated by the permeability - thickness production of the reservoir and by the wellbore geometry. Therefore, using 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 actual production data will result in a common value of productivity index. (It would be possible to fix the value of r_w at any reasonable value and find a value of kh that would match the early time production data.) To obtain a unique match of early time data requires a series of well tests and/or a long term pressure buildup test.

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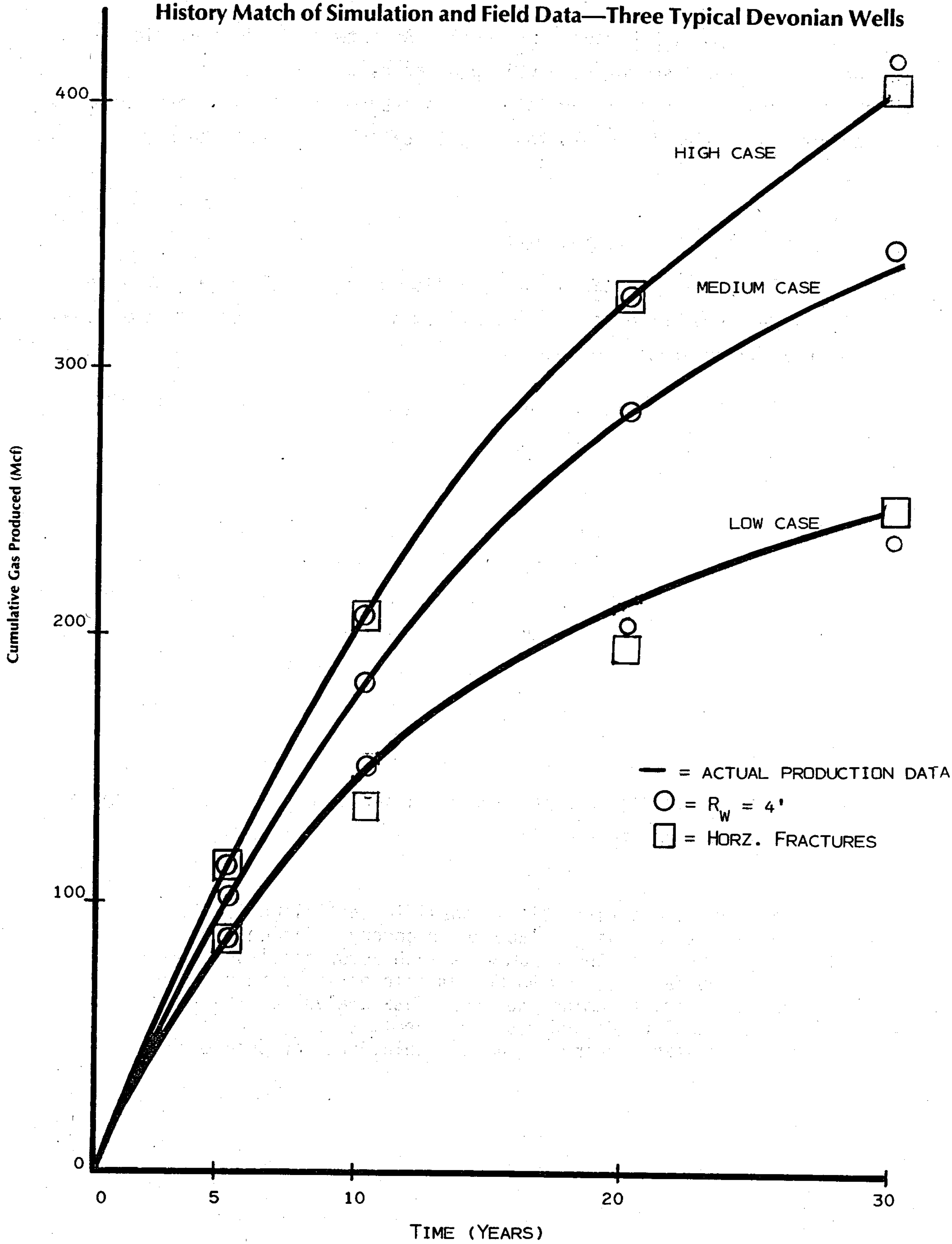
* According to the analyst: "It is possible that slightly different values of gas in place and recovery efficiency could be obtained, if the parameters such as original pressure, reservoir temperature, flowing bottom hole pressure. etc. were altered. However. assuming the input data are valid. the established withdrawal rates and reservoir decline rates are of sufficient duration to provide unique solutions for øh and kh."

Exhibit 4-12

History Match of Simulation and Field Data—Three Typical Devonian Wells



The reservoir decline rate, however, is dominated by the formation porosity-thickness product, which determines the original gas in place. Normally, if 30 years of production data can be history matched, the value obtained for gas in place is considered to be a unique solution.

The values used for porosity were insensitive to the wellbore geometry. Permeability, however, did slightly vary according to the wellbore geometry, but in general, the range of variation was not significant.

d. <u>The Results of the Analysis</u>

Several major conclusions emerge from this history matching:

- The Devonian shale gas reservoirs have porosities of less than 1%; higher production is a direct function of higher porosity as would be accounted for by more intense fractures:

Sample Wells	ϕ
High Production	0.8%
Medium Production	0.6%
Low Production	0.3%

- The permeabilities average about 0.02 md ranging from 0.018 md to 0.027 md.

- 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:

Sample Wells	Øh	kh
High Production	4	12
Medium Production	3	11
Low Production	1-2	10

- Considering the high values of kh compared to the low values of Øh, the analysis shows that a typical Devonian shale gas reservoir consists of a vast network of interconnected, natural fractures. Moreover, since all of the production could be accounted for by the free gas in the fractures, the contribution of gas in matrix porosity, to the extent such matrix porosity exists, would be small.

- 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 pressure build-up in the field and in the laboratory using restored state pressure conditions:

Reservoir Properties	Pressure Build-Up Data	Reservoir Simulation
Porosity	0.8 to 1.9%	0.3 to 0.8%
Permeability	0.01 to 0.18 md	0.02 to 0.03 md

4. Summary of the Productive Capacity of the Devonian Shales

The analysis strongly indicates that the Devonian shales are essentially a traditional, low pressure and low permeability gas reservoir where the natural fracture system provides the permeability and gas storage porosity.* Further, 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, as discussed in the next section.)

The major unknown is whether the wellbore is in contact with full vertical extent of the natural fracture system in a drainage area. This question would be further examined by one of the R&D programs recommended for the Devonian shales.

5. Estimation of Production

Additional reservoir data and improved capacity to model this resource may allow a more traditional approach for estimating the productive capacity of the Devonian shale to be pursued in the future. Until that time, however, the analysis must rely on an empirical approach using a representative sample of production histories from the nearly 10,000 wells that have produced from these shales.

The basis of the production estimates was empirical well data acquired from various gas companies on 250 individual wells. These data include annual production, rock pressures, and line pressures which enabled development of specific production decline curves for the areas defined as having potential shale gas.

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* It may be that the matrix contains additional porosity and gas. However, this matrix porosity does not appear to be in contact with the wellbore. Adding one more fracture plane to a well drainage area containing several hundred such fractures could not be expected to appreciably interconnect the now occluded areas.

Each well chosen had to meet five criteria:

- It was individually metered.
- The shale gas production was distinguishable from other producing horizons.
- The well needed to have a minimum historical production of 25 years for older fields and 15 years for newer fields.
- The sample needed to include high, average, and low producers.
- The sample had to contain at least 4-6 wells for each county defined within an areal unit.

The wells were classified by the eleven areally defined analytic units (Area XII was excluded because it appears thoroughly depleted). For each area, production from the sample wells was averaged and fit to a cumulative 30 year production curve using Marquardt's Algorithm,* providing the base production profiles required for economic analysis.

These base profiles were then modified to reflect two factors: that fields tend to produce less as drilling moves into extension and step-out areas; and that production from wells stimulated by hydraulic fracturing is generally higher than production from wells stimulated by shooting. Production multiplier values (PMVs) were created to account for these two factors.

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

Development of the field play-out value was based on experience in the eastern Kentucky Big Sandy Field.* Sample wells from the four primary counties comprising the Big Sandy Field were found to have a 30 year cumulative recovery of 512 MMcf, while those in outer counties were found to have 30 year cumulative recoveries of 255 MMcf, about one-half of the best area.

Using these values as indicators, each of the eleven areal units was divided into three portions and assigned a field play-out factor (a percentage of the base production curve) that reflected the shale thickness and extensiveness of fracturing, as estimated from the stratigraphy and tectonic activity.

Next, the base production curves (derived from shot well data) were increased to reflect anticipated improved performance from using hydraulic fracturing rather than shooting. Work done by Ray[8/], described above, suggests that wells having initial open flows between 100-200 Mcf would increase cumulative production by 46% after 5 years with hydraulic fracturing; while wells with an initial open flow of 200-300 Mcf would increase cumulative production by 17% after 5 years. Thus, production was increased by 15 to 50 percent, depending on the initial open flow.

Exhibit 4-13 shows the area, the original shot well production, and the field play-out adjustment and fracturing adjustment that provide the final thirty-year cumulative recovery estimates. (Because of extremely limited production history, Areas IX, X and XI were estimated from other areas without adjustment for stimulation technology.) The annual production profiles developed through this procedure were used in the economic analysis.

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* Historically, Kentucky wells averaged initial open flows near 330 Mcf/D. Recent wells are clustered in the range of 100-275 Mcf/D, suggesting less production as the better portions of the reservoirs are depleted. The decreasing production as reservoir boundaries are approached is known as field play-out.

Exhibit 4-13

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

IV. IMPROVING GAS RECOVERY FROM DEVONIAN SHALES -- THE FEDERAL ROLE

As the Devonian shale resource base becomes further understood, the major challenge will be to increase the amount and advance the timing of gas production from these shales. For this, one needs to pose the basic question:

What appears to constrain rapid development and economic production from the Devonian shales:

-- *Are the natural gas reservoirs within the Devonian brown/black shale sequence being effectively drained?*

-- *Are there additional reservoirs of natural gas in the brown/black shales from which recovery of the resource is constrained by the lack of suitable technology and/or economic incentives?*

An analysis of the resource base through reservoir engineering indicates that three basic strategies should be followed for increasing gas recovery from the Devonian shales:

- Identifying additional Devonian shale areas in the Appalachian Basin having economic potential for gas recovery.

- Testing dual-completion practices for recovering gas from low production, economically marginal formations in central Ohio (and if possible in other parts of the Basin).

- Improving recovery efficiency in the identified and productive parts of the Basin.

A. Additional Potential

The research effort involved in the first strategy -- identifying additional areas of Devonian shale potential -- is straightforward. One needs to drill and test a number of resource characterization wells to establish that a sufficiently intense natural fracture system is present and that gas fills this fracture system. This is what the gas production industry has done, in the Basin, for over 50 years. The special aspect is that the area under consideration is deep, expensive to drill, and costly to produce. Economic recoverability in these areas, even if the shales are found to be fractured and gas containing, will likely require gas prices considerably in excess of today's levels. Thus, the gas production industry has relegated resource definition in these areas to a lower priority. It appears that public R&D is required to accelerate a definition of the productive potential of these deeper, higher cost areas.

Traditional exploration and production analysis was used to assess the potential of this first R&D strategy.

B. Dual-Completion Practices

A second target for research and development involves areas where non-commercial, but physically productive, shale sequences overlie deeper, traditional producing horizons. Here it may be possible to use dual-completion (with improved stimulation) and produce the now uncommercial shale by having the primary formation bear the major drilling and operating costs.

Such an opportunity exists in central and eastern Ohio. Given the need to tailor special completion practices as well as work over existing wells, a demonstration of the technical and economic feasibility of such an approach appears required before industry could be expected to vigorously pursue this second target.

A marginal cost analysis was used to assess the potential of this second R&D target.

C. Improved Recovery Efficiency

A third and traditional target for R&D is improving recovery efficiency to a level above that being attained by traditional production practices. Three approaches appear worthy of consideration:

- Closer well spacing in the more productive areas
- Improved stimulation practices, such as using more efficient and cost-effective stimulation and fracture technology.
- Placing the wellbore in contact with the full vertical fracture system, should current completion practices be falling short of this goal.

History matching with a reservoir simulator using a two dimensional, finite difference model, described previously, was used to assess the potential of this third R&D target.

Three actual sets of field data from typical Devonian gas wells having the properties previously shown on Exhibit 4-12 were used in the analysis. The findings from this analysis are discussed below.

1. The Efficiency of Small Fractures

At 150 acre spacing and with small fractures, in general, the field is already being drained efficiently with recovery efficiencies of 50 to 60 percent.

Using an economic limit of 8 Mcfd the following recovery efficiencies are found for shot versus fractured wells*, at 150 acre spacing:

- Shot Wells (4' radius or 6 horizontal fracs):

	Gas in Place (MMcf)	30 Year Production (MMcf)	Recovery Efficiency (%)
- High Production	880	410	47
- Medium Production	666	330	50
- Low Production	352	220	61

* Additional analysis was conducted on the wells in Ohio, however, since recovery efficiencies in these areas appear to be about 60%, significant improvements in recovery efficiency did not appear feasible.

- Small Vertical Fractures (100 feet)

	Gas in Place (MMcf)	30 Year Production (MMcf)	Recovery Efficiency (%)
- High Production	880	500	57
- Medium Production	666	430	65
- Low Production	352	220	62

Using small vertical fractures 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.

2. The Potential of Infill Drilling

A first step toward assessing the potential for further improving 30 year recovery in low permeability formations would be to examine closer well spacing. For this, analytic areas were developed on 75 rather than 150 acres, using shooting as well as small fractures. The simulation showed that 30 year recovery in the high production case could be further improved by 20%, from a base of 56% to a range of 65% to 70%. Smaller improvements were realized in the medium production case, while the low production case had (because of the economic limit) essentially no change. This is shown on the table below:

- Reducing Spacing (75 acres) with Small Fracs:

	Gas in Place (MMcf)	30 Year Production (MMcf)	Recovery Efficiency (%)
- High Production	440	300	68
- Medium Production	333	230	70
- Low Production	176	120	66

Under reduced spacing, recovery efficiencies are in the 60 to 70 percent range and production reaches economic limits within the 30 year period. At this spacing, further recovery efficiency* improvements do not appear feasible, although acceleration of production into the earlier years would be possible through improved stimulation practices and enlarged wellbores.

3. Other Potential Improvements

The major unknown is: What portion of the total natural fracture system in a drainage area is in contact with the wellbore? Since no unusual boundary effects are evident from matching field data, the model gives strong evidence that the wellbore is in contact with the full horizontal plane of the drainage area. However, the Devonian shale comprises several depositional cycles, and vertical communication between intervals may not be naturally present or included by conventional completion procedures. The relatively narrow range of response of wells in any particular area argues against this. Nevertheless, a high priority must be assigned to determining whether it is possible to enhance Devonian gas production by selective and multiple completions within the total Devonian shale section.

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* The simulation model was run to test the potential of using larger, 500 to 1,000 fractures. The results of the analysis showed no significant difference in 30 year recovery efficiency between using 100 to 200 foot fractures and using larger 500 to 1,000 fractures. This result is due to the fact that recovery efficiency using smaller fractures is already quite high and additional production can only be achieved at what appears to be less than economic flow rates.

V. POTENTIAL OF THE DEVONIAN SHALE OF APPALACHIA

A. Approach

Estimating the economic potential of the Devonian shales requires two sets of assumptions, namely:

- Specifying the level of technology:

  -- Base Case: The level of the resource development expected to be attained by industry during the next five years without active federal involvement.

  -- Advanced Case: The level of the resource development expected to be attained by virtue of active federal-industry collaboration.

- Defining field development costs, return on capital requirements, prices, and timing.

These two key steps are further described below.

1. The Technological Assumptions

Two levels of resource development and technology were assumed -- the Base Case and the Advanced Case. The Base Case conditions were derived from discussions with producers in the Basin concerning their development plans and the status of the technology over the next five years. The Advanced Case was specified as the result of successful execution of the Federal R&D program described in detail in Part 2 of this chapter.

Exhibit 4-14 shows the principal differences between the Base and Advanced Cases. These differences can be grouped under four broad headings:

- Resource Characterization
- Technology
- Economics
- Development

Each is discussed further below.

a. Resource Characterization

Industry's efforts are centered currently on the probable areas -- essentially extension drilling and step-outs.

A focused program of resource characterization could obtain sufficient data on the poorly defined, possible areas of the Devonian shale to stimulate further drilling and development, where economic. Such a program would be directed at a 30,000 square mile area (Areas IX, X, and XI) of Devonian shale, and should sufficient fracture intensity and gas be discovered, this could appreciably increase the potential in the Appalachian Basin.

A second purpose of the resource characterization effort would be to apply improved geologic and reservoir engineering measures to the probable areas to reduce the number of marginal and dry wells from the current rate of 20%.

A third purpose would be to quantify the distribution of "free gas" porosity between matrix and fractures and to obtain a range of gas permeability contrast between matrix and fracture porosity systems.

Exhibit 4-14

Summary of Major Differences Between Base and Advanced Cases in Devonian Shale Analysis

STRATEGY/ITEM	BASE CASE	ADVANCED CASE
Resource Characterization		
• Eligible Areas	Probable Areas	Probable and Possible Areas
• Dry Hole Rates	20%	10%
Technology		
• Completions	Single	Dual where low producer underlain by other productive pay
• Stimulation	Standard 1000-bbl fractures	Optimized fractures
• Recovery Efficiency per unit area	Current levels	Improved by 20% in higher producing areas
Economics		
• Risk - reflected in discount rates* of	21%	16%
Development		
• Start Year for Drilling		
- Probable Areas	1978	1981 (R&D effect begins)
- Possible Areas	1987	1987
• Development Pace		
- Probable Areas	17 years to completion	13 years to completion
- Possible Areas	17 years to completion	15 years to completion

*Discount rates include a constant ROR base of 10 to 15% and an inflation adjustment of 6%.

The remainder of the resource characterization effort would be directed at obtaining sufficient reservoir data to support improved production technology. This becomes a prerequisite to the technology improvements discussed below.

b. Technology

The Base Case assumes that producers will use small fracturing technology. Further, technological improvements due to R&D are twofold:

- Achieving improved well completion practices to enable the dual completion of economically marginal, low producing pays with underlying economically producible gas horizons (particularly in Ohio).

- Increasing recovery efficiency in the high production areas (the heart of the Big Sandy) by 20% by using infill drilling and improved stimulation technology.

c. Economics

Producers currently view gas production in the Devonian shales as a moderate risk venture. The intended outcome of the R&D program is to reduce the financial risk premium to conventional levels.

d. Acceleration

The final purpose of the R&D program is to accelerate the time by which the Devonian resource could be drilled and produced.

2. Economics and Timing

A net present value (discounted cash flow) model was used to simulate the economics of production.* The unit of analysis was the individual well and its drainage area representing specific areal units. The estimated investment and operating costs of the well were offset by the revenue stream generated by gas production times its price. This net cash flow was then discounted by the specified return on investment. The areal units for which this discounted (present) value exceeded zero were developed, according to the timing model.

State-level drilling and completion costs were drawn from the API Joint Association Survey of Costs. Well stimulation costs were provided by major service companies. Surface equipment and operating costs were developed from studies by Gruy Federal, Inc.[9/] Dry hole and exploration costs were functions of drilling and completion costs and the areas involved. All costs were varied as a function of depth and geographic region. Taxes, royalties, burden rates, and accounting procedures were drawn from actual applications in each region. Constant 1977 dollars were used throughout the analysis.

These costs were then compared with company records and modified to incorporate any unusual features of Appalachian shale wells.

The analysis was conducted for three gas prices -- $1.75, $3.00, and $4.50 per Mcf. Where the well, representing a specific areal unit, was found to be economic, it was extrapolated to the full area. Each area was assumed to be developed according to a fixed schedule. The better defined (probable) areas were assumed to be developed first, followed by the less well defined (possible) areas.

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* See Volume III for additional detail.

B. Base Case Estimates

The amount of gas production and its rate in the Base Case is highly sensitive to gas price. As shown on Exhibits 4-15 and 4-16, additional recovery could range from less than 2 Tcf at $1.75 per Mcf to over 10 Tcf at $4.50 per Mcf; the production rate in 1990 would range from about 0.1 Tcf per year (at $1.75/Mcf) to 0.3 Tcf per year (at $4.50 per Mcf). This is discussed further below.

1. Ultimate Recovery

In terms of ultimate recovery (total production or reserve additions in 30 years of well life):

- About 2 trillion cubic feet will be economic at $1.75 per Mcf.

- Increasing the price of gas to $3.00 per Mcf could raise the estimate to about 8 Tcf. This significant increase is contingent on the conclusion that apparent field play-outs have been primarily dictated by sheer economic considerations.

- At $4.50 per Mcf, estimated ultimate recovery could only rise another 2.5 trillion, to 10.5 trillion cubic feet.

2. Production Rates

- At $1.75 per Mcf, the Base Case production rates would peak at 0.1 Tcf in 1990 and decline thereafter.

- Higher prices could sustain production over a longer period, providing 0.3 Tcf per year in 1990.

Exhibit 4-15

Devonian Shale Ultimate Recovery at Three Prices — Base Case

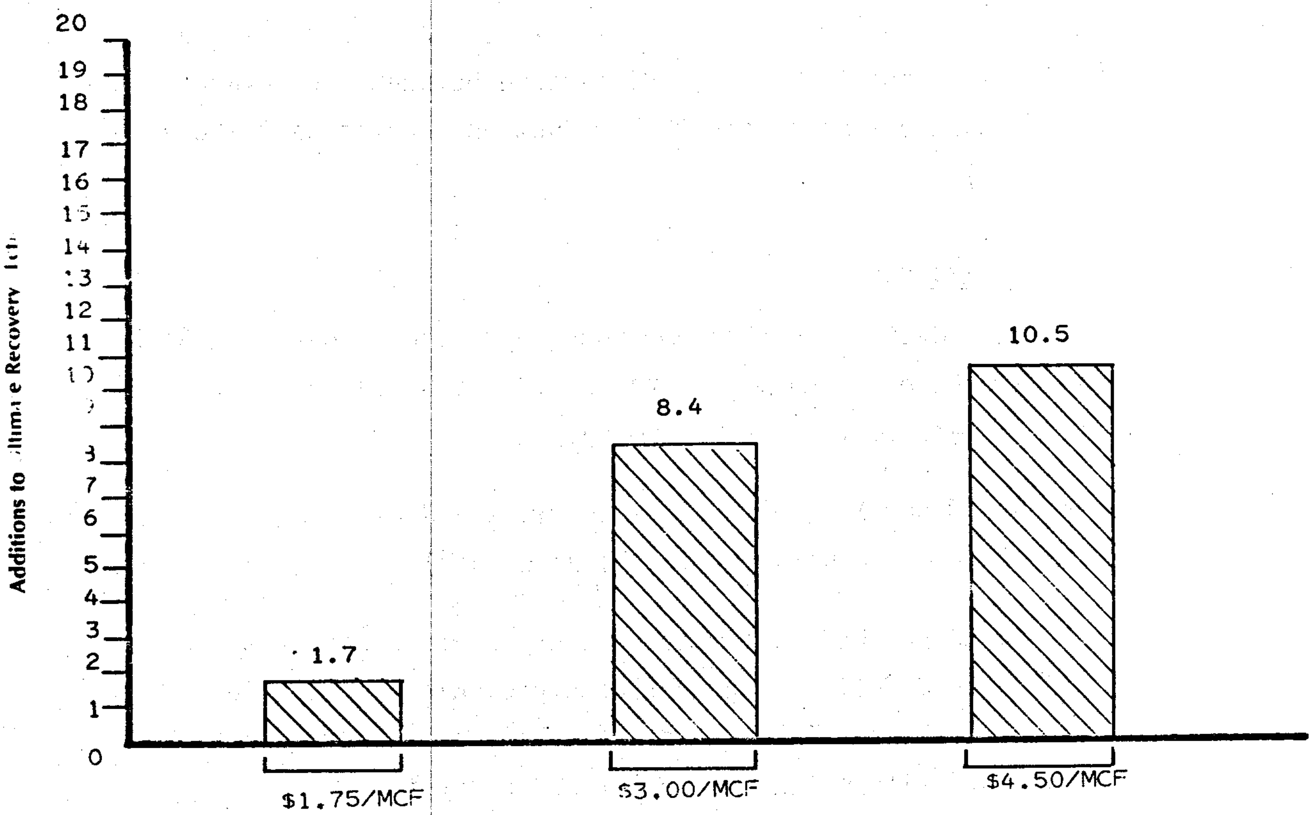
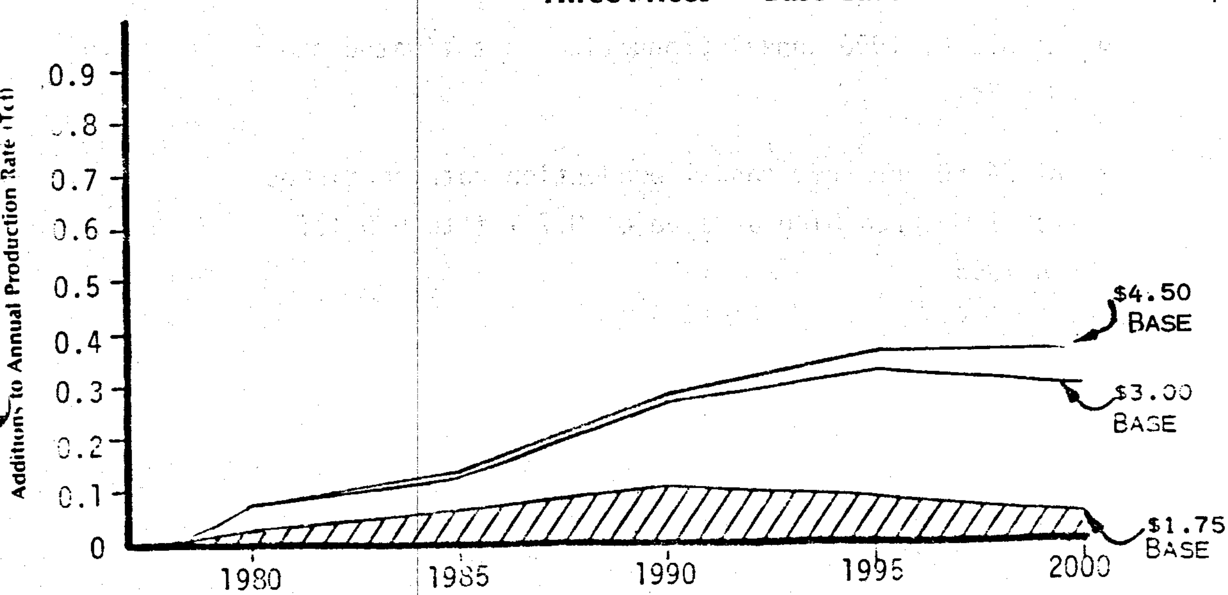


Exhibit 4-16

Annual Production from the Devonian Shale to the Year 2000 at Three Prices — Base Case



C. The Advanced Case Estimates

Considerable amounts of additional gas could accrue from a successful R&D program in the Devonian shales -- the Advanced Case, as shown on Exhibits 4-17 and 4-18. (The difference between the Advanced Case and the Base Case estimates are the production benefits attributable to the R&D program.)

1. Ultimate Recovery

Under the Advanced Case assumptions, ultimate recovery at $1.75 rises from the Base Case estimate of 2 to 4 Tcf. At higher prices, considerably more recovery could be forthcoming:

- At $3.00 per Mcf, ultimate recovery could rise to 16 Tcf (versus about 8 Tcf in the Base Case).
- At $4.50 per Mcf, ultimate recovery could range from 18 to 25 Tcf (the range reflects geological uncertainties in the possible areas where little is known about the intensity of the natural fracture system).

2. Production Rate

- In 1990, annual production under the Advanced Case and at $1.75 per Mcf is projected at about 0.2 Tcf.
- At $3.00, 1990 annual production is estimated at 0.6 Tcf.
- At $4.50 per Mcf, annual production rate continues to climb, reaching a range of 0.7 Tcf to 0.9 Tcf in 1995.

Exhibit 4-17

Devonian Shale Ultimate Recovery (at Three Gas Prices)

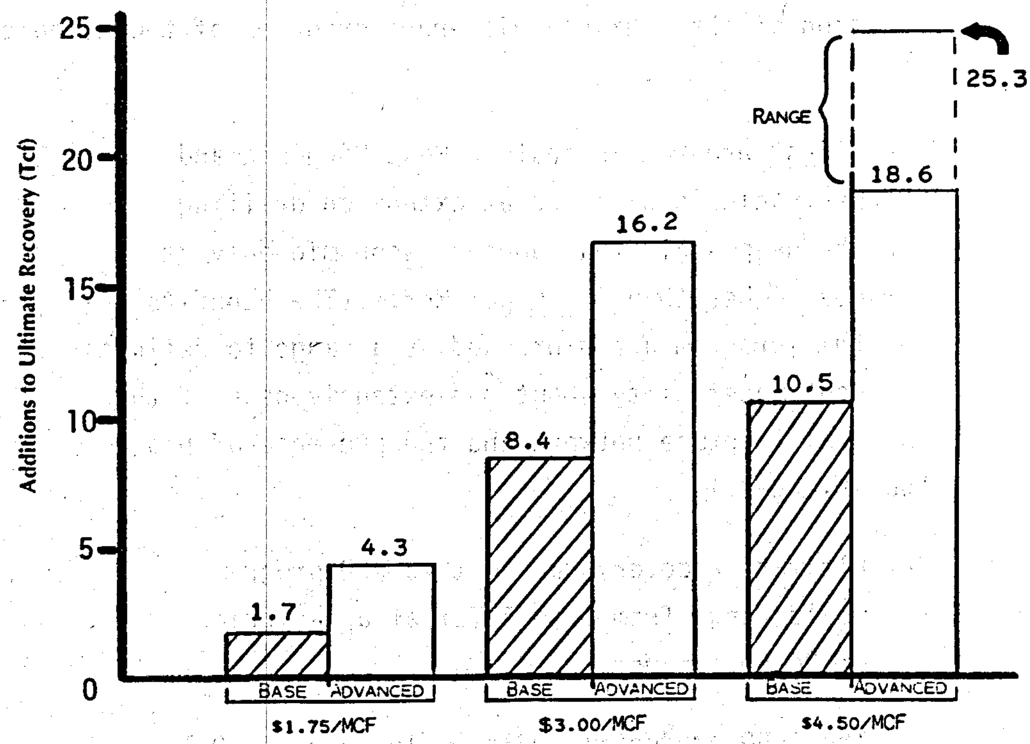
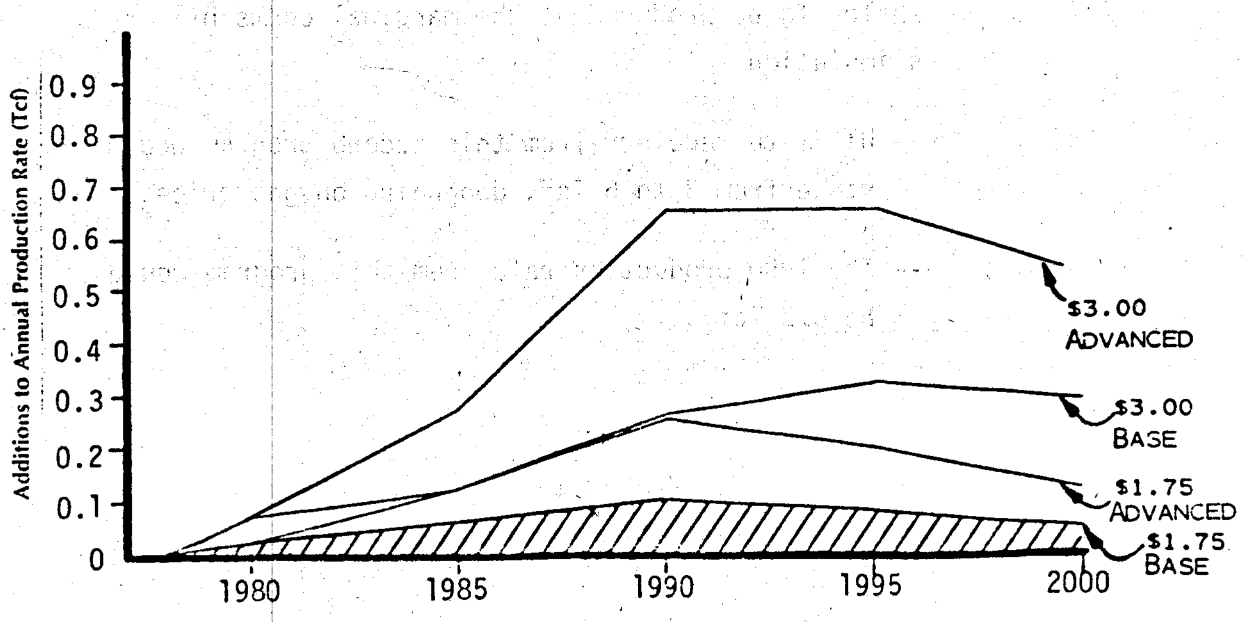


Exhibit 4-18

Annual Production from the Devonian Shale to the Year 2000 (at $1.75 and $3.00 per Mcf)



3. The Essential R&D Programs

The improvements in production in the Advanced Case come from successful execution of three highly different programs of technological advance:

- The first program in eastern West Virginia and Pennsylvania is directed at extension drilling in the deep shale that appears economic only at prices higher than $3.00 per Mcf. (The benefits of this program are expressed as a range to reflect present uncertainty about the extensiveness of the natural fracture network and the presence of producible gas.)

    -- Ultimate recovery due to this R&D program would range from 0 to 7 Tcf at a gas price of $4.50 per Mcf.

    -- The 1990 production rate would be below 0.1 Tcf.

- The second program (in Ohio) depends on dual completions of wells in the shales, underlying sandstone and limestone gas reservoirs, thus permitting the shales to be produced at the marginal costs of stimulation.

    -- Ultimate recovery from this second program would range from 3 to 6 Tcf, depending on gas price.

    -- The 1990 production rate from this program would be 0.2 Tcf.

- The third program (in eastern Kentucky and western West Virginia) is to improve recovery efficiency in the heart of the currently being developed area through optimizing stimulation, well spacing, and development practices.

  -- Increasing recovery efficiency would add about 2 Tcf at gas prices of $3.00 per Mcf.

  -- The 1990 production rate would be about 0.1 Tcf.

Exhibits 4-19 and 4-20 show the Base Case and the Advanced Case for the three R&D programs, at three gas prices.

D. Summary

The Devonian shales could add from 2 to nearly 25 Tcf of gas to domestic production, depending on the technology and price assumptions. From a public policy perspective, a combination of technological advances and higher prices appears to provide the most cost-effective strategy for ensuring additional quantities of gas for portions of the country that have been seriously imperilled by curtailments in interstate gas supplies.

Exhibit 4-19

Base Case — Ultimate Recovery from the Devonian Shales at Three Prices by Program

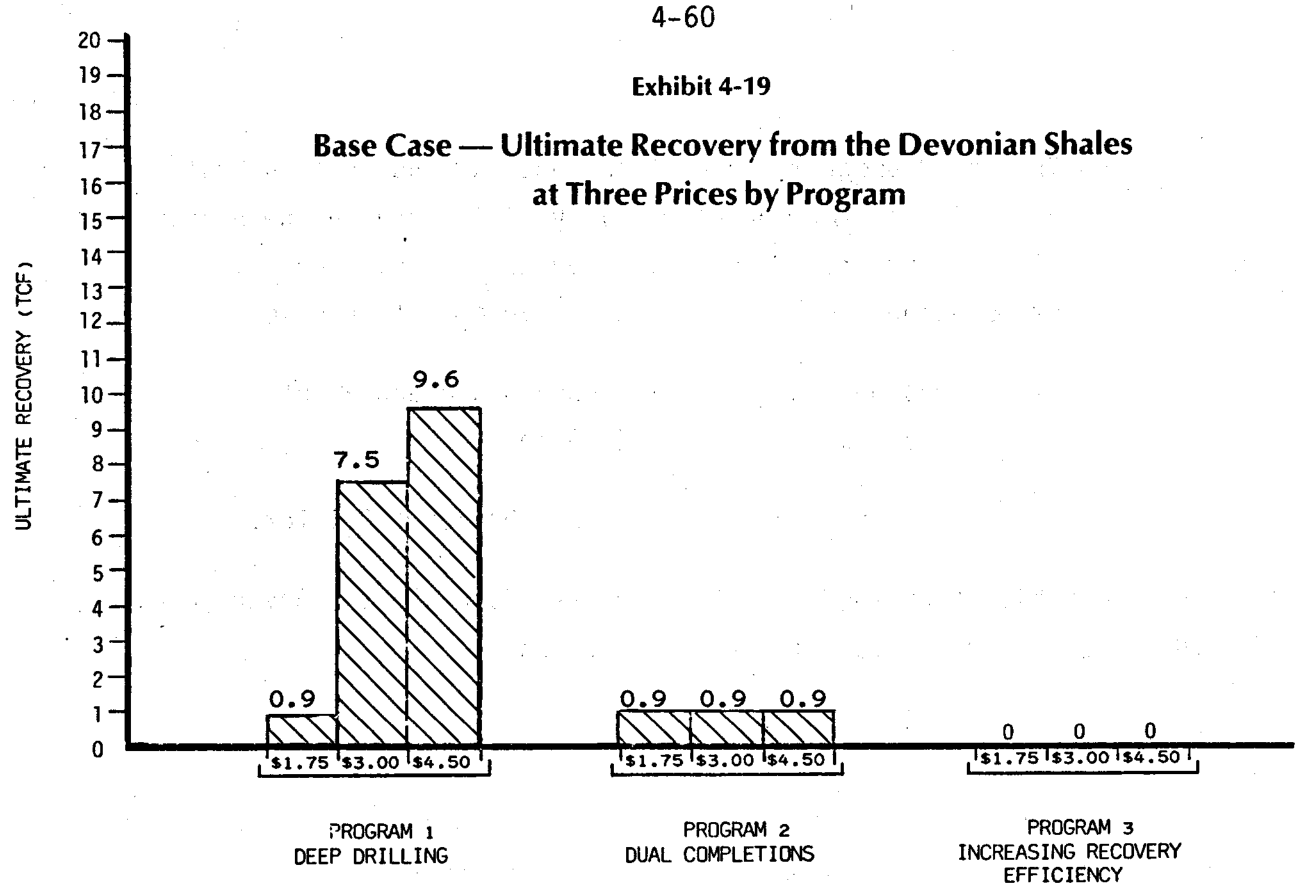
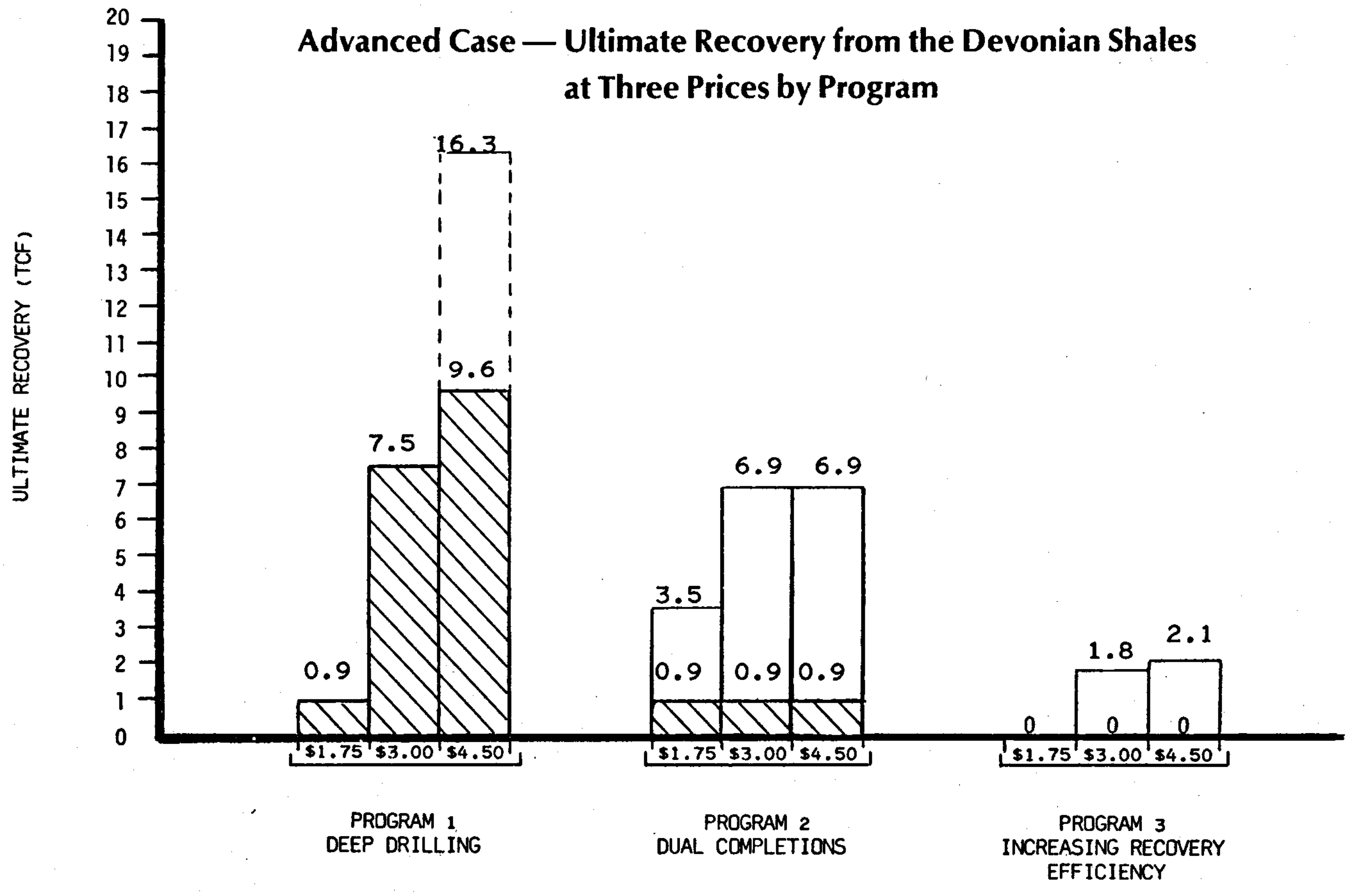


Exhibit 4-20

Advanced Case — Ultimate Recovery from the Devonian Shales at Three Prices by Program



VI. SUMMARY OF THE R&D PROGRAM AND ITS POTENTIAL

This final section of Part 1 summarizes the major R&D goals, the production benefits, the costs, and the cost-effectiveness ratios of a successful R&D program. Part 2 of this chapter provides further details of the proposed programs.

A. Research and Development Goals

The three technological challenges -- new areas, dual-completion, and improved recovery efficiency -- form the R&D goals of the Devonian shale programs in the Appalachian Basin, listed below:

- Define the Potential of Deep Devonian Shales. Drill exploratory wells and employ improved stimulation technologies to the deep (over 5,000 feet), currently non-producing shales in northern West Virginia and southern Pennsylvania.

- Produce Marginal Devonian Shales Through Dual-Completion. Use dual completion and improved stimulation technologies in areas where the currently non-producing shale sequences overlie deeper producing horizons (the Clinton formation) in central and eastern Ohio.

- Improve Recovery Efficiency. Infill drill and apply improved stimulation techniques in areas of major historical production, particularly the Big Sandy Field and its extension.

B. Activities and Costs

The activities required to achieve these goals can be grouped in four broad categories:

- Resource Characterization
- Improved Diagnostic Tools
- Field-Based Research, Development, and Demonstration
- Technology and Information Transfer

The amount of professional time and the number of tests required to carry out these activities are summarized in Exhibit 4-21. A total of 65 person-years are devoted to resource characterization, 25 to improved diagnostic tools, and 20 to technology transfer. Field-based R&D is a mix of resource characterization cores and wells, measurement calibration tests, technology improvement tests, and field demonstrations of improved technology. A total of 106 such projects are required.

Exhibit 4-22 summarizes the costs of these strategies for the five-year period FY 79 to FY 83. The total five-year cost, in constant 1977 dollars, is $38.1 million. The program is designed to take advantage of industry's interests in producing the Devonian shales, thus presenting cost-sharing opportunities. Of the $38.1 million total, industry is expected to contribute $8 million, leaving a federal cost of about $30.1 million.

Exhibit 4-21

Summary of Program Activities for Devonian Shales of Appalachia (Five-Year Strategy Totals)

Target/Program		Resource Characterization (Person-Years)	Improved Diagnostic Tools (Person-Years)	Field-Based RD&D (Cores/Wells)	Technology/ Information Transfer (Person-Years)
PROGRAM 1:	Define Potential of Deep Devonian Shales	15	10	19	5
PROGRAM 2:	Produce Marginal Devonian Shales Through Dual-Completion	30	15	30	10
PROGRAM 3:	Improve Recovery Efficiency	20	-	57	5
	TOTAL	65	25	106	20

Exhibit 4-22

Costs of the R&D Program for the Devonian Shales

Target/Program		5 Year Program Costs (in millions) Total	Federal Share
PROGRAM 1:	Define Potential of Deep Devonian Shales	$10.6	$8.6
PROGRAM 2:	Produce Marginal Devonian Shales Through Dual-Completion	13.0	11.5
PROGRAM 3:	Improve Recovery Efficiency	14.5	10.0
	TOTAL	$38.1	$30.1

Exhibit 4-23

Production Benefits Due to Successful R&D
(at $3.00/Mcf)

Target/Program		Ultimate Recovery (Tcf)	1990 Annual Production (Tcf)	1990 Cumulative Production (Tcf)
PROGRAM 1:	Define Potential of Deep Devonian Shales	*	*	*
PROGRAM 2:	Produce Marginal Devonian Shales Through Dual-Completion	6.0	0.3	1.7
PROGRAM 3:	Improve Recovery Efficiency	1.8	0.1	0.3
	TOTAL	7.8	0.4	2.0

*Gas production from Program 1 is economic only at $4.50 per Mcf; the production benefits at $4.50/Mcf are: Ultimate Recovery - 0-6.7 Tcf; 1990 Annual Production - 0-0.3 Tcf; 1990 Cumulative Production - 0-0.1 Tcf.

C. Incremental Production Benefits

Successful execution of these R&D strategies -- improvements in resource characterization and advances in technology, stimulated by federal/industry research -- yield substantial benefits:

- At $3.00 per Mcf, about 8 Tcf of additional gas could be ultimately recovered through the research program, providing 0.4 Tcf of additional annual production in 1990.

- At a higher, $4.50 per Mcf, gas price, the gas potential from Program 1 could also become economic, raising the ultimate benefits of the three programs to a range of 8 to 15 Tcf.

D. Cost-Effectiveness Measures

Two measures were used to assess the relative cost-effectiveness of the R&D strategies, stated in terms of Mcf of incremental recovery per dollar of federal expenditure (in constant 1977 dollars).

- Long-term measure - incremental ultimate recovery (at $3.00 per Mcf) per dollar of federal cost.

- Near-term measure - incremental cumulative recovery to 1990 (at $3.00 per Mcf) per dollar of federal cost.

Exhibit 4-24 shows the cost-effectiveness measures for the three Devonian shale strategies:

- The long-term benefit of the program would be about 270 Mcf per dollar of federal R&D.
- In the near-term, between now and 1990, about 110 Mcf could be added to production per dollar of R&D costs.

Exhibit 4-24

Cost-Effectiveness Devonian Shale Strategies

Target/Program		Long-Term (Mcf/Dollar)	Near-Term (Mcf/Dollar)
PROGRAM 1:	Define Potential of Deep Devonian Shales	*	*
PROGRAM 2:	Produce Marginal Devonian Shales Through Dual-Completion	520	150
PROGRAM 3:	Improve Recovery Efficiency	180	30
	WEIGHTED AVERAGE	270	110

* For Program 1, the benefits can only be calculated at a price of $4.50/Mcf: Long-Term = 0-780; Near-Term = 0-1.

CHAPTER FOUR

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CHAPTER FOUR

DEVONIAN SHALE

Part 2

DEVONIAN SHALE

- Extension of the Devonian Into the Deep Devonian Shale in Northern West Virginia and Eastern Pennsylvania
- Devonian Shale Production in Conjunction With the Formation Below Devonian Shale in Ohio
- Devonian Shale in the Producing Regions of Eastern Kentucky and Western West Virginia

RESEARCH AND DEVELOPMENT STRATEGIES FOR THE DEVONIAN SHALE - APPALACHIAN BASIN

The research and development program for recovering gas from Devonian shales of the Appalachian Basin is organized into three programs:

- Program 1 - Resource definition and improved stimulation techniques applied to deep shale formations in Northern West Virginia and eastern Pennsylvania.

- Program 2 - Dual completion of wells where the major gas producing horizon is below the shale sequences in Ohio.

- Program 3 - Improving recovery efficiency by using infill drilling, improved stimulation, and advanced well completion techniques.

TARGET: Extension of the Devonian Into the Deep Devonian Shale in Northern West Virginia and Eastern Pennsylvania

R&D STRATEGY: Resource Definition and Improved Stimulation Techniques

1. Central Problem

Since the Devonian shale reservoirs, even in the best producing regions, provide marginal economic returns, there are considerable areas where the brown/black shale sequences have not been explored by industry. One of the major areas consists of northern West Virginia and eastern Pennsylvania where the Devonian sequence is deeper than 5,000 feet. Exploration has not progressed to any substantial degree because of the higher costs associated with deep drilling and the lack of confirmation that the sequences would produce sufficient quantities of gas to be economical.

Moreover, systematic resource characterization of the shales at these depths has not been done. Natural fracturing has been identified in the shallow, productive Devonian shale, but it is uncertain whether the fractures at greater depth still exist or have healed over time. Finally, the gas content of the shale needs to be established.

The intent of the program would be to accelerate extension drilling through an aggressive exploration and technology application program.

2. Scope of the Effort

The target formations in the Middle Devonian brown/black shale are sequences which are at depths over 5000 feet. The gross formation contains several intervals of shales with intervening sandstone and limestone, including the Elk, Sycamore, and Tully formations.

The geographic location of this target exists from Ritchie, Tyler, and Wetzel counties, West Virginia into Fayette, Westmoreland, and Indiana counties, Pennsylvania.

3. R&D Goals

The research, development, and demonstration goals for this target are to:

- Confirm the areal extent, vertical sequence, natural fracture system, and gas saturation of the target area.
- Compare incremental additions of gas from various stimulation technologies if gas reservoirs are discovered.
- Compare various completion techniques to identify potential cost reductions.
- Encourage industrial exploitation of the resource by showing the cost effectiveness of shale gas production.

4. R&D Activities

To achieve these goals, ERDA would need to engage in the following R&D activities:

- Task 1 - Identify from known geological information ten well locations which if found productive would demonstrate the value of further exploration in the overall target area.

- Task 2 - Drill ten wells through the total Devonian section; systematically complete and treat each well with a series of increasingly complex stimulation technologies, allowing sufficient time in between treatments to determine the amount of additional gas derived from each type of stimulation.

- Task 3 - Study the entire intervals and conduct a complete set of logs for each well to be stimulated. Analyze the core data under in situ conditions to measure gas porosity and gas permeability in both matrix and fracture porosity.

- Task 4 - Test each well in a comparable fashion, using build-ups, logging, and selective stimulation, to identify the production potential and ultimate recovery.

- Task 5 - Analyze the economic feasibility of producing these wells under the most cost-effective stimulation technology.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements are based on the need to gather considerable basic geologic and reservoir data to improve the capacity to diagnose this data and to transfer the findings to the gas production industry.

The number of characterization cores and stimulation demonstration tests are based on:

- Taking 10 resource evaluation and characterization cores in the undefined portions of the deep Devonian shale areas.
- Conducting 10 demonstration tests.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Deep Devonian Shales

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(1)	1	1	1	1	1	5	(6)
• Reservoir Properties Measurement	(1)	1	1	1	1	1	5	(6)
• Recovery and Economic Studies	(1)	1	1	1	1	1	5	(6)
2. Improved Diagnostic Tools and Methods (man-years)								
• Development		2	2	2	2	2	10	(10)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Cores	(1)	3	3	2	1		9	(10)
• Stimulation Tests		1	3	3	2	1	10	(10)
4. Technology/Information Transfer (man-Years)		1	1	1	1	1	5	(5)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of drilling, coring, logging, and testing a resource characterization well is $400,000.
- The incremental cost of a sequence of stimulation demonstration tests is $400,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 100% of the costs of the resource characterization wells.
- ERDA pays 50% of the costs of the incremental technology and demonstration tests.

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Deep Devonian Shales

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Properties Measurement	(100)	100	100	100	100	100	500	(600)
• Recovery and Economic Studies	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(300)	300	300	300	300	300	1,500	(1,800)
2. Improved Diagnostic Tools and Methods								
• Development	(200)	200	200	200	200	200	1,000	(1,200)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Cores	(400)	1,200	1,200	800	400		3,600	(4,000)
• Demonstration Tests		400	1,200	1,200	800	400	4,000	(4,000)
SUBTOTAL	(400)	1,600	2,400	2,000	1,200	400	7,600	(8,000)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL COST	(900)	2,200	3,000	2,600	1,800	1,000	10,600	(11,500)

EXHIBIT 3
ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Deep Devonian Shales

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(100)	100	100	100	100	100	500	(600)
• Reservoir Properties Measurement	(100)	100	100	100	100	100	500	(600)
• Recovery and Economic Studies	(100)	100	100	100	100	100	500	(600)
SUBTOTAL	(300)	300	300	300	300	300	1,500	(1,800)
2. Improved Diagnostic Tools and Methods								
• Development	(200)	200	200	200	200	200	1,000	(1,200)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Cores	(400)	1,200	1,200	800	400	-	3,600	(4,000)
• Demonstration Tests		200	600	600	400	200	2,000	(2,000)
SUBTOTAL	(400)	1,400	1,800	1,400	800	200	5,600	(6,000)
4. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(900)	2,000	2,400	2,000	1,400	800	8,600	(9,500)

7. Production Benefits

The anticipated benefits from a successful completion of the research and development program in extending the development of production into the deep Devonian shales are not economic at $3.00 per Mcf. Thus, the production benefits for both the Base Case and the Advanced Technology Case are shown at $4.50 per Mcf. A range of estimated production is given due to the considerable geological uncertainty of the resource base.

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to Tcf (Tcf)
• Ultimate Recovery	9.6	9.6-16.3	0-6.7
• Production Rate in:			
1985	0.1	0.1	0
1990	0.2	0.2	*
1995	0.3	0.3-0.5	0-0.2
2000	0.4	0.4-0.7	0-0.3
• Cumulative Production by:			
1985	0.2	0.2	0
1990	1.1	1.1	*
1995	2.5	2.5-3.1	0-0.6
2000	4.1	4.1-6.0	0-1.9

*Less than 0.05 Tcf

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for the deep Devonian shales (at $4.50 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	0-800
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	0-6

TARGET: Devonian Shale Production in Conjunction with the Formations Below Devonian Shale in Ohio

R&D STRATEGY: Demonstrate Economic Feasibility of Dual Technologies

1. Central Problem

Economically producing the Devonian shale in Ohio poses a severe challenge since the productive capacity of the Devonian sequence in much of Ohio is low. A typical well in Ohio may produce one-fourth of the already economically marginal wells in Kentucky and West Virginia.

Much of the central area of Ohio has been drilled for the deeper pays, notably the Clinton, the Medina, and the Oriskany sands. Although the shale has been penetrated, the gas "shows" encountered have been so minimal that the shale formation has been virtually ignored.

In Ohio, the Huron shale deposition is relatively uniform, and while the expected permeabilities and porosities are small, these appear in line with other areas. The major problem is the noticeable lack of natural fracturing. Only two known faulting areas exist in the interior: one is in the vicinity of the Parkersburg Syncline and the Cambridge fault; the other is around the New Cumberland fault.

Tectonically, central Ohio did not experience the same massive upheavals that effected the Devonian sequence along the Allegheny Front.

Since its appears the Devonian in this area cannot be economically produced on its own, the challenge becomes one of producing the shale in conjunction with another known producing pay zone such as the Clinton or Medina sands. The incremental amount of gas which could be generated through a carefully selected designed research and development program could possibly, over a large extent of time, secure the needed gas on a regionalized basis to make up the deficiencies experienced in Ohio during severe winter conditions, as well as provide additions to overall gas supply.

The purpose of the program is to demonstrate to industry the feasibility of developing their resources as an emergency supplemental source.

2. Scope of the Effort

The main target formation is the brown shale sequences between the Berea and Onondaga (Corniferous) which would include the Cleveland, Chagrin, and Huron shale members of the Ohio shale formation.

Geographically the program would first investigate the defined and anticipated drilling areas of the Clinton and then test formations for Devonian shale deposition.

3. R&D Goals

The research, development, and demonstration goals for this target are to:

- Establish the production level of the Ohio shales.

- Identify the well completion techniques that will secure the Ohio shales as a marginal pay zone supported by the better producing lower sand formations.

- Determine the most effective stimulation technology that will maximize total production.

- Demonstrate that a supplemental source of gas might be regionally developed, although at a high price, where the benefits of avoiding plant closures might justify the required investment and costs.

4. <u>R&D Activities</u>

To achieve these goals, ERDA would need to engage in the following activities:

- Task 1 - Identify ten geographically dispersed typical areas where the Devonian shales overlay the major deeper producing zones. The locations must be selected where a reasonable potential is anticipated in recompleting the deeper pay.

- Task 2 - Drill ten wells over this defined area, where each well would be systematically completed, and retreated with a series of increasing complex stimulation technologies. Sufficient time would be allowed in between treatment for accurate measurement of the additional gas derived from each type of treatment.

- Task 3 - Fully test the Devonian interval including coring and logging each well. Analyze cores under in situ conditions to measure gas porosity and permeability in matrix and fracture porosity.

- Task 4 - Test each well in a comparable fashion; examine the entire formation for any damage which might preclude using the technology for stimulating the secondary formation.
- Task 5 - Recomplete and analyze production test results to evaluate successive recompletions.
- Task 6 - Analyze the economic feasibility of producing these wells under the most cost-effective stimulation technology.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of resource characterization wells and tests to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements are based on the need to define the Devonian as well as the Clinton formations in the area and to transfer the results of the dual completion technology to the industry.

The number of resource characterization wells and demonstration tests are based on:

- Placing a total of 15 resource evaluation and characterization wells in the basin.
- Conducting 15 demonstration tests.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Devonian Shale Production in Conjunction With the Clinton Formation in Ohio

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Basic Geological Studies	(2)	2	2	2	2	2	10	(12)
• Reservoir Properties Measurement	(2)	2	2	2	2	2	10	(12)
• Recovery and Economic Studies	(2)	2	2	2	2	2	10	(12)
2. Improved Diagnostic Tools and Methods (man-years)								
• Development		4	4	3	2	2	15	(15)
3. Field-Based Research, Development, and Demonstration (cores/wells)								
• Resource Characterization Wells		4	4	3	2	2	15	(15)
• Stimulation Tests		2	4	4	3	2	15	(15)
4. Technology/Information Transfer (man-years)		2	2	2	2	2	10	(10)

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of drilling, coring, logging, and testing a resource characterization well is $200,000.
- The incremental cost of a multiple completion demonstration test is $300,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 100% of the costs of the resource characterization wells.
- ERDA pays 67% of the costs of the technology and demonstration tests.

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Devonian Shale Production in Conjunction with the Clinton Formation in Ohio

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(200)	200	200	200	200	200	1,000	(1,200)
• Reservoir Properties Measurement	(200)	200	200	200	200	200	1,000	(1,200)
• Recovery and Economic Studies	(200)	200	200	200	200	200	1,000	(1,200)
SUBTOTAL	(600)	600	600	600	600	600	3,000	(3,600)
2. Improved Diagnostic Tools and Methods								
• Development		400	400	300	200	200	1,500	(1,500)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Wells		800	800	600	400	400	3,000	(3,000)
• Demonstration Tests		600	1,200	1,200	900	600	4,500	(4,500)
SUBTOTAL		1,400	2,000	1,800	1,300	1,000	7,500	(7,500)
4. Technology/Information Transfer		200	200	200	200	200	1,000	(1,000)
TOTAL COST	(600)	2,600	3,200	2,900	2,300	2,000	13,000	(13,600)

EXHIBIT 3

ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Devonian Shale Production in Conjunction with the Clinton Formation in Ohio

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Basic Geological Studies	(200)	200	200	200	200	200	1,000	(1,200)
• Reservoir Properties Measurement	(200)	200	200	200	200	200	1,000	(1,200)
• Recovery and Economic Studies	(200)	200	200	200	200	200	1,000	(1,200)
SUBTOTAL	(600)	600	600	600	600	600	3,000	(3,600)
2. Improved Diagnostic Tools and Methods								
• Development	-	400	400	300	200	200	1,500	(1,500)
3. Field-Based Research, Development, and Demonstration								
• Resource Characterization Wells		800	800	600	400	400	3,000	(3,000)
• Demonstration Tests		400	800	800	600	400	3,000	(3,000)
SUBTOTAL		1,200	1,600	1,400	1,000	800	6,000	(6,000)
4. Technology/Information Transfer		200	200	200	200	200	1,000	(1,000)
TOTAL ERDA COST:	(600)	2,400	2,800	2,500	2,000	1,800	11,500	(12,100)

7. Production Benefits

The anticipated benefits from a successful completion of the research and development program for Dual Completion of Devonian Shales are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	ΔDue to R&D (Tcf)
• Ultimate Recovery	0.9	6.9	6.0
• Production Rate in:			
1985	*	0.1	0.1
1990	0.1	0.4	0.3
1995	*	0.3	0.3
2000	*	0.2	0.2
• Cumulative Production by:			
1985	0.1	0.5	0.4
1990	0.4	2.1	1.7
1995	0.7	4.0	3.3
2000	0.8	5.5	4.7

*Less than 0.05 Tcf

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for Dual Completion of Devonian Shale (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	521
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	148

TARGET: Devonian Shale in the Producing Regions of Eastern Kentucky and Western West Virginia

R&D STRATEGY: Improving Recovery Efficiency

1. Central Problem

A typical Devonian shale well will produce between 200 and 500 MMcf over a thirty year lifetime and based on analysis supported by simulation,* recover 40 to 60% of the original gas in place. Given the existing development practices, it may be possible, through infill drilling and new stimulation technologies, to improve the recovery efficiency and thus recover more of the original gas in place.

2. Scope of the Problem

The target area for this program is the Upper Devonian brown/black shales of eastern Kentucky and western West Virginia. Parts of this area are currently producing, and several are being developed.

3. R&D Goals

The research, development, and demonstration goals for this target are to:

- Confirm the potential of improving recovery by approximately 20% through infill and developmental drilling.
- Compare incremental additions of gas from various stimulation technologies and well completion techniques.
- Encourage industrial exploitation by showing the cost effectiveness of increasing production.

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* Assuming isotropic homogeneous and non-homogeneous gas flow.

4. R&D Activities

To achieve these goals ERDA would need to engage in the following activities:

- Task 1 - Identify the higher potential areas of Devonian shale gas production amendable to improved recovery practices.

- Task 2 - Drill or recomplete wells in the identified areas and systematically treat each well with a series of increasingly complex stimulation technologies, allowing sufficient time between each treatment to determine the additional increment of gas derived from the method of stimulation.

- Task 3 - Analyze the economic feasibility of producing this incremental addition to ultimate recovery under the most cost effective stimulation technology.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of cores and resource characterization wells to carry out the above research, development, and demonstration activities are shown in Exhibit 1.

The manpower requirements for resource characterization are small as much of the area is expected to be defined by industry.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Improving Recovery Efficiency in the Devonian Shales

R&D ACTIVITIES (Physical Units) Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Reservoir Properties Measurement	(5)	2	2	2	2	2	10	(15)
• Recovery and Economic Studies	(5)	2	2	2	2	2	10	(15)
2. Field-Based Research, Development, and Demonstration (cores/wells)								
• Technology Test Wells		3	3	2	2	2	12	(12)
• Demonstration Test Wells		10	10	10	10	5	45	(45)
3. Technology Information Transfer (man-years)		1	1	1	1	1	5	(5)

The number of technical tests and demonstration tests are based on:

- Conducting 10 technical stimulation and 2 deviated well tests.
- Conducting 45 demonstration tests, 10 per each of the three developed areas (Areas I, II, and III), with the wells divided equally between the drilled and undrilled areas, and 5 each in the undrilled portions of Areas IV-VI.

6. R&D Costs

The R&D activities listed in Exhibit 1 are translated into yearly budgets in Exhibit 2 (Total Program Costs) and Exhibit 3 (ERDA Share of Total Program Costs).

The line items in the budget are based on the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of conducting an advanced fracturing and well completion test is $200,000 and the cost of a deviated well is $500,000.
- The cost of a demonstration test is $200,000.

The assumptions as to ERDA's share of total program costs are as follows:

- ERDA pays 100% of the professional man-year costs for resource characterization, measurement research, and technology transfer.
- ERDA pays 100% of the costs of the technology tests.
- ERDA pays 50% of the costs of the demonstration tests.

EXHIBIT 2
TOTAL PROGRAM COSTS

TARGET: Improving Recovery Efficiency in the Devonian Shales

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Reservoir Properties Measurement	(500)	200	200	200	200	200	1,000	(1,500)
• Recovery and Economic Studies	(500)	200	200	200	200	200	1,000	(1,500)
SUBTOTAL	(1,000)	400	400	400	400	400	2,000	(3,000)
2. Field-Based Research, Development, and Demonstration								
• Technical Tests		900	900	400	400	400	3,000	(3,000)
• Demonstration Tests		2,000	2,000	2,000	2,000	1,000	9,000	(9,000)
SUBTOTAL		2,900	2,900	2,400	2,400	1,400	12,000	(12,000)
3. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL COST:	(1,000)	3,400	3,400	2,900	2,900	1,900	14,500	(15,500)

EXHIBIT 3
ERDA SHARE OF TOTAL PROGRAM COSTS

TARGET: Improving Recovery Efficiency in the Devonian Shales

R&D COSTS (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Reservoir Properties Measurement	(500)	200	200	200	200	200	1,000	(1,500)
• Recovery and Economic Studies	(500)	200	200	200	200	200	1,000	(1,500)
SUBTOTAL	(1,000)	400	400	400	400	400	2,000	(3,000)
2. Field-Based Research, Development, and Demonstration								
• Technical Tests		900	900	400	400	400	3,000	(3,000)
• Demonstration Tests		1,000	1,000	1,000	1,000	500	4,500	(4,500)
SUBTOTAL		1,900	1,900	1,400	1,400	900	7,500	(7,500)
3. Technology/Information Transfer		100	100	100	100	100	500	(500)
TOTAL ERDA COST:	(1,000)	2,400	2,400	1,900	1,900	1,400	10,000	(11,000)

7. Production Benefits

The anticipated benefits from a successful completion of the research and development program for increasing recovery efficiency in the Devonian shales are estimated (at $3.00 per Mcf) as:

	Base Case (Tcf)	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
• Ultimate Recovery	0	1.8	1.8
• Production Rate in:			
1985	0	*	*
1990	0	0.1	0.1
1995	0	0.1	0.1
2000	0	0.1	0.1
• Cumulative Production by:			
1985	0	0.1	0.1
1990	0	0.3	0.3
1995	0	0.6	0.6
2000	0	0.8	0.8

*Less than 0.05 Tcf

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for increasing recovery efficiency in the Devonian shales (at $3.00 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	180
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	30

CHAPTER FIVE

METHANE FROM COAL SEAMS

Part 1

I. INTRODUCTION

A. Background

Since the inception of underground coal mining, the release of methane from coal beds ("coal gas") has posed a hazard to mining safety. When methane combines with air, it forms a flammable mixture and is the cause of countless mine explosions.

In response to this hazard, the Federal government has undertaken numerous efforts to install improved safety measures and regulations. While considerable information has now been gathered on methane emissions, most of this has been gathered from a perspective of safety, disposing of the unwanted methane in mines -- rather than from a perspective of supply -- capturing the methane for increasing domestic gas supplies.

Recovering this now vented methane could provide an important augmentation to local supplies of natural gas. Moreover, these supplies could be made immediately available since the technology is relatively simple and is commonly used in several European countries, notably Great Britain and Belgium.

In addition to methane recovery in association with mining, additional potential sources of methane are in the deep, currently unminable coal seams of the West. Such coal seams are currently considered too thin or too deep for mining, and may contain considerable methane resources that could be economically produced.

Recent efforts by the Bureau of Mines, Pittsburgh Mining and Safety Research Center, under the direction of Maurice Deul, have initiated research and demonstration efforts toward the dual objectives of increasing mining safety and adding to domestic gas supply through methane recovery from coal seams. This chapter draws on the considerable knowledge base that has resulted from these past R&D efforts.

B. Nature of the Problem

The methane released from coal mining stems from three sources: (1) from the coal seam itself where the methane is held by adsorption in the structure of the coal and is released when the coal is mined; (2) from the thin sand lenses adjacent to the coal seams that also serve as a reservoir for desorbed gas; and (3) from fractures where methane has accumulated by desorption.

Since coal is impermeable, the 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 and have produced gas, none, as of yet, have demonstrated economic feasibility as purely a gas recovery project. Each approach must rely upon the safety benefits and mining production efficiencies that accrue from lowered emissions (particularly instantaneous gas bursts). The production rates and duration of production have, to date, been too low or too uncertain to offset the considerable costs of well drilling, water removal, compression, piping, stimulation, gas purification, and gathering costs associated with commercial recovery of methane from coal.

In addition to methane recovery in currently mined coal seams, a considerable resource could exist in formations too thin or too deep for economic mining, at least at present. Should these unminable coalbeds have geological features that are favorable to efficient recovery, e.g., high intensity of natural fractures, relatively thick pays, high gas content, and uniform beds and seams, they could represent a commercial source of natural gas supply.

At this time, however, rapid exploitation is hampered by an inadequate definition of the resource, uncertainties in recovery technologies for the deep coal, and the marginal economics of collecting and marketing the resource. These limitations are further described in the following sections.

Thus, evaluation of potential commercial production of methane from coal should consider both:

- Methane recovery from minable coal where the major drilling costs are allocated to improved safety and productivity so that the proceeds from the sale of the methane may be used to pay for the incremental costs of purifying, compressing, and gathering the gas from the wellbores.
- Methane production from deep, currently unminable coal seams having geological highly favorable characteristics.

II. METHANE FROM MINABLE COAL SEAMS

A. Resource Base

Basic studies of methane emission from U.S. coal mines[1/] 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 5-1).

- 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 the total methane emissions; the 20 mines with the largest daily emission rates accounted for 48%, as shown on Exhibit 5-2.

- The Appalachian region accounted for 86% of the total emissions. Exhibit 5-3 provides the location of the high methane emission mines.

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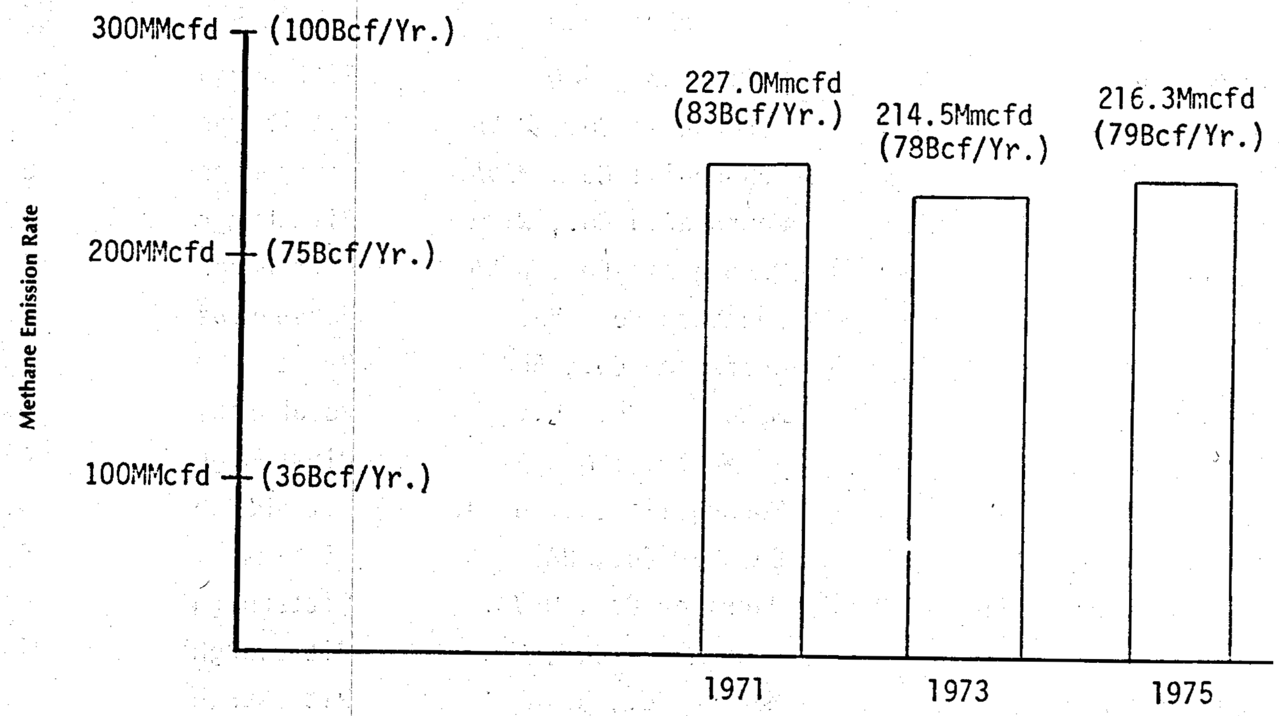
* The recovery estimates for this now vented methane were based on a series of investigative reports by the BOM (RI 8195, RI 7703, RI 8047, RI 8174, RI 7968, and RI 8195, among others) and from personal correspondence and discussion with major coal production companies. Companies contacted as part of this study included: Bethleham Mining Corp., Island Creek Coal Co., Lykes Resources, and United Gas Pipeline.

Exhibit 5-1

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 5-2

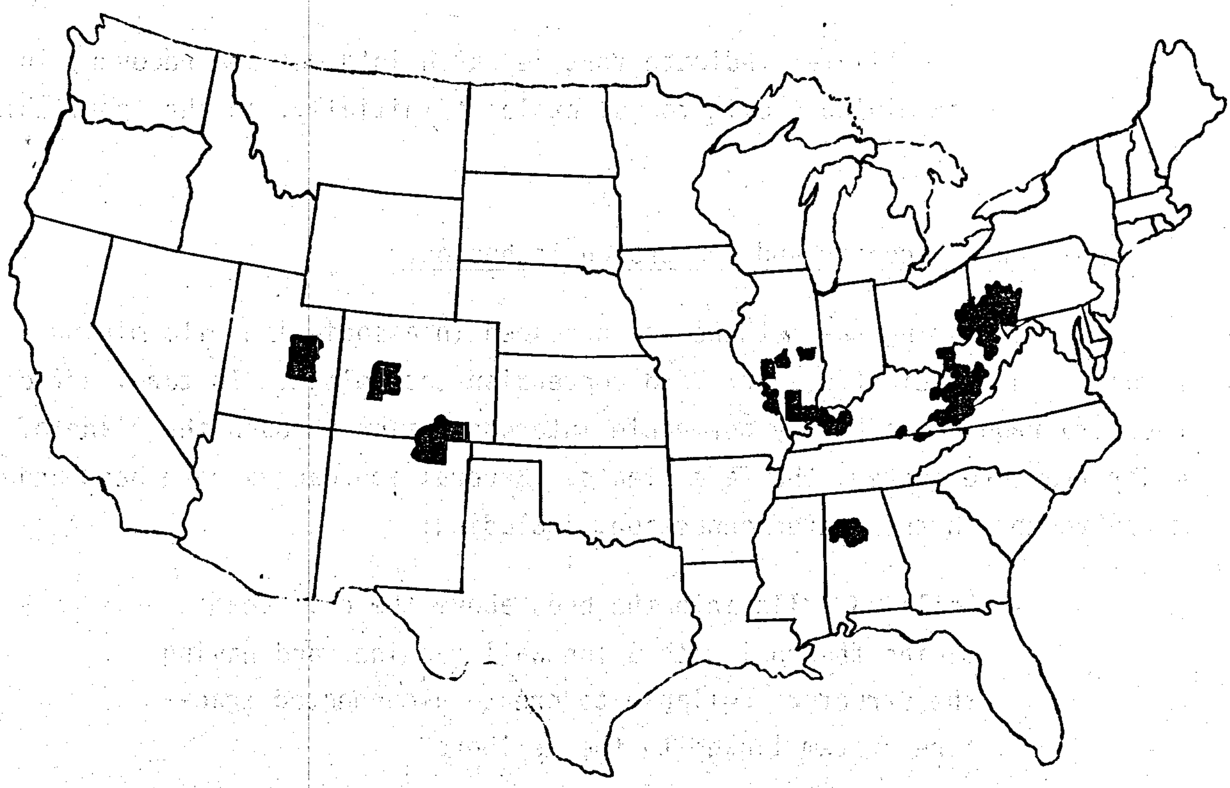
Methane Emissions from U.S. Coal Mines (20 Largest Methane Emission Coal Mines)

	Mine Name	Location	Coalbed	Methane Emission MMcfd
1.	Loveridge	Marion Co., W.VA.	Pittsburgh	11.6
2.	Humphrey No.7	Monongalia Co., W.VA.	Pittsburgh	9.3
3.	Federal No.2	Monongalia Co., W.VA.	Pittsburgh	8.1
4.	Blacksville No.2	Monongalia Co., W.VA.	Pittsburgh	6.3
5.	Osage No.3	Monongalia Co., W.VA.	Pittsburgh	5.9
6.	Beatrice	Buchanan Co., VA.	Pocahontas #3	5.6
7.	Concord No.1	Jefferson Co., ALA.	Pratt	5.1
8.	Olga	McDowell Co., W.VA.	Pocahontas #4	5.0
9.	Robena	Green Co., PA.	Pittsburgh	4.9
10.	Blacksville No. 1	Monongalia Co., W.VA.	Pittsburgh	4.5
11	Bethlehem No. 32	Cambria Co., PA.	Kittanning	4.5
12.	Robinson Run No.95	Harrison Co., W.VA.	Pittsburgh	4.3
13.	Arkwright	Monongalia Co., W.VA.	Pittsburgh	4.0
14.	Federal No.1	Marion Co., W.VA.	Pittsburgh	4.0
15.	Virginia Pocahontas No.1	Buchanan Co., VA.	Pocahontas #3	3.9
16.	Cambria Slope No.33	Cambria Co., PA	Kittanning	3.9
17.	Virginia Pocahontas No.2	Buchanan Co., VA.	Pocahontas #3	3.4
18.	Virginia Pocahontas No.3	Buchanan Co., VA.	Pocahontas #3	3.3
19.	L.S. Wood	Pitkin Co., COL.	Basin B	3.3
20.	Gateway	Green Co., PA.	Pittsburgh	2.7
		TOTAL TOP 20		103.5
		TOTAL - Top 20 Percent of U.S.		47.8

SOURCE: Irani, M.C., J.H. Jansky, P.W. Jeran, and G.L. Hassett, Methane Emissions from U.S. Coal Mines in 1975, A Survey. U.S. Bureau of Mines, IC 8133, 1977.

Exhibit 5-3

Location Map of Counties With Bituminous Coal Mines Emitting At Least 100,000 cfd of Methane in 1975



SOURCE: Irani, M.C., J.H. Jansky, P.W. Jeran, and G.L. Hassett, Methane Emissions from U.S. Coal Mines in 1975, A Survey. U.S. Bureau of Mines, IC 8133, 1977.

- Mines in the Pittsburgh coal bed 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 coal bed 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.

B. Applicable Recovery and Conversion Technology

Capturing the methane now produced in association with mining requires an efficient recovery and conversion technology. In turn, efficient recovery requires a highly permeable interconnection through the plane of the major fracture system, the face cleats. Several approaches have been undertaken to obtain this interconnection, including:

- Drilling wells into the beds above the coal seams, mining the coal with a longwall machine, and having the structure collapse to create a connected fracture system linked to the wellbore.

- Drilling deviated wells from the surface into the coal seam to intersect the planes of the face cleats.

- Using hydraulic fracturing to intersect the natural, face and butt cleat, fracture system.

- Drilling horizontal holes at 90 degree angles to the face cleats (horizontal holes drilled parallel to the face cleats generally have much lower production).

The first three of these entail drilling from the surface of the earth, whereas horizontal drilling takes place from the mine shaft. All four methods have produced gas, but none, as yet, have demonstrated economic feasibility as a stand alone project. Economically, all depend on the benefits of more rapid and efficient mining and mine safety for their justification. The technological problems and limitations of each of these recovery approaches are described below.

1. <u>Degasification by Vertical Drilling</u>

a. <u>Using Vertical Wells With Longwall Mining</u>

One means for degasifying mines involves combining longwall mining with vertical wells, drilled above coal seams. The technique is essentially designed to draw off the methane accumulating in mined-out areas (gob gas). Data based on 10 years of experience in the Lower Kittanning coalbed in central Pennsylvania indicate that:

- This approach is particularly effective when a considerable portion of the methane is trapped in the rock strata above the coal seam (as well as within the micropores and fractures of the coalbed).

- Little, if any, flow can be expected until mining passes beneath the well, allowing settling of the mine ceiling with corresponding fracture of the gas-bearing overburden.

- Exhaust fans or vacuum pumps are required to extract the methane.

In terms of methane flow, the initial rate was above 1,000 Mcfd and decreased steadily after its initial peak. The results of field investigations of this technique by the BOM[2/] showed that appreciable quantities of methane and methane/air mixtures can be produced.*

However, for the methane to be economically convertible for traditional use, it needs to have a concentration of at least 50% of the total gas produced. The produced methane/air mixtures may have a sufficient concentration during the first 3 to 6 months of life of the well to be economic.

The past field tests show that about one-third to two-thirds of the gas produced will have methane concentrations of 50% or greater.**

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* The data from the field test showed:
- Methane flow from one borehole started at 1,400 Mcfd, declined to 300 Mcfd in 5 months;
- Production from a second borehole started at 1,000 Mcfd, decreased to about 200 Mcfd in 5 months, and slowly declined to about 100 Mcfd in 2 years; and
- The two boreholes together vented about 150 MMcf of methane while in service.

** In the BOM test, reported above:
- The first well started with a 90% methane concentration and declined to 50% in three months.
- The second well started with a 60% methane concentration that declined below 50% in 2 months but experienced an increase in concentration to over 50% that was maintained during its full second year of operation.

Ten year experience in the Lower Kittanning coalbed shows that a vertical borehole with longwall mining can produce from 60 to 100 MMcf of total methane at a concentration of 50% or more of the potentially explosive gas. The two wells in the BOM study produced an immediate 75% decrease in the methane emission identified within the mine.

In terms of economically recoverable methane (having methane concentration of 50% or greater), a borehole may recover from 40-60 MMcf based on BOM and other company data.

As such an approach begins to be further used in the gassier coalbeds (such as the Pocahontas No. 3), a single borehole may be able to produce over 200 MMcf of methane, with 120 MMcf having a concentration of 50% or greater.

b. Using Deviated Wells and Stimulated Wells

Two additional surface based techniques have potential for recovering methane in association with and in advance of coal mining, namely:

- Using wells drilled vertically from the surface and then deviated to horizontally intersect the coal face.
- Using vertical wells from which hydraulic fractures are induced in the coal seam.

Although each approach has been tried in the Appalachian Basin, the results to date have been disappointing. Deviated wells are expensive and technically difficult to control in the often thin and discontinuous coal seams of the Appalachian Basin. Vertical wells hydraulically stimulated and drilled in advance of mining may be useful for draining water and reducing the hazards of instantaneous bursts of gas and thus useful in terms of mine safety and productivity. However, this approach provides only limited recovery efficiency of the methane contained in the coal seam and thus offers a low potential alternative for methane recovery and utilization.* (Should the gas be trapped in the strata above the coalbed, it may be possible to recover this using stimulated vertical wells; however, since this involves fracturing the overburden, it may prove a significant safety hazard to subsequent mining operations.)

2. Degasification by Horizontal Boreholes

A second means for recovering methane in conjunction with mining is by using a horizontal borehole drilled into the coal face. This approach appears more efficient when the larger portion of the methane is contained within the microporous structure of the coal rather than in the rock strata adjacent to the coalbed.

Horizontal boreholes have been used widely in the major, gassy coal mines, including the Pittsburgh and Pocahantas No. 3 coalbeds in Appalachia and the Sunnyside coalbed in Utah.

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* As discussed further in Section III, Methane from Unminable Coal Seams, the fracture will tend to parallel the face cleats and thus will provide low recovery efficiencies, on the order of 10 to 20% of the amount that would result from intersecting the face cleat system.

In tests conducted by BOM[3/] (using a total of 15 horizontal boreholes from a multipurpose borehole and an air shaft) in the Pittsburgh coalbed, two projects recovered 1.8 Bcf of methane in 4 years, for an average of over 100 Mcf per day, or 100 MMcf per life of each horizontal borehole.

A more common approach is to use horizontal boreholes of about 500 to 1,000 feet drilled about 2 to 4 weeks ahead of mining. In this case, the production rate may range from a negligible amount (less than 1 Mcfd) to over 200 Mcfd, depending on the orientation of the borehole with the face cleat system, the continuity of the pay, and the gas content of the coal. Based on the past data, an average production of 100 Mcfd for 30 days, for a total of 3 MMcf per service life, may be a reasonable target for a 1,000 foot horizontal borehole. Under a higher priority methane recovery program, it may be possible to drill the horizontal borehole 6 months or more ahead of mining, thus possibly raising the target recoveries to 20 MMcf or more per horizontal borehole.

A final option for using horizontal boreholes would be to drill the borehole so that it intersects other coal seams overlying or underlying the mined coalbed. While considerable geological study would be required to define the potential, this could provide an important means for increasing the potential of methane recovery from coal seams.

3. Additional Knowledge Required to Optimize the Recovery Technology

The recent work by BOM has greatly advanced the knowledge base in methane recovery from coal seams -- particularly by defining the methane content of the coal and orientation of the cleat system. Designing the appropriate recovery technology now requires that the following research tasks be undertaken:

- Determining the precise diffusion constants applicable to the different coalbeds, particularly in relation to the water and existing pressure in the coalbed (to assist in predicting recovery).

- Identifying the location of the bulk of the methane to be drained, as to whether it is in the coalbed or in the overlying structure (to assist in choosing between surface versus underground boreholes).

- Mapping the uniformity of the coalbeds (to assist in designing borehole length and direction).

- Determining the intensity and dominant direction of the cleat systems (to assist in predicting recovery and designing the drilling program).

- Designing the appropriate auxiliary equipment (e.g., pumps, gathering lines, etc.) essential for recovering a larger percentage of the methane now being vented.

C. Converting the Methane for Commercial Use

Once the coal gas has been recovered from the coalbed (or overlying rock strata), it can be diverted toward three uses:

- Directly into a natural gas pipeline -- when the quality and methane content of the recovered gas is sufficiently high, the coal gas can be gathered, purified, pressurized, and injected into a pipeline. Pipeline specifications require methane contents of at least 95%, with carbon dioxide content of 3% or less. Much of the coal gas will need to be first purified and upgraded before it can be injected into a commercial natural gas pipeline.

- Conversion into liquified natural gas (LNG) -- particuarly for the lower methane concentration gob gas collected as part of longwall mining. Here the gas is first upgraded (e.g., dewatered and stripped of the CO_2) and then processed through a series of heat exchangers and a rectification column to produce pure LNG. Under current technology about 30 to 80%* of the energy value of the coal gas, depending on its purity, would be used as fuel for the process.

- Other end uses -- finally, it may be possible to use the coal gas, particularly coal gas with methane concentration between 50 and 80%, for local power generation, coal drying, or, after upgrading to about 80%, for local industrial uses such as in the production of ammonia.

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* The energy consumption for producing LNG is about 300 to 400 cubic feet per 1,000 cubic feet of 90% plus concentration methane feedstock and establishes the minimum required concentrations for technical and economic feasibility.

Other methane recovery and conversion approaches, beyond the above three, have been proposed, such as the use of membrane separation, centrifugation, or solvent extraction. While each of these requires further basic study at this time, they do not appear economic nor highly efficient. For example, using membrane separation, even in five stages, would provide a recovery efficiency of about 2% and the energy input requirements of centrifugation are far above the energy output.

D. Economic Issues in Recovery and Conversion

The economics of recovering methane in association with mining rely greatly on the residual safety and efficiency benefits that accompany mine degasification. The costs are as follows:

- Drilling and completing a vertical hole from the surface costs from $20 to $30 per foot; adding other components, which will vary from one installation to another (exhaust fan, pump, pipe, access roads, etc.), makes the cost of a typical 1,000 foot vertical hole about $50,000 to $60,000.

- Drilling and completing a horizontal hole from the mine face is cheaper, at about $6.00 per foot; adding a collection system, pump, exhaust fan, etc. makes the cost of a typical 1,000 foot horizontal hole about $10,000 to $15,000.

However, even though the initial drilling and completion equipment and well operating costs are relatively low and can be readily justified on the basis of safety and mine efficiency (for example, a 1% increase in mine efficiency will readily pay back the capital costs of degasification), the surface collection, upgrading, and transportation costs can be considerable. Preliminary estimates show that without a charge for drilling or well equipment or well operations, it may be economic to convert the methane to LNG, to use it directly for generating local power or direct heat, or to collect and upgrade it (where necessary) for delivery directly into pipelines at $1.75 to $3.00 per Mcf. Thus, the major barriers to making recovery economic (in addition to the technological and geological uncertainties described above), would include:

- Obtaining sufficient quantities of gas in each location to justify the building of gathering and transportation facilities.

- Designing the most appropriate recovery system for a given type of mining operation and coal seam, including:

  -- Using horizontal boreholes drilled into the coal seam from the bottom of a shaft or an air vent

  -- Using vertical wells drilled above coal seams, generally with longwall mining, to capture gob gas.

- Developing economical small-scale means for purifying and upgrading the produced air/methane mixture using cryogenic liquification to generate LNG, particularly for individual rural and industrial consumers not now served by a utility.

E. Potential Production from Appalachian Coal Seams

The recovery of methane from the Appalachian Basin will need to follow the pace of current mining and the opening of new mines. Currently, the mine shaft and its progress through the coalbed provide the most ideal wellbore imaginable to a reservoir engineer and serves as the point of release for the total of the methane emitted in association with mining. Since this is the maximum that would be emitted through a predrainage program, all estimates of methane recovery and production are scaled from this base figure.

Drawing on this base, the following assumptions were used to establish the recovery target:

- Current emissions - 80 Bcf/year (217 MMcf/d)
- Proportion of emissions estimated from Appalachian Basin - 90%
- Rate of growth in mining:
  -- doubling of coal production by 1990
  -- an equal (absolute) amount of increase by 2000
- Ultimate recovery - equivalent to recovery over the next 30 years
- Proportion of mines with methane recovery facilities:

1980	10%
1985	30%
1990	50%
2000	50%

- Methane recovery efficiency for mines with methane capture facilities:

1980	30%
1985	50%
1990	50-75%
2000	50-75%

Using these assumptions, the yearly and cumulative rates are as follows:

	Rate MMcfd	Rate (Bcf/Year)	Cumulative (Bcf)
1980	8	3	3
1985	50	18	50
1990	100-150	36-54	190-230
1995	123-186	45-68	390-530
2000	142-214	52-78	640-910
2008	148-222	54-81	1080-1560

Thus, the thirty year ultimate recovery target for the Appalachian Basin is 1.1 - 1.6 Tcf.

In that there is currently little private sector activity in recovering methane from minable coal seams, it is likely that publicly supported research and development programs will be require to overcome the present problems and limitations. A substantial research, demonstration and implementation program of methane recovery from coal seams could add important quantities of natural gas supplies in the Appalachian Basin area and accelerate the implementation of the technology, clear the legal and gas ownership issues, and gain mine operators acceptance and support.

F. Sensitivity of the Recovery Estimates to Key Variables

The Appalachian Basin coal seams are too thin and too lean in methane content to economically support methane recovery on its own. Since estimates of recovery need to parallel closely the pace of mining and the opening of new mines, there is little leeway in making production rate and recovery estimates. However, the actual rate may vary due to the following:

- The near term production rate and cumulative production may be 20% (10 to 20 Bcf/year) higher than projected if considerable drainage ahead of mining rather than with mining is used.

- The 30 year recovery (used as ultimate recovery for this analysis) could be 20% (or 0.3 Tcf) higher if the rate of growth in mining led to a redoubling of capacity between 1990 and the year 2000. (That is, coal production in the year 2000 would be 4 times current rates rather than the assumed 3 times current rates.)

- It may be possible to place methane recovery facilities in additional mines, accounting for 75% of the methane emission. Should this be done, ultimate recovery would increase by 0.3 Tcf.

- Since the recovery of methane in association with mining depends so greatly on the associated productivity and safety benefits, base production estimates are relatively insensitive to price changes. The major area of price sensitivity centers on the methane recovery efficiency of the captured total gas emissions. As price goes up, coal gas with lower methane concentration can be economically extracted.

III. METHANE FROM UNMINABLE COAL SEAMS

A. Resource Base

1. Gas in Place

In general, coal seams are considered unminable because they are too thin or too deep to be mined economically. While volumetric data on unminable coal is sketchy, at best, recent studies[4/] do permit gross estimates of gas in place:

- 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.

- An additional 388 billion tons of coal are too deep (3,000-6,000 feet) to be mined economically. About 45% of this coal is ranked as bituminous or higher; the balance is subbituminous coals and lignite.

- Gas content of bituminous (and higher) coals averages 480 cf/ton, accounting in total for 80 Tcf.

- Gas content for subbituminous coals is substantially lower than that for bituminous and higher rank coal. Their high moisture content tend to limit their gas-adsorption capacity. Assuming a gas content of 100 cf/ton, one-fifth that for bituminous coals, deep subbituminous coals would contain about 20 Tcf.

In total, the 668 tons of unminable coal contains an estimated 170 Tcf of gas.* Economic recovery of this methane depends on five geologic variables:**

- Adequate thickness of the coalbed
- Intensity of the nature fracture system
- Uniformity of the bed and seam
- Water content in the coalbed
- Gas content

Because of the controlling effect of the first of these variables -- thickness of the coalbed -- the analysis assumes the remaining four geologic variables (i.e., fracture intensity, coal seam uniformity, water, and gas content) are favorable. The analysis then establishes the minimum required coalbed thickness as a function of costs and gas price.

2. Thin Coal Seams

The 70 Tcf of methane held in thin coal seams (averaging 15 inches thick) cannot be produced economically for their methane content under any reasonable set of technological assumptions. At 260 cf/ton, an average well

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* Previous estimates have used the same gas content for bituminous and subbituminous. This appears to overestimate the gas in place due to the higher moisture content of the lower grade coal. Using the lower gas content for subbituminous coal would reduce the initial estimate of 250 Tcf to 170 Tcf.

** The methane content in unminable coalbeds must be classified as speculative. Major uncertainties surround each of the essential geologic variables. Finding where these five conditions may converge favorably will require considerable basic study of the unminable coal resource.

drainage area of 72 acres, the drainage area will contain only 40,000 Mcf of methane.* Using deviated wells costing $300,000 (2 wells drilled to 800 feet), operating, compressing, separating, and gathering costs of $0.40 Mcf and normal royalty and tax requirements, it is obvious that thin coal seams lack the minimum required coalbed thickness.**

Because thin coalbeds are so far from economic viability, they were eliminated from further analysis of methane potential.

3. Deep Coal Seams

The deep, unminable but thick coalbeds pose a more attractive economic potential. Given the scarcity of published data, much of the above analysis was based on recent test data with state geological societies and BOM officials. Thus, only a preliminary appraisal can be made of the five key geological variables that govern the economics of producing methane from deep, unminable coalbeds.

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* The gas in place can be calculated from the following equation:
- GIP = (Drainage Area) x (Methane Content per Cubic Foot) x (Thickness)
- The drainage area equals: Acres x 43,560 square feet
- The methane content per cubic foot equals:
  260 cf/ton x 80 lb/cf x 2000 lb/ton = 10 cf (0.01 Mcf) per cubic foot

** The calculation of the required thickness is as follows:
- Required gas production @ $1.75 Mcf to pay back costs = 300 MMcf
- Required thickness to produce 300 MMcf in 10 years = 300 MMcf ÷ [Drainage area (in ft^2) x gas in place (per ft^3) x 10 year recovery efficiency]
- Required $h = \dfrac{300 \text{ MMcf}}{(3 \times 10^6 ft^2) \times (0.01 \text{ Mcf}/ft^3) \times 30\%}$

a. Thickness

The distribution of coalbed thickness was based on data in Colorado and the combined data in 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:

Coal Bed Thickness-Feet	% of the Resources	
	Colorado	Three Western States
0-15	52	61
15-50	36	33
>50	12	6

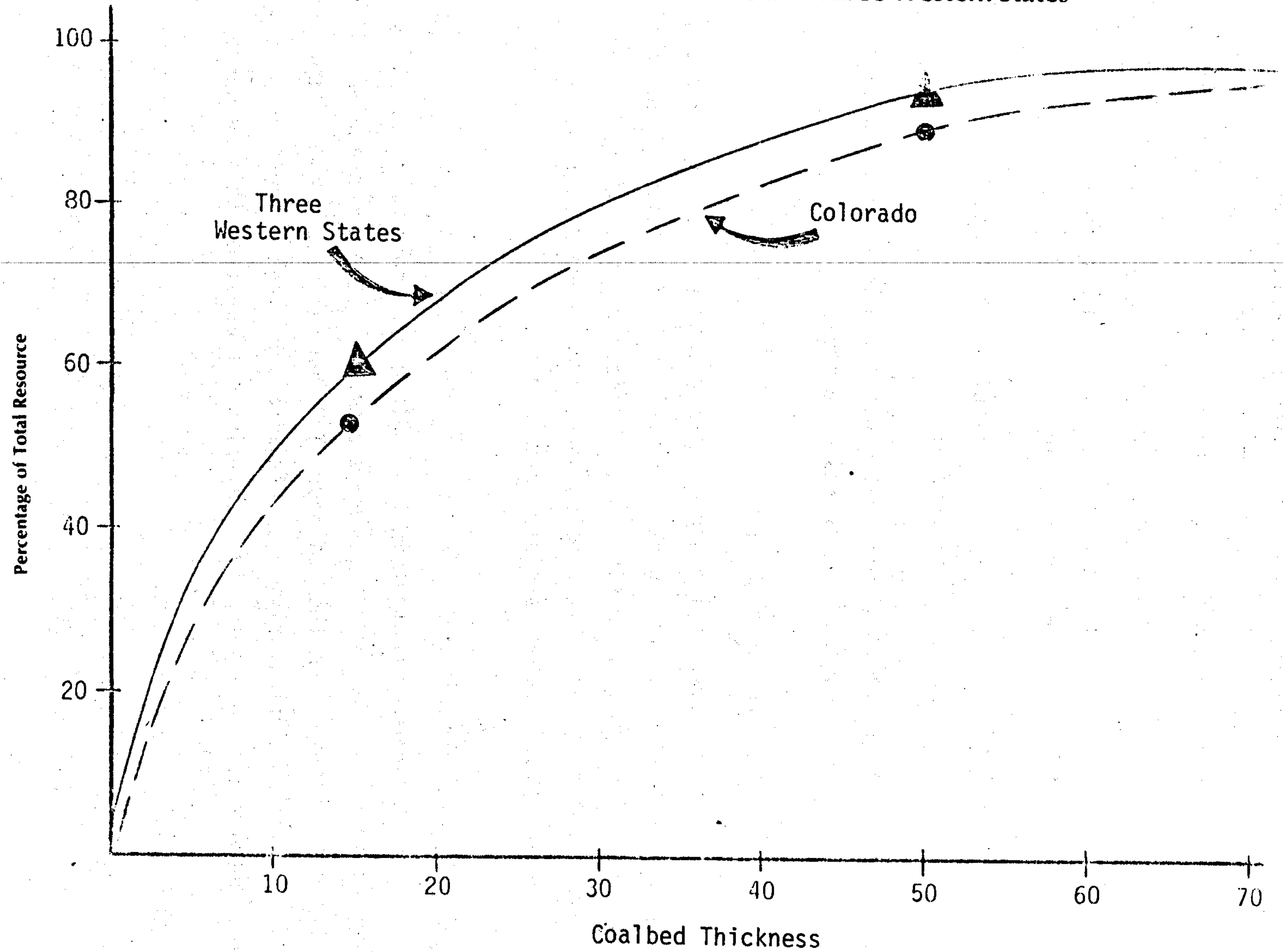
These data are plotted on a cumulative percentage curve of total resource versus coalbed thickness to provide estimates of coalbed thickness between the three points in the table (Exhibit 5-4).

b. Intensity of Natural Fractures

Unlike the Appalachian Basin that has undergone considerable tectonic upheaval and where the subsurface is highly fractured, the tectonic history of the Western Basins is considered to have been less intense. Discussions with state geological officials and related studies of the Uinta Basin indicate that low fracture intensity may pose severe geological barriers for recovering methane from this deeper, unminable coal. Preliminary examination of the shallower geologic formations indicates that:

Exhibit 5-4

Estimated Distribution of Total Bituminous Coal Resources by Coalbed Thickness for Colorado and Three Western States



SOURCE: Booz, Allen & Hamilton, ERDA's Underground Coal Gasification Program, Volume III - Resources, May, 1977.

- Only limited fracture systems are evident in the coal, although they do exist in the surrounding sandstone and shale.

- Hydraulically induced fractures tend to migrate vertically to the surface rather than horizontally through the formation.

- The coal is blocky, not friable, with a poorly developed cleat structure.

Whether these conditions hold for the bulk of the deeper bituminous coal will require further resource study.

c. Uniformity of Deposits

Recent coal mining and methane recovery in the Uinta Basin have identified numerous clay veins that would restrict flow. Also, the depositional history of the basins and geologic horizon in which the deep coals are located has probably created non-uniform deposits, however, further geologic definition is cleary required.

d. Water Content

High water content in the coalbed can cause major problems for degasification. To produce gas most efficiently, the connate water must be first removed from the coalbed. The general presence of water in Western coalbeds (particularly in subbituminous coalbeds) may thus pose a serious challenge to economically recovering methane from this resource base.

e. Gas Content

The gas content of the bituminous and higher grade coals appears high, estimated at 480 cf/ton. In turn, the gas content in sub-bituminous coals and lignites is low and assumed at one-fifth that for higher grades, due to their higher moisture content. However, even for the higher rank coal, the deposit must have a natural caprock seal to have prevented the escape of the gas over geologic time. Thus, additional research is required to ascertain the true gas content for the deep coals.

f. Assessment of the Resource Base

The available data on the deeply buried coals are inadequate at present for definitive assessment of these deposits, and thus this resource is classified as speculative. Considerable resource analysis and testing are required before one can begin to make judicious longer term decisions for recovering methane from this resource base.

B. Applicable Recovery Technology

For efficient recovery, a wellbore will need to communicate with the full natural fracture system in the drainage area. Since for all practical purposes coal is impermeable, the methane must travel through the fracture system or desorb through the structure of the coal in response to a pressure gradient. Three techniques are available for achieving this communication for the deep, unminable coals:

- Vertical wellbores with stimulated fractures
- Large boreholes with horizontal wells
- Deviated wells

Using vertical wellbores with stimulated fractures, under current fracture technology, does not appear to be a technically viable option at this time. The induced fracture will tend to parallel the existing natural fractures and face cleats rather than intersect them, providing only limited connection with the dominant natural fracture system. Additional research may be required to confirm this hypothesis.

Deviated wells, though costly, appear to provide the most technically feasible means for exploiting the deeply buried, unminable coal. However, drilling and controlling deviated wells in coal seams is not a proven technology, particularly since the drilled well will need to intersect the face cleats of the natural fracture system. Although the oil and gas industry has used deviated wells for some time, transferring that technology to the "methane from coal" program will require considerable adaptation in directional drilling and well completion technology, and economic optimization.

C. Key Economic Issues in Recovery

Only limited information is available on the key geological variables that govern recovery and economics of recovering methane from deep, unminable coal seams. Thus, while the analysis in this study served as a first approximation, it is possible to place a range on the economic potential. Assuming that the thickness of the coal seam is the controlling variable and that all other geological features are favorable, economic feasibility will depend on finding coal deposits having sufficient thickness.

Using deviated well costs of $600,000 (2 wells drilled to 4,000 feet, then 1,000 feet into the coalbed) and all other costs as noted above, the minimum 10 year production to yield a 10 year payback can be calculated as a function of price.* This, in turn, can be converted into minimum required coalbed thickness. This 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.

Under the above costs, a diffusion constant of $K = 5 \times 10^{-8}$ cm^2/sec, and assuming a major, natural fracture every 1 foot, one can define the minimum required production (in 10 years) and, in turn, the minimum coalbed thickness.

Price/Mcf	Production (Mcf)	Minimum Thickness (feet)
$1.75	600,000	34
$3.00	300,000	17
$4.50	188,000	11

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* Required Production = [(Ten Year Production) x (1-royalty and severance Taxes) x Gas Price)] - [(Operating Costs x Ten Year Production] > Investment

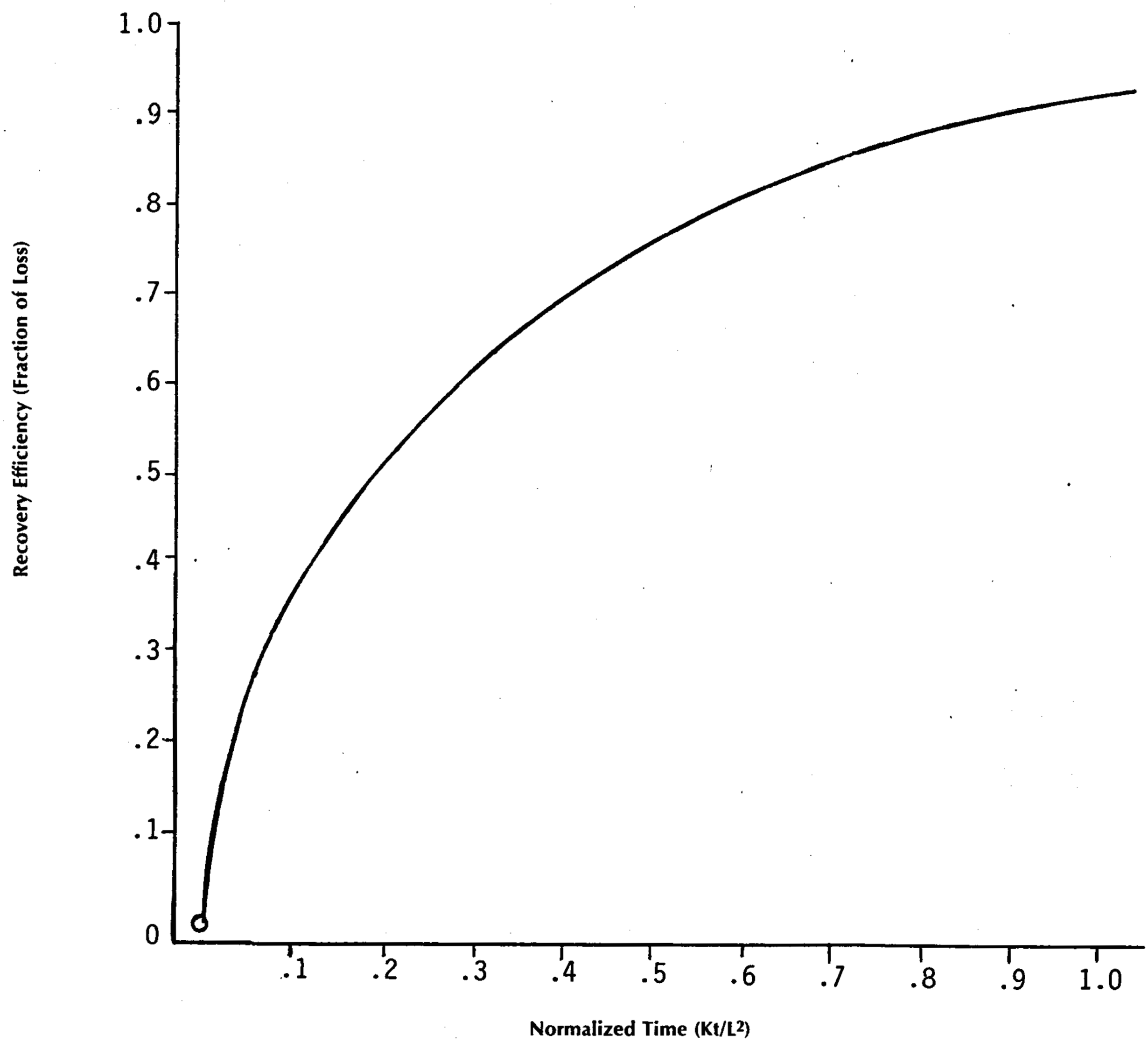
<u>Actual Production</u> = Drainage Area x Coal Bed Thickness x Methane Content x Recovery Efficiency (for t = 10 years)

- Effective drainage area where the pressure is sufficiently low to induce effective desorption is assumed at 72 acres
- Methane content is assumed at 480 cubic feet per ton or 0.019 Mcf per cubic foot
- Recovery is calculated from using the recovery efficiency function on Exhibit 5-5; for time equals 10 years (in seconds) recovery efficiency is 30%
- Required production is set equal to actual production and the equation is solved for coalbed thickness

(Addtional detail is provided in Volume III of this report)

Exhibit 5-5

Relationship of Recovery Efficiency Versus Time (From Fraction of Heat Loss From A Slab With Surface Temperature Kept at T = O, As A Function of Kt/L²)



SOURCE: Derived from Carslaw and Jaegger - Conduction of Heat in Solids, Oxford, 2nd Edition, 1959, Chap. III. PP. 92-102. Equivalent substitute units for any diffusion phenomenon, viz., fraction of adsorbed material lost.

The above analyses, however, make several relatively optimistic assumptions on three variables that effect 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 provide 30% recovery in 10 years; for this the fractures will need to occur one foot apart and extend uninterrupted through the drainage area of the well.
- Diffusion constant -- assumes K of 5×10^{-8} cm^2/sec.

The sensitivity of these assumptions on estimates of the total potential is examined in the next section.

D. Potential Production from the Western Unminable Coal Seams

1. Recovery Estimates

The production potential may be estimated by combining the distribution of minimum required economic thickness* with the distribution of thickness of the resource. Reading from the Colorado curve in Exhibit 5-4, the following distribution can be approximated:

Price/Mcf	Minimum Thickness (feet)	Percentage of Resource
$1.75	34	24%
$3.00	17	44%
$4.50	11	60%

* The calculation of the required thickness is as follows:
- Required gas production @ $1.75 Mcf to pay back costs = 300 MMcf
- Required thickness to produce 300 MMcf in 10 years = 300 MMcf ÷ [Drainage area (in ft^2) x gas in place (per ft^3) x 10 year recovery efficiency]
- Required h = $\dfrac{300 \text{ MMcf}}{(3 \times 10^6 ft^2) \times (0.01 \text{ Mcf}/ft^3) \times 30\%}$

Assuming 30-year recovery efficiency $R^*_{(30)}$ of 51%, 480 cf of methane per ton of coal, and 170 billion tons of bituminous and higher grades of coal, the distribution of economic thicknesses can be converted to estimates of potential recovery at three prices, rounded to the nearest significant figure. (Because the resource base is considered speculative, the estimates of potential recovery are expressed as ranges.)

Price	Recoverable Methane
$1.75	0-10 Tcf
$3.00	0-20 Tcf
$4.50	0-25 Tcf

Given the speculative nature of the resource base, no estimates can yet be made of yearly production rates for recovering methane from the deep, unminable coals.

2. Sensitivity of the Recovery Estimates to Key Variables

The above recovery estimates have been based on a series of generally optimistic assumptions on key variables. It is instructive to determine how sensitive these estimates are to reasonable bounds of variation, particularly on:

- Intensity of the fracture system
- The diffusion constant
- A higher risk premium investment criterion

* Derived by solving the Kt/L^2 equation for t = 30 years (in seconds) on Figure 5-5.

- Use of vertical hydraulically stimulated wells
- Effective drainage area
- Contribution of fracture porosity gas
- Methane content in subbituminous coals

The results of this sensitivity analysis is shown below.

a. Intensity of the Fracture System

Should the fractures be less intense, 5 feet rather than 1 foot apart, the recovery potential drops to essentially zero. Assuming that the coalbed is less intensely naturally fractured, one fracture every 5 feet rather than 1 every 1 foot, the 10 year recovery percentage drops to about 2% and the minimum required coal seam thickness at $3.00/Mcf is over 200 feet.

b. Diffusion Constant

Should the diffusion constant be lower than assumed, for example, 1×10^{-8} cm^2/sec., the potential from the Western Basins drops to about 1 Tcf. Introducing this lower diffusion constant and keeping all other variables the same, the 10 year recovery efficiency $R_{(10)}$ becomes about 8% and the required coal seam thickness at $3.00/Mcf is over 60 feet. Since only about 6% of the resource is over 60 feet thick, the potential 30 year recovery drops to less than 1 Tcf, as compared to about 20 Tcf under the assumed higher diffusion constant.

c. Risk Premium

Should a higher risk premium investment criterion, 20% ROR,* be imposed, the potential from the Western Basins drops to 12 Tcf. Using a 5 year payback (as a proxy for a 20% ROR), and assuming all other parameters

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* In financial terms, a 20% ROR under 6% inflation is equivalent to a real value of 26%; similarly, a 10% ROR is equivalent to 16%.

stay the same except that t = 5 years; then $Kt/L^2 = 0.035$ and 5 year recovery efficiency $R_{(5)}$ becomes 19%. Required coal seam thickness at $3.00/Mcf becomes 26 feet. Since about 30% of the resource is over 26 feet thick, the potential at $3.00/Mcf drops to about 12 Tcf (as compared to about 20 Tcf under the conventional 10% ROR investment criterion).

d. Vertical Wells With Artifical Fracturing

If vertically drilled and fractured wells were substituted for the deviated wells, the potential could either increase to 30 Tcf or decrease to 1 Tcf. Assuming that a single vertically drilled and hydraulically stimulated well (costing $300,000) could have the same production as the two deviated wells, the minimum required thickness would drop to 8 feet and the recovery potential at $3.00 per Mcf would increase to about 30 Tcf. However, it is likely that the induced fracture would parallel rather than intersect the face cleats. Under this condition, 10 year recovery would drop to 6% (about 1/5 of that assumed in the Base Case), and even under these lower costs, the potential at $3.00/Mcf would decrease to about 1 Tcf.

e. Effective Drainage Area

It may be possible to increase the effective drainage area -- the area where the coalbed pressure is sufficiently low in the first 10 years -- to allow highly efficient desorption. One means for doing this would be to drill, where geologically feasible, the deviated wells further into the coalbed.

Assuming three deviated wells can be effectively drilled 2,000 feet into the coalbed, the drainage area increases fourfold to 288 acres, and ten year recovery increases threefold. Adjusting for higher investment costs (essentially double those in the Base Case), the analysis shows that the potential at $3.00/Mcf could increase by 5 Tcf.

f. Contribution of Fracture Porosity Gas

The analysis assumes that the methane is adsorbed within the coal and the fractures are essentially filled with water. Should the fractures (assumed at 5% porosity) be fully filled with methane, the contribution to ultimate recovery is small, less than 5%.

g. Subbituminous Coals

Assuming pay thickness and fracture intensity of the subbituminous coals in the sand, the subbituminous coals with a methane content of 100 cf/ton could add about 1 Tcf to the above estimates in the $3.00 to $4.50 per Mcf price range.

IV. SUMMARY OF THE R&D PROGRAM AND ITS POTENTIAL

This final section of Part 1, Methane Recovery from Coal Seams, summarizes the major R&D goals, the production benefits, the costs, and the cost-effectiveness ratios of a successful program. Part 2 of this chapter provides the details of the proposed R&D programs.

A. The Research and Development Goals

The geological and technological challenges for recovery of methane from coal seams form the R&D goals of the program.

1. Methane from Minable Coal Seams - Appalachian Basin

- To ascertain the optimum means for collecting the gas released during coal mining operations.
- To establish that methane captured in association with coal mining can provide a reliable economic supply for:

  -- transmission into natural gas pipelines, or

  -- supplemental LNG, or

  -- other end uses.
- To test and stimulate the installation of methane capture and utilization facilities such that 25 to 38% of the methane released as part of mining operations is captured for use:

-- one-half of all mines would contain methane recovery facilities

-- the recovery efficiency of the methane at a target mine reaches 50-75% of total emissions.

- To accumulate additional geological and technical insights into the nature and occurrence of methane in coal seams and in situ diffusion coefficients.

2. Methane from Unminable Coal Seams - Western Basins

- To identify the geologic characteristics of the thick coal seam basins, particularly the extent of the in situ natural fracture system and the methane content.

- To develop and successfully apply deviated drilling technology to coalbeds.

- To ascertain the economic feasibility of pre-drainage, given the geology of the Western coal basins and the efficiency and costs of applying the recovery technology.

B. Production Benefits

The production benefits, stated in terms of ultimate recovery (recovery in 30 years), 1990 cumulative recovery, and 1990 production rate, are as follows:

	Price Per Mcf		
	$1.75	$3.00	$4.50
• Ultimate Recovery (Tcf)			
- Appalachian Basin	1.1	1.6	1.6
- Western Basins	0-10	0-20	0-25
• 1990 Cumulative Production (Tcf)			
- Appalachian Basin	0.19	0.23	0.23
- Western Basins	*	*	*
• 1990 Production Rate (Tcf)			
- Appalachian Basin	0.04	0.05	0.05
- Western Basins	*	*	*

*Not estimated

C. R&D Costs

The research program costs for the two programs in methane recovery from coal are as follows:

	5 Year Program Costs (in millions)	
	Total	ERDA
Appalachian Basin	$16.5	$16.5
Western Basins	29.1	24.1

D. Cost-Effectiveness of the Program

Two cost-effectiveness ratios serve to illuminate the potential benefits of the R&D program:

- Long Term Measure - Ultimate Recovery (Mcf) @ $3.00 Mcf/Total ERDA Costs
- Near Term Measure - 1990 Cumulative Recovery (Mcf) @ $3.00 Mcf/Total ERDA Costs

The cost-effectiveness ratios for methane recovery from coal are:

	Long Term Measure Mcf/Total ERDA Costs	Near Term Measure Mcf/Total ERDA Costs
Appalachian Basin	95	14
Western Basins	0 - 830	-

E. Summary

These sensitivity analysis show that the methane from minable coal seams can be a steady source of natural gas and will increase as the pace of mining, the efficiency of collection, and prices increase. The methane adsorbed in deep coal seams is a more speculative resource in that less is known of the methane content or the extent of the natural fractures system.

CHAPTER 5

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CHAPTER FIVE

METHANE FROM COAL SEAMS

Part 2

RESEARCH AND DEVELOPMENT STRATEGY FOR METHANE FROM COAL SEAMS

The research and development program for methane from coal seams is organized into two programs:

- Program 1 - Methane from Coal/Appalachian Basins: Recover Methane in Association With Mining
- Program 2 - Methane from Coal/Western Basins: Recover Methane from Unminable Coal

Program 1

TARGET: Methane from Coal/Appalachian Basin

R&D STRATEGY: Recover Methane in Association With Mining

1. Central Problem

Methane, to varying extent, is contained in all coal accumulations. The methane must be locked on and in the coal since the porosity of the coal is inadequate to account for its presence (200 cf of methane per ton of coal would require a pore space of 26% at a pressure of 500 psi).

In Appalachia, the coalbeds average 5 feet; hence, a 72 acre "reservoir" would contain but 130 MMcf, and recovery during the first ten years would be about 30% of this amount. Standing alone, production in advance of mining (and having no significant residual benefits to subsequent mining) from such reservoirs is generally uneconomic, particularly in light of the considerable surface equipment and gathering systems costs.

The principal targets for recovering methane from coalbeds are the active mines in which it has been established that methane is released in significant quantities as mining proceeds.

The economics of pursuing this activity will be dependent on benefits derived from increasing the rate of mining permitted and improving safety due to diminution of gas in mines. Any captured gas can be used for local industry and household use. The erratic nature of the delivery in the early years suggests specialized use as LNG or local use for direct combustion and power generation may be feasible. In the longer term it may be possible to use the methane as a regional industry feedstock, such as for ammonia production.

2. Scope of the Effort

The recovery of methane in association with mining would concentrate on the high methane emission mines of the Appalachian Region that account for nearly 90% of total national methane emissions. The initial target would be the 30 largest methane emission mines concentrated heavily in the Pittsburgh, Pocahontas No. 3, Pratt, and Kittanning coalbeds that account for over one-half of total emissions.

3. R&D Goals

The problems discussed above set the basis for the R&D goals for recovering methane from coal seams in the Appalachian Basins:

- To verify that methane can be economically recovered from coal in association with the mining cycle.

- To ascertain the optimum way for collecting the released gas as mining progresses in Appalachia and Alabama. Appalachian mines should be the prime target because of: (a) the size and concentration of mining, (b) the gasiness of the mines, and (c) the potential for a ready market not now served by utility lines.

- To accumulate additional technological insight into the nature of the occurrence and release of methane in coal seams.

- To develop alternative end-uses and the associated markets for the recovered methane.

4. R&D Activities

- Task 1 - Complete a comprehensive digest and interpretation of all past and ongoing activities on coal degasification and methane recovery, particularly to document the extent of the natural fracture system, gas content, and continuity of the coal seams in the Appalachian Basin, including engaging in basic geological studies where the data is scarce.

- Task 2 - Conduct a definitive engineering study of schemes for recovering methane from active coal mines in Appalachia using:

  -- horizontal wellbores drilled from the base of the mine

-- vertical wells with longwall mining

-- recovery tests in shut-in mines

-- vertical wells with stimulation and deviated wells to produce the gas, drain the water, and reduce the pressure.

- Task 3 - Assess the economic feasibility of each approach, including working with BOM to ascertain the relative contribution each approach makes to productivity, reduced ventilation equipment, and safety.

- Task 4 - Pursue studies on in situ methane source and quantity and geometry of potential flow paths by multi-discipline research teams in the laboratory and on-site.

- Task 5 - Establish the most efficient methane drainage and recovery technique for each geologic setting/mining technique combination.

- Task 6 - Develop and test small scale, site specific technology for producing LNG from recovered gas with low (less than 80%) methane content.

- Task 7 - Assist operators install appropriate methane recovery facilities by providing direct professional assistance and technology transfer.

- Task 8 - Evaluate alternative end-uses for recovered methane in relation to location, facilities, supply of gas, and potential demand.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of methane recovery and utilization tests to carry out the above research, development, and demonstration activities are provided on Exhibit 1.

The decreasing manpower requirements are based on the considerable base of knowledge that has already been accumulated and that needs to be expanded in key areas.

The number of tests is based on the need to introduce methane recovery technology into the 30 largest methane emission mines that account for about 50% of all emissions.

Five alternative end-use technology demonstrations would be conducted, one per year.

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Methane from Coal/ Appalachian Basins

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Document and Study Geology	(2)	2	2	1	1		6	(8)
• Conduct Engineering Studies	(1)	2	1	1	1	1	6	(7)
• Conduct Economic Studies	(1)	1	1	1	1	1	5	(6)
• Conduct Basic Studies of Methane Occurrence and Flow	(1)	1	1	1			3	(4)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Studies	(2)	3	3	2	1	1	10	(12)
3. Field-Based Research, Development, and Demonstration (tests)								
• Recovery Tests	(6)	6	6	6	6	6	30	(36)
• End Use Technology		1	1	1	1	1	5	(5)
4. Technology Information Transfer (man-years)		2	2	2	2	2	10	(10)

6. R&D Costs

Exhibit 2 provides the cost of the R&D program using the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of conducting one methane recovery and utilization test is $250,000.
- The cost of conducting one end use technology demonstration is $1,000,000.

To ensure timely installation of methane recovery facilities, ERDA would pay the full costs of the demonstration program.

Program 1

EXHIBIT 2

TARGET: Methane From Coal/
Appalachian Basins

TOTAL PROGRAM AND ERDA COSTS

R&D ACTIVITIES (Thousands of 1977 Dollars) Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal	(500)	600	500	400	300	200	2,000	(2,500)
2. Improved Diagnostic Tools and Methods	(200)	300	300	200	100	100	1,000	(1,200)
3. Field-Based Research, Development, and Demonstration								
• Recovery Tests	(1,500)	1,500	1,500	1,500	1,500	1,500	7,500	(9,000)
• End Use Technology		1,000	1,000	1,000	1,000	1,000	5,000	(5,000)
4. Technology Information Transfer	(200)	200	200	200	200	200	1,000	(1,200)
TOTAL ERDA COST	(2,400)	3,600	3,500	3,300	3,100	3,000	16,500	(18,900)

7. Production Benefits

The anticipated benefits from a successful completion of the research and development program in recovering methane from Appalachian Coal Basins are estimated (at $3.00/Mcf) as:

	Base Case	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
• Ultimate Recovery	-	1.6	1.6
• Production Rate in:			
1985	-	0.02	0.02
1990	-	0.05	0.05
1995	-	0.07	0.07
2000	-	0.08	0.08
• Cumulative Production by:			
1985	-	0.05	0.05
1990	-	0.23	0.23
1995	-	0.53	0.53
2000	-	0.91	0.91

8. Benefits and Costs

The key cost-effectiveness measures (incremental production per dollar of ERDA cost) for methane recovery from the Appalachian Coal Basin (at $3.00/Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	95
• Near Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	14

TARGET: Methane from Coal/Western Basins

R&D STRATEGY: Recover Methane from Unminable Coal

1. Central Problem

The major focus of methane recovery from the Western Basins is the unminable coal. Here, the economics of recovery will need to stand on their own, with no credits accruing from improved mining productivity or safety, as might be the case for methane recovery programs conducted in association with mining.

Two types of unminable coal deposits have been identified as targets for the methane recovery program -- the thin coal seams (averaging 15 inches) that contain 70 Tcf of adsorbed methane, and the deep bituminous coal seams (between 3,000 to 6,000 feet) that contain 80 Tcf in place.*

As shown in Part 1, thin coal beds could not be economically produced for their methane content under the cost and price assumptions and within the present scope of the study.

As one goes deeper in search for the deep, unminable coals, costs increase even though methane content may also increase. Assuming that a similarly favorable natural fracture system has been created, and has not healed due to overburden stress, one would need coal seams on the order of 20 feet thick (at $3.00 per Mcf gas price) to provide an economic payback. (Coal seam thickness could be less if vertical wells could be successfully used.)

* The deep, unminable subbituminous coals, assuming a methane content of 100 cf/ton, would contain 20 Tcf in place.

Assuming sufficiently favorable geology, the challenge will be to intersect the natural fracture system (face cleats) and to provide a high-conductivity path to the wellbore. At this time, deviated wells, drilled 1000 feet into the pay, provide the most technically feasible means of intersecting the natural fracture system. Conventionally applied hydraulically-induced fractures would tend to parallel the existing fracture system rather than intersect them as required for optimum flow.

The final task will be to install highly efficient recovery systems that will: (a) maintain a very low pressure at the face of the coal exposed to the fracture system to stimulate desorption; (b) ensure efficient water removal from the wellbore; and (c) purify and repressure the methane at low cost.

2. Scope of the Effort

The recovery of methane from unminable coal would concentrate on the four western states of Colorado, New Mexico, Utah, and Wyoming, that collectively account for over 90% of the deep (over 3,000 feet of overburden) coal. Colorado, having by far the largest portion (about 70%) of the bituminous deep coal, would be the major target. Within Colorado, the San Juan, Uinta, and North Park Basins appear to offer sufficient favorable characteristics for initial resource evaluation.

3. R&D Goals

The R&D goals for recovering methane from coal in the Western Basins are:

- Provide a definitive assessment of the size and economic feasibility of the ultimate target, in particular specifying what percentage of the domestic deeply buried coal is sufficiently thick for economic recovery.

- Define the extent of the natural fracture system and its in situ conductivity, including the location and influence of any clay veins and discontinuities in the coal seam.

- Establish the methane content of the coal and the desorption rates for these deeply buried coalbeds.

- Prepare a definitive feasibility assessment of the size and economic potential of the ultimate target.

- Ascertain the optimum means for intersecting the natural fracture system (face cleats) and connecting it to a vertical wellbore.

- Improve the technical efficiency of placing deviated wells into the coal seams and at right angles to the face cleats.

4. R&D Activities

The R&D activities required to reach the above goals include:

- Task 1 - Obtain a series of cores from a few selected locations deemed most favorable for the occurrence of rich methane containing coal. If required, carry out needed geological studies to define such locations. Use core holes for characterization of in situ resources. Determine all parameters pertinent to estimating methane recovery feasibility.

- Task 2 - Conduct resource characterization studies of the thickness, continuity, and methane content of the deep, Western coalbeds in the vicinity of the foregoing selected coreholes.

- Task 3 - Construct reliable recovery and economic models to study the effects of variations in key reservoir parameters.

- Task 4 - Assuming sufficiently favorable locations are defined, confirm the hypothesis of the relative efficiencies of using deviated wells versus vertical wells with fracturing by conducting a series of tests in the same geologic setting.

- Task 5 - Develop improved means for directing and controlling deviated wells to ensure the horizontal hole stays in the seam and intersects, at right angles, the face cleat system in the coal seam.

- Task 6 - Should vertical wells with fracturing prove successful, develop improved, fracturing techniques for stimulating production rates from coal seams.

- Task 7 - Conduct a basic research study to determine the in situ diffusion constants in the deep coals.

- Task 8 - Conduct a thorough, definitive study of the economic potential of producing methane from deep, unminable Western coalbeds.

- Task 9 - Transfer the technology and assessment of the potential to the industry.

5. Manpower and Field Test Requirements

The levels of manpower and the numbers of resource definition cores and recovery tests to carry out the above research, development, and demonstration activities are provided on Exhibit 1.

The large resource characterization manpower requirements are based on the sketchy base of knowledge that now exists in the Western Basins and that needs to be expanded in key areas.

The number of cores is based on the need to take 20 cores in Colorado and 5 each in the other four major Western coal producing states.

The number of tests is based on the need to conduct 6 tests in Colorado and one each in the other four major Western coal producing states.

EXHIBIT 1
TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Methane from Coal/Western Basins

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal (man-years)								
• Document and Study Geology	(3)	3	3	3	3	3	15	(18)
• Conduct Engineering Studies	(1)	1	1	1	1	1	5	(6)
• Conduct Economic Studies	(1)	1	1	1	1	1	5	(6)
• Conduct Basic Studies of Methane Occurrence and Flow	(2)	2	2	2	2	2	10	(12)
2. Improved Diagnostic Tools and Methods (man-years)								
• Lab Studies		1	2	3	2	2	10	(10)
3. Field-Based Research, Development and Demonstration (cores/tests)								
• Cores		8	8	8	8	8	40	(40)
• Tests			2	2	2	4	10	(10)
4. Technology Information Transfer (man-years)				2	2	2	6	(6)

6. R&D Costs

Exhibit 2 (Total Program Costs) provides the total cost of the R&D program using the following assumptions:

- One fully supported professional man-year costs $100,000.
- The cost of taking one core is $100,000.
- The cost of conducting one technology demonstration test is $2,000,000.

To ensure timely implementation of the program, ERDA would pay the full costs of the professional manpower and coring program and 75% of the cost of conducting the technology demonstration tests. ERDA costs are shown in Exhibit 3.

EXHIBIT 2

TOTAL PROGRAM COSTS

TARGET: Methane from Coal/Western Basins

R&D ACTIVITIES (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
	(700)	700	700	700	700	700	3,500	(4,200)
2. Improved Diagnostic Tools and Methods								
		100	200	300	200	200	1,000	(1,000)
3. Field-Based Research, Development and Demonstration								
• Cores		800	800	800	800	800	4,000	(4,000)
• Tests			4,000	4,000	4,000	8,000	20,000	(20,000)
4. Technology Information Transfer								
				200	200	200	600	(600)
TOTAL COSTS	(700)	1,600	5,700	6,000	5,900	9,900	29,100	(29,800)

EXHIBIT 3

TOTAL SHARE OF ERDA PROGRAM COSTS

TARGET: Methane from Coal/Western Basins

R&D ACTIVITIES (Thousands of 1977 Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-YEAR TOTAL	(STRATEGY TOTAL)
1. Resource Characterization and Appraisal								
	(700)	700	700	700	700	700	3,500	(4,200)
2. Improved Diagnostic Tools and Methods								
		100	200	300	200	200	1,000	(1,000)
3. Field-Based Research, Development and Demonstration								
• Cores		800	800	800	800	800	4,000	(4,000)
• Tests			3,000	3,000	3,000	6,000	15,000	(15,000)
4. Technology Information Transfer								
				200	200	200	600	(600)
TOTAL ERDA COST	(700)	1,600	4,700	5,000	4,900	7,900	24,100	(24,800)

7. Production Benefits

The anticipated benefits from a successful completion of research and development in methane recovery from Western Coal Basins are estimated (at $3.00/Mcf) as:

	Base Case	After Successful R&D (Tcf)	Δ Due to R&D (Tcf)
• Ultimate Recovery	-	0 - 20	0 - 20
• Production Rate in:			
1985	-	Not Available	Not Available
1990			
1995			
2000			
• Cumulative Production by:			
1985	-	Not Available	Not Available
1990			
1995			
2000			

8. Benefits and Costs

The cost-effectiveness measures (incremental production per dollar of ERDA cost) for methane recovery from Western Coal Basins (at $3.00/Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/$)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	0 - 830
• Short Term Measure: 1990 Cumulative Production/ERDA 5-Year Costs	N/A

CHAPTER SIX

METHANE FROM GEOPRESSURED AQUIFERS

Part 1

I. INTRODUCTION

A. Background

Water-bearing reservoirs, characterized by significantly higher temperatures and pressures than their depth alone would suggest, have been identified beneath the Gulf of Mexico and the coastal regions of Texas. These are referred to as geopressured aquifers. In many of these aquifers the water may contain dissolved methane. Should it be possible to produce the formation water, extract the methane, and dispose of the spent water in an economically and environmentally sound way, these reservoirs could make substantial contribution to the nation's gas supply.

Although the geopressured aquifers have been known to exist for some time -- having caused difficulties in drilling for deep oil and gas reservoirs -- interest in their commercial potential has been relatively recent. The initial estimates of gas-in-place have been vast, ranging from 3,000 Tcf (B. R. Hise[1/]) to 50,000 Tcf (P. H. Jones[2/]). The USGS, in Circular 726, placed the estimate at 23,618 Tcf.[3/] These large gas-in-place figures have led to considerable public interest and discussion. Popular publications such as Fortune[4/] and the Wall Street Journal and publicly known individuals such as Herman Kahn (Hudson Institute)[5/] have speculated that geopressured aquifers can provide gas for 1,000 years. More intensive interpretation of these initial estimates have placed the recoverable potential at 250 to 500 Tcf.[6/]

A variety of geological assumptions lead to the conclusion that the resource in place is large. The essential question, however, is not the total size of the resource, but the portion that may be technically and economically recoverable.

The results of recent work suggest that, even at prices up to \$4.50/Mcf, the technically and economically recoverable methane may be a small fraction of the initial estimates.

Further, geologic and reservoir studies are required before the full potential of this resource base can be confidently assessed. It is possible, however, to establish the minimum geologic conditions that must be found for economic recovery of methane from these aquifers. In addition, the currently limited resource data base can be measured by these standards to illuminate the economic potential. The essential but missing data would provide focus to a research program aimed at ascertaining the total potential.

B. Nature of the Problem

The basic technology for recovering methane from the geopressured aquifers consists of drilling one or more production wells capable of producing vast quantities of gas-bearing water, installing facilities to capture the methane that comes out of solution at atmospheric conditions, and disposing the water once it has given up its gas.

With improved extraction facilities, it is believed that up to 85% of the gas in solution can be recovered from the produced water. However, only about 2 to 5 percent of the reservoir's water* can be produced in 30 years or before exhausting the reservoir's drive mechanism.** Thus, even

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* The modeling of defined Texas Gulf Coast geopressured aquifers gives recoveries of about 2-3%. The 5% recovery efficiency assumes: (1) a compression drive coefficient of about 11 x 10^{-6} psi^{-1}; (2) high permeability (100 md); (3) thick pay (500 feet); and (4) high pressure (14,000 psi).

** Artifically lifting methane-bearing water from the substantial depths of geopressured aquifers was considered to be beyond conceivable economic limits.

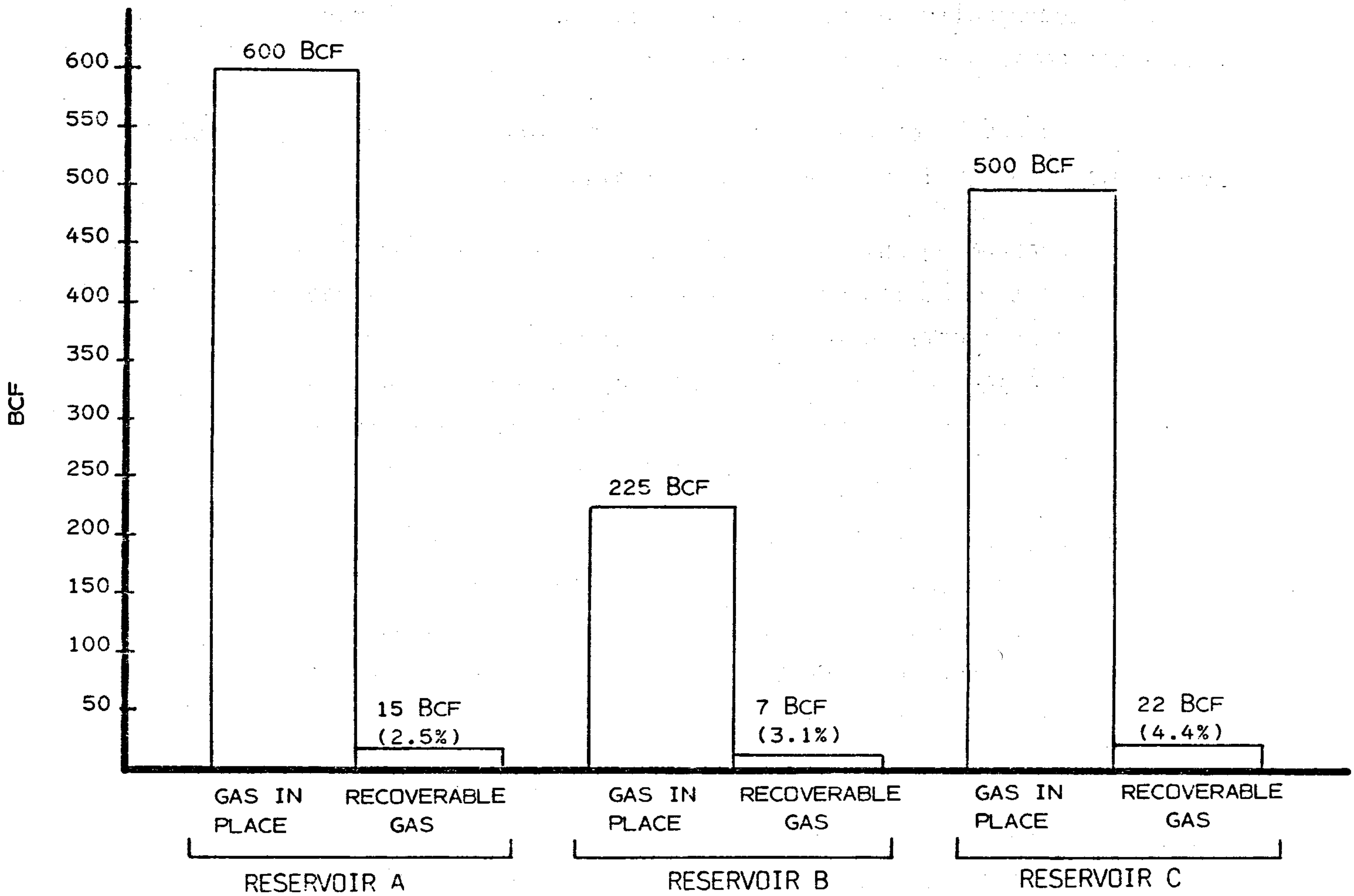
under optimistic assumptions on reservoir properties and high methane extraction efficiency, less than five percent of the gas resource in place is technically recoverable, as shown in Exhibit 6-1 for three Texas and Louisiana Gulf Coast reservoirs.

Moreover, certain technological problems must be solved before even this quantity is recoverable, including:

- Overcoming any well completion or production problems that might impede high rates of production. The poorly consolidated nature of the reservoir sands may pose problems of sand control and may, as the pressure is drawn down, significantly reduce the permeability in the portions of the formation nearest the wellbore.
- Developing high efficiency methane extraction facilities. For optimum economics, particularly for the lower methane concentration brines, the goal of methane extraction operation would be to recover 85% or more of the methane dissolved in the water.
- Disposing the produced brine in an environmentally safe manner. The brine will need to be injected into the subsurface because of the salinity and residual methane content or reinjected into the original producing formation to maintain the production rate and counteract subsidence.

Exhibit 6-1

Analysis of Technical Recovery Efficiency from Geopressured Aquifers



	Reservoir A	Reservoir B	Reservoir C
SINGLE RESERVOIR AREA (SQUARE MILES)	60	42	20
PAY THICKNESS, FEET	300	200	500
PAY PERMEABILITY TO BRINE, MDS	20	125	100
PRESSURE, INITIAL, PSI	11,000	11,000	14,000
METHANE CONTENT, SCF/BBL	40	25	47
LOCATION	BRAZORIA FAIRWAY, TEXAS	LOUISIANA (W. MAURICE)	LOUISIANA (DEPTH RANGE, 18,000-19,000)

C. Economic Feasibility

Minimum economic feasibility is governed by two broad characteristics:

- Large initial investment costs due to the depth of geopressured formations, the size of the casing and extraction facilities required to handle vast quantities of water, and the costs of reinjection wells to dispose of the spent brines.

- Substantial operating and power costs of handling, repressuring, and disposing of the produced water.

Given the cost of applying the technology, to be economic the resource base must support:

- High, sustained rates of water production; although numerous reservoir characteristics contribute to this, the dominant factors are the gross volume of the reservoir (area and thickness, with thickness becoming dominant once a minimum areal extent is reached), and the permeability of the pay.

- High concentrations of methane in the produced water; here the central factors, given the presence of methane, are high pressure, high temperature, and low salinity.

The next sections discuss the minimum required flow rate and methane content combinations and examine the published geologic data on geopressured aquifers in light of these minimum required conditions.

D. The Contribution of Ongoing R&D

Much of the theoretical analysis and all of the geologic data has accrued from the valuable and quality research efforts that are and have been underway for some time. The R&D program recommendations stemming from this analysis are an extension of this past work.

II. MINIMUM ECONOMIC CONDITIONS

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.

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* 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 charge for large industrial use electricity. Making power costs of disposal a direct function of gas price provides the following equation:

  Power costs = [\$0.01 + \$0.005 (price of natural gas in \$/Mcf)] x Disposal pressure (P_i in ksi)

- Combining the four components provides the following operating cost equation:

  Total operating costs per barrel of water = \$0.04 + [0.01 + 0.005 (price in \$/Mcf)] x P_i (ksi)

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. The above costs reconciled closely with these two sources.

2. Investment Cost Estimate

The investment costs are based on drilling, completing, and equiping 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*		450,000
	Subtotal	$3,570,000
• Overhead and G&A @ 10%		357,000
	TOTAL	$3,927,000

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.

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* 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.

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 (price in \$/Mcf) x (recoverable methane per barrel) $\geq$ \$0.04 + [\$0.01 + 0.005 (price in \$/Mcf)] x P_i (ksi)

- Methane content per barrel (in Mcf) $\geq \frac{\$0.073}{\text{price in \$/Mcf}} + 0.007$

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:

Price Per Mcf	Minimum Required Methane Content (cu. ft./bbl.)
\$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:

- 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:

Price Per Mcf	Production Rate (B/D)	Minimum Required Methane Content (Cu. Ft./Bbl.) (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

		Methane Content (Cu. Ft./Bbl.)		
Price ($/Mcf)	Production Rate (B/D)	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 6-2 provides the graph of the minimum required production rate and methane content for the five year payback case (the current high risk situation). Exhibit 6-3 provides the graph for the 10 year payback case and assumes that future resource characterization, technology development, and demonstration will reduce the risk.

Minimum Required Production Rate and Methane Content from Geopressured Aquifers (Under Five-Year Payback)

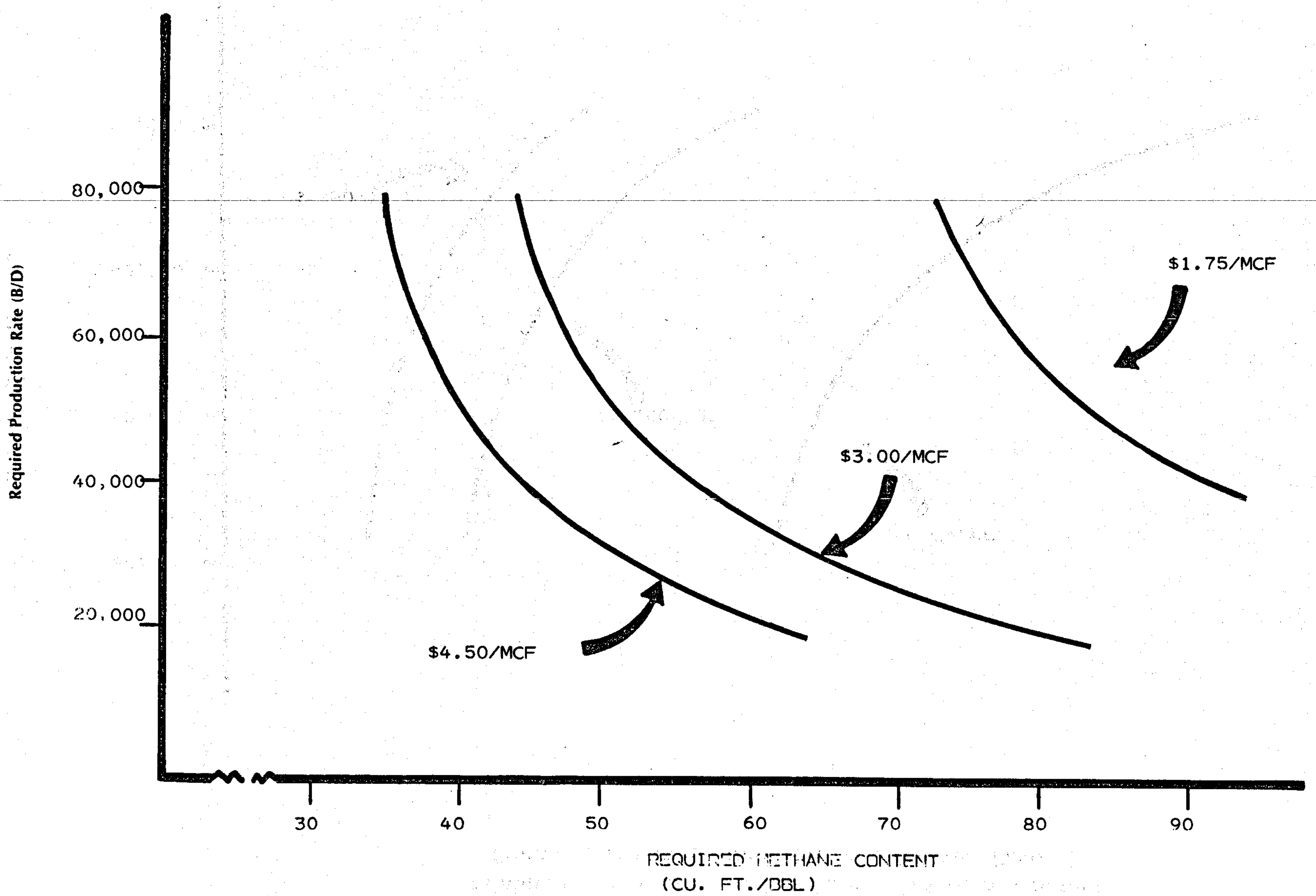
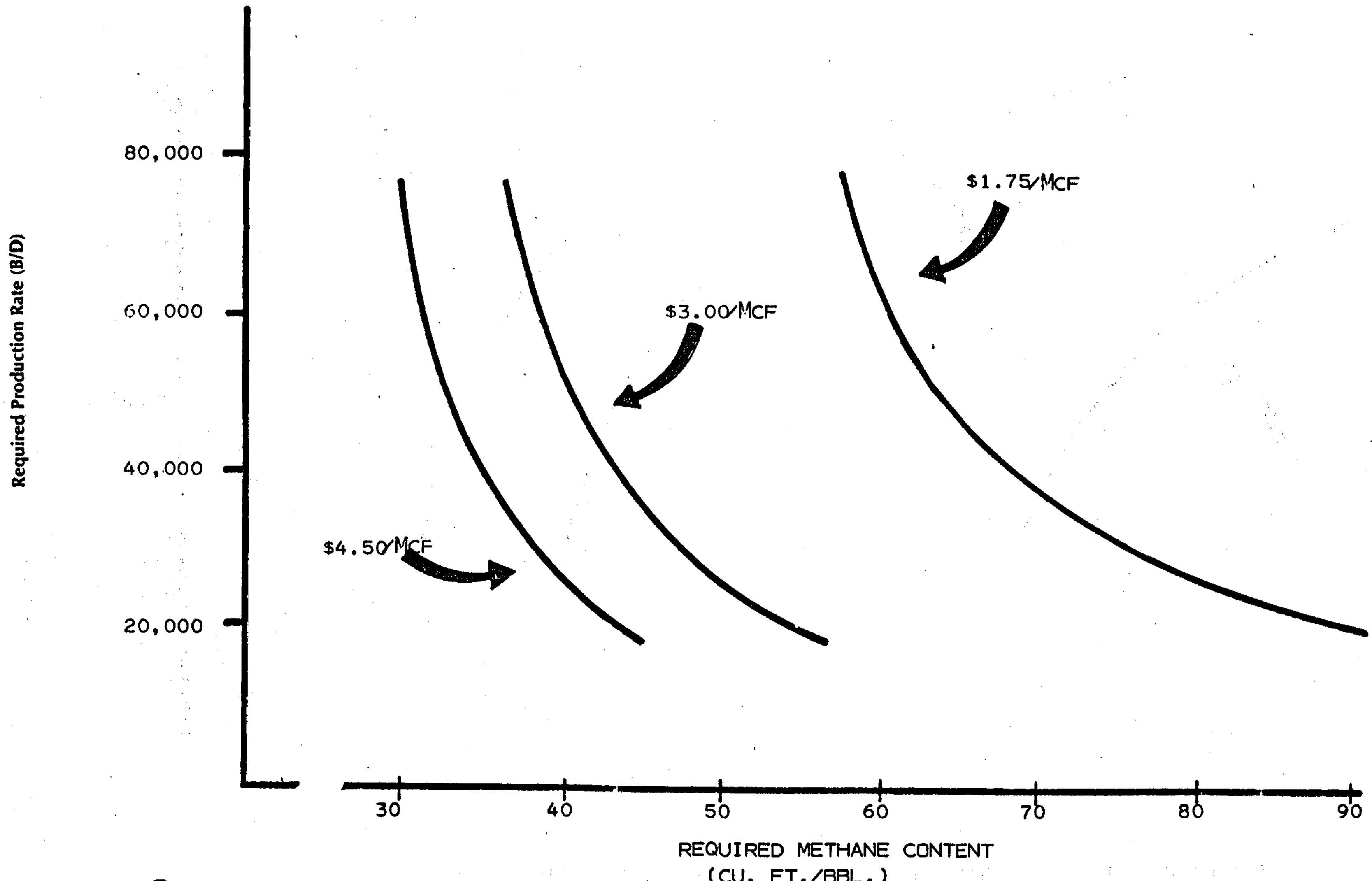


Exhibit 6-3

Minimum Required Production Rate and Methane Content From Geopressured Aquifers (Under Ten-Year Payback)



III. THE RESOURCE BASE

This section describes the methods used to estimate methane content and production rates of the identified geopressured resources in Texas and Louisiana and then applies these analytic methods to evaluate their economic potential.

A. Estimation Methods

1. Methane Content

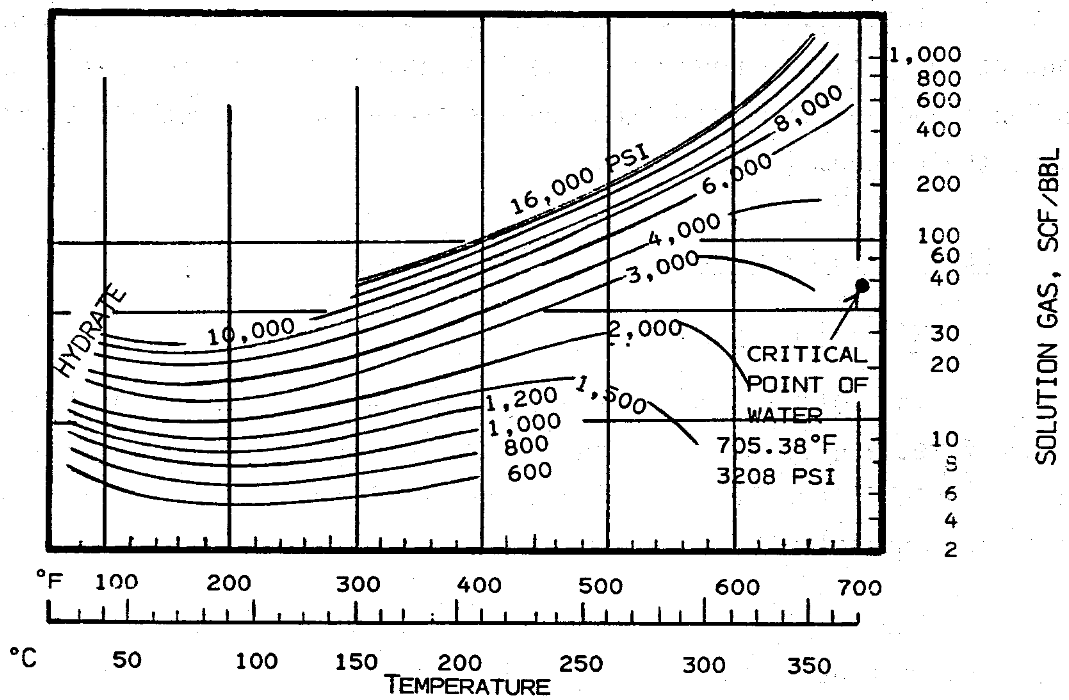
The volume of methane per barrel of water depends on the presence of methane to be dissolved and the solubility of the methane in water. Solubility, in turn, depends on the interplay of temperature, pressure, and salinity.

The original work by Culberson and McKetta[7/] on the saturation values of methane in pure water has been extended to higher pressures and temperatures by Sultanav, Skripka, and Namoit (Exhibit 6-4). These values were then adjusted using work by Standing and Dodson[8/] to account for the salinity of the reservoir water (Exhibit 6-5).

The resulting estimates are reported later in this section. However, a quick examination of the two curves, in light of the previous analysis, readily shows that an extraordinary combination of temperature, pressure, and low salinity is required for economic feasibility at current and near term gas prices. For example, at the $3.00/Mcf gas price and assuming a reservoir can support a 40,000 B/D production rate, the minimum

Exhibit 6-4

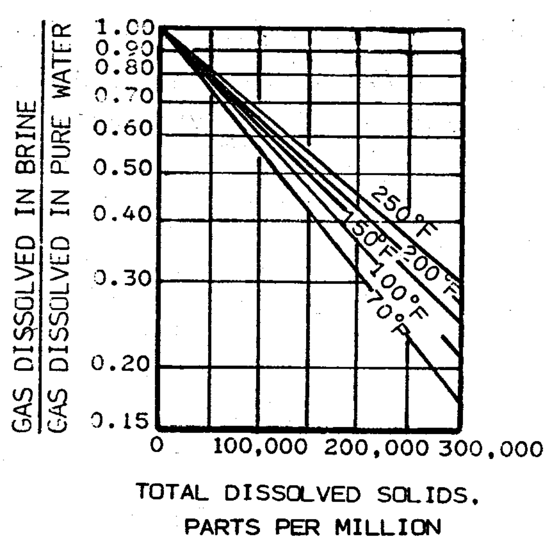
Solubility of Methane in Fresh Water



SOURCE: Sultanov, Skripka, and Namoit, 1972.

Exhibit 6-5

Effect of Salinity on Gas In Solution



SOURCE: Standing and Dodson

methane requirement (under a 5-year payback) could be met only by pressures greater than 16,000 psi, temperature greater than 350°F, and salinity of less than 20,000 ppm. (Because the three variables interact to determine methane content, less than ideal conditions on one variable may be compensated by improved conditions on the others.)

2. Production Rate

a. Analysis of Production Rate - Sample Reservoir

The rate of production from geopressured aquifers is determined by the interplay of numerous reservoir and fluid properties. Within the range of conditions expected to be encountered in the geopressured 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.

(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 for water is well known (at approximately 3×10^{-6} 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.

One company, after having studied the question for two years, estimates that the rock matrix compression and compaction of the formation is approximately 7.6×10^{-6} psi^{-1}, for unconsolidated sandstone, and 3×10^{-6} psi^{-1} for semi-consolidated sandstone. When the water and rock (formation) coefficients are combined, one arrives at 7×10^{-6} psi^{-1} for the compression drive coefficient.

It may, however, be possible to have higher compression coefficients, estimated by some as high as 40×10^{-6} psi^{-1}. Should these higher compression coefficients be found with no counterbalancing effects, it could be possible, theoretically, to recover considerably larger portions of the resource and to produce substantially smaller reservoirs. The effect of variation in this parameter has been shown to have direct, linear relationship to recovery efficiency. However, the counterbalancing effects of high compressibility coefficients could be severe:

- Permeability near the wellbore will be dramatically lowered as the compressibility increases.
- 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.

Because of the vast unknowns concerning compressibility, a relatively optimistic coefficient of 11 x 10^{-6} psi^{-1} with no counterbalancing effects were assumed throughout the analysis.

(2) <u>Permeability, Thickness, and Area</u>

Assuming a fixed compressibility coefficient and the other baseline reservoir data on the sample reservoir (Exhibit 6-6), the production from geopressured 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. The results of these calculations are displayed in Exhibit 6-6.

Exhibits 6-7 and 6-8 show the relationship of production rate to net pay and permeability for a small (5 square miles) and a large (50 square miles) reservoir.

EXHIBIT 6-6

TEN YEAR AVERAGE WATER PRODUCTION
FROM GEOPRESSURED AQUIFERS AS A FUNCTION OF
NET PAY, PERMEABILITY, AND RESERVOIR AREA
(MB/D)

AREA (mi^2)	NET PAY (FT.)	PERMEABILITY (md) 5	10	20	50	100
5	100	4	5	6	7	7
	200	8	10	12	13	14
	300	11	15	17	19	19
	500	18	23	26	28	29
10	100	5	8	10	12	13
	200	10	15	19	22	24
	300	15	21	26	30	32
	500	23	31	36	40	42
20	100	6	10	15	20	22
	200	12	19	26	33	36
	300	17	26	34	41	44
	500	26	37	44	49	52
50	100	7	12	20	30	36
	200	13	22	33	44	48
	300	19	30	41	50	54
	500	28	40	50	57	59
100	100	7	13	22	36	43
	200	13	23	35	48	54
	300	19	31	43	54	58
	500	29	42	52	59	62

Initial Pressure:	11,000 psi
Depth:	13,000 ft
Porosity:	0.216
Viscosity:	0.199 cp
Wellbore Radius:	0.275 ft
Minimum Wellhead Pressure:	500 psi
Fluid Head:	0.465 d = 6045 psi
Friction Loss (psi):	$7.477 \times 10^{-11}\ dq^2 = 9.7201 \times 10^{-7}\ q^2$
Compressibility:	$11 \times 10^{-6}\ psi^{-1}$
Shape Factor:	30.8828 (for one well)
Time:	10 years for economic payback calculations - 30 years for ultimate recovery

Exhibit 6-7

Ten Year Average Production Rate As A Function of Net Pay, Permeability, and Area

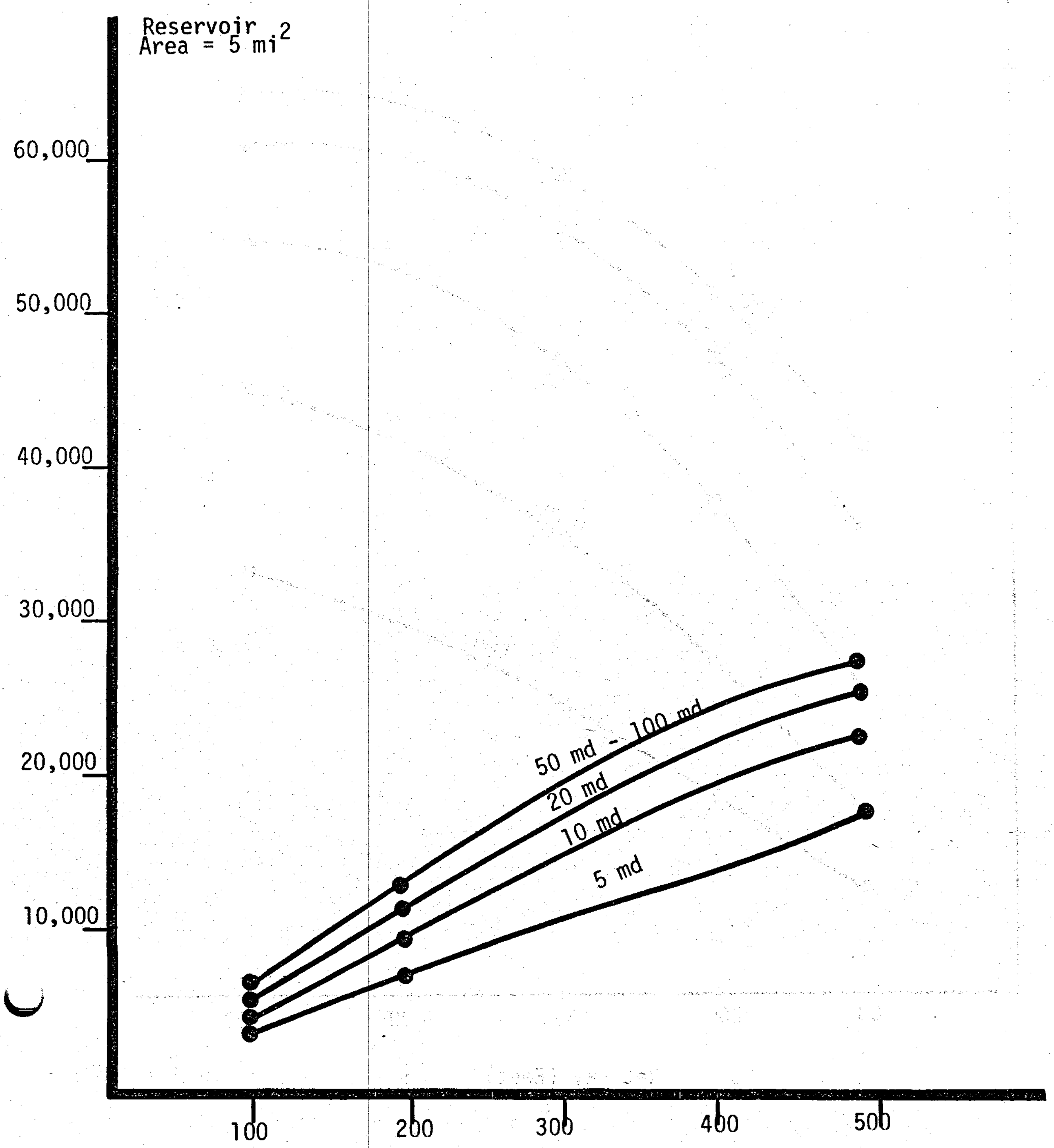
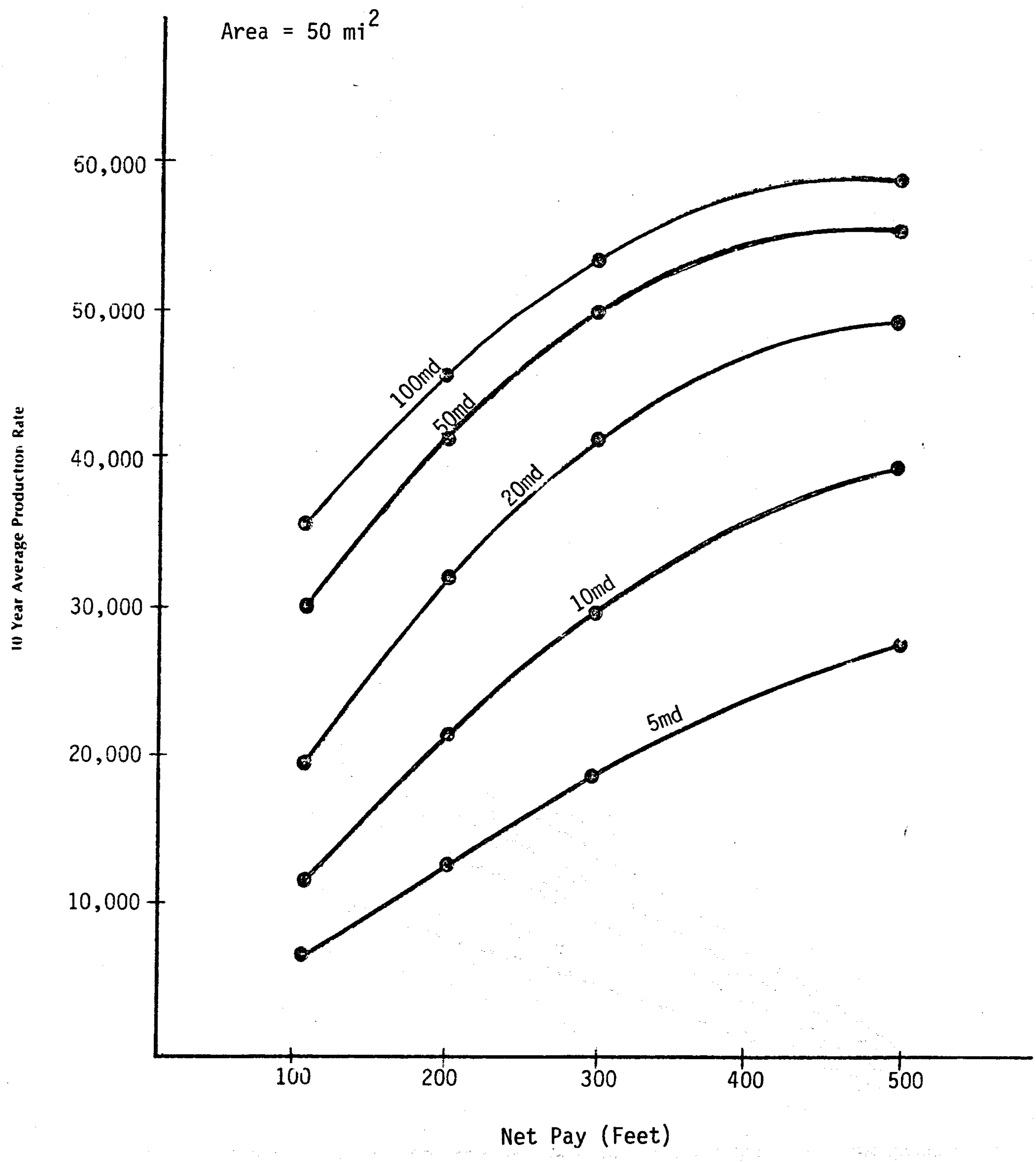


Exhibit 6-8

Ten Year Average Production Rate As A Function of Net Pay, Permeability, and Area



(3) Porosity and Pressure

The final two parameters, porosity and pressure, were analyzed for their effect on production rate estimates according to the flow analysis performed by Randolph,[9/] as shown on Exhibits 6-9 and 6-10.

(4) 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 ever to be produced economically, at affordable gas prices, reservoirs of over 5 cubic miles* (50 square miles x 500 feet in thickness) will be required to provide the minimum required flow rates to pay back investment. The investigation to date shows, as reported in the next section, that such large reservoirs are episodic and difficult to find.

b. Engineering Calculations of the Production Rate

(1) The Basic Formulae

The basic mechanics of fluid flow through the aquifer formed the basis for calculating the production rates of the identified geopressured reservoirs.

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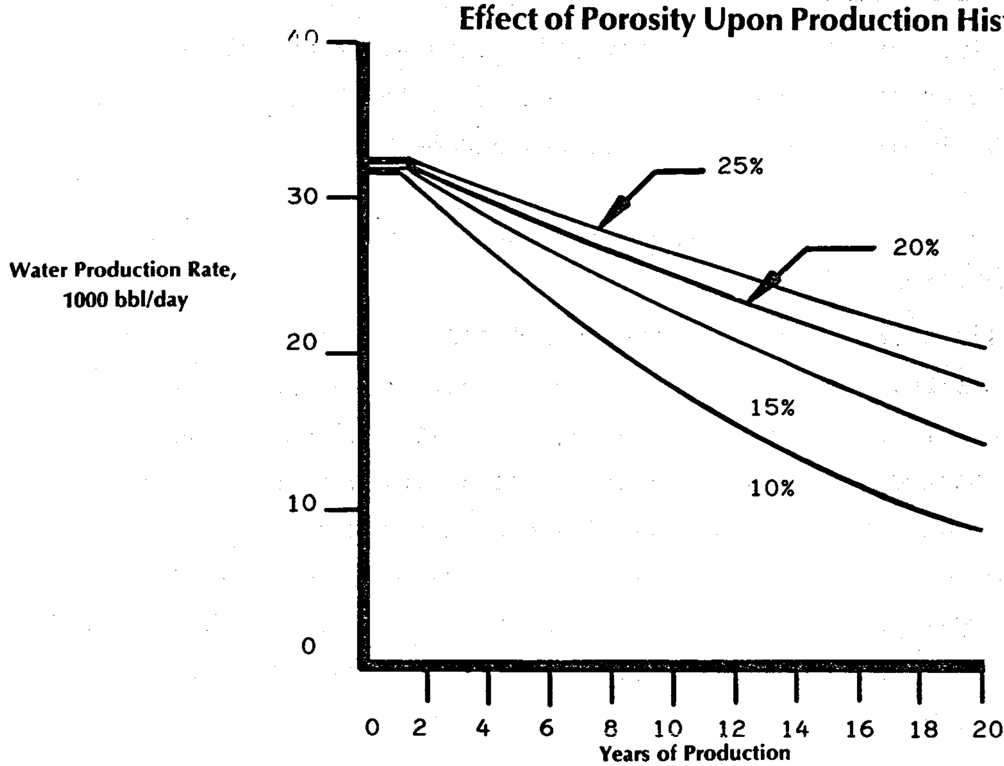
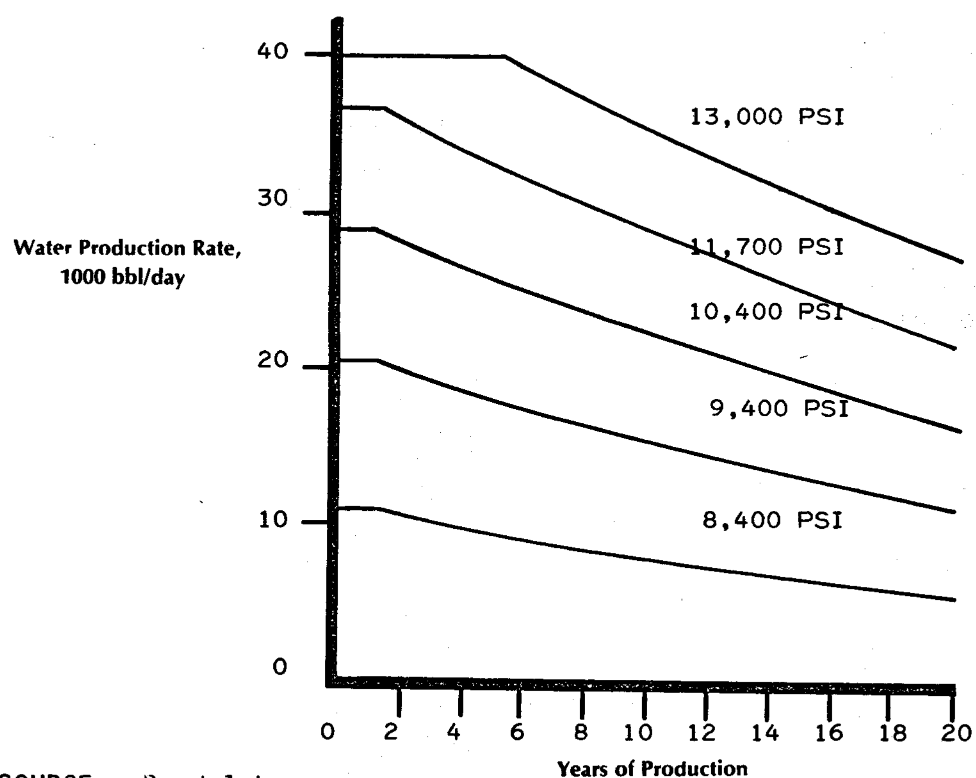
* Equivalent to reservoirs approaching Prudhoe Bay in size.

Exhibit 6-9
Effect of Porosity Upon Production History



SOURCE: Randolph

Exhibit 6-10
Effect of Reservoir Pressure Upon Production History



SOURCE: Randolph

Two formulae were used to calculate fluid flow:

- The infinite reservoir solution (or the exponential integral solution) was used to describe pressure behavior around a single well producing at constant rate from an infinite reservoir.

- The pseudo-steady state formula was used to describe the pressure behavior of a well producing from a bounded reservoir after the pressure disturbance of the well has reached the boundaries of the reservoir.

Volume III of the study provides additional discussion of the reservoir mechanics of producing the geopressured aquifers.

(2) Application of the Recovery Model

To illustrate the calculations, the fluid flow formulae were applied to the sample reservoir (Exhibit 6-6):

- The basic equation derived from the above two formulae of fluid flow is:

$$q\,(BPD) = (PI/\phi ch\Delta P)$$

- Substituting as follows:

PI: productivity index
ϕ: 0.216
c: 11.12×10^{-6} psi^{-1}
h: 162 ft.
P_{DO}: 10.44

- Solving for PI,* the equation becomes:

  $$q(BPD) = 6.96\Delta P(psi)$$

- Solving for ΔP, the pressure differential -- the initial aquifer pressure less the fluid head to surface, the producing well head pressure and the friction loss --

  $$\Delta P = 11{,}900 - 6045 - 5$$
  $$- (9.7201 \times 10^{-7} q^2)$$

- Substituting ΔP yields:

  $$q(BPD) = 30{,}990\ (BPD) - 6.761 \times 10^{-6} q(BPD)^2$$

  for the sample reservoir.

---

* PI, the productivity index function, is:
$PI/\phi c(BPD/ft.) = 21.3/[(t(yr)/A(AC)) + 18.79P_{DO}/\eta\ (ft^2/day)]$
for the pseudo-steady state period, when η, the hydraulic diffusivity is:

$$\eta = 0.00633\ k/\phi\mu c$$
$$= 2.38 \times 10^5 ft.^2/dry \text{ (for the sample reservoir)}$$

B. <u>The Potential of Producing Geopressured Aquifers at Gas/Water Ratios in Excess of Solution Value</u>

Recently, the possibility that geopressured aquifers might be produced at gas/water ratios in excess of the ratio that exists in the reservoir has been posed.

This hypothesis may stem from experience with undersaturated crude oil reservoirs that produce oil and gas at solution ratios between initial pressure and bubble point pressure. Production during this initial period is due to liquid expansion such as that presumed to occur in the production of geopressured aquifers. However, below the bubble point pressure, gas/oil ratios increase quite rapidly for undersaturated crude oil reservoirs. This is due to the release of gas from solution within the bulk of the reservoir and the subsequent and rapid migration of this gas to the wellbore because of its far greater mobility than that of the crude oil.

Before this released gas can flow it must first build up in saturation to some critical value. Most estimates of critical gas saturation are based on laboratory flow studies, and are usually in the range of 2 to 3% pore volume. These may be high estimates, because of problems in calculating material balances on small volumetric changes and the actual observation of very small flow rates in laboratory studies.

The key question becomes what is critical gas saturation for gas flow to occur. For crude oil reservoirs with solution gas ratios in the hundred and even as high as 1000 to 2000 cf/Barrel, there is no problem in accounting for the release of sufficient gas to reach a critical gas saturation. However, in the case of geopressured brines containing 40 cf/Barrel or less, the assurance of critical gas saturation becomes more problematic. Should the reservoir pressure of a geopressured aquifer decrease from 11,000 to 6,000 psi (approximate economic limit), the equilibrium gas saturation decreases from some 40 cf/B to 30 cf/B. At 6000 psi, the released 10 cf/B will occupy a reservoir volume of only 0.7%. This saturation is significantly less than any reported or presumed values of a critical gas saturation.

It has been suggested, based on the performance of the Edna Delcambre et. al. No. 1 well, that the geopressured aquifers may contain initially a free gas saturation of 6% or higher which is nevertheless below the critical gas saturation for the reservoir. On the release of a trivial quantity of gas from solution it has been suggested the critical gas saturation is surpassed, resulting in the production of gas/water ratios significantly greater than solution values. This conclusion is without foundation, as detailed in Volume III of this study. The subsequent computer modeling of the well's behavior did not obtain a good fit of the actual performance. The data on the well, because of the short equilibration times, large drawndown, and absence of definitive proof about behind pipe communication between zones, is an inadequate base for the far-reaching conclusions presented.

One assessment of the way in which gas-bearing geopressured aquifers came into existence is to assume that the gas was developed in bounding shales and then entered the brines which saturated the adjacent porous sands. Under such conditions, the gas upon reaching a critical gas saturation would begin to migrate and collect under conventional trapping conditions. Thus, in the body of a geopressured aquifer, no more than critical gas saturation should be expected to be encountered except where the reservoir configuration provided a conventional gas trap. If only critical gas saturation is encountered, then the additional small release of gas on pressure drawdown will not contribute significantly to gas production at ratios above solution values.

On the other hand, where critical gas saturation was earlier reached and gas generation continued, the accumulation of free gas must be sought in conventional traps by relatively conventional exploration techniques. The industry has been and continues to explore for geopressured gas accumulations. The development of such reservoirs, because of the high gas-bearing capacity of a geopressured pore, is a very rewarding and profitable operation. However, as noted above, the total volume of such accumulations tend to be quite small. These accumulations of free gas in anticlinal, stratigraphic, or fault traps are not considered part of the potential of gas supply from geopressured aquifers, even should geopressured aquifers be adjacent or the source of such gas.

C. General Resource Base -- Findings to Date

1. Areal Extent of Geopressured Aquifers

Generalizations about the likely size of geopressured aquifers have proven unreliable since local geology, especially tectonic activity and local geological deposition, determine the size of the reservoirs. Several recent studies illustrate this point.

The geologic studies by Wilson and Osborne[10/] indicate that the likely maximum sizes of individual sand bodies in selected delta facies is of the order of 3 to 4 cubic miles and the median volume would be somewhat less than 1 cubic mile. This is prior to the secondary modifications that result in faulted reservoirs. They find that the occurrence of multiple, "stacked" reservoirs amenable to multiple completions has low likelihood based on the depositional history of the aquifers.

Bebout and his associates at the University of Texas have carried out some exemplary studies on regional and site specific sedimentology.[11/] 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. Thus, the total volume of the multi-story package is about 3.4 cubic miles.*

Very recently, Wallace (USGS)[12/] 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, the areal distribution of the fault blocks that comprise the 31 largest oil fields in the Gulf of Mexico were examined (Exhibit 6-11).

---

* 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. Recent data indicate that the 60 square miles may be comprised of four or more separate sand bodies, thus a well at the targeted location is expected to drain sands within a 15 to 16 square mile area.

Exhibit 6-11

Distribution of Fault Block Sizes, Gulf of Mexico

SIZE DISTRIBUTION (Mi^2)	NUMBER OF RESERVOIRS	TOTAL AREA (Mi^2)	PERCENTAGE
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	16	4%
TOTAL		366	100%

Based on 380 fault blocks in these 31 fields, covering 371 square miles, only one fault block (covering 16 square miles) met the minimum size requirement of 10 square miles that could, when combined with the thick pay and high permeability, support a production rate of 40,000 B/D.

Should the same conditions hold for the geopressured water bearing aquifers as for oil bearing fault blocks, only about 4% of southern Louisiana's surface area would contain aquifers of sufficient size to provide economically attractive production rates.*

2. 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, based on the above analysis, 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[13/] indicate that pay thickness may be considerably lower than initially assumed. For example, the recovery estimates of 250 Tcf (Dorfman[14/]) assumed 1,500 feet of pay. Recent

* The possibility that the geopressured aquifers and oil and gas traps may have a different distribution parallels the assumption that the productive geopressured aquifers will be found in massive deposition occurring in the salt withdrawal synclinal areas. Oil and gas traps, of course, are found at structure locations. However, for the synclinal reservoirs to be large the assumption must also be made that these areas are not as frequently faulted.

data indicates high porosity, adequate permeability methane bearing pays are in the 300 foot range, about 20% of the initial estimates of pay thickness.

Finally, 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 geopressured reservoirs[15/] reveal that absolute permeabilities to gas range from 1.5 mds to 50 mds in the Texas Gulf Coast (although they may be higher in Louisiana), and are probably substantially less to hot brines.

While the work to date has shed considerable light on the geology and reservoir properties associated with geopressured aquifers, much remains unknown. These unknowns set the basis for the research agenda posed at the conclusion of this chapter.

The remainder of this section combines the general analysis of geopressured aquifers with detailed geological studies in defining the potential of the "identified to date" resource base in Texas and Louisiana.

D. Geopressured 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 prospective geothermal/geopressured reservoirs in the Texas Gulf Coast-Frio Formation.

Five major geothermal/geopressured fairways were identified by Bebout in the Frio Formation (Tertiary) of the Texas Gulf Coast. The geologic data (Exhibit 6-12) and the analytic methods discussed above were used to estimate the methane content of the water and calculate the average production rates for the five identified prospects, as follows:

	Estimated Methane Content (Cu. Ft/Bbl.)	Estimated Production Rate (Avg. Bbl/D; 10 yrs.)
• Hidalgo Fairway	45	7,000
• Armstrong Fairway	35	34,000
• Corpus Christi Fairway	40	9,000
• Matagorda Fairway	55	2,000
• Brazoria Fairway		
-- Austin Bayou	45	51,000*
-- Other	40	41,000

* Assumes a sand body of 60 square miles; subsequent analysis indicates that the 60 square mile area may be composed of numerous discrete sand bodies and that a well in the Austin Bayou prospect may drain sands only with a 16 square mile area. Should the more recent data hold, the estimated 10 year production rate would decrease to about 35,000 B/D, and the Austin Bayou prospect would be economic only at a higher, $4.50/Mcf, gas price.

Exhibit 6-12

Reservoir Properties of Prospective Fairways in Texas

Prospective Fairway	Temperature (°F)	Pressure (psi)*	Dissolved Solids (ppm)**	Permeability (md)	Net Pay (ft)	Area of Individual Sand Body (mi^2)	Areal Extent (mi^2)
1. Hidalgo	300+	11,000	(20,000)	1.5	300	50	500
2. Armstrong	250	10,000	(20,000)	20	300	50	50
3. Corpus Christi	300	10,000	(20,000)	5	350	4	200
4. Matagorda	350	12,000	(20,000)	35	30	4	100
5. 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 ft

**Estimated for Fairways 1-4

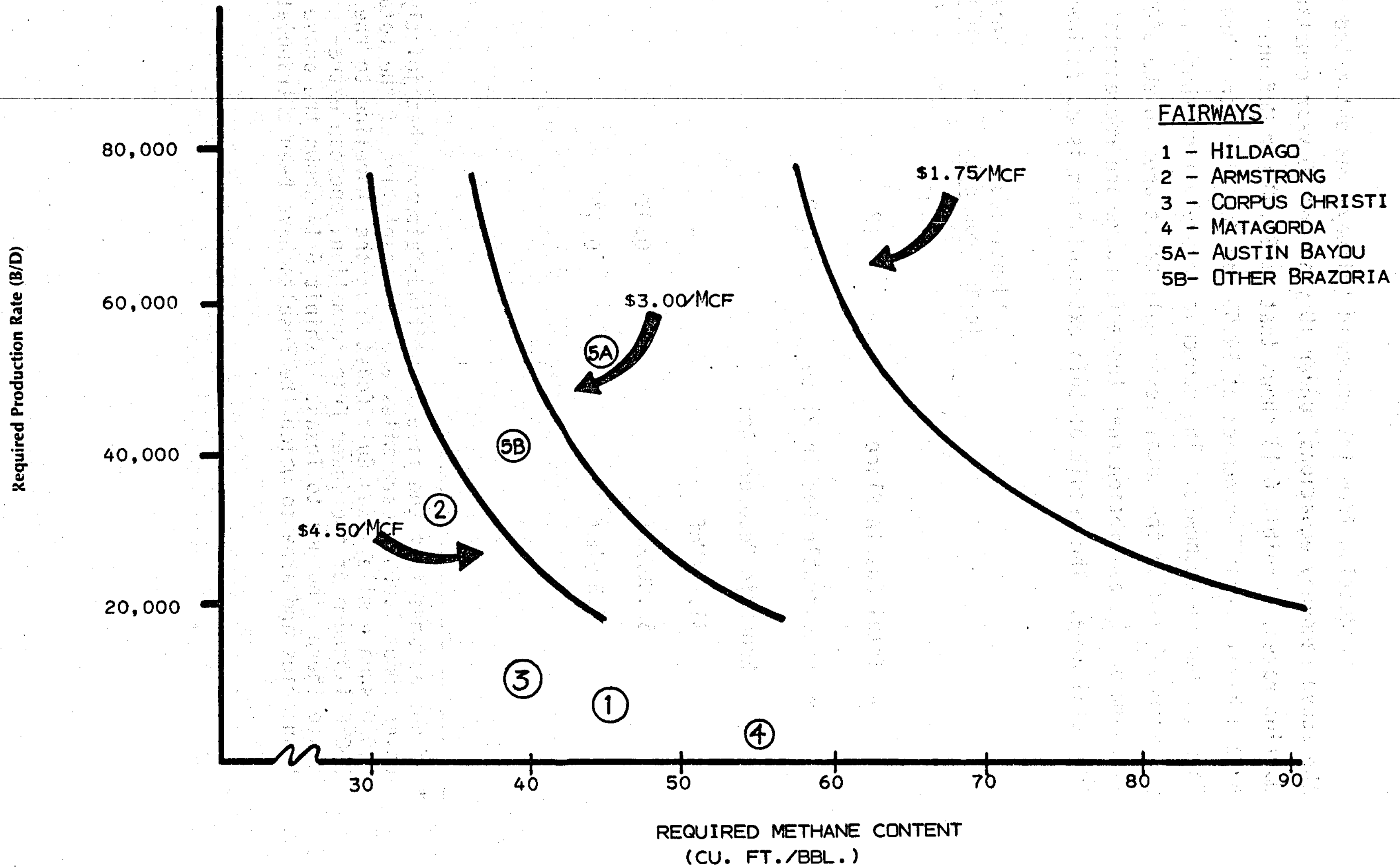
When these five prospects were compared to the minimum economic conditions for the (low-risk) payback period of ten years, the following results were drawn (also shown in Exhibit 6-13):

	Gas in Place	Technically Recoverable (Tcf)	Economic Status
• Hidalgo Fairway	6.7	0.03	Not economic at $4.50/Mcf
• Armstrong Fairway	0.6	0.01	Not economic at $4.50/Mcf
• Corpus Christi Fairway	2.2	0.17	Not economic at $4.50/Mcf
• Matagorda Fairway	0.2	0.02	Not economic at $4.50/Mcf
• Brazoria Fairway			
-- Austin Bayou	0.8	0.02	Economic at $3.00/Mcf*
-- Other	1.7	0.05	Economic at $4.50/Mcf
TOTAL	12.2	0.30	

* Assumes a sand body of 60 square miles; subsequent analysis indicates that the 60 square mile area may be composed of numerous discrete sand bodies and that a well in the Austin Bayou prospect may drain sands only with a 16 square mile area. Should this more recent data hold, the estimated 10 year production rate would decrease to about 35,000 B/D, and the Austin Bayou prospect would be economic only at a higher, $4.50/Mcf, gas price.

Exhibit 6-1?

Economic Analysis of Texas Gulf Coast Fairways



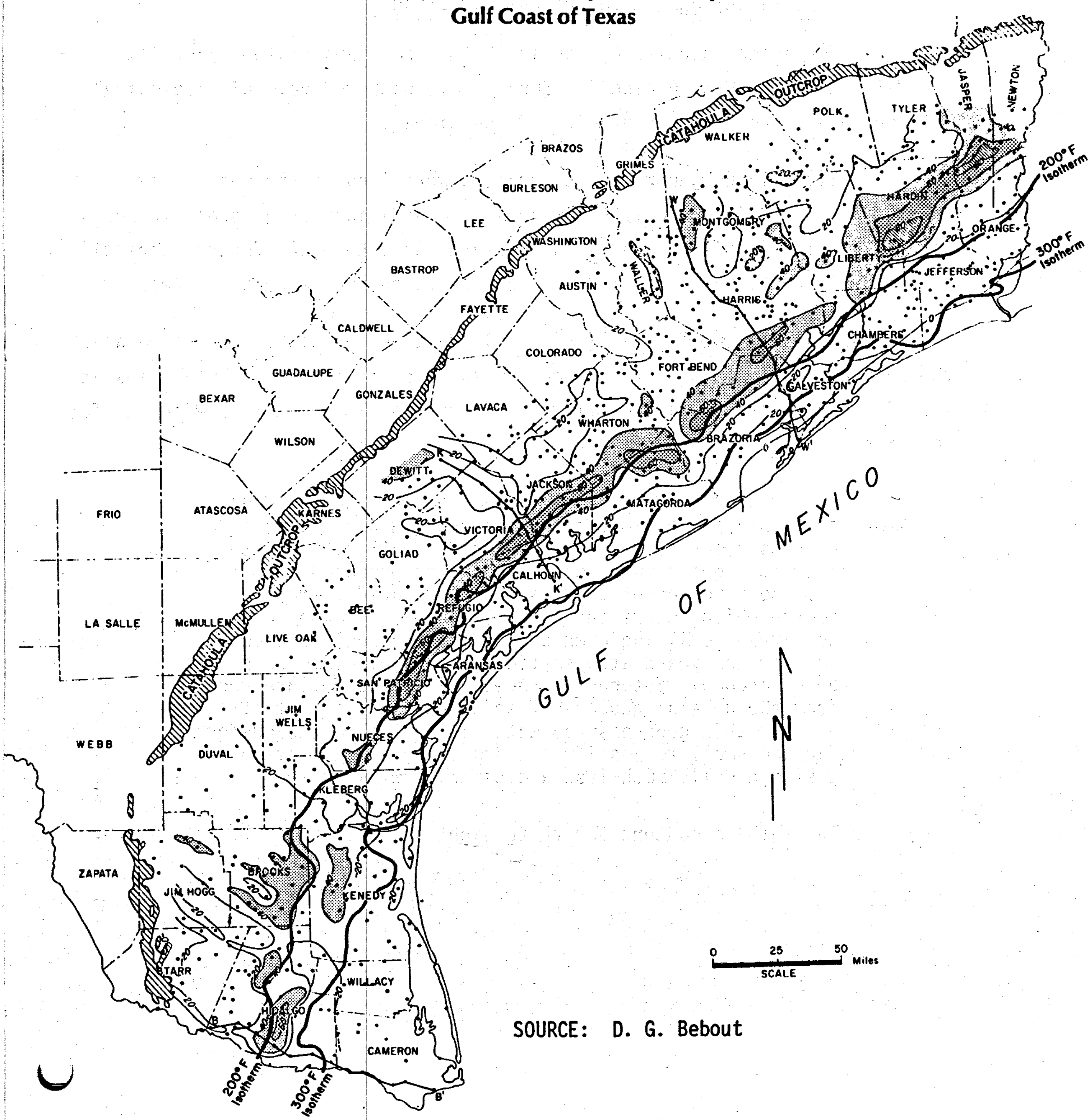
Production from the economic fairways was estimated (using the above recovery equations) under 10 year and 30 year constant production rates. Exhibit 6-13 shows that at $3.00 per Mcf only the Austin Bayou appears economic; at $4.50 per Mcf, the Other Brazoria Fairways become economic. The economic recovery from these fairways was extrapolated to the total Texas Gulf Coast area to the 300^{o}F isotherm on the assumption that these fairways are representative* of the total area. The result of this extrapolation is as follows (in Tcf):

	Identified Texas Prospects (Tcf)	Total Texas Gulf Coast (Tcf)
• Total Gas In Place	12	60
• Recoverable Gas In Place	0.30	2
• Economic Recovery At:		
$1.75/Mcf	-	-
$3.00/Mcf	0.02	0.1
$4.50/Mcf	0.07	0.4

* If one assumes that the five identified fairways that jointly cover about 1,000 square miles are representative of the total 5,000 square mile Texas Gulf Coast from the shoreline to the 300^{o}F isotherm of the lower Frio formation, one can extrapolate these findings to Texas. Exhibit 6-14 shows the above boundaries and area to which the results have been extrapolated.

Exhibit 6-14

Potential Areal Extent of Geopressured Aquifers — Gulf Coast of Texas



SOURCE: D. G. Bebout

D. Geopressured Aquifers of the Louisiana Gulf Coast

1. Analysis of Geopressured Aquifers - LSU

Two recent studies by Hawkins[16/] 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 realized 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 geopressured energy could be produced, and (b) the fraction of the total geopressured energy resource which occurs in aquifers which are large enough to warrant drilling even one well which would produce for say ten years at a sufficiently high volume rate to be of economic interest. Indeed, it is to be inferred from the general geology of southern Louisiana, that much of this geopressured 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: Temperature (°F)	Pressure (psi)	Dissolved Solids (ppm)	Estimated Methane Content (Cu.Ft./Bbl)
1. Newton	190	7,000	80,000	14
2. S. Midland	250	10,000	80,000	21
3. N. Lake Arthur	240	9,000	80,000	20
4. W. Lockport	220	10,000	80,000	19
5. W. Maurice	250	11,000	80,000	25
6. S. White Lake	280	9,000	80,000	25
7. Big Mouth Bayou	220	8,000	80,000	17
8. SE Peron Island	270	12,000	80,000	28

Under a minimum required methane content of 35-45 cubic feet per barrel (assuming a 10 year production rate of 40,000 B/D), none of the eight prospective areas are economic at $4.50/Mcf.

2. Analysis of Geopressured 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 offshore 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 began at about 10,500 feet of depth. Thus, about 800 Tcf of gas in place is in reservoirs that are both geopressured and onshore.

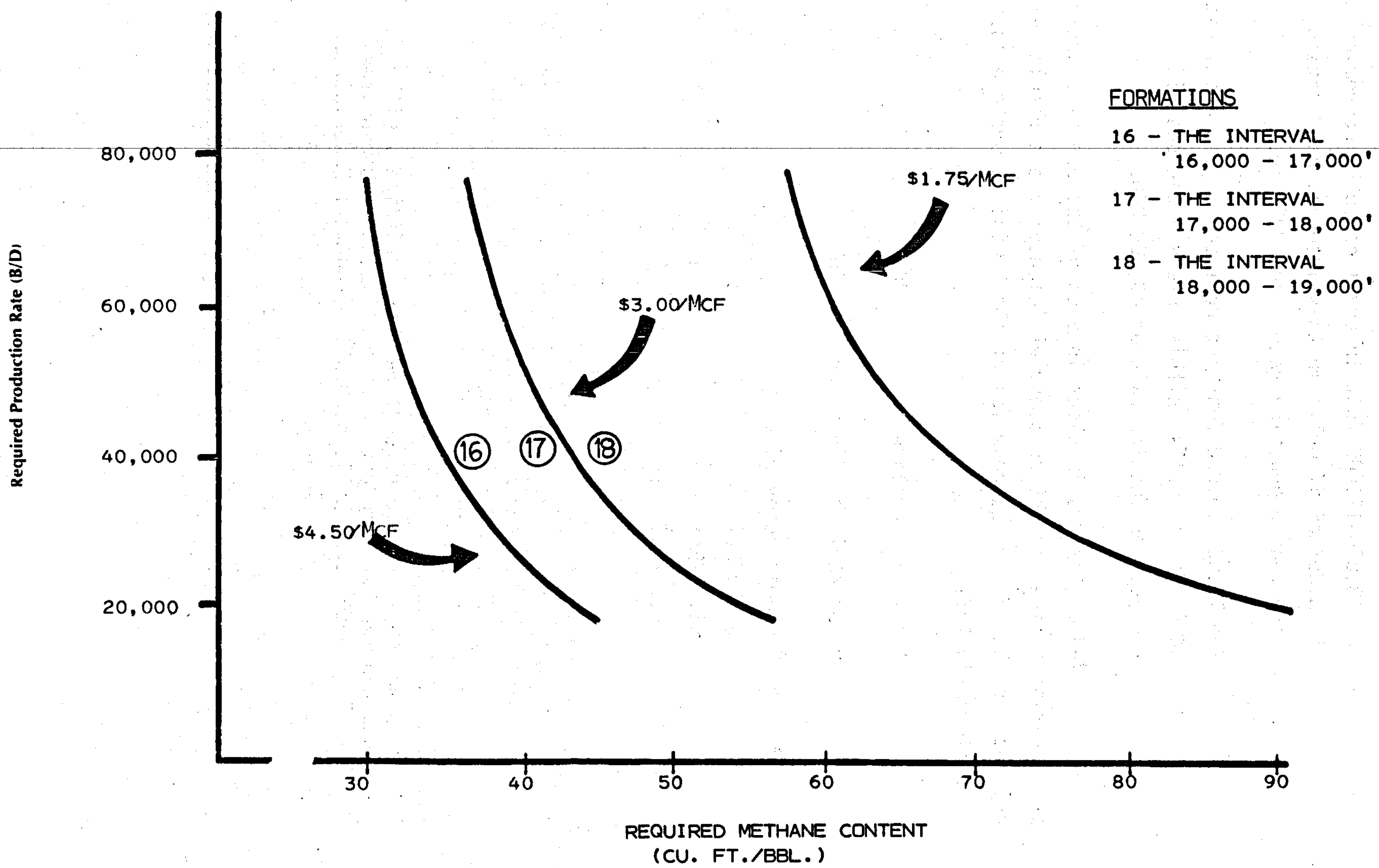
Using data on temperature, pressures, and salinities from USGS, the following methane concentrations were determined for the geopressured interval 10,500 to 19,000 feet:

Geopressured Interval (ft.)	Reservoir Properties Temperature (°F)	Pressure (psi)	Salinity (ppm)	Methane Content (Cu. Ft/Bbl)	GIP Onshore (Tcf)
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	270	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

Since limited conclusive data are available on areal size or permeability of the south Louisiana geopressured aquifers, for economic and recovery purposes it was assumed that each interval could support a ten year production rate of 40,000 B/D, a reasonably optimistic assumption. (Such a rate could be provided by large reservoir volumes with high permeability -- see Exhibit 6-6.)

Plotting the methane content and assumed production rates on Exhibit 6-15 shows that:

Economic Analysis of Louisiana Geopressured Aquifers



- The 18,000-19,000 foot interval could be economic at \$3.00/Mcf if wells in this interval can sustain a ten year production rate of 40,000 B/D.

- The 16,000-19,000 foot interval could be economic at \$4.50/Mcf if wells in this interval can sustain a ten year production rate of 40,000 B/D.

Based on the gas in place in each of the economic depth intervals, and assuming a five percent recovery efficiency* these results were extrapolated for the 25,000 square miles of the Louisiana onshore target area, as follows (in Tcf):

• Total gas in place	800
• Recoverable gas in place	40
• Economic recovery at:	
\$1.75/Mcf	-
\$3.00/Mcf	1
\$4.50/Mcf	5

* The assumption of a five percent recovery efficiency with a sustained ten year production rate of 40,000 B/D requires thick (500 feet+) and highly permeable (100 md+) reservoirs.

IV. SUMMARY AND SENSITIVITY ANALYSES OF ECONOMICALLY RECOVERABLE METHANE FROM GEOPRESSURED AQUIFERS

A. Summary of Potential

The analysis above shows that the economic potential of currently identified Texas and Louisiana reservoirs ranges from 1 to 5 Tcf, at gas prices of up to $4.50/Mcf.

	Texas (Tcf)	Louisiana (Tcf)
Gas in Place	60	800
Recoverable Gas in Place	2	40
Economically Recoverable at:		
$1.75/Mcf	-	-
$3.00/Mcf	0.1	1.0
$4.50/Mcf	0.4	5.0

B. Sensitivity of the Recovery Estimates to Key Variables

These recovery estimates have been based on a series of key assumptions about economics, geology, and reservoir performance. It is useful to determine how sensitive these estimates are to reasonable bounds of variation, particularly:

- Investment costs for the well
- Operating costs
- Risk premium investment criteria

- New producing horizons/supplemental free gas
- Free gas saturation
- Thickness of pay
- Areal extent
- Reinjection pressures

The results of this sensitivity analyses are shown below.

1. Investment Costs

The recovery estimates of 1 to 5 Tcf are insensitive to $\pm$ \$1,000,000 changes in investment costs. Reducing or increasing investment costs by \$1,000,000 per well changes the minimum methane content requirements (at the 40,000 B/D level) by only $\pm$ 2-3 cubic feet per barrel and would not have an appreciable effect on the economically recoverable portion of the resource base.

2. Operating Costs

The recovery estimates of 1 to 5 Tcf are highly sensitive to changes in the operating and energy costs of reinjection. The operating costs used herein are tied to the selling price of the produced gas, and to the energy required for disposing the produced water; for example, if the average disposal pressure was 2000 psi rather than 1000 psi, the increase in operating costs would reduce the economic potential of the identified Texas and Louisiana reservoirs to essentially zero at prices up to \$4.50/Mcf.

It may be possible, in the future, to design large, reliable gas-fired compressors for reinjecting the reservoir brines. Should this be feasible, the power costs, and thus the operating costs, could decrease to \$0.05 + [0.002(price per Mcf) x P_i (ksi)]. Under this assumption (and reinjection pressures of 1,000 psi), the 1 to 5 Tcf potential would increase to a range of 2 to 9 Tcf at gas prices of \$3.00 and \$4.50 per Mcf, respectively.

3. Investment Criterion

Requiring a higher risk premium reflected in a 20% ROR (or a five-year payback) would reduce the economically recoverable estimates of 1 to 5 Tcf to about 1 Tcf. When the production rates and methane content of the Texas and Louisiana reservoirs are analyzed using the five-year payback curves (a shown previously in Exhibit 6-1), the economic potential becomes as follows:

	Texas (Tcf)	Louisiana (Tcf)
Economic at:		
\$1.75/Mcf	-	-
\$3.00/Mcf	-	-
\$4.50/Mcf	0.03	1

4. New Horizons

New producing horizons may serve to increase the economic potential. It may be that other formations, such as the Wilcox and Vicksburg in Texas, and the Upper and Lower Cretaceous in Louisiana, contain sufficiently geologically favorable aquifers of high methane content to be economically recoverable. Should this be verified by further R&D, the potential of the geopressured aquifers would increase.

5. Free Gas Saturation

The potential from geopressured aquifers could be substantially enhanced should free gas in the pores or in an overlying gas cap be consistently found in conjunction with large geopressured aquifers. However, it is generally believed that geopressured free gas accumulations occurring in conventional traps will be sought and developed as an intrinsic part of conventional exploration and production activities.

Additional analysis and resource definition will be required to define any parallels between the occurrence of geopressured methane bearing aquifers and geopressured gas reservoirs.

6. Thickness

Should the formations prove to be twice as thick as have been found in Texas and be able to produce at 60,000 B/D in Louisiana, economically recoverable methane would increase by 1 Tcf. In Texas, given the areal, permeability, and methane content data on the five identified fairways, only the Armstrong and Brazoria are economic even at pays up to 600 feet. However, since the volume of two economic fairways doubles, the total recoverable from Texas would double. In Louisiana, increasing the productive capacity sufficient to raise the 10 year production rate to 60,000 B/D would not economically bring on the next interval of 15,000-16,000 feet, and thus would not add to currently identified recovery.

7. Areal Extent

Should the five identified fairways in Texas be the most favorable and the fault blocks in Louisiana be small (comparable to the offshore oil fields), the economically recoverable potential drops to below 1 Tcf. The five identified Texas fairways, on their own, will produce 0.01 Tcf (at $4.50 per Mcf). If the fault blocks in Louisiana are small with only 4% being 10 square miles or larger, the 5 Tcf in Louisiana now estimated to be economically recoverable at $4.50/Mcf may drop to 0.2 Tcf. Thus, together these two areas would provide about 0.3 Tcf.

8. Reinjection Into the Producing Aquifer

Should the produced water need to be reinjected into the producing reservoir, the economics of recovery would be severely impaired. For reinjection into the original reservoir, at 6,000 psi, operating costs could reach $0.15 to $0.20 per barrel, depending on fuel costs. The minimum required methane content, even at $4.50/Mcf, would be over 70 cubic feet/barrel, and would make all of the above identified prospects uneconomic.

V. SUMMARY OF THE R&D STRATEGY AND ITS POTENTIAL

This final section of Part 1 summarizes the major R&D goals, the production benefits, the costs, and cost-effectiveness of a successful program. Part 2 of this chapter will provide the details of the proposed program.

A. The Research and Development Goals

- Establish the economic sensitivity of production for a wide range of parameters to define the critical bounds.
- Estimate the anticipated distribution of reservoir sizes from geological and analog studies.
- Confirm by drilling and completion the extent of reservoir continuity.
- Determine the water salinities, pressure gradients, and water temperatures in these reservoirs, as well as the quantities of methane dissolved per barrel of water.
- Determine the optimum manner for the disposal or reinjection of the produced fluids.
- Define any potential well completion and production problems due to sand production and corrosion, and secure technical contributions in these problem areas from industry and service companies.
- Develop highly efficient methane extraction facilities.

B. Production Benefits

The production benefits are only stated in terms of ultimate recovery. Given the speculative nature of the resource base, no estimates are made for cumulative recovery or production rates.

	Price Per Mcf		
	$1.75	$3.00	$4.50
Ultimate Recovery (Tcf)	-	1	5

(Future work may identify new producing horizons to increase this potential.)

C. R&D Costs

The research program costs for the methane recovery from geopressured aquifers programs are as follows:

	Program Costs (in millions)	
	5 Year	Total (including FY 78)
Total	$36.2	$42.6
ERDA	$36.2	$42.6

D. Cost-Effectiveness

The long-term cost-effectiveness measures of yield per ERDA dollar (Ultimate Recovery in Mcf/Total ERDA 5 Year Costs) at three prices are:

	Price Per Mcf		
	$1.75	$3.00	$4.50
Ultimate Recovery (Tcf)	-	30	140

E. Summary

From these summary sensitivity analyses, it is evident that considerable uncertainty exists regarding the potential of geopressured aquifers for contributing to the nation's energy supply. This uncertainty can only be resolved by using R&D to define the geological value and extent of this resource base. It is clear, however, that the early estimates of hundreds of years of supply are grossly exaggerated. The next section provides an overview of a strategy for resolving these central uncertainties.

CHAPTER SIX

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CHAPTER SIX

METHANE FROM GEOPRESSURED AQUIFERS

Part 2

RESEARCH AND DEVELOPMENT STRATEGY FOR METHANE FROM GEOPRESSURED AQUIFERS

The research and development strategy for methane from geopressured aquifers consists of one program:

- Ascertain Reservoir Size, Methane Content, and Well Production Technology

TARGET: Methane from Geopressured Aquifers

R&D STRATEGY: Ascertain Reservoir Size, Methane Content, and Well Production Technology

1. Central Problem

It has been postulated that the geopressured thermal zones underlying the Gulf of Mexico and coastal areas of Texas and Louisiana contain large aquifers characterized by high temperatures and extremely high pressures. Should high concentrations of methane be dissolved in these waters and the methane bearing water be produced and disposed of economically, these aquifers could produce substantial quantities of methane.

Thus, the exploitation of this resource depends on two essential geological conditions:

- Continuous reservoirs of considerable size, 3 billion barrels of water in place and larger, with sufficient millidarcy feet to maintain high rate of natural production -- on the order of 40,000 B/D initially.

- A high content of methane which in turn requires fresh water, elevated temperatures, and high pressures.

Successful exploitation also depends on the resolution of leasing and ownership questions and environmental issues relating to subsidence, reinjection of water, and impacts of possible blowouts.

The principal technical issue is sand control, especially if the geopressured aquifers rock is found to be unconsolidated sandstone.

These conditions -- reservoir size, methane content, and disposal/reinjection -- along with the technical challenge of sand control and the legal issue of ownership will determine the economic feasibility of producing methane from geopressured aquifers.

The problem is that too little is known to define the resource with any significant degree of credibility. The thrust of this R&D strategy is to continue evaluation and projection of the potential while collecting the information required to make these estimates more precise.

2. Scope of the Effort

The recovery of methane from geopressured aquifers would be directed to the Gulf Coast regions of Texas, Louisiana, and Mississippi. The target would be the Tertiary (Frio and Wilcox) age formations in Texas and the Miocene and Upper Cretaceous formations in Louisiana and Mississippi.

3. R&D Goals

- Establish the economic sensitivity of production for a wide range of parameters to define the critical bounds.

- Estimate the anticipated distribution of reservoir sizes from geologic and analog studies.

- Confirm by drilling and completion the reservoir continuity.
- Determine the water salinities, pressure gradients, and water temperatures in these reservoirs as well as the quantities of methane dissolved per barrel of water.
- Determine the optimum manner for the disposal or reinjection of the produced fluids.
- Define any potential well completion and production problems due to sand production and corrosion, and secure technical contributions in these problem areas from industry and service companies.
- Develop high efficiency methane extraction facilities.

4. R&D Activities

The sequence of activities required to reach these R&D goals is as follows:

- Task 1 - Complete detailed geological studies to estimate expected reservoir size and geometry distributions. Determine optimum locations for test wells and wells of opportunity.

- Task 2 - Drill several wells at preferred locations to test productive capacity, dissolved and associated free gas, and continuity of reservoirs.

- Task 3 - Study water disposal issues, and where possible evaluate potential of subsidence.

- Task 4 - Conduct detailed cost analysis and prepare detailed reservoir engineering predictions to pinpoint estimated cost of production.

- Task 5 - Should the above results continue to be favorable, develop appropriate technologies for well completion and methane extraction.

5. Manpower and Field Test Requirements

Considerable manpower will be devoted in the initial years toward completing detailed geological study (see Exhibit 1). As this information is gathered, the manpower efforts will shift toward improving the diagnostic capacity to complement the test well and demonstration program.

Ten test wells are proposed. The first five would be placed in the currently identified higher potential prospects (in Texas, the Austin Bayou and the Other Brazoria Fairways and in Louisiana, the 17,000-18,000 foot and the 18,000-19,000 foot intervals): the second five would be reserved for other

EXHIBIT 1

TOTAL PROJECT/MANPOWER REQUIREMENTS

TARGET: Methane From Geopressured Aquifers

R&D ACTIVITIES (Physical Units)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal (man-years)								
• Detailed Res. Eng. and Cost Studies	(5)	3					3	(8)
• Size, Continuity and Content of Geopressured Sources	(5)	5	3				8	(13)
• Basic Geologic Support	(1)	3	2	1	1	1	8	(9)
• Laboratory Support	(3)	2	3	3			8	(11)
2. Improved Diagnostic Tools and Methods (man-years)								
• Well Completions		2	5	5	2	2	16	(16)
• Stripping		2	5	5	1	1	14	(14)
3. Field-Based Research, Development, and Demonstration (tests)								
• Test Wells		2	2	2	2	2	10	(10)
• Demonstration	(1)		1		1		2	(3)
4. Technology Transfer (man-years)			1	1	1	2	5	(5)

prospects such as the Upper Cretaceous, Tuscaloosa sands of central Louisiana, but would not be committed until advanced study of the first set is well underway.

Assuming favorable response from the test wells, two major demonstrations, in addition to the one in FY 78, should be sufficient to prove the potential.

6. R&D Costs

The research, development, and demonstration costs have been estimated from the following:

- A fully supported professional man-year costs $100,000.
- A test well costs $4,000,000 to drill, complete, and test.
- A demonstration project, requiring the test well to operate over a longer period of time, will cost $5,000,000.

These costs are displayed in Exhibit 2. All costs of this program will be borne by ERDA.

EXHIBIT 2

TOTAL PROGRAM AND ERDA COSTS

TARGET: Methane From Geopressured Aquifers

R&D ACTIVITIES (Thousands of Dollars)

Strategy Elements	(FY 78)	FY 79	FY 80	FY 81	FY 82	FY 83	5-Year Total	(Strategy Total)
1. Resource Characterization and Appraisal								
• Detailed Res. Eng. and Cost Studies	(500)	300					300	(800)
• Size, Continuity and Content of Geopressured Sources	(500)	500	300				800	(1,300)
• Basic Geologic Support	(100)	300	200	100	100	100	800	(900)
• Laboratory Support	(300)	200	300	300			800	(1,100)
SUBTOTAL	(1,400)	1,300	800	400	100	100	2,700	(4,100)
2. Improved Diagnostic Tools and Methods								
• Well Completions		200	500	500	200	200	1,600	(1,600)
• Stripping		200	500	500	100	100	1,400	(1,400)
SUBTOTAL		400	1,000	1,000	300	300	3,000	(3,000)
3. Field-Based Research, Development, and Demonstration								
• Test Wells		4,000	4,000	4,000	4,000	4,000	20,000	(20,000)
• Demonstration	(5,000)		5,000		5,000		10,000	(15,000)
SUBTOTAL	(5,000)	4,000	9,000	4,000	9,000	4,000	30,000	(35,000)
4. Technology Transfer								
			100	100	100	200	500	(500)
TOTAL AND ERDA COST:	(6,400)	5,700	10,900	5,500	9,500	4,600	36,200	(42,600)

7. Production Benefits

The anticipated production benefits from a successful research and development program for Geopressured Aquifers (at \$3.00 and \$4.50 per Mcf) are:

	Base Case	After Successful R&D (@\$3.00/Mcf)	After Successful R&D (@\$4.50/Mcf)	Due to R&D (@\$3.00/Mcf)	Due to R&D (@\$4.50/Mcf)
• Ultimate Recovery	-	1	5	1	5
• Production Rate in:					
1985	-	Not Available		Not Available	
1990	-				
1995	-				
2000	-				
• Cumulative Production by:					
1985	-	Not Available		Not Available	
1990	-				
1995	-				
2000	-				

8. Benefits and Costs

The key cost-effectiveness measures for producing methane from Geopressured Aquifers (at \$3.00 and \$4.50 per Mcf) are:

Cost-Effectiveness Measures	Value (Mcf/\$) (@ \$3.00/Mcf)	Value (Mcf/\$) (@ \$4.50/Mcf)
• Long Term Measure: Ultimate Recovery/ERDA 5-Year Costs	30	140